ORDER NO. 25-500

ENTERED Dec 09 2025

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1893

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation Into the Methodology and Process for Developing Avoided Costs Used in Energy Efficiency Cost-Effectiveness Tests.	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED

At its public meeting on December 9, 2025, the Public Utility Commission of Oregon adopted Staff's recommendation in this matter. The Staff Report with the recommendation is attached as Appendix A.

BY THE COMMISSION:

Alison Lackey
Chief Administrative Law Judge

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Circuit Court for Marion County in compliance with ORS 183.484.

ITEM NO. RA1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: December 9, 2025

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** ____N/A____

DATE: December 1, 2025

TO: Public Utility Commission

FROM: Peter Kernan

THROUGH: Caroline Moore and Sarah Hall **SIGNED**

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF:
(Docket No. UM 1893)
Request for approval of energy efficiency avoided cost data to be used by Energy Trust of Oregon.

STAFF RECOMMENDATION:

Approve the energy efficiency avoided cost data in Attachments A and B for use by Energy Trust in 2027 planning.

For Northwest Natural, approve the inclusion of geographically specific avoided costs.

For Portland General Electric, adopt the avoided cost of capacity values calculated using Staff's marginal avoided cost resource approach.

DISCUSSION:

Issue

Whether to approve the attached energy efficiency avoided cost data, including: geographically specific avoided costs for Northwest Natural, for use by Energy Trust.

In addition, decide whether to adopt Staff's proposed avoided cost of capacity at $438/kW-yr or, alternatively, adopt PGE's proposed avoided cost of capacity of $284/kW-yr.

Applicable Rule or Law

OAR 860-030-0011(1) requires an energy utility to submit its data for calculation of energy efficiency avoided costs in the manner and method specified in a Commission-approved reporting form. The form must be submitted by October 15 of each year for use in the next energy efficiency program budget cycle.
Under OAR 860-030-0011(2), the Commission may approve, at its discretion, the use of data more recent than data used in the utility's last acknowledged Integrated Resource Plan (IRP) or general rate case in which the Commission has issued a final order.

OAR 860-030-0013 prohibits Energy Trust from using utility-specific energy efficiency avoided cost data until it has been approved by the Commission. The Commission generally considers energy efficiency avoided cost data for approval within 60 days of submission.

<u>Background</u>

Analysis
Utilities file annual updates to their energy efficiency avoided cost rates for use in Energy Trust planning in Docket No. UM 1893 using a Commission approved reporting form. Since 2023, Staff and stakeholders have used Docket No. UM 1893 to investigate changes to the methodology and data to determine energy efficiency avoided costs. The need for changes was driven by Integrated Resource Plan (IRP) results considering the policies of House Bill 2021 compliance for electric utilities and Climate Protection Program compliance for gas utilities. For reference, energy efficiency avoided cost data was last updated in January 2025 with Order No. 25-017, which approved an electric avoided costs increase of 7.9 percent and a gas avoided cost decrease of 5 percent.[1]

In 2024, substantive changes were made to electric avoided cost methodology after the Commission adopted Staff's Recommendation 4 in the acknowledgement Order for Portland General Electric's (PGE) 2023 IRP and Clean Energy Plan (CEP):

> Direct PGE to work with Staff to propose a new method for calculating avoided costs in Docket No. UM 1893. The avoided cost proposal should resolve the shortcomings identified by PGE and Staff, including but not limited to the shift from one avoided capacity value to annual values, the impact of constraints observed in the model, and the need to procure clean electricity not captured by forward market prices.[2]

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1 *See* Docket No. UM 1893, Order No. 25-017, (Jan. 21, 2025), https://apps.puc.state.or.us/orders/2025ords/25-017.pdf.

2 *See* Docket No. LC 80, *Staff Report for Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan,* (December 14, 2024), p. 18, https://edocs.puc.state.or.us/efdocs/HAU/lc80hau325590032.pdf.

PGE and Staff worked together to consider methodological changes, which resulted in PGE providing a proposal detailing requisite changes to align energy efficiency avoided costs with long-term planning on June 3, 2024.[3]

In this memo, Staff first presents a summary of activities since the last Staff Report.[4] The memo then presents Staff's recommendations regarding data for use by Energy Trust for electric and gas utilities, including review of avoided capacity options to inform a Commission decision. The third section of the memo summarizes the results of Energy Trust's analysis regarding overall impacts of using the recommended energy efficiency avoided costs data.

Energy Trust analyzed the avoided costs data and prepared annual reports for Staff review and consideration by the Commission. Attachment A is the *Final 2027 Electric Avoided Cost Update Summary* and Attachment B is the *Final 2027 Gas Avoided Cost Update Summary.* Additionally, Staff prepared Attachment C to summarize the recommended data for electric and gas avoided costs. Attachment C does not include all data submitted by utilities, which are submitted via utility-specific dockets online.[5]

Section I: Summary of Activities

In 2024-2025, Staff led a public process with stakeholders and utilities to update avoided costs, concluding with the Commission's Order 25-017. Staff's corresponding memo recommended adoption of utility-submitted capacity values but noted that neither electric utility submission fully met the spirit of an annually changing marginal capacity resource as identified in utility preferred portfolios. Staff illustrated its alternative proposal for awareness.

In the summer of 2025, after presenting the Staff proposal for avoided capacity in response to PGE's 2025-2026 Flexible Load Multiyear Plan,[6] Staff hosted a workshop on July 21, 2025. Staff referenced the most-recently available IRP modeling results and utilities' previously submitted avoided cost data and used the workshop to socialize its proposal for calculation of avoided capacity.[7]

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3 *See* Docket No. UM 1893, *PGE's Phase II Slides,* (June 3, 2024), https://edocs.puc.state.or.us/efdocs/HAH/um1893hah329014025.pdf.

4 Order No. 25-017, (January 21, 2025).

5 Utilities submit data in utility-specific dockets as follows: Avista RG 85; CNG RG 86; NWN RG 87; PacifiCorp RE 181; PGE RE 182.

6 *See* Docket No. UM 2141, *Staff Comments on PGE's Flexible Load Cost-Effectiveness Proposals,* (March 10, 2025), pp. 2-4, https://edocs.puc.state.or.us/efdocs/HAC/um2141hac335353115.pdf.

7 *See* Docket No. UM 1893, *Final slide deck for the July 21, 2025 Workshop,* (July 24, 2025), pp. 32-38, https://edocs.puc.state.or.us/efdocs/HAH/um1893hah338503035.pdf.

As part of the July workshop, three utilities shared presentations about potential avoided cost impacts from their most recent IRP modeling.

- NW Natural presented a proposal for inclusion of an emissions compliance risk reduction value that the Company included as part of its 2025 IRP.
- PGE focused on winter reliability constraints and the limitations of using four-hour batteries alone for providing sufficient capacity for extended duration winter reliability events. As it relates to selecting an avoided capacity resource, PGE proposed a blended net cost of capacity approach, rather than using a specific resource that was selected in the most recently acknowledged IRP. The blended net cost of capacity approach is calculated by the weighted average of the capacity contribution and costs of all resources added in the IRP prior to 2030.
- Pacific Power discussed the Oregon energy efficiency selections from the 2025 IRP and key drivers for selection.

On August 14, 2025, Staff published an update to UM 1893 that clarified guidance for upcoming utility data submissions and updates to the data templates in the areas of avoided capacity, transmission expansion, and an emissions compliance risk reduction value for gas utilities. On November 6, 2025, Staff and Energy Trust hosted a workshop to review the utilities' October 2025 data submissions.[8] Staff made an updated proposal which aligned with its earlier recommendations and presented a different avoided capacity cost than submitted by PGE and Pacific Power. Staff solicited stakeholder comments through a deadline of November 21, 2025. Staff received four comments and highlights those in relevant sections of this memo.

Section II: Data Recommendations
The utilities populated the updated UM 1893 templates using data from recently published IRPs or IRP Updates and other dockets such as recent general rate cases. Utilities used the alternate tabs of the workbook to submit other data for consideration. In situations where utilities provided alternate sets of data, Staff reviewed whether the data were reasonable.

Staff recommends using the most recent utility data when available and reasonable for use by Energy Trust. In a narrow set of cases, Staff also proposes a different approach than what has been submitted by the utilities. Staff's data recommendations are below, organized by fuel and avoided cost component.

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8 *See* Docket No. UM 1893, *Staff's Presentation for the November 6, 2025 Workshop*, (Nov. 4, 2025), https://edocs.puc.state.or.us/efdocs/HAH/um1893hah341449028.pdf.

Electric Utility Data Recommendations
A complete overview of electric avoided costs can be found in Attachment A, Energy Trust's *Final 2027 Electric Avoided Cost Update Summary,* including updates to electric cost categories receiving more routine updates. Staff makes the following three main recommendations for electric avoided costs:

1. **Energy**: Staff recommends adoption of PacifiCorp's alternate avoided energy submission. Staff also recommends adoption of PGE's forward market prices for 2027-2029 and avoided energy starting in 2030.
2. **Capacity**: Staff presents its primary proposal for Commission consideration but notes that PGE's proposal is a reasonable alternative if the Commission seeks to further emphasize cost containment.[9]
3. **Transmission Expansion**: Staff recommends adoption of utility-submitted values.

<u>Avoided Energy Costs</u>
Utilities submit two data streams to reflect what marginal energy costs are expected to be during the IRP planning horizon. The first energy forecast is forward prices using the PacifiCorp Official Forward Price Curve (OFPC) format. The second form of avoided energy costs is titled "avoided energy" or also referred to as "avoided build costs." Avoided energy values reflect costs of marginal energy resource procurement identified in IRPs. Staff solicits two different streams of avoided energy values, and makes recommendations for use of one or the other during specific time periods.

PacifiCorp submitted four variations on its avoided energy analysis, two OFPC options and two tax credit treatment options. The primary submission reflects the OFPC used in the Company's 2025 IRP, dated September 2024. The alternative OFPC is dated September 30, 2025, and represents PacifiCorp's most recent data.

To determine an avoided energy premium, PacifiCorp's analysis reviewed which resources were allocated to Oregon in the 2025 IRP and created a marginal resource incremental cost based on those additions. In the workbook, PacifiCorp adds this incremental "clean energy net cost" to all monthly-hourly prices starting in 2030, to reflect the binding compliance timing of HB 2021. The Company provided two net cost scenarios, one with the inclusion of federal tax credits and one without.[10] PacifiCorp recommends using the most recent OFPC and the clean energy net cost adder without federal tax credits. This is referred to as PacifiCorp's alternate avoided energy

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9 PGE submitted two avoided capacity options which will be discussed below.
10 The inclusion of values with and without tax credits reflects the planning environment when the Company filed it's 2025 IRP versus after the July 2025 passage of the One Big Beautiful Bill which accelerated the removal of tax credits for wind and solar.

submission. Staff agrees and Energy Trust used those values for its analysis in Attachment A.

PGE submitted its OFPC with operational Mid-C price curves dated September 30, 2025, for the three-year period of 2026-2028. Years 2030-2043 reflect the long-term Aurora forecast from PGE's 2023 IRP Update, with 2029 as an interpolation year per the OFPC format. For the avoided energy submission, PGE determined the marginal energy resource by identifying the most expensive levelized cost of electricity (LCOE) resource built in each year in PGE's 2023 IRP Update preferred portfolio. To create average monthly hourly values (12x24), PGE used the levelized annual cost and shaped values using the hourly pricing forecast from PGE's 2023 IRP Update's Aurora model. PGE provided avoided energy values on a net cost basis removing capacity and transmission expansion costs.

Consistent with Order No. 25-017, Staff recommends the use of PGE's forward prices for 2027 through 2029, then switching to the avoided energy submission starting in 2030. Staff notes that this is consistent with PacifiCorp's submission, which does not apply the clean energy net cost adder until 2030, meaning near-term costs are forward prices. In addition, PGE's marginal avoided energy resources in the near term are lower cost than the market, indicating that acquiring new resources costs less than meeting need through market purchases. Such an example occurred when PGE's Clearwater Wind Project was added to customer rates and had the effect of decreasing residential bills 0.7 percent.[11]

The most notable change to avoided energy costs is the removal of the transmission expansion credit. In the previous round of avoided costs, both PGE and PacifiCorp embedded the transmission expansion credit within the avoided energy costs, and thus all charts demonstrating the value of avoided energy also included the value of avoided transmission expansion. In this cycle, utilities provided net energy costs, so that each component could be considered independently.[12] Figure 1 clearly illustrates the change.

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11 *See* Advice No. 25-07, *Schedule 122, Renewable Resource Automatic Adjustment Clause,* Docket No. UE 427, (Feb 26, 2025), https://edocs.puc.state.or.us/efdocs/UHR/ue427uhr335154026.pdf.

12 Staff notes that while the transmission expansion credit was discussed and its magnitude quantified as a separate element in 2026 avoided costs, it was only included in calculations as part of the avoided energy cost. Thus, transmission expansion was not double counted in modeling.

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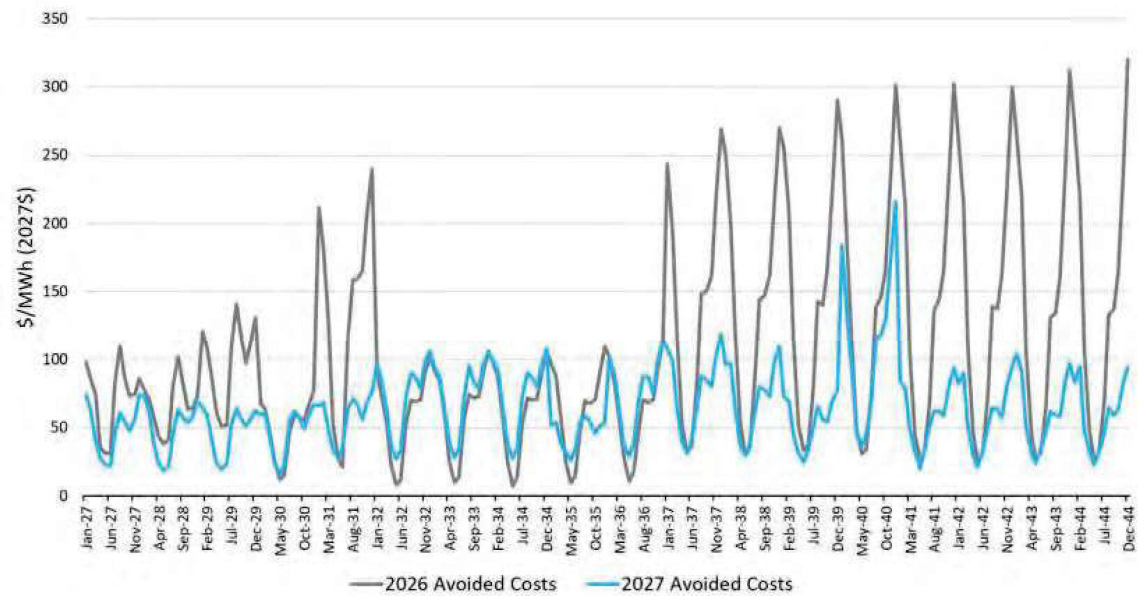
Figure 1: Weighted Average Energy Value Comparison



In addition to the netting of transmission expansion credit value, PGE and PacifiCorp's avoided energy submissions have opposing impacts. PacifiCorp's avoided energy values increase by 45 percent, driven by changes to the avoided energy methodology, to reflect the marginal clean energy additions in the IRP. PacifiCorp's removal of tax credit value also contributed to the Company's higher forecast. PGE's avoided energy values decreased 45 percent even after removing the transmission expansion credit from 2026 values. This was driven by additional netting of capacity value from energy fixed costs.

<u>Capacity Deferral Value</u>
Utilities provide capacity avoided costs in $/kW-yr to reflect the cost of generation capacity to the utility's system. Staff presents two avoided capacity options for the Commission's consideration.

PacifiCorp's submission results in a net cost of capacity of $146/kW-yr and is based on four-hour batteries as the marginal resource from 2027-2034. After 2035, PacifiCorp selects a proxy simple cycle combustion turbine (SCCT) for marginal capacity. After meeting with the Company, Staff understands that PacifiCorp's use of an SCCT for capacity relies upon carbon free fuels such as renewable natural gas, such that the submission remains HB 2021 compliant.

PGE submitted a portfolio-blended net avoided capacity cost of $284/kW-yr. To derive the value, the Company calculated a weighted average of all resources selected in the preferred portfolio and anticipated to come online between now and 2030. The blended value reflects the weighted costs and effective load carrying capabilities (ELCC) of the underlying resources.

Avoided Capacity Recommendation and Alternative Option
PacifiCorp's 2026 value was $46/kW-yr and PGE's was $146/kW-yr, which were significant decreases from prior values of $105/kW-yr and $228/kW-yr respectively. Staff finds that PGE and PacifiCorp's submissions both made progress on resolving issues identified with 2026 avoided costs.

In the Staff report supporting Order No. 25-017, Staff raised several primary concerns about the data which resulted in large decreases. First, utilities indicated four-hour batteries as the marginal capacity resource in each year of the planning horizon despite the IRP selecting more expensive capacity in some years. Second, Staff found dated fixed cost assumptions that did not reflect more recent bid data or inflation. Staff also noted that ELCC assumptions varied significantly between the companies and even among vintages of reporting within each company.

Despite documenting such issues and discussing them with the utilities, Staff ultimately recommended adoption of utility-submitted values. Staff discovered the discrepancies too late in the process without sufficient time to develop and share an alternative with stakeholders and utilities. As discussed in Section I, Staff has shared its thinking for annual, marginal avoided costs in multiple venues over the course of 2025.

Staff's current proposal builds on last year's findings and references each utility's most recent IRP modeling to identify the marginal capacity resource. Both PGE and PacifiCorp IRP rely on four-hour batteries in the near term. In 2030, PacifiCorp's model selects 100-hour iron air batteries as a more expensive form of capacity. In 2040, PGE's model selects pumped hydro as a more expensive capacity resource.[13]

In reviewing the avoided costs with PacifiCorp, the Company helped make minor tweaks to its initial submission to reflect Staff's observations. Staff's proposal for PacifiCorp's avoided capacity differs by switching to a more expensive capacity resource sooner, in 2030 versus 2035. Additionally, Staff suggested the IRP results as published in the 2025 Oregon Clean Energy Plan were better aligned with the 100-hour iron air battery than a SCCT with renewable fuel.[14] Staff's proposed capacity value for

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[13] LC 80 PGE Response to OPUC DR 242.
[14] *See* Docket No. LC 85, *PacifiCorp 2025 Oregon Clean Energy Plan,* (June 30, 2025), p. 74, https://edocs.puc.state.or.us/efdocs/HAQ/lc85haq337820115.pdf.

PacifiCorp is $169/kW-yr. Staff shared its proposal with PacifiCorp, and the Company helped ensure its accuracy.

After review, Staff's proposed changes for PGE are more substantive. PGE's blended capacity resource does align with the guidance of either an annual resource or a marginal resource, but is designed to address emerging findings in development of its 2023 IRP Update and 2026 IRP. These more recent IRP analyses indicate that the value of 4-hours batteries in addressing winter reliability events is likely to diminish earlier in the planning horizon, after which PGE's updated IRP analysis selects pumped hydro. The capacity cost of pumped hydro is meaningfully higher that 4-hour batteries, which results in a higher avoided capacity value for energy efficiency over the Energy Trust planning horizon. This led PGE to propose an alternative methodology that mitigates the impact of pumped hydro on the avoided capacity cost.

Table 1 compares the Staff proposed avoided resource approach to PGE's net cost of capacity data for modeled resources data the Company provided in PGE's 2023 IRP Update.[15] Staff applied those data using the same values and netting calculations as present in PGE's workpaper and shared the proposal with the Company prior to the November workshop. The result is a levelized avoided capacity cost of $438/kW-yr shown in Table 1.

Table 1: Staff Proposal for PGE's Avoided Capacity

Year	Resource	Fixed Cost	Tax Credit	Energy	Flex	ELCC	Net Cost in 2025$
2027	4-hour Battery	$205	($51)	($11)	($15)	32%	$399
2028	4-hour Battery	$205	($51)	($11)	($15)	32%	$399
2029	4-hour Battery	$205	($51)	($11)	($15)	32%	$399
2030	4-hour Battery	$190	($48)	($10)	($20)	32%	$354
2031	4-hour Battery	$190	($48)	($10)	($20)	32%	$354
2032	4-hour Battery	$184	($46)	($10)	($20)	32%	$338
2033	4-hour Battery	$184	($46)	($10)	($20)	32%	$338
2034	4-hour Battery	$184	($46)	($10)	($20)	32%	$338
2035	4-hour Battery	$184	($46)	($10)	($20)	32%	$338
2036	4-hour Battery	$184		($10)	($20)	32%	$482
2037	4-hour Battery	$184		($10)	($20)	32%	$482
2038	4-hour Battery	$184		($10)	($20)	32%	$482
2039	4-hour Battery	$184		($10)	($20)	32%	$482
2040	Pumped Hydro	$349		($18)	($17)	52%	$604

15 LC 80 PGE Response to OPUC DR 240.

Year	Resource	Fixed Cost	Tax Credit	Energy	Flex	ELCC	Net Cost in 2025$
2041	Pumped Hydro	$349		($18)	($17)	52%	$604
2042	Pumped Hydro	$349		($18)	($17)	52%	$604
2043	Pumped Hydro	$349		($18)	($17)	52%	$604
2044	Pumped Hydro	$349		($18)	($17)	52%	$604
2045	Pumped Hydro	$349		($18)	($17)	52%	$604
						Levelized net cost	**$438**

Staff is aware that the avoided capacity cost magnitude of $438/kW-yr is substantially higher than prior values, including PGE's $228/kW-yr value used for 2025 avoided costs. However, Staff believes it is directionally consistent with PGE's modeling results from both the 2023 IRP and the 2023 IRP Update. PGE's discussion of winter reliability in the 2023 IRP Update indicates that "short duration storage resources are effective at addressing PGE's summer capacity needs and inefficient at meeting winter capacity needs."[16] To illustrate the point, PGE shared that 1800 MW of four-hour batteries in the preferred portfolio are required to meet a 123 MW winter capacity need, equating to a 6.8 percent ELCC.[17] Since net costs are very sensitive to ELCC, such a low value would put large upward pressure on avoided capacity costs. A four-hour battery with the cost-profile in Table 1 for 2027 and a 6.8 percent ELCC, would have a net capacity cost of $1,882/kW-yr.

In response to Staff's proposal, PGE submitted comments on November 21, 2025, raising concerns about the drastic pace of increase, the impact to other dockets that rely on these values, and the real-world ability to procure such resources at stated costs. PGE also submitted an alternative proposal that produces a levelized avoided capacity cost of $252/kW-yr and identifies four-hour batteries as the avoided capacity cost from 2027-2029, and 100-hour iron, air batteries as the avoided capacity resource starting in 2030. While PGE did not model 100-hour batteries in its 2023 IRP Update, the Company notes that it did characterize the costs in that document and that application in UM 1893 would be consistent with PacifiCorp.

Staff notes the obvious concern that the application of a 100-hour battery in 2030 is inconsistent with PGE's modeling. PGE's model does not select a battery of longer than four-hour duration and only selects a pumped hydro resource in 2040. This differs from PacifiCorp, which did model a 100-hour battery that was selected in the preferred

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16 *See* Docket No. LC 80, *PGE's 2023 Clean Energy Plan and Integrated Resource Plan Update*, p. 154 (June 18, 2025), https://edocs.puc.state.or.us/efdocs/HAD/lc80had337596113.pdf.
17 2023 IRP/CEP Update, p. 154.

portfolio in 2030. Secondarily, Staff notes that ELCC values from PGE's alternate submission appear to come from Appendix K of the 2023 IRP, which does not reflect the updated modeling of the 2023 IRP Update, which, based on the winter reliability discussion, has potentially materially lower ELCC values. Finally, Staff raises PGE's magnitude concern in the opposite direction. Is PGE's alternate submission, with the lowest capacity avoided cost of the three options, the most reasonable given the uncertainty of suggesting a 100-hour battery is the marginal capacity resource starting in 2030?

Staff Recommendation: Ultimately, Staff's proposed methodology and the PGE alternative are reasonable options to navigate changing planning conditions. Staff's proposed approach adheres to established practices and is grounded in IRP analysis that has been vetted and acknowledged by the Commission. This option represents a steep 17.6 percent increase in overall avoided costs and emphasizes the role of energy efficiency as a least-regrets resource in a complex planning environment. On the other hand, PGE's proposal represents a moderate 3.9 increase in overall avoided costs, which emphasizes near-term cost containment and allows the Commission to adapt more quickly to evolving conditions and emerging 2026 IRP findings.

Staff believes the $438/kW-yr value best captures the planning need and risk as identified in PGE's 2023 IRP Update. The model continues to call for substantial volumes of on-system resources. A higher avoided capacity cost sends a more acute signal for resource procurement needs by both PGE and Energy Trust.

That said, Staff sees PGE's proposal as a reasonable alternative if the Commission seeks greater cost containment and adaptability to newer planning analyses. Adopting PGE's submission acknowledges that the Company's avoided capacity costs are increasing, yet allows for continued avoided capacity conversation in this docket and others. Staff notes that in addition to this docket, multiple planning venues will provide the Commission opportunities to contemplate avoided capacity including the PURPA investigation in Docket No. UM 2000 and PGE's 2026 IRP, in which the Company will model a 100-hour battery option. These proceedings will provide opportunities for parties to further explore these related issues.

Should the Commission adopt the PGE alternative, Staff believes there are substantive issues to continue improving upon next year, including greater review of ELCC given the impact to overall avoided capacity costs. While Staff focuses on the energy efficiency implications of PGE's modeling, Staff agrees that increases to avoided costs impact the findings and analyses for related dockets such as utility distributed energy resource offerings. The planning signal which applies to Energy Trust also applies to

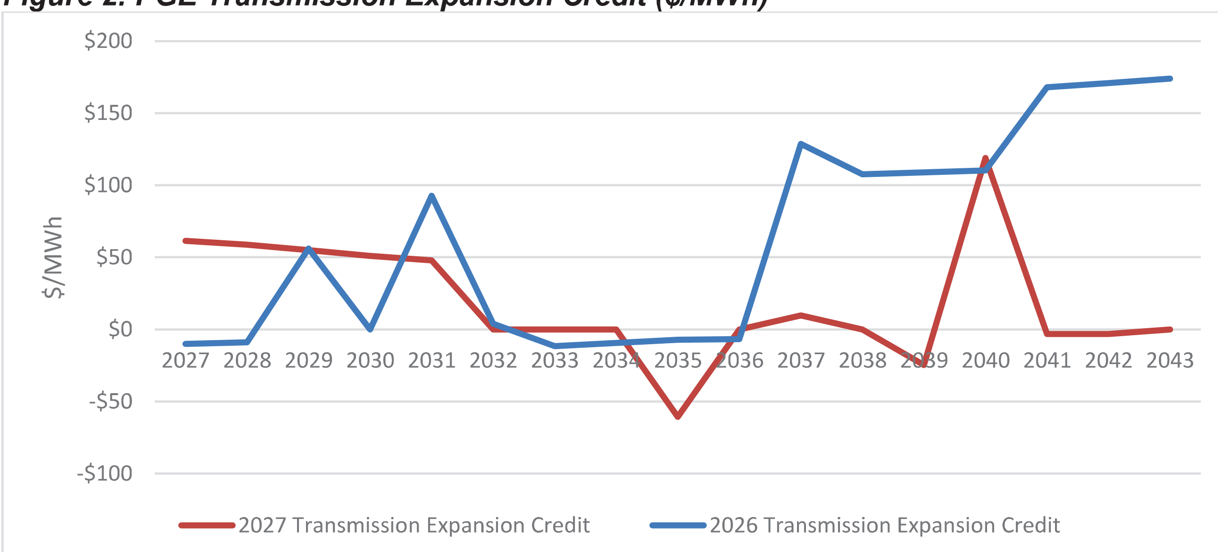
PGE's on-system resource procurement options including CBREs, flexible loads, and distributed generation and storage.

Transmission Expansion Credit

In response to Order No. 24-096, PGE submitted a proposal in UM 1893 to align Energy Trust's avoided costs with PGE's long-term planning from its IRP process. A core feature of PGE's proposal is the addition of a transmission expansion credit that is connected to the IRP preferred portfolio. The credit will be separate and additional to the existing transmission deferral credit.

PGE used the method of documenting a preferred portfolio LCOE with and without transmission constraints. The LCOE difference between the marginal resource with and without transmission constraints represents the value of the transmission expansion credit. Figure 2 shows the $/MWh value of PGE's transmission expansion credit from both this UM 1893 cycle and the prior submission.

Figure 2: PGE Transmission Expansion Credit ($/MWh)



Staff provides two observations. First, in certain years the value of the credit is negative, which raises concerns over why a transmission constrained portfolio would select less expensive resources than a model with no constraints. In last year's 2026 planning cycle, PGE attributed the differences to unrelated changes in the preferred portfolio between modeling runs. Similar to how negative risk reduction values are treated in avoided costs, negative transmission expansion credits in specific years were treated as zero.

Second, the magnitude of transmission costs remains substantial, despite concerns about the underlying analysis. Staff understands that PGE made notable progress on improving transmission modeling in the 2023 IRP Update, yet the difference between the two data submissions raises questions about why the avoided transmission costs largely disappear in the later planning years despite the stated resources being wind from North Dakota and offshore, and solar from Nevada. Each of those requires transmission build. Staff includes Table 2 to illustrate PGE's UM 1893 submission of resources which are selected with and without transmission constraints from the 2023 IRP Update.

Table 2: PGE's 2027 Transmission Expansion Credit

	With transmission constraints		*Without transmission constraints*		Transmission Expansion Credit ($/MWh)
Year	Marginal energy resource	Avoided cost of energy ($/MWh)	Marginal energy resource	Avoided cost of energy ($/MWh)	
2027	MCMN_Hyb_1	$38	Wind_MT	-$23	$61
2028	MCMN_Hyb_1	$38	Wind_MT	-$21	$59
2029	MCMN_Hyb_1	$38	Wind_MT	-$17	$55
2030	MCMN_Hyb_1	$36	Wind_MT	-$15	$51
2031	MCMN_Hyb_1	$33	Wind_MT	-$15	$48
2032	Wind_MT	$65	Wind_MT	$65	$0
2033	Wind_MT	$66	Wind_MT	$66	$0
2034	Wind_MT	$67	Wind_MT	$67	$0
2035	Wind_WY	$7	Wind_MT	$68	-$61
2036	Wind_MT	$69	Wind_MT	$69	$0
2037	Wind_Gorge	$78	Wind_MT	$68	$10
2038	Wind_MT	$67	Wind_MT	$67	$0
2039	Wind_ND	$32	Wind_Off	$57	-$25
2040	MCMN_Hyb_1	$175	Wind_Off	$56	$119
2041	Solar_NV	$52	Wind_Off	$55	-$3
2042	Solar_NV	$51	Wind_Off	$54	-$3
2043	Wind_Off	$53	Wind_Off	$53	$0

For discussion's sake, Staff reviewed a discovery request from PGE's 2023 IRP Update that documented transmission options selected in PGE's preferred portfolio. Staff shared these at the November 6, 2025 workshop for stakeholder awareness and to open dialogue around alternative methods to PGE's modeling with and without constraints.[18]

PacifiCorp provided anticipated transmission expansion costs from the 2025 IRP preferred portfolio and generated a net cost of transmission on a capacity basis ($/kW-yr). The Company attached a workpaper to the UM 1893 data template to document its analysis which included an allocation for how many MW of interconnection support Oregon customers, the annualized build cost, and a net adjustment to remove the portion of costs shared by third parties as part of its transmission tariff.
Staff recommends use of utility data as submitted. Energy Trust applies the transmission expansion value as non-duplicated avoided costs in the format provided by utilities. For PGE, as an energy avoided cost, and for PacifiCorp as a capacity avoided cost and allocated based on the Company's loss of load probability (LOLP).

Loss of Load Probability

Utilities produce LOLP heatmaps that allocate the LOLP to a 12x24 grid of hours within each month. Energy Trust uses LOLPs to allocate capacity avoided costs to hours of higher risk. Efficiency measures with higher savings coincidence with higher risk periods are allocated more value. This sends a planning signal on which measures are valuable to utility systems.

PGE and PacifiCorp each submitted revised LOLP heatmaps based on respective recent IRP modeling. Both submissions identify a marked shift away from summer risk and toward winter risk. PGE submitted an LOLP that showed 19 percent of the 2030 loss of load risk in summer hours, with the other 81 percent in winter. Previously the risk was 48 percent summer and 52 percent winter. PacifiCorp's newest LOLP heatmap decreases the summer risk from 83 percent to 59 percent and increases the winter risk by the reciprocals, up from 17 percent to 41 percent. The impact of this change is that more value gets allocated to resources which have coincident savings with the elevated winter risk.

Remaining Electric Avoided Cost Values

Staff recommends accepting the remaining electric avoided costs values as submitted by utilities. These include the risk reduction value, transmission deferral credit, and distribution deferral credit. Staff notes that there were minimal changes to transmission loss assumptions (2.71 percent) and distribution loss assumptions (2.51 to 4.32 percent based on sector).

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[18] *See* Docket No. UM 1893, *November 6, 2025 Workshop Slides*, (Nov. 4, 2025), https://edocs.puc.state.or.us/efdocs/HAH/um1893hah341449028.pdf.

There were minor changes to the inflation rate, discount rate, and risk reduction value. The transmission deferral credit which reflects deferring on-system transmission investments decreased by 4.2 percent. The distribution deferral credit increased by 28.2 percent. Both changes were due to revised data from PacifiCorp. PGE's distribution and transmission values remained unchanged. Values presented in Table 3 are weighted averages from both PGE and PacifiCorp and are recommended for Commission adoption.

Table 3: Summary of Revenue Weighted Electric Avoided Cost Changes[19]

	Final Blended Value for 2026 Avoided Costs (2027$)	Blended Value for 2027 Avoided Costs (2027$)	Percent Change in Component
Inflation Rate	2.13%	2.10%	-1.2%
Real Discount Rate	4.40%	4.30%	2.3%
Regional Act Credit	10.00%	10.00%	0.0%
Transmission Deferral Credit	$23.21	$22.24	-4.2%
Distribution Deferral Credit	$8.73	$11.20	28.2%
Risk Reduction Value	$2.89	$2.83	-2.0%

Gas Utility Data Recommendations
A complete overview of gas avoided costs can be found in Attachment B, Energy Trust's *Final 2027 Gas Avoided Cost Update Summary,* including updates to gas cost categories receiving more routine updates. In the section below, Staff highlights notable recommendations for gas avoided costs.

<u>Commodity and Transport Costs</u>
Each gas utility provided recent commodity and transport costs that are 17 percent lower than forecasts adopted in 2026 avoided costs. For NW Natural and Avista, the most current forecast is from the 2025 IRP. Cascade Natural Gas (CNG) provided forecasts from both the 2023 IRP Update and a more recent forecast dated October 1, 2025. Staff recommends adoption of the more recent submissions from each of the three gas utilities where variations exist.

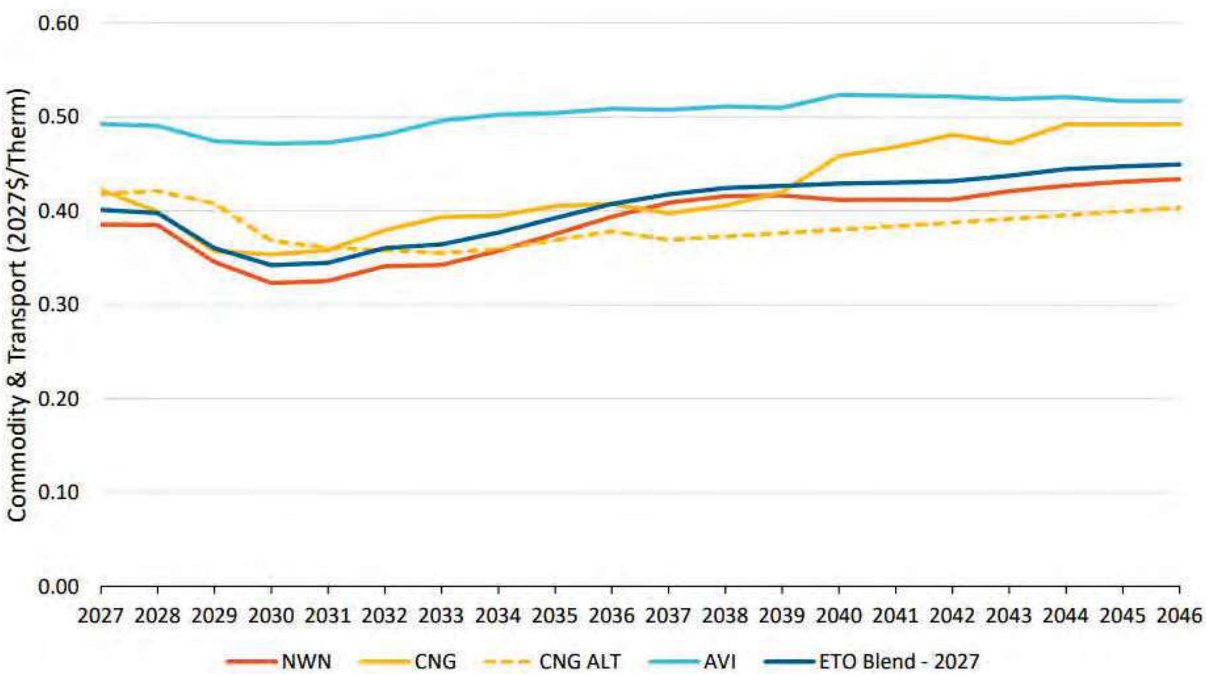
All three forecasts for commodity and transport costs depict a uniform view of near term costs moderating and longer term costs rising modestly. Avista's costs are roughly 25 percent higher than CNG and NW Natural, which the Company attributes to inclusion

[19] *See* Energy Trust's *Final 2027 Electric Avoided Cost Update Summary*, included as Attachment A.

of higher cost gas resources such as renewable natural gas in the commodity cost forecast.

In written comments, NW Natural questioned Avista's higher gas commodity and transport costs as higher than other utilities. Staff agrees with NW Natural that this should be an issue to explore in future UM 1893 proceedings to ensure that avoided costs are not double-counting CPP compliance costs.
The range of submissions can be seen in Figure 3, which comes from Energy Trust's *Final 2027 Gas Avoided Cost Update Summary* (Attachment B).

Figure 3: Gas Commodity and Transport Costs ($/therm)



Carbon Compliance Costs

In prior avoided cost cycles, the Commission adopted gas carbon compliance costs valued at the cost of Community Climate Investment (CCI) credit amounts found in Table 6 of the Division 273 rules.[20] Staff made this recommendation amidst uncertainty

[20] OAR 340-273-9000, Table 6. CCI credit contribution amount, (Nov. 21, 2024), https://ormswd2.synergydcs.com/HPRMWebDrawer/Record/6828109/File/document.

of the Climate Protection Program (CPP) 2024 rules after the Oregon Court of Appeals issued an opinion deeming the initial CPP rules invalid in December 2023.[21]

Now that each gas utility has completed IRP modeling after the adoption of CPP 2024 rules, Staff recommends use of compliance avoided costs based on the marginal compliance resources and costs as identified by each company. Since gas companies do not anticipate having enough compliance instruments to rely on CCIs alone, utilities must use more expensive resources. Gas utilities identify multiple resources including renewable thermal certificates and various renewable natural gases such as landfill gas, wastewater gas, and methane syngas from biomass. The use of marginal CPP compliance resources instead of CCIs results in a large, 126 percent avoided compliance cost increase.

CNG provided corrected carbon compliance values to Staff over email, filed those values in Docket No. RG 86, and submitted a letter in UM 1893 acknowledging the change. CNG submitted two carbon compliance values in its initial, RG 86 submission. The primary submission was based on the 2023 IRP, and an alternative submission was submitted to reflect updated carbon compliance costs. Energy Trust used the corrected values in its final analysis for Commission approval, as those values represent the most recent avoided costs under CPP 2024.

<u>Infrastructure Avoided Costs</u>

The most substantive change is to the supply capacity avoided costs, a 53 percent reduction from 2026 values. NWN updated its prior IRP analysis to the 2025 IRP, which included a higher near-term avoided cost, and a zeroing out after 2033. Staff confirmed with the Company that the result was due to the identification of no supply capacity expansion needs after 2033 as system peak day loads start to decline in 2034 until the end of the planning horizon. Distribution capacity avoided costs had a more modest, seven percent decline.

In written comments, NW Natural asked how Energy Trust calculates its “70-year average blended distribution capacity value by loadshape,” as presented at the November 6, 2025 workshop. Energy Trust responded that the table’s title, referring to a 70-year average, was an error from prior analyses. The underlying calculation, based on utility-submitted values, created a net present value for only as many years as there were data.

[21] *See* NW Natural Gas Company v. Environmental Quality Commission, Oregon Court of Appeals, A178246, Opinion, https://ojd.contentdm.oclc.org/digital/pdf.js/web/viewer.html?file=/digital/api/collection/p17027coll5/id/35371/download#page=1&zoom=auto.

Remaining Gas Avoided Costs
A summary of the gas avoided costs changes can be seen in Table 4 below. Energy Trust used updated peak day and peak hour coincidence factors which vary by end-use load shape. Current data come from NWN's 2025 IRP and the Northwest Power and Conservation Council.

Table 4: Summary of Revenue Weighted Gas Avoided Cost Changes [22]

Avoided Cost Component	2026 AC Blended Value	2027 AC (Updated) Blended Value	Percent Change
Inflation rate	2.46%	2.51%	2%
Real Discount rate	4.40%	4.30%	-2%
Regional Act Credit	10%	10%	0%
20-year Levelized Value (2027$/therm)			
Commodity and Transport Prices	$0.48	$0.40	-17%
Distribution Capacity	$241.42	$224.03	-7%
Supply Capacity	$5.39	$2.55	-53%
CO2 Compliance	$0.79	$1.79	126%
CO2 Compliance Risk Reduction	$0.00	$0.41	N/A
Risk Reduction	$0.13	$0.11	-10%

Northwest Natural Location-specific Avoided Costs
NW Natural submitted additional data in RG 87 to be used for planning in collaborative geographically targeted energy efficiency (GeoTEE) programs with Energy Trust. NW Natural's near-term action plan in the 2025 IRP proposes action items to plan and develop GeoTEE offerings to achieve localized peak hour therm savings.[23] To start planning prior to a Commission decision on acknowledgement, NW Natural submitted avoided distribution peak hour avoided costs for the Dallas and McMinville portions of the Company's territory. These regions carry a higher avoided cost due to known capacity expansion projects that would be necessary but for intervention. These avoided costs are about 27 percent higher than NW Natural's system-wide avoided costs. Staff recommends the Commission adopt these higher values so that NW Natural and Energy Trust can plan for implementation.

22 *See* Energy Trust's *Final 2026 Gas Avoided Cost Update Summary*, included as Attachment B.
23 *See* Docket No. LC 86, *NW Natural, 2025 Integrated Resource Plan*, (August 1, 2025), p. 13-18, https://edocs.puc.state.or.us/efdocs/HAA/lc86haa338770056.pdf.

Section III: Results of Recommended Avoided Costs Updates

Energy Trust applied Staff's proposed data recommendations in this memo to produce high-level estimates on impacts to 2027 avoided costs.

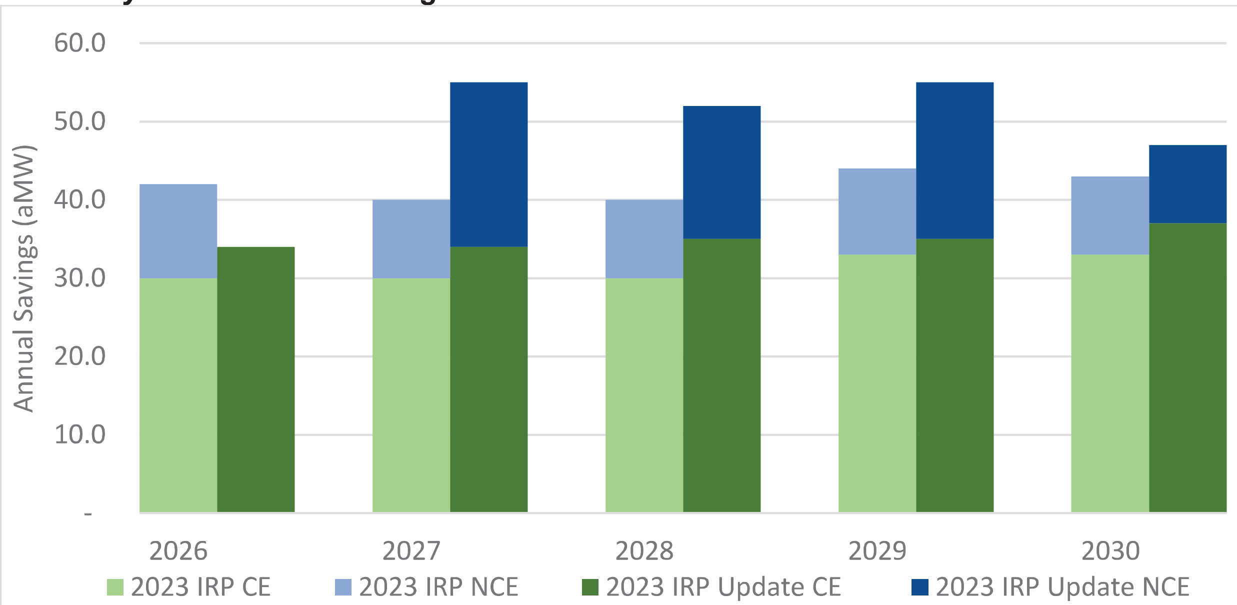
Electric Avoided Costs

Electric avoided costs are projected to increase by either 3.9 percent or 17.6 percent compared to values used for 2026 depending on which avoided capacity value the Commission adopts. The increase reflects the net movements of avoided costs, most notably a reduction in avoided energy and increase to avoided capacity.

PGE provided comments on November 21, 2025, that requested additional review of UM 1893 methodology and process. A part of that request, PGE provided some policy implications related to how avoided costs are used and a specific request to have both a public workshop and a separate working session with Staff. With respect to specific avoided costs in the cycle, PGE noted that methodological review could address avoided capacity cost and ELCC, the transmission expansion credit, and the use of alternative data provided in the UM 1893 template. Staff supports future initiatives to keep aligning avoided costs with IRP planning, including workshops and working sessions.

In terms of the policy choice for the Commission, PGE's IRP modeling continues to show on-system resources are cost-effective and necessary in the near term. Figure 5 compares how much cost-effective energy efficiency was planned for by Energy Trust with how much additional "non-cost-effective" energy efficiency was competed in PGE's model and subsequently selected in the preferred portfolio. The selection of non-cost-effective energy efficiency in the preferred portfolio means the selected efficiency becomes cost-effective despite the misnomer. A higher overall avoided cost is better aligned with PGE's IRP selection of more-expensive efficiency than is supported by current avoided costs.

Figure 4: Comparison of Cost-effective (CE) and Non-cost-effective (NCE) Energy Efficiency in PGE IRP Modeling



Gas Avoided Costs
Gas avoided costs are projected to increase by 61 percent compared to 2026 avoided costs. The increase is attributable to higher emissions compliance avoided costs and the associated risk reduction. Commodity cost forecasts, commodity risk reduction, and supply and distribution capacity all decreased in this cycle. Notably, NW Natural's supply capacity avoided cost reduces to zero after 2033, as IRP modeling shows system peak day loads start to decline in 2034 through the end of the planning horizon.

Green Energy Institute (GEI) highlighted that significant CPP compliance costs are driving up gas avoided costs. GEI then raised the concern that under the current, single-fuel cost effectiveness and planning framework used by Energy Trust, the elevated gas avoided costs might send a planning signal inconsistent with other state policy. Specifically, GEI referenced Oregon Department of Energy's State Energy Strategy[24] and the governor's Executive Order (EO) 25-29 to indicate the direction to "advance the state's interest in increasing cost-effective, strategic electrification of vehicles, buildings, and water heating systems".[25] GEI asked the Commission to take action consistent with Executive Order 25-29 to ensure avoided costs for gas and electric provide pathways to strategic electrification for Oregon buildings and homes.

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[24] Or. Department of Energy, Oregon Energy Strategy 104–05 (Nov. 2025), https://www.oregon.gov/energy/Data-and-Reports/Documents/Oregon-Energy-Strategy.pdf.
[25] Oregon Executive Order 25-29 (Nov. 18. 2025), https://www.oregon.gov/gov/eo/eo-25-29.pdf.

Staff agrees with GEI's assessment that the avoided costs submitted by utilities on October 15, 2025, clearly demonstrate the need to advance dual fuel planning. Gas avoided costs have a high carbon compliance value, while electric avoided costs have elevated avoided capacity value. Taken together, the clear planning signal is that efficiency solutions that reduce total gas consumption and minimize electricity consumption during peak demand are valuable. For example, a measure to attach heat pumps to existing gas furnaces would help achieve multiple planning outcomes, a reduction in gas consumption, a minimization of reliance on electricity for capacity, and an overall efficiency improvement from the reduction in total energy consumption net of the gas decrease and electric increase.

Staff notes its recommendations from the Multiyear Plan that Energy Trust should, (1) Further develop data collection and reporting for electrification and dual fuel activities, and (2) Explore and implement least-regrets electrification and dual fuel program strategies.[26] Staff will work with Energy Trust to develop a 2026 workplan on these topics.

Northwest Natural Location-specific Avoided Costs
NW Natural submitted location specific avoided costs to be used for planning in geographically targeted energy efficiency efforts with Energy Trust. These avoided costs are about 27 percent higher than NW Natural's system-wide avoided costs.

<u>Conclusion</u>

Staff recommends the Commission approve updated avoided costs data. Gas avoided costs are expected to increase 61 percent. For electric avoided costs, Staff gives the Commission the option to adopt Staff's avoided capacity proposal resulting in a 17.6 percent avoided cost increase or adopt PGE's avoided capacity proposal, which would result in a 3.9 percent increase to electric avoided costs. Staff also recommends approval of location-specific avoided costs for use in geographically targeted energy efficiency planning between Energy Trust and Northwest Natural. The location-specific avoided costs are on average 27 percent higher than NW Natural's avoided costs.

Staff believes the attached data are ready for Commission approval and for use by Energy Trust in planning for 2027 avoided costs. The recommended data include notable signals about today's planning environment. On the electric side, capacity is persistently high when considering annual, marginal resources and their declining ELCC. For gas avoided costs, marginal CPP compliance resources beyond CCIs drive

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[26] *See* Docket No. ETO 1. *Staff report on Energy Trust of Oregon 2026 – 2030 Multiyear Plan,* (Oct. 9, 2025), https://edocs.puc.state.or.us/efdocs/HAU/eto1hau340588027.pdf.

up overall avoided costs. Staff finds that both avoided cost drivers are directionally consistent with the most recently filed utility IRPs and IRP Updates.

PROPOSED COMMISSION MOTION:

Approve the energy efficiency avoided cost data in Attachments A and B for use by Energy Trust of Oregon in 2027 planning.

For Northwest Natural, approve the inclusion of geographically specific avoided costs.

For Portland General Electric, adopt the avoided cost of capacity values calculated using Staff's marginal avoided cost resource approach.

RA1 - UM 1893

Memo

To: Peter Kernan, Oregon PUC

From: Brian Conlon, Energy Trust of Oregon

Date: November 26, 2025

Re: 2027 Electric Avoided Cost Update Summary

This memo provides a summary of the updates to Energy Trust's 2027 Electric Avoided Cost buildup, including an overview of the utility inputs provided, a discussion of the results, and a comparison of the final updated blended values to current 2026 Avoided Cost values.

Utility Provided Inputs and PUC Direction

Pursuant to AR 621, each funding utility provides Energy Trust with Avoided Cost inputs for use in the Energy Trust Final 2027 Blended Avoided Costs. Each utility provides the individual components in Table 1 below from the most recently acknowledged IRP (IRP Column) and an optional additional input for the OPUC to consider (Update Column). Table 1 shows the values currently utilized in 2026 Avoided Costs, the inputs provided by each electric utility from their most recently acknowledged IRPs, and alternative submissions for consideration in 2027 Avoided Costs. The last column for each utility identifies the inputs selected for the 2027 Avoided Costs presented here; these values are also highlighted in gold.

Table 1. Utility Inputs Pursuant to AR 621 for use in the Final Energy Trust 2027 Blended Avoided Costs

Avoided Cost Element		Pacific Power				Portland General Electric			
		Current	IRP	Update	Selection	Current	IRP	Update	Selection
		PAC Current (2026 AC)	PAC IRP Submission	PAC Updated Submission	Final Inputs for 2027 Avoided Cost	PGE Current (2026 AC)	PGE IRP Submission	PGE Updated Submission	Final Inputs for 2027 Avoided Cost
Global Assumptions	Inflation Rate	2.28%	2.18%	0.00%	IRP	2.02%	2.04%	0.00%	IRP
	Real Discount Rate	4.31%	4.11%	0.00%	IRP	4.67%	4.71%	0.00%	IRP
	Regional Act Credit	10.00%	10.00%	10.00%	IRP	10.00%	10.00%	10.00%	IRP
T&D Line Losses	Transmission Loss Factor	3.50%	3.50%	0.00%	IRP	2.07%	2.07%	0.00%	IRP
	Distribution Loss Factor, Commercial	3.69%	3.69%	0.00%	IRP	4.02%	4.02%	0.00%	IRP
	Distribution Loss Factor, Industrial	3.20%	3.20%	0.00%	IRP	1.96%	1.96%	0.00%	IRP
	Distribution Loss Factor, Residential	4.46%	4.46%	0.00%	IRP	4.20%	4.20%	0.00%	IRP
Transmission Capacity Value	Transmission Deferral Credit	$7.10	$7.10	$0.00	IRP	$32.02	$32.24	$0.00	IRP
	Seasonal Capacity Split - Summer	95%	98%	0%	IRP	50%	50%	0%	IRP
	Seasonal Capacity Split - Winter	5%	2%	0%	IRP	50%	50%	0%	IRP
	Deficiency start year	2026	2025	0	IRP	2026	2026	0	IRP
Distribution Capacity Value	Distribution Deferral Credit	$10.46	$15.65	$0.00	IRP	$6.31	$6.35	$0.00	IRP
	Seasonal Capacity Split - Summer	100%	100%	0%	IRP	50%	50%	0%	IRP
	Seasonal Capacity Split - Winter	0%	0%	0%	IRP	50%	50%	0%	IRP
	Deficiency start year	2026	2025	0	IRP	2026	2026	0	IRP
Generation Capacity Value	Generation Capacity Credit	$51.67	$143.67	$168.53	Alt 2	$145.93	$248.99	$458.27	Alt 2
	Seasonal Capacity Split - Summer	82.8%	58%	58%	IRP	50.0%	50%	50%	IRP
	Seasonal Capacity Split - Winter	17.2%	42%	42%	IRP	50.0%	50%	50%	IRP
	Deficiency start year	2027	2027	2027	IRP	2026	2026	2026	IRP
Other Values	Risk Reduction Value	$1.89	$1.93	$0.00	IRP	$3.00	$3.00	$0.00	IRP
	Transmission Expansion Value	$0.00	$0.00	$18.28	Alt1	$0.00	$24.44	$65.62	IRP
	Energy Prices				Energy Alt1				FP Alt1

Energy Trust took these inputs and blended them into electric Avoided Cost values that can be used throughout Energy Trust territory. The blended values are weighted averages where the weighting is based on forecasted 2026 electric utility expenditures from Energy Trust's 2025 Multiyear Plan. In the 2026 avoided costs, the weighting was 41% PAC and 59% PGE, whereas for this 2027 update, the split is 45% PAC, 55% PGE. This change means that 2026 vs. 2027 comparisons may differ from expectations, particularly with blended values. For consistency with the natural gas avoided costs, Energy Trust uses a single discount rate, which weights utility-submitted discount rates by the forecasted expenditures for the two electric and three natural gas investor-owned utilities in Oregon.

Some additional notes on Table 1:

1) The values provided in this table are in the dollar years provided by the utility. These values will be inflated to 2027$ for use in the 2027 Avoided Costs.
2) The values labeled IRP are sourced from the latest published IRPs as well as workpapers for upcoming IRP updates
3) The table does not include all options for generation capacity credit and forward prices. These are described below.
4) PGE did not provide alternative global input values for 2027 Avoided Costs.
5) For Transmission Expansion credit, PAC provided a levelized cost in 2025 $/kW-yr, and PGE provided an annual time series in $/MWh. PGE's value in this table is a 20-year levelized cost in 2027 $/MWh.

Table 2 below provides a comparison of the blended 2026 Avoided Cost Component Values to the updated final 2027 Avoided Cost Component values and their percent change from 2026.

Table 2. Comparison of Component Values from 2026 Avoided Costs to the blended Final 2027 Avoided Costs Values (2027 $)

Avoided Cost Component	2027 (Updated) Blended Value	2026 Blended Value	Percent Change
Inflation Rate	2.10%	2.13%	-1.2%
Real Discount Rate	4.30%	4.40%	-2.3%
Northwest Power Act 10% Credit	10.00%	10.00%	0.0%
Risk Reduction Value ($/MWh) ($ 2027)	$2.83	$2.89	-2.0%
Transmission Loss Factor	2.71%	2.65%	2.2%
Transmission Credit ($/kW-yr.) ($ 2027)	$22.24	$23.21	-4.2%
Distribution Loss Factor, Commercial	3.87%	3.89%	-0.3%
Distribution Loss Factor, Industrial	2.51%	2.46%	2.1%
Distribution Loss Factor, Residential	4.32%	4.31%	0.2%
Distribution Credit ($/kW-yr.) ($ 2027)	$11.20	$8.73	28.2%
Generation Deferral Credit ($/kW-yr.) ($ 2027)	$328.61	$109.89	199.0%

Final Results Summary

Once the updated values provided by electric utilities were blended, Energy Trust compared each of the 186 electric load shapes updated in the 2027 Avoided Costs to the current 2026 iteration of Avoided Costs and compared the overall impact of the changes based on end use load profiles from the Energy Trust measure mix from 2023 and 2024. This savings portfolio-weighted average was $1.585/kWh for 2027 Avoided Costs**. Compared to the $1.348/kWh NPV weighted average from the 2026 Avoided Costs, this is an increase of 17.58 percent or $0.237/kWh.**

As shown in Figure 1, the overall increase relative to the 2026 avoided costs is attributable to a relatively large increase in the value of generation capacity along with the addition of the transmission expansion credit. This increase is somewhat offset by a sizeable decrease in energy value. In comparison, decreases in transmission capacity and risk reduction values and an increase in distribution capacity value are less impactful. The overall change in avoided costs is mirrored by the 10% Power Act credit, which is applied to the other values.

Figure 1. Changes in avoided cost components relative to 2026 – weighted average based on 2023-24 measure mix

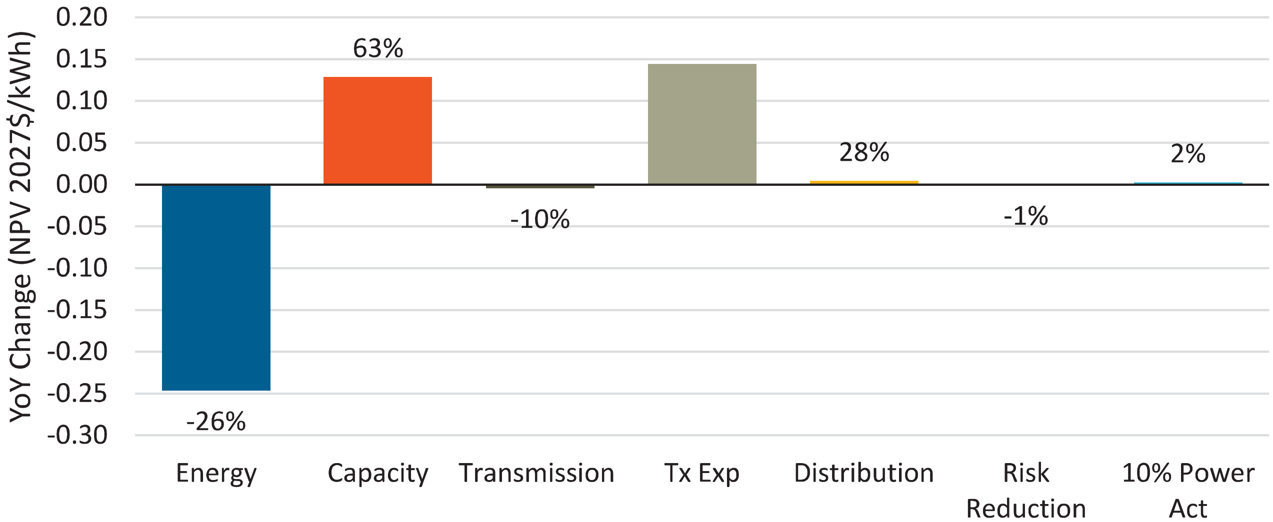
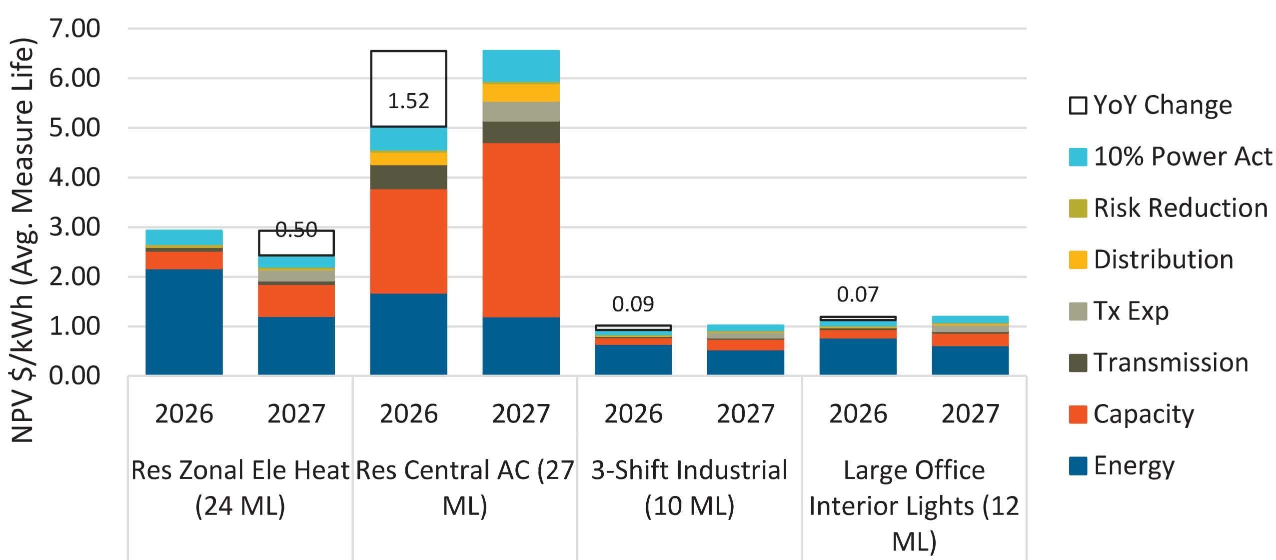


Figure 2 below shows the impact of the individual component parts for both the 2027 and 2026 Avoided Costs based on a sample of illustrative end use load profiles. These load shapes are used for illustrative purposes and do not necessarily represent end uses that make up large portions of Energy Trust's portfolio.

Figure 2. Comparison of Load Shape Value by Component



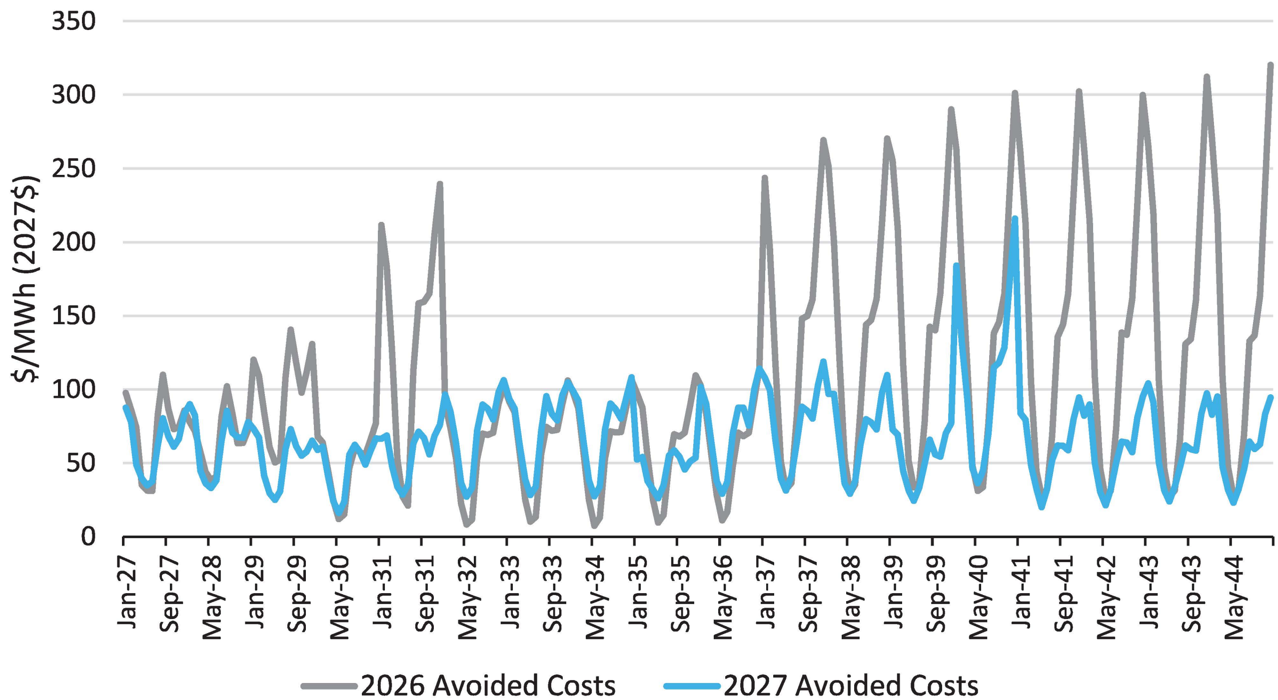
The next section of this memo details the changes to each component of the Avoided Costs update.

Final 2027 Electric Avoided Cost Component Changes and Impacts

Avoided Energy Value

When the transmission expansion value component was introduced in the previous 2026 avoided costs, it was embedded in the energy value component. For this 2027 update, the transmission expansion and energy value components were reported separately. Consequently, the energy value in certain years appears significantly smaller than in 2026, as reflected in Figure 3.

Figure 3. Blended Avoided Energy Value



Utilities submitted a number of options to be considered for avoided energy value. Table 3 summarizes the underlying methodology, along with the mean and range of monthly prices for the first twenty years of the forecast horizon. As indicated by the ranges, month-to-month variability increases significantly in most cases. While the selected PGE values are lower than 2026 on average, this decrease is outweighed by the large increase in PAC's forward prices.

Table 3. Summary of avoided energy value series submitted by utilties 2027-43 (2027 $/MWh)

Utility	Category	Template Tab	Description	Min	Max	Mean
PAC			2026 Avoided Costs	3.81	272.85	57.99
	Forward Prices	2	2025 IRP	-8.72	301.81	49.69
	Avoided Energy	3	2025 IRP	-6.44	301.81	54.56
	Forward Prices	2a	2025 Price Forecast	-8.88	232.40	70.58
	Avoided Energy*	3a	2025 IRP w/ clean energy net cost	-2.41	250.42	84.35
PGE			2025 Avoided Costs	-5.95	483.68	133.06

	Forward Prices	2	2026-2028: 2025 Operational Power Curve 2029: Interpolation Year 2030-2043: 2023 IRP Curve	-4.05	108.48	32.52
	Avoided Energy	3	Marginal LCOE resource costs shaped by AURORA model, Preferred Portfolio	-5.36	315.04	47.54
	Avoided Energy	3a	Marginal LCOE resource costs shaped by AURORA model, Reliability Needs Only Portfolio	-33.02	410.68	73.62
	Blend*		2027-2029: Forward Prices 2030-2043: Avoided Energy, Preferred Portfolio	-5.36	315.04	51.08

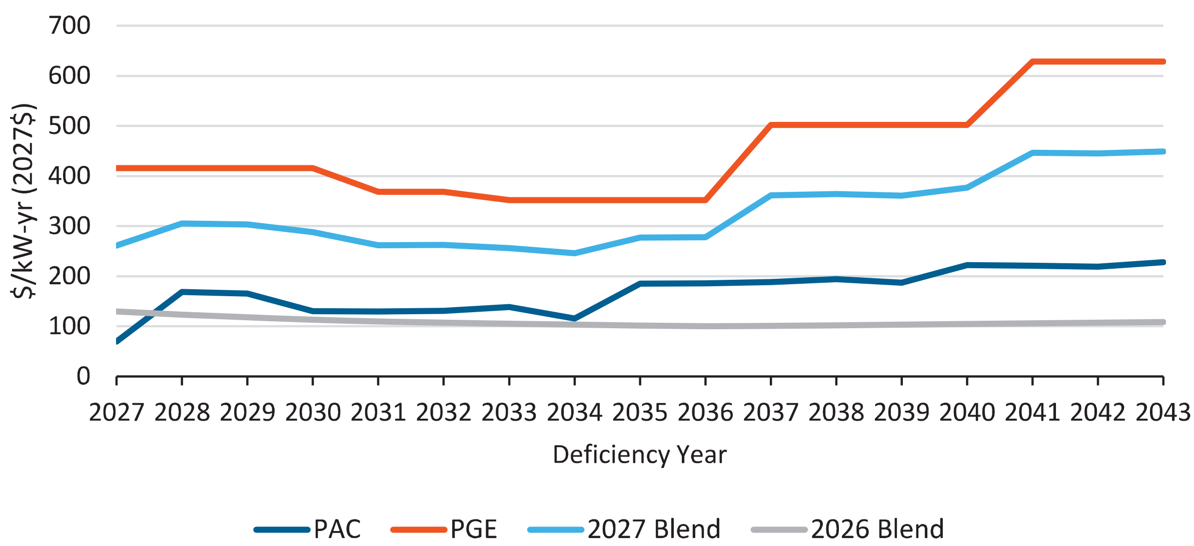
** Selected avoided energy value series for weighted average blend*

Generation, Transmission, and Distribution Capacity Values

For the 2027 update, utilities submitted annual forecasts of generation capacity value. Traditionally, a simple-cycle natural gas combustion turbine with well-known and consistent costs was used as the proxy marginal resource to value generation capacity. However, in moving towards a high renewables future, the marginal capacity resource will vary in technology and cost. Including annual capacity values in the avoided costs better reflects this dynamic future.

Relative to 2026 avoided costs, PGE's generation capacity deferral value increased by 208% and PAC's increased by 219%. These values represent the utilities' net capacity cost of their forecasted marginal resource. To arrive at these figures, the utilities forecasted the ELCC-adjusted generation installation costs and subtracted the tax credits, energy, and ancillary service benefits the generator would provide. Utilities submitted several capacity value forecasts with varying portfolio compositions. For PGE, the selected values are based on a 4-hour lithium-ion battery from 2027-2039, followed by more expensive, but higher ELCC pumped storage hydro from 2040-2043. PAC's portfolio shifts from the 4-hour lithium-ion battery in 2027-2029 to a 100-hour iron-air battery from 2030-2043.

Figure 4. Generation Capacity Deferral Values



Compared to 2026, the blended transmission deferral credit value that was used as an input to 2027 avoided cost calculations went down 4%. The blended distribution credit input value in the 2027 avoided cost calculations increased by 28%.

To reflect the additional value associated with expanding the transmission system for renewable energy integration, transmission expansion was introduced in the 2026 avoided costs. This 2027 update, however, is the first edition to represent it as a separate component, as it was previously embedded in the energy component. Utilities could report transmission expansion value as $/kW-year or $/MWh. While PGE's selected submission is an annual forecast of $/MWh, PAC's submission is a levelized $/kW-year value, which is allocated using the generation capacity peak factors, per guidance from PAC. For comparison purposes, 20-year levelized values were calculated for both utilities. This transmission expansion value is $19.09/kW-year for PAC and $68.32/kW-year for PGE.

For PAC, the seasonal allocation factor for transmission shifted slightly from 95% summer / 5% winter for 2026 to 98% summer / 2% winter for 2027. Similarly, PAC's distribution allocation remained 100% summer as it was for 2026. Consistent with updates in UM 1893 proceedings for 2026 Avoided Costs, a seasonal 50% summer/50% winter split was used for PGE generation, transmission, and distribution capacity value.

Risk Reduction & NW Power Act Credit

Risk Reduction values that were used as inputs to avoided cost calculations decreased about 1% in the 2027 Avoided Costs. The same 10% NW Power Act Credit value was also utilized in the 2027 Avoided Costs. This credit is applied to each of the Avoided Cost components and therefore its impact is proportional to the changes in other individual components of each load shape.

Measure Level Impacts

On a measure level, the overall impact of the input changes varies by measure and load profile due to changes in the submitted values. Currently the peak coincident factors for transmission and distribution are specific to each utility and then blended.

The following figures show changes in NPV Avoided Costs per unit of savings for representative measures across each sector. The NPV is shown according to each measure's typical measure life.

The measures shown in these graphs are meant to show differential impacts across end uses and do not necessarily represent measures that make up most of the savings within each sector.

Figure 5. Residential Avoided Cost Comparison of Example Measures

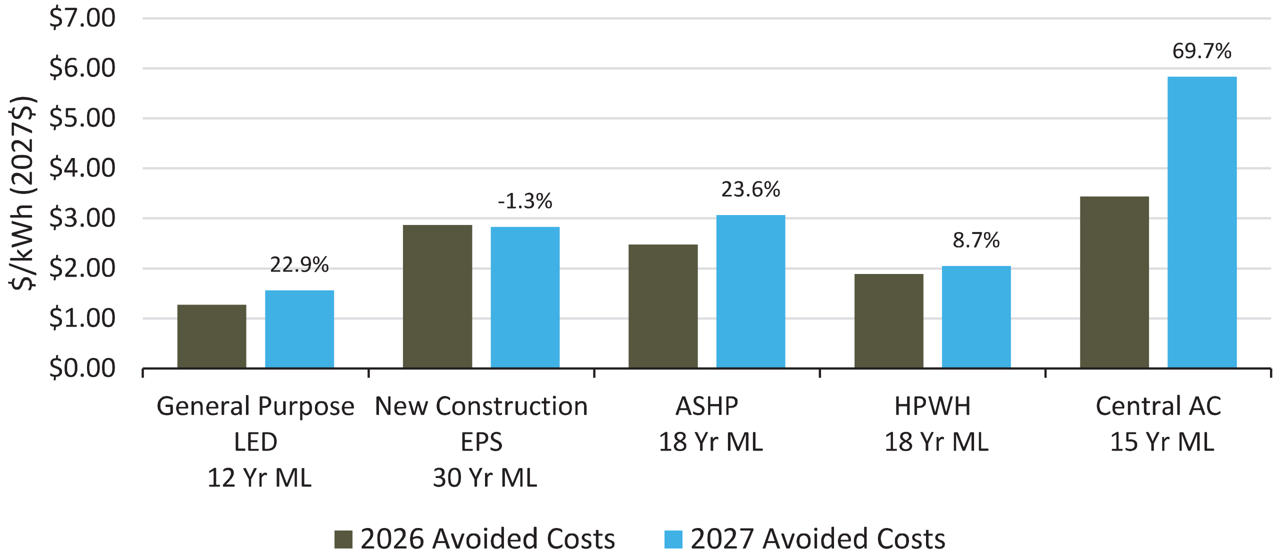


Figure 6. Commercial Avoided Cost Comparison of Example Measures

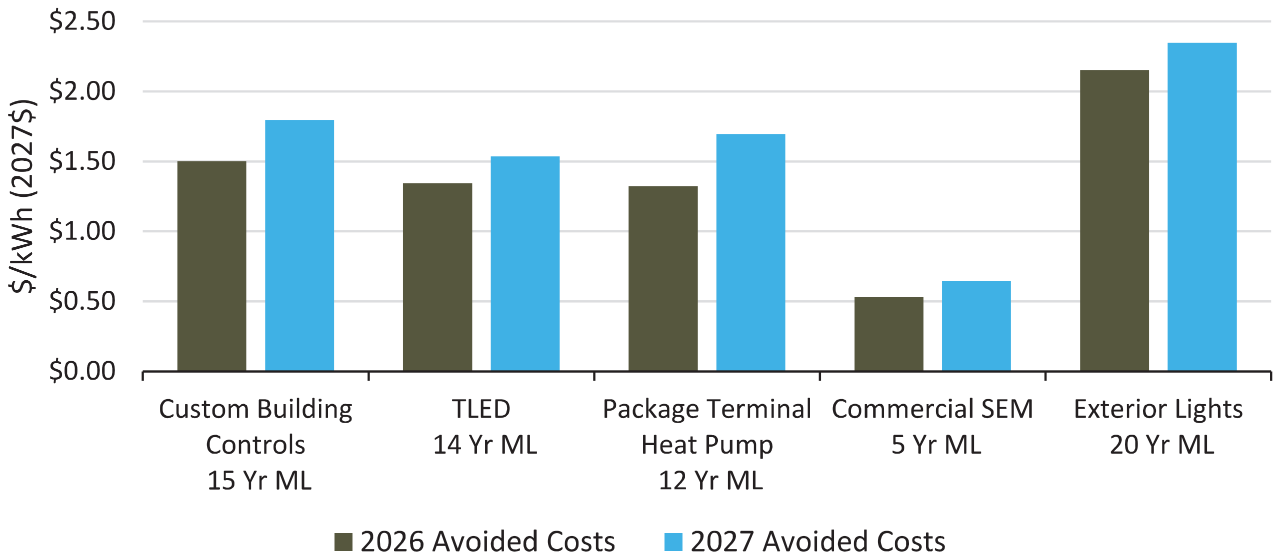
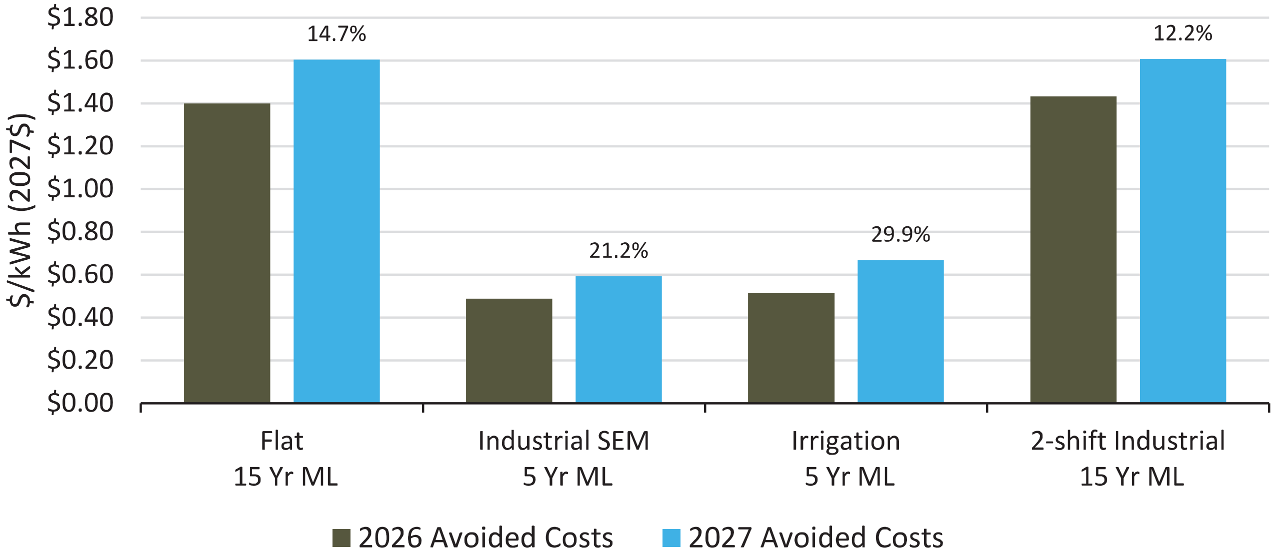


Figure 7. Industrial Avoided Cost Comparison of Example Measures



Memo

To: Peter Kernan, Oregon PUC

From: Brian Conlon, Energy Trust of Oregon

Date: November 26, 2025

Re: 2027 Natural Gas Avoided Cost Update Summary

This memo provides a summary of the updates to Energy Trust's 2027 Natural Gas Avoided Cost buildup, including an overview of the utility inputs provided, a discussion of the results, and a comparison of the updated blended values to current 2026 Avoided Cost values.

Utility Provided Inputs and PUC Direction

Pursuant to UM 1893, each funding utility provides Energy Trust with Avoided Cost inputs for use in 2027 Blended Avoided Costs. Each utility provides each component in the table below from the most recently acknowledged IRP and an optional additional input for the OPUC to consider. Table 1 below shows the values currently utilized in 2026 Avoided Costs, the inputs provided by each gas utility from their most recent IRPs and updated utility submissions for consideration in 2027 Avoided Costs. The table also shows the values that Energy Trust used in 2027 Avoided Cost calculations; these values are identified in their own rows as well as being highlighted in orange. Finally, Table 1 compares the blended values used to calculate Avoided Costs for the current 2026 vintage with the blended values used to calculate Avoided Costs for the 2027 vintage.

Table 1. Utility Inputs for use in Energy Trust 2027 Blended Avoided Costs

Input Vintage Description	Avoided Cost Element								
	Inflation Rate	Discount Rate	Regional Act Credit	Commodity & Transport	Distribution Capacity	Supply Capacity	CO2 Compliance	CO2 Compliance Risk Reduction	Risk Reduction
	Percentage	Percentage	Percentage	$/Therm	$/Therm/Year	$/Therm/Year	$/Therm	$/Therm	$/Therm
Northwest Natural									
Selected Input for 2026 Avoided Cost (2027$)	2.45%	3.87%	10%	$0.49	$292.01	$4.06	$0.79	$0.00	$0.14
Current Submission - IRP (2027$)	2.45%	3.87%	10%	$0.38	$288.41	$3.21	$1.93	$0.52	$0.13
Current Submission - ALT (2027$)	n/a	n/a	10%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Selected Input for 2027 Avoided Cost (2027$)	**2.45%**	**3.87%**	**10%**	**$0.38**	**$288.41**	**$3.21**	**$1.93**	**$0.52**	**$0.13**
2027 Avoided Cost Input Source	**NWN Update**	**NWN Update**	**2025 IRP**	**2025 IRP Model**	**2025 IRP**	**2025 IRP**	**2025 IRP**	**2025 IRP**	**2025 IRP**
Cascade Natural Gas									
Selected Input for 2026 Avoided Cost (2027$)	2.91%	4.24%	10%	$0.38	$8.23	$0.00	$0.80	$0.00	$0.02
Current Submission - IRP (2027$)	3.20%	3.94%	10%	$0.41	$0.00	$0.00	$3.32	$0.00	$0.01
Current Submission - ALT (2027$)	2.98%	4.16%	10%	$0.38	$0.00	$0.00	$1.65	$0.02	$0.01
Selected Input for 2027 Avoided Cost (2027$)	**3.20%**	**3.94%**	**10%**	**$0.41**	**$0.00**	**$0.00**	**$3.32**	**$0.02**	**$0.01**
2027 Avoided Cost Input Source	**Woods & Poole**	**2021 Operations**	**2023 IRP Update**	**2023 IRP Update**	**none submitted**	**none submitted**	**2023 IRP Update**	**Alt**	**2023 IRP Update**
Avista									
Selected Input for 2026 Avoided Cost (2027$)	2.00%	4.52%	10%	$0.48	$8.06	$0.00	$0.79	$0.00	$0.13
Current Submission - IRP (2027$)	2.17%	4.42%	10%	$0.50	$0.55	$0.57	$0.87	$0.05	$0.00
Current Submission - ALT (2027$)	n/a	n/a	10%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Selected Input for 2027 Avoided Cost (2027$)	**2.17%**	**4.42%**	**10.00%**	**$0.50**	**$0.55**	**$0.57**	**$0.87**	**$0.05**	**$0.11**
2027 Avoided Cost Input Source	**2025 IRP**	**2025 IRP**	**2025 IRP**	**2025 IRP**	**2025 IRP**	**2025 IRP**	**2025 IRP**	**2025 IRP**	**NWN/CNG**
Energy Trust									
Old Blended Input for 2026 Avoided Cost (2027$)	**2.46%**	**4.40%**	**10%**	**$0.48**	**$241.42**	**$5.39**	**$0.79**	**$0.00**	**$0.13**
New Blended Input for 2027 Avoided Cost (2027$)	**2.51%**	**4.30%**	**10%**	**$0.40**	**$224.03**	**$2.55**	**$1.79**	**$0.41**	**$0.11**
Percent Difference	**2%**	**-2%**	**0%**	**-17%**	**-7%**	**-53%**	**126%**	**n/a**	**-10%**

Energy Trust took these inputs and blended them into gas Avoided Costs values that can be used throughout Energy Trust territory. The blended values are weighted averages where the weighting is based on forecasted 2026 gas utility expenditures from Energy Trust's 2026-2030 Multiyear Plan.

Some additional notes on Table 1.

1) The values provided by utilities were in dollar years specific to their source. These values were inflated to 2027$ for use in the 2027 Avoided Costs.
2) Some submitted input values are multiyear forecasts. The first 20 years are levelized to produce the values in this table.
3) All values are sourced from each respective utility's IRP or alternate submission with the exception of Avista's risk reduction value. These values rely on a utility expenditure-weighted average of values from the other two respective utilities for input.

Table 2 below provides a comparison of the blended 2026 Avoided Cost Component Values to the updated 2027 Avoided Cost Component values and their percent change from 2026.

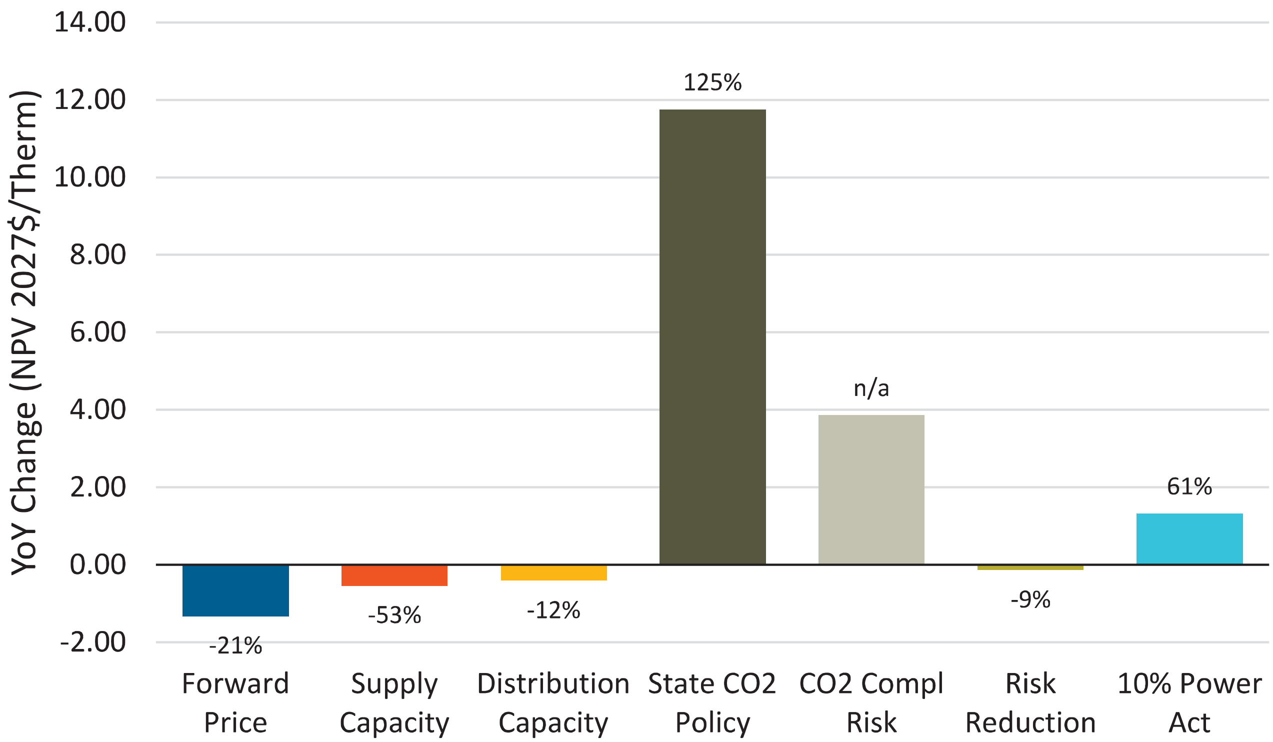
Table 2. Comparison of Component Values from 2026 Avoided Costs to 2027 Avoided Costs

Avoided Cost Component	2026 AC Blended Value	2027 AC (Updated) Blended Value	% Change
Inflation rate	2.46%	2.51%	2%
Real Discount rate	4.40%	4.30%	-2%
Regional Act Credit	10%	10%	0%
20-year Levelized Value (2027$/Therm)			
Commodity and Transport Prices	$0.48	$0.40	-17%
Distribution Capacity	$241.42	$224.03	-7%
Supply Capacity	$5.39	$2.55	-53%
CO2 Compliance	$0.79	$1.79	126%
CO2 Compliance Risk Reduction	N/A	$0.41	N/A
Risk Reduction	$0.13	$0.11	-10%

Results Summary

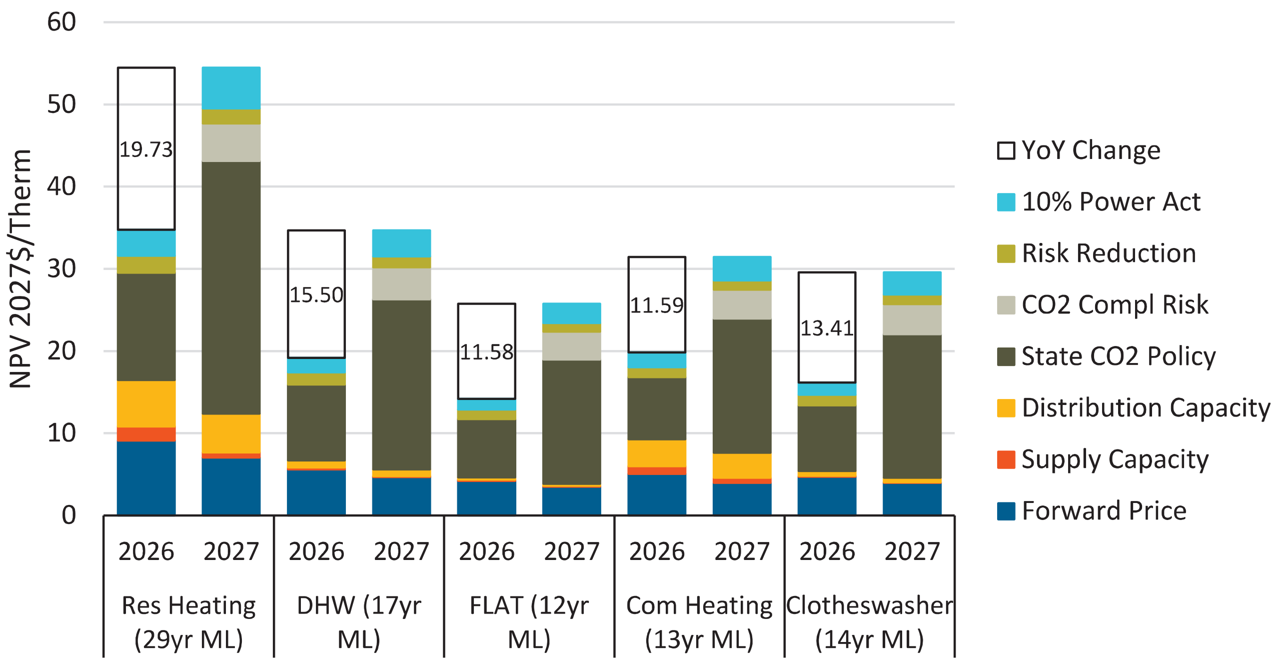
Once the updated values provided by the gas utilities were blended, Energy Trust compared the respective value components of the updated 2027 Avoided Costs to the current 2026 iteration of Avoided Costs. To gauge an overall impact of the changes, the avoided costs were weighted by the Energy Trust measure mix from 2023 and 2024. **Overall, the weighted NPV 2027 natural gas Avoided Costs increased by 61.1 percent or $14.51/Therm** compared to current 2026 Avoided Costs. Figure 1 shows the underlying components of this change. This increase is largely due to an increase in carbon compliance costs as well as the addition of a new component – carbon compliance risk reduction – that accounts for uncertainty in procuring resources for carbon compliance.

Figure 1. Changes in Avoided Cost Components Relative to 2026 – Weighted Average Based on 2023-24 Measure Mix



On an end use basis represented per loadshape, the contribution of each individual Avoided Cost component differs depending on how much that loadshape coincides with defined utility peak periods. Figure 2 below illustrates the differential impact of the individual component parts of 2026 and 2027 Avoided Costs associated with specified end use load profiles. The contributions of the value components of the load profiles shown in this graph are based on characteristic measure lives. This figure does not represent the proportional contribution of each loadshape to Energy Trust's overall portfolio.

Figure 2. Comparison of Load Shape Value by Component



The next section of this memo details the changes to each component of the Avoided Costs update.

Natural Gas Avoided Cost Component Changes and Impacts

Commodity and Transport Forward Prices

Figure 3 compares blended commodity and transport forward prices from 2026 Avoided Cost inputs and 2027 Avoided Cost inputs. The utility-submitted values are shown in Figure 4. Overall blended commodity and transport prices decreased by 17%.

Figure 3. Blended Commodity and Transport Price Comparison

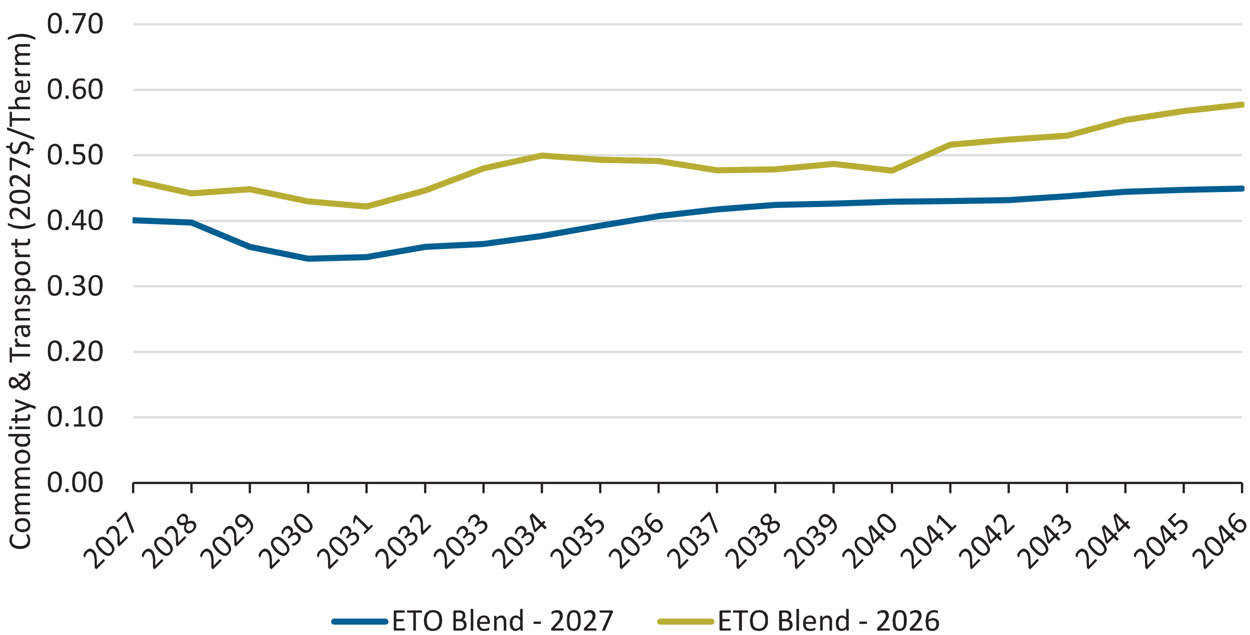
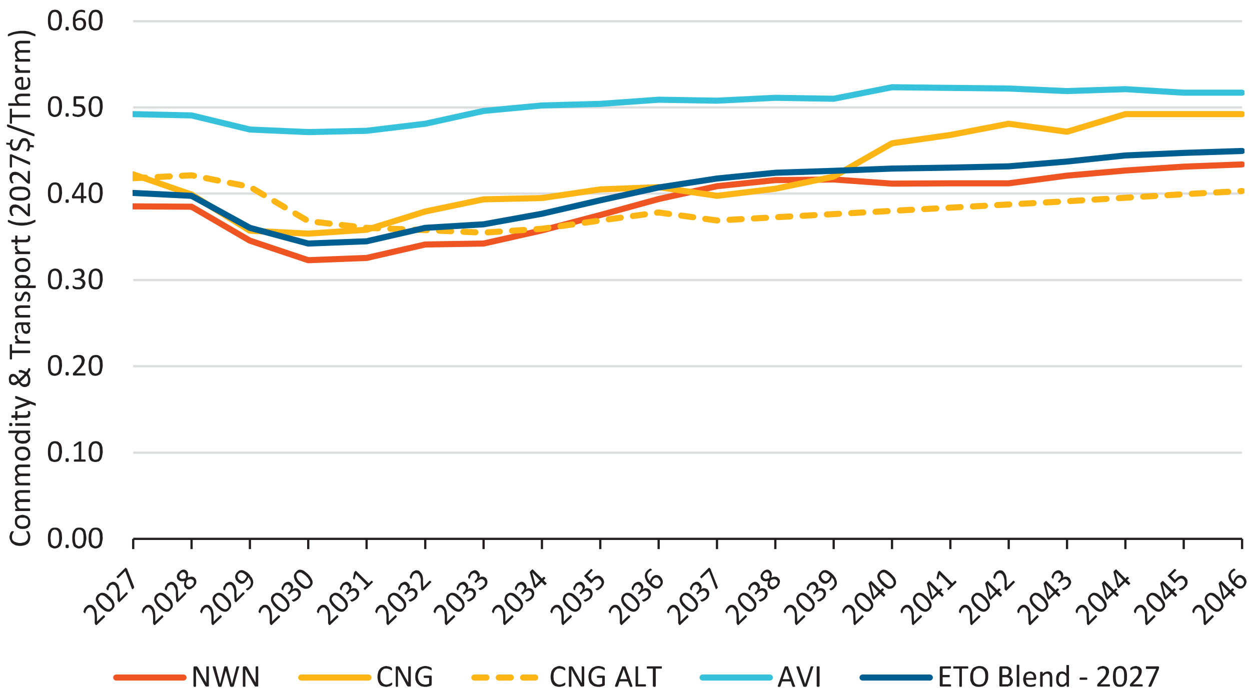


Figure 4. Comparison of Utility-specific Commodity and Transport Price for 2027 Avoided Costs



Peak Factors

Energy Trust uses peak factors to determine the proportion of end-use consumption that takes place on a peak day or a peak hour for natural gas utilities. Peak day and peak hour factors are defined for each of the end-use load profiles that Energy Trust utlizes in avoided cost calculations.

Supply capacity values are shaped using peak day factors, which represent the proportion of annual end-use consumption that falls on a peak day. A peak day is assumed to be the maximum daily coincidence of end-use consumption on a December or January weekday. Distribution capacity values are shaped using peak hour factors, which represent the proportion of end-use consumption that falls on a peak hour.

Historically, Energy Trust relied on peak hour factors that were calculated seperately from peak day factors. This separate calculation resulted in some instances where the peak hour factor was less than 1/24th of a peak day factor. As a result, starting with the 2021 Avoided Costs, Energy Trust altered its method for calcuating peak hour factors for space heating end-uses. For space heating end-uses, a peak hour factor is calculated based on the proportion of consumption during the maximum hour on the peak day as characterized by peak day factors in Table 3. This method was applied for the 2026 Avoided Costs and is also applied to the 2027 Avoided Costs.

For non-space heating end-uses a peak hour is characterized as the maximum hourly coincidence of end-use consumption on a December or January weekday morning from 7-10 A.M. Peak day and peak hour factors are derived from a combination of electric analog end-use load profiles from the Northwest Power and Conservation Council (NWPCC) and Northwest Natural regression modeling. Table 3 and Table 4 show each of the peak factors used in 2027 Avoided Costs and their respective sources.

Table 3. Daily Peak Factors for 2027 and 2026 Avoided Costs

End-Use Load Shape	2027 Peak Day Factor	Peak Day Factor Source	2026 Peak Day Factor	Peak Day Factor Source
Residential Space Heating	0.0177	Northwest Natural 2025 IRP	0.0198	Northwest Natural 2022 IRP
Commercial Space Heating	0.0177	Northwest Natural 2025 IRP	0.0177	Northwest Natural 2022 IRP
Domestic Hot Water	0.0036	NWPCC	0.0036	NWPCC
Flat	0.0030	NWPCC	0.0030	NWPCC
Clotheswasher	0.0020	NWPCC	0.0020	NWPCC

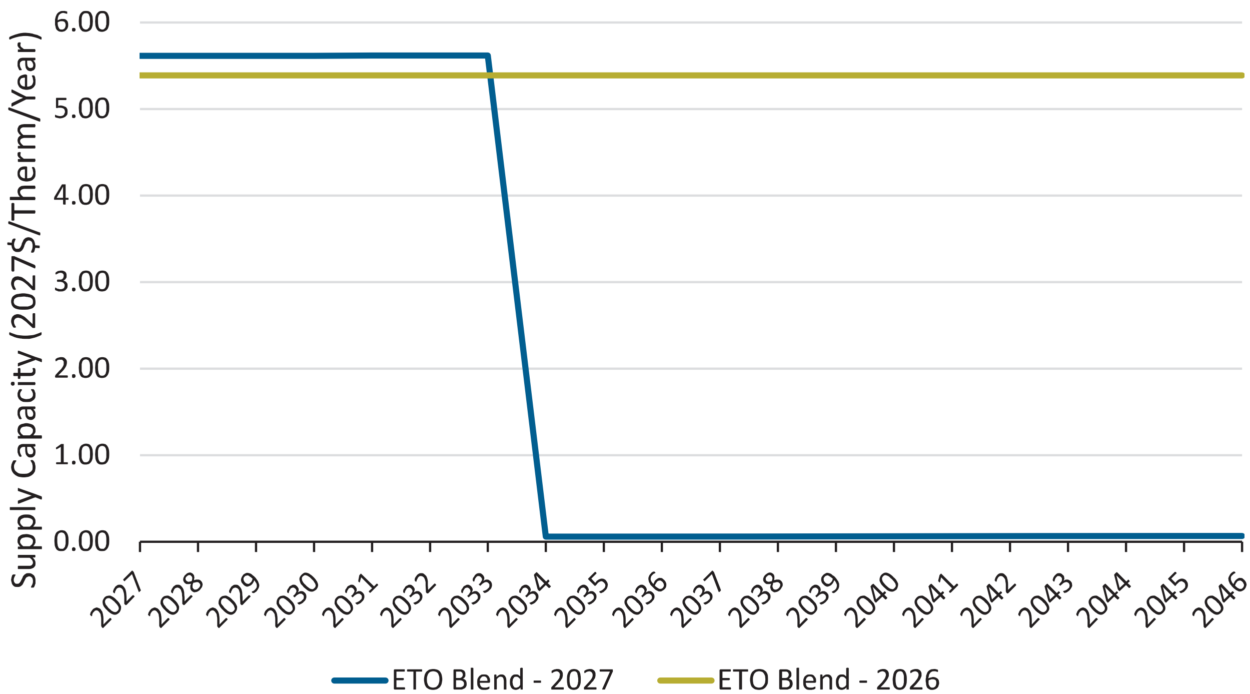
Table 4. Hourly Peak Factors for 2027 and 2026 Avoided Costs

End-Use Load Shape	2027 Peak Hour Factor	Peak Hour Factor Source	2026 Peak Hour Factor	Peak Hour Factor Source
Residential Space Heating	0.00128	NWPCC & Northwest Natural 2025 IRP	0.00144	NWPCC & Northwest Natural 2022 IRP
Commercial Space Heating	0.00140	NWPCC & Northwest Natural 2025 IRP	0.00140	NWPCC & Northwest Natural 2022 IRP
Domestic Hot Water	0.00030	NWPCC	0.00030	NWPCC
Flat	0.00013	NWPCC	0.00013	NWPCC
Clotheswasher	0.00024	NWPCC	0.00024	NWPCC

Supply Capacity

The blended supply capacity values that were used as inputs to avoided cost calculations decreased by 53% from the prior round of avoided costs submissions. This is largely due to NWN's value going to $0/Therm/year in 2034. Also, CNG did not identify any avoidable supply capacity infrastructure expansion so submitted no values. Blended supply capacity values used in the 2026 and 2027 avoided costs are illustrated in Figure 5.

Figure 5. Blended Supply Capacity Values for 2027 and 2026 Avoided Costs



Distribution Capacity

The blended distribution capacity values that were used as inputs to avoided cost calculations decreased by 7% from the prior round of avoided costs submissions. Similar to supply capacity, CNG did not identify any avoidable distribution capacity infrastructure expansion so submitted no values.

Table 5 illustrates the change in distribution capacity costs for each end use load profile from 2026 blended avoided costs to the current 2027 blended avoided cost.

Table 5. 20-year Levelized Blended Distribution Capacity Values (2027$/peak-hour Therm)

End Use Load Shape	DHW	FLAT	Res Heating	Com Heating	Clotheswasher
2026 Blended Avoided Costs	$0.072	$0.030	$0.348	$0.337	$0.057
2027 Blended Avoided Costs	$0.067	$0.028	$0.288	$0.313	$0.053
Percent Change	-7%	-7%	-17%	-7%	-7%

Carbon Policy Compliance Value

Carbon compliance values increased by 126% from the prior blended value of $0.79 per Therm to $1.79 per Therm.

To calculate carbon value in the previous 2026 avoided costs, Energy Trust used the Community Climate Investment (CCI) credit schedule published by DEQ in the then newly adopted Climate Protection Program 2024.[1] For this 2027 update, the utilities submitted their carbon values that bring them into compliance with CCI. As the amount of CCI credits utilities may purchase is capped, the utilities must reach compliance by procuring renewable natural gas, which is much more expensive. Figure 6 illustrates the respective carbon cost values provided by each natural gas utility and the blended value for use in Energy Trust avoided costs. Figure 7 shows the comparison of the 2026 and 2027 carbon compliance values.

[1] https://www.oregon.gov/deq/rulemaking/Pages/CPP2024.aspx

Figure 6. Comparison of Utility and DEQ Carbon Compliance Costs

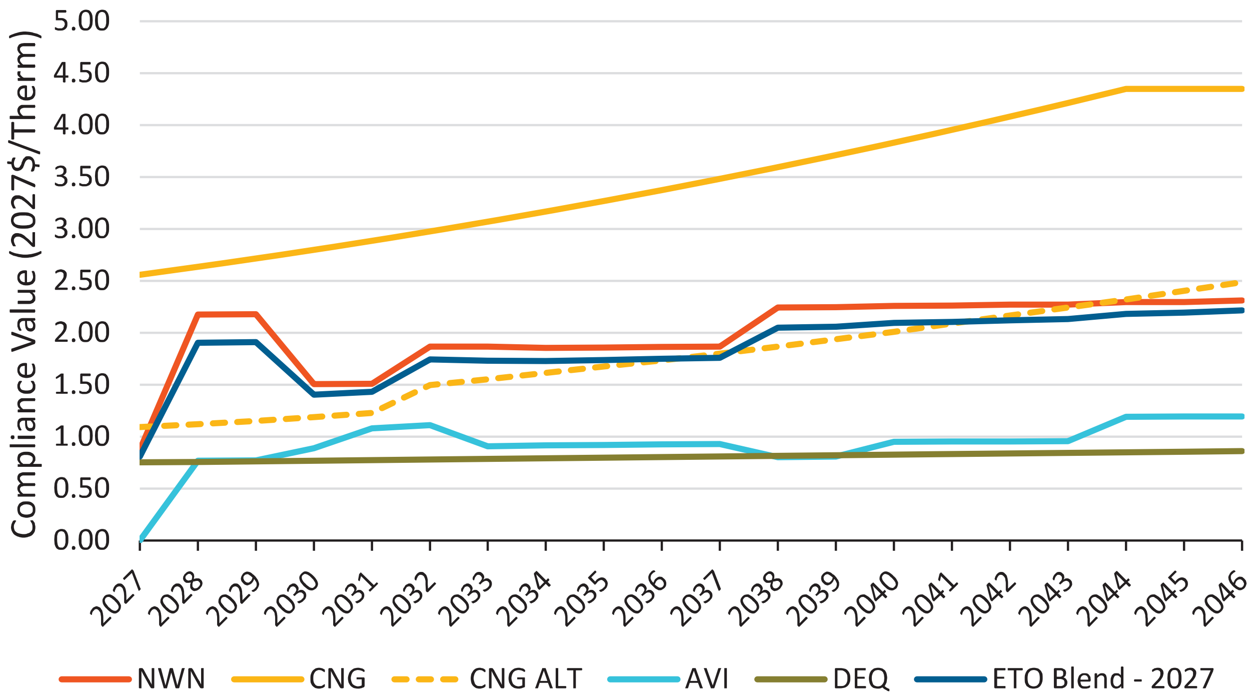
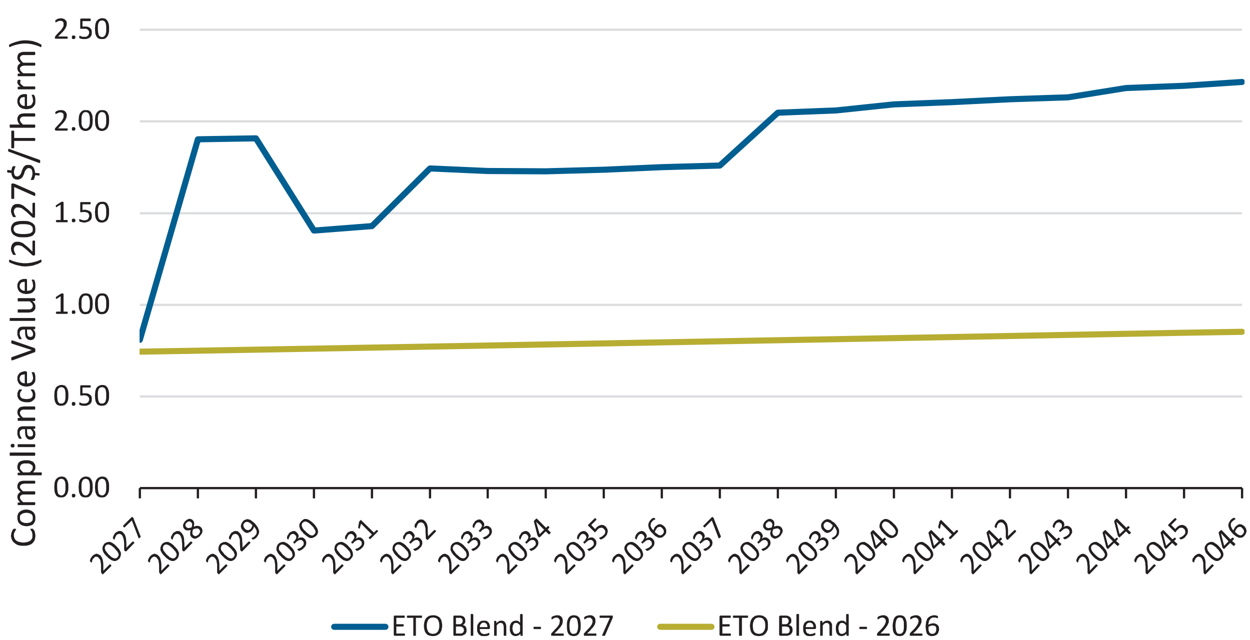


Figure 7. Blended Carbon Compliance Values for 2027 and 2026 Avoided Costs



Each gas utility submitted utility-specific carbon intensity values (MTCO2e/Dth) shown in Table 6 and carbon compliance costs in $/MTCO2e. These are multiplied together to calculate the final blended dollar per therm values for carbon compliance in the 2027 Avoided Costs.

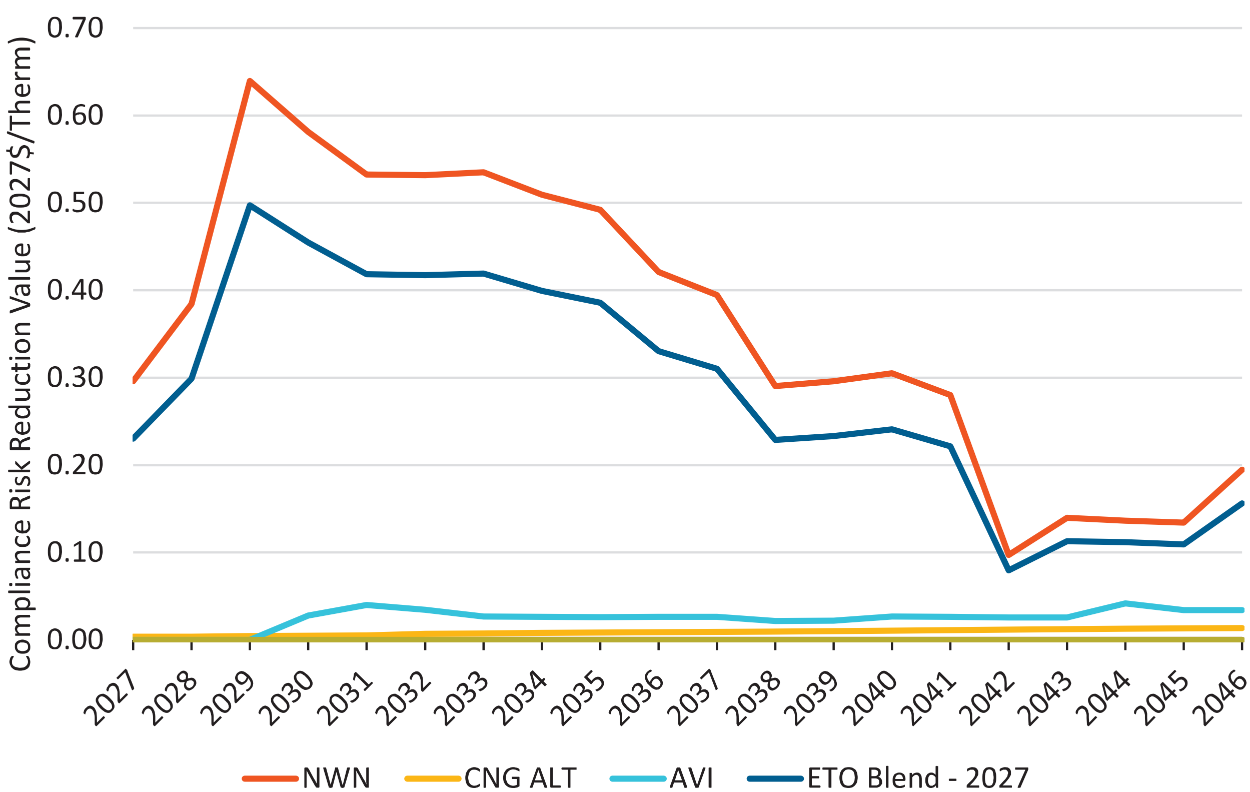
Table 6. Utility-specific Carbon Intensity Values

Utility	Carbon Intensity (MTCO2e/Dth)
Northwest Natural	0.064654
Cascade Natural Gas	0.053060
Avista	0.053000
Energy Trust Blended	0.062057

Carbon Compliance Risk Reduction Value

Carbon compliance risk reduction value has been adopted as a new avoided cost component for the 2027 update. This component was proposed by Northwest Natural, who added this value to their 2025 IRP to account for uncertainty in compliance resource acquisition costs. This value is similar to the commodity risk reduction component in that avoiding natural gas consumption reduces the amount of hedging products the utility needs to purchase in order to mitigate costs associated with fluctuations in resource procurement. Utilities submitted carbon compliance risk reduction values, which are shown in Figure 8.

Figure 8. Comparison of Utility Carbon Compliance Risk Reduction Values and 2027 ETO Blend



Risk Reduction & NW Power Act Credit

Risk reduction decreased by 10% from the 2026 avoided costs with a blended value of $0.13 per therm to a blended value of $0.11 per therm for the 2027 avoided costs. As was the case for the 2026 vintage, Avista did not submit values, so their value is replaced with a weighted average of the risk reduction values for NWN and CNG.

The NW Power Act Credit is applied to each of the avoided cost components and therefore its impact is relative to the changes in other individual components of each loadshape. The NW Power Act Credit continues to be 10% of avoided cost value.

Measure Level Impacts

The following figures show changes in NPV avoided costs per unit of savings for representative measures across each sector. The NPV is shown according to each measure's typical measure life. The measures shown in these graphs are meant to show differential impacts across end uses and do not necessarily represent measures that make up the majority of savings within each sector.

Figure 9. Residential Avoided Cost Comparison of Representative Measures

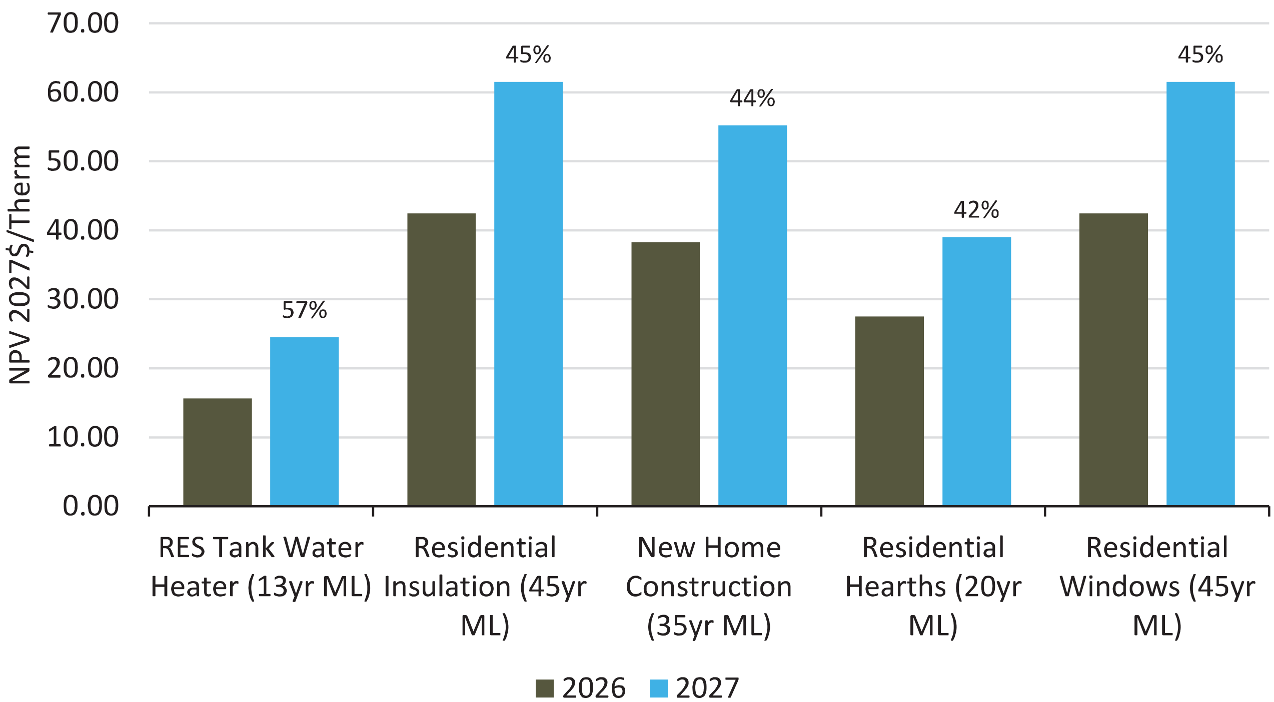


Figure 10. Commercial Avoided Cost Comparison of Representative Measures

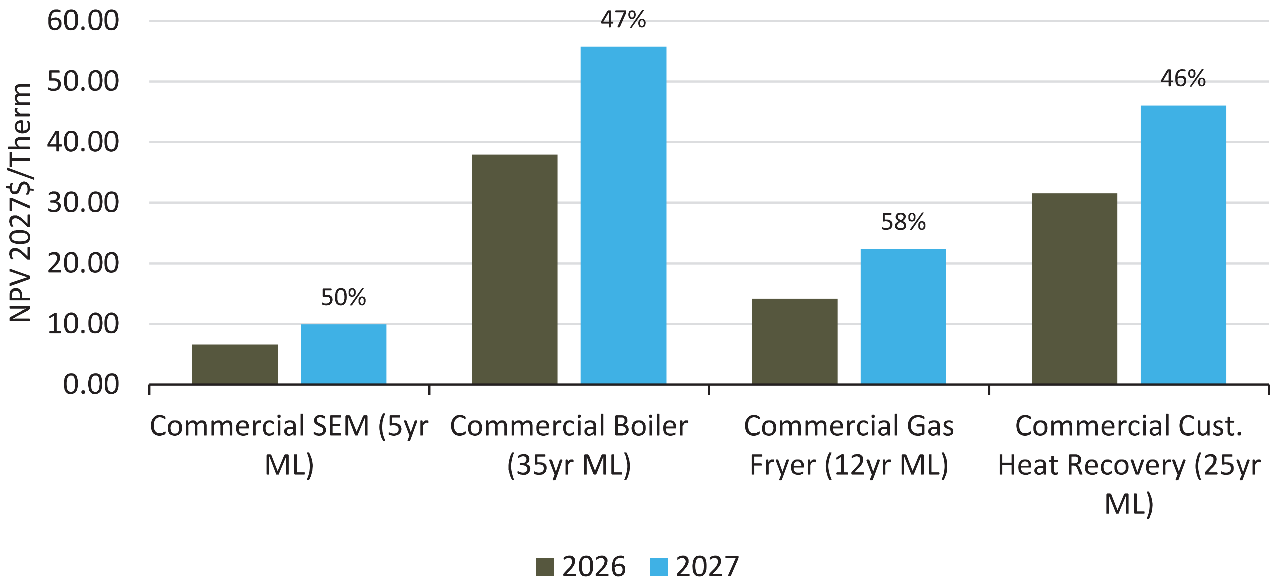
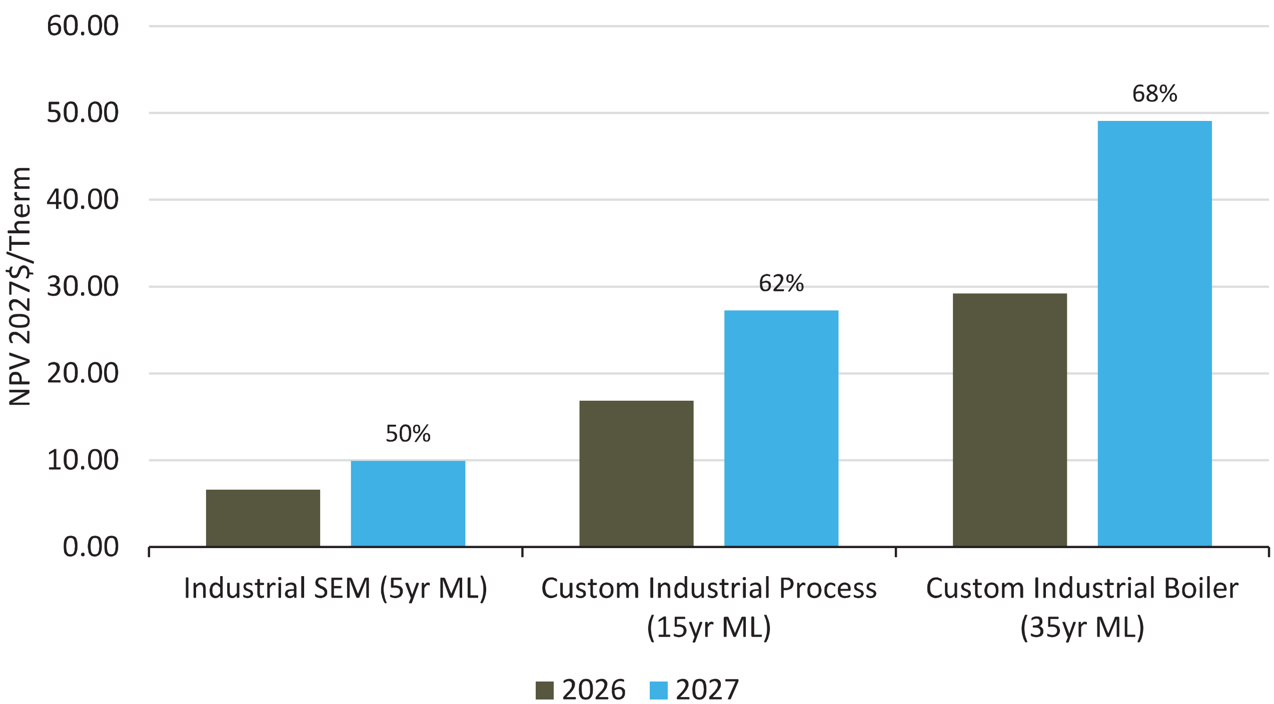


Figure 11. Industrial Avoided Cost Comparison of Representative Measures



Localized Avoided Costs for Geographically Targeted Energy Efficiency (GeoTEE)

Energy Trust began partnering with NW Natural on Natural's Geographically Targeted Energy Efficiency (GeoTEE) efforts beginning with a Pilot project that ran from 2019-2022. Moving forward, Energy Trust and NW Natural will continue to partner on GeoTEE efforts for the Dallas and McMinnville areas, as described in the action items included in NW Natural's 2025 IRP[2]. Geographically Targeted Energy Efficiency is a strategy designed to achieve incremental peak hour savings in a targeted area where the distribution system is expected to be constrained in the near future, with the goal of delaying the need for system upgrades and reinforcement. GeoTEE is also commonly referred to as Targeted Load Management (TLM).

Energy Trust worked with NW Natural in 2025 to develop localized avoided costs for use in NW Natural efforts in the Dallas and McMinnville areas as part of the 2027 Avoided Cost update process. NW Natural provided localized avoided cost inputs specific to the Dallas and McMinnville areas in their 2025 UM 1983 data submission that reflects the additional value of distribution peak hour savings for these capacity constrained areas. Energy Trust and NW Natural agreed to use a weighted average of the Dallas and McMinnville distribution capacity values to calculate GeoTEE avoided costs where the weighting factor is the cumulative peak load savings need for the locations for the period of 2025-2028 (historical EE reduction and enhanced GeoTEE reductions).

Table 7. GeoTEE Distribution Capacity Values

Avoided Cost Component	2027 AC Blended Value	Dallas AC Value	McMinnville AC Value	Weighted Average GeoTEE AC Value
Distribution Capacity	$224.03	$1,152.04	$767.45	$905.96

Excepting distribution capacity values, all other inputs used to develop GeoTEE avoided costs are derived from NW Natural's statewide UM1893 avoided cost submission. Table 8 below shows the percent increases of GeoTEE avoided costs above the statewide blended and NW Natural base values for residential and commercial heating load profiles using a 22-year measure life.

Table 8. GeoTEE Avoided Costs Compared to Statewide and NW Natural Base

Avoided Costs	Residential Heating 22-year ML	Commercial Heating 22-year ML
GeoTEE compared to 2027 Blended	37.6%	39.9%
GeoTEE compared to 2027 NW Natural Base	26.1%	28.0%

The following figure shows the savings weighted average value of GeoTEE/TLM avoided costs compared to statewide 2027 avoided costs, using Energy Trust's measure mix from 2023 and 2024. GeoTEE avoided costs are 34% higher than 2027 statewide gas avoided costs.

[2] https://www.nwnatural.com/-/media/nwnatural/pdfs/nwn2025integratedresourceplan_chapters.pdf?rev=295fbb822aea43078338643fcdd57f73&hash=6231D4EDB86155212B2142AF10548474

Figure 12 GeoTEE Avoided Costs Compared to 2027 Statewide Avoided Costs

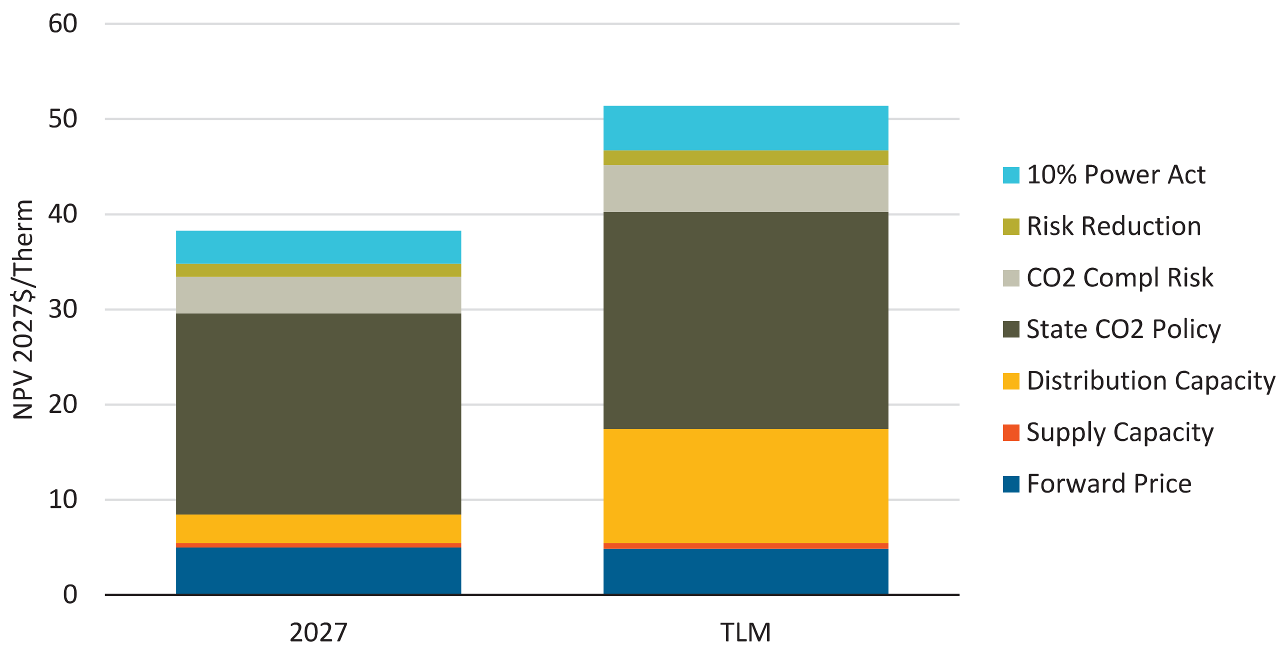
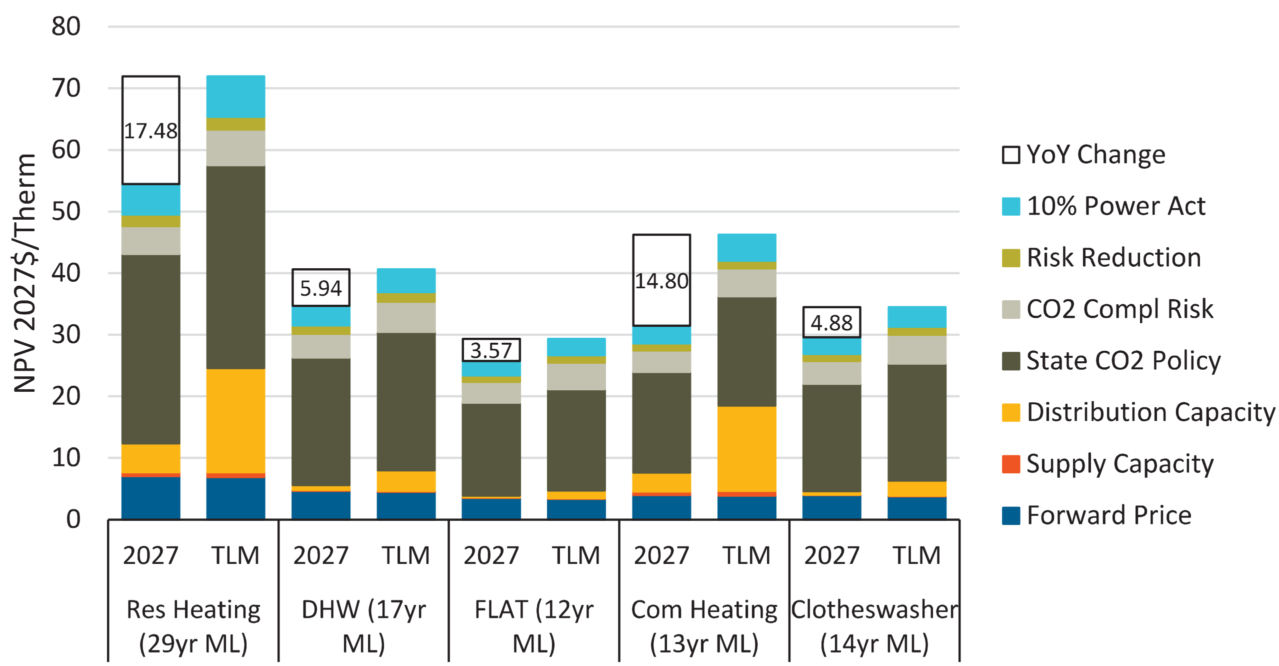


Figure 12 below shows the impact of the individual component parts for GeoTEE/TLM avoided costs and 2027 statewide avoided costs based on a sample of illustrative end use load profiles

Figure 13 Comparison of Load Shape Value by Component, GeoTEE versus 2027 Statewide Avoided Costs



The GeoTEE avoided costs presented here, if approved by the Commission, will be used to determine maximum incentives and to assess the overall cost-effectiveness of GeoTEE activities in the Dallas and McMinnville areas for the years 2027-2030.

Data References

Original submissions and source documentation can be found in the following dockets

Utility	**Report Docket**	**Submission set (main or alternate) unless otherwise specified**
PacifiCorp	RE 181	Main submission; Alt2-4 avoided energy costs (more current; no tax credits); Staff capacity recommendation (1.7% increase over PAC submission)
PGE	RE 182	Main submission (2023 IRP Update), Forward prices (2027-2029); Avoided energy (2030-2043); Two capacity options for commission decision: - Option A: Staff proposal - Option B: PGE submission
Avista	RG 85	Main submission
Cascade	RG 86	Alt Global Inputs (more current); Alt commodity & transport (more current); Alt Environ. Compliance (CPP 2024)
Northwest Natural	RG 87	Main submission plus location-specific avoided distribution infrastructure costs

Global Assumptions Electric

		PacifiCorp		PGE	
Avoided Cost Element	**Units**	**Value**	**Dollar Year**	**Value**	**Dollar Year**
Inflation Rate	Percent	2.18%	N/A	2.04%	N/A
Real Discount Rate	Percent	4.11%	N/A	4.71%	N/A
Regional Act Credit	Percent	10%	N/A	10%	N/A
Transmission Loss Factor	Percent	3.50%	N/A	2.09% (summer); 2.04% (winter)	N/A
Distribution Loss Factor, Commercial	Percent	3.69%	N/A	4.02%	N/A
Distribution Loss Factor, Industrial	Percent	3.20%	N/A	1.96%	N/A
Distribution Loss Factor, Residential	Percent	4.46%	N/A	4.20%	N/A
Risk Reduction Value	$/MWh	*$1.93*	2024	$3.00	2020
Transmission Deferral Credit	$/kW-yr	$7.10	2025	$32.24	2024
Seasonal Capacity Split - Summer	Percent	97.96%	N/A	50%	N/A
Seasonal Capacity Split - Winter	Percent	2.04%	N/A	50%	N/A
Summer Peak Period Definition	Month/Day/Hour	Trans. 12x24 profile	N/A	N/A	N/A
Winter Peak Period Definition	Month/Day/Hour	Trans. 12x24 profile	N/A	N/A	N/A
Deficiency start year	Year	2025	N/A	2026	N/A
Distribution Deferral Credit	$/kW-yr	$15.65	2024	$6.31	2024
Seasonal Capacity Split - Summer	Percent	100.00%	N/A	50%	N/A
Seasonal Capacity Split - Winter	Percent	0.00%	N/A	50%	N/A
Summer Peak Period Definition	Month/Day/Hour	Dist. 12x24 profile	N/A	N/A	N/A
Winter Peak Period Definition	Month/Day/Hour	Dist. 12x24 profile	N/A	N/A	N/A
Deficiency start year	Year	2025	N/A	2026	N/A
Generation Capacity Credit (Option A)	$/kW-yr	$168.93	2027	$438.40	2025
Generation Capacity Credit (Option B)	N/A	N/A	N/A	$284.16	2026
Seasonal Capacity Split - Summer	Percent	58.00%	N/A	50%	N/A
Seasonal Capacity Split - Winter	Percent	42.00%	N/A	50%	N/A
Deficiency start year	Year	2027	N/A	2026	N/A
Transmission Expansion Credit	$/kW-yr (PAC) $/MWh (PGE)	$18.28	2025	$24.44	2027
Already included in energy prices?	Y/N	No	N/A	No	N/A

Avoided Energy Cost

PAC Recommendation	3b) Avoided Energy Costs Alt2-4; Estimated Clean Energy Cost (2025 IRP Energy Resource Net Cost, excluding PTC, Sep 2025 OFPC)
PGE Recommendation	Tab 2) Forward Prices for 2027-2029; Tab 3) Avoided Energy Costs for 2030-2043

Date	**PacifiCorp Average ($/MWh)**	**PGE Average ($/MWh)**
1/1/2027	$86.88	$88.14
2/1/2027	$78.41	$77.43
3/1/2027	$46.62	$50.71
4/1/2027	$39.36	$39.71
5/1/2027	$35.05	$34.71
6/1/2027	$39.10	$36.57
7/1/2027	$65.12	$59.92
8/1/2027	$84.55	$77.33
9/1/2027	$70.43	$66.47
10/1/2027	$56.34	$65.00
11/1/2027	$61.88	$70.41
12/1/2027	$83.83	$83.68
1/1/2028	$85.66	$97.14
2/1/2028	$85.96	$82.61
3/1/2028	$40.16	$50.22
4/1/2028	$34.80	$38.96
5/1/2028	$33.11	$34.31
6/1/2028	$43.99	$35.02
7/1/2028	$70.57	$63.35
8/1/2028	$92.93	$82.64
9/1/2028	$78.32	$67.09
10/1/2028	$70.44	$67.93
11/1/2028	$63.89	$72.47
12/1/2028	$75.49	$82.94
1/1/2029	$79.92	$73.81
2/1/2029	$80.69	$62.08
3/1/2029	$47.09	$40.27
4/1/2029	$37.18	$25.63
5/1/2029	$34.94	$18.87
6/1/2029	$49.48	$18.22
7/1/2029	$85.72	$43.77
8/1/2029	$97.43	$59.33
9/1/2029	$79.04	$52.15
10/1/2029	$62.85	$53.19
11/1/2029	$60.48	$60.15
12/1/2029	$66.88	$69.19
1/1/2030	$69.82	$57.32
2/1/2030	$87.38	$47.25
3/1/2030	$54.50	$34.54

4/1/2030	$41.87	$12.71
5/1/2030	$34.51	$2.99
6/1/2030	$55.11	$1.06
7/1/2030	$98.46	$27.66
8/1/2030	$98.31	$40.83
9/1/2030	$85.32	$42.18
10/1/2030	$62.81	$43.50
11/1/2030	$72.77	$54.27
12/1/2030	$81.32	$62.91
1/1/2031	$96.96	$52.57
2/1/2031	$113.81	$43.44
3/1/2031	$79.74	$30.65
4/1/2031	$69.27	$11.12
5/1/2031	$62.43	$5.71
6/1/2031	$83.31	$2.42
7/1/2031	$124.65	$24.71
8/1/2031	$128.90	$36.59
9/1/2031	$117.11	$37.92
10/1/2031	$86.58	$40.11
11/1/2031	$103.81	$50.87
12/1/2031	$111.63	$59.60
1/1/2032	$103.32	$110.62
2/1/2032	$117.68	$75.32
3/1/2032	$83.07	$61.17
4/1/2032	$72.17	$15.51
5/1/2032	$65.78	$1.90
6/1/2032	$83.83	-$0.62
7/1/2032	$124.23	$45.14
8/1/2032	$133.91	$72.72
9/1/2032	$120.88	$77.50
10/1/2032	$96.28	$82.13
11/1/2032	$109.28	$109.33
12/1/2032	$110.68	$124.41
1/1/2033	$104.19	$108.17
2/1/2033	$113.92	$86.52
3/1/2033	$79.23	$63.26
4/1/2033	$78.26	$17.07
5/1/2033	$67.06	$3.97
6/1/2033	$86.28	$0.48
7/1/2033	$125.86	$46.52
8/1/2033	$151.83	$73.67
9/1/2033	$117.49	$76.57
10/1/2033	$100.13	$81.04
11/1/2033	$113.26	$105.98
12/1/2033	$111.46	$125.22
1/1/2034	$107.97	$120.46
2/1/2034	$126.13	$92.27

3/1/2034	$87.06	$62.05
4/1/2034	$80.08	$15.74
5/1/2034	$71.11	$0.32
6/1/2034	$89.29	$0.11
7/1/2034	$136.09	$42.97
8/1/2034	$143.58	$73.97
9/1/2034	$128.89	$77.88
10/1/2034	$106.48	$82.18
11/1/2034	$115.37	$105.75
12/1/2034	$122.46	$128.00
1/1/2035	$123.75	$12.86
2/1/2035	$132.23	$9.86
3/1/2035	$92.86	$6.47
4/1/2035	$83.20	$1.85
5/1/2035	$69.33	$0.61
6/1/2035	$93.17	$0.42
7/1/2035	$142.21	$4.44
8/1/2035	$147.23	$7.66
9/1/2035	$135.02	$8.03
10/1/2035	$111.21	$8.93
11/1/2035	$122.03	$11.66
12/1/2035	$125.79	$14.36
1/1/2036	$119.74	$125.56
2/1/2036	$143.78	$81.89
3/1/2036	$96.36	$59.57
4/1/2036	$77.10	$20.64
5/1/2036	$67.20	$9.80
6/1/2036	$91.09	$8.93
7/1/2036	$144.75	$37.26
8/1/2036	$150.62	$70.56
9/1/2036	$144.77	$75.09
10/1/2036	$102.80	$82.30
11/1/2036	$131.20	$113.14
12/1/2036	$136.91	$138.83
1/1/2037	$124.85	$140.57
2/1/2037	$147.11	$103.81
3/1/2037	$102.28	$64.77
4/1/2037	$80.77	$23.49
5/1/2037	$66.15	$17.07
6/1/2037	$94.26	$16.36
7/1/2037	$134.09	$36.52
8/1/2037	$147.50	$78.49
9/1/2037	$135.70	$81.66
10/1/2037	$109.26	$90.91
11/1/2037	$131.62	$124.17
12/1/2037	$136.96	$154.63
1/1/2038	$119.74	$124.32

2/1/2038	$159.43	$93.10
3/1/2038	$113.13	$58.04
4/1/2038	$77.75	$20.86
5/1/2038	$66.73	$13.27
6/1/2038	$91.38	$13.25
7/1/2038	$137.40	$34.19
8/1/2038	$146.30	$64.90
9/1/2038	$134.82	$68.69
10/1/2038	$108.84	$78.47
11/1/2038	$147.29	$104.79
12/1/2038	$144.92	$133.50
1/1/2039	$137.07	$60.07
2/1/2039	$145.44	$45.41
3/1/2039	$96.72	$26.35
4/1/2039	$80.29	$9.70
5/1/2039	$62.19	$7.35
6/1/2039	$88.94	$6.72
7/1/2039	$128.84	$12.96
8/1/2039	$153.87	$30.55
9/1/2039	$123.84	$31.06
10/1/2039	$110.63	$38.15
11/1/2039	$138.67	$52.66
12/1/2039	$138.97	$68.33
1/1/2040	$122.85	$335.97
2/1/2040	$138.01	$201.40
3/1/2040	$99.85	$142.48
4/1/2040	$78.77	$47.32
5/1/2040	$61.73	$36.96
6/1/2040	$92.36	$32.73
7/1/2040	$117.40	$71.72
8/1/2040	$138.01	$161.95
9/1/2040	$127.62	$177.96
10/1/2040	$118.36	$209.12
11/1/2040	$133.53	$300.29
12/1/2040	$152.81	$387.78
1/1/2041	$129.98	$99.31
2/1/2041	$149.84	$73.12
3/1/2041	$101.77	$37.16
4/1/2041	$83.16	$13.27
5/1/2041	$48.90	$9.86
6/1/2041	$87.37	$9.47
7/1/2041	$135.32	$18.51
8/1/2041	$129.56	$47.01
9/1/2041	$122.79	$51.90
10/1/2041	$99.52	$62.59
11/1/2041	$131.76	$88.90
12/1/2041	$141.67	$116.00

1/1/2042	$131.10	$98.46
2/1/2042	$188.81	$72.49
3/1/2042	$109.60	$38.03
4/1/2042	$79.16	$12.76
5/1/2042	$54.90	$9.13
6/1/2042	$89.85	$8.64
7/1/2042	$131.24	$20.69
8/1/2042	$141.64	$47.35
9/1/2042	$138.13	$48.33
10/1/2042	$102.81	$59.96
11/1/2042	$144.89	$84.64
12/1/2042	$153.30	$113.27
1/1/2043	$202.17	$102.25
2/1/2043	$196.12	$74.99
3/1/2043	$112.80	$38.28
4/1/2043	$83.67	$13.34
5/1/2043	$64.47	$9.39
6/1/2043	$97.76	$9.16
7/1/2043	$129.20	$17.27
8/1/2043	$139.71	$45.66
9/1/2043	$127.10	$48.95
10/1/2043	$107.76	$61.79
11/1/2043	$150.03	$92.15
12/1/2043	$154.48	$122.55

Avoided Energy Cost

PacifiCorp
20-year levelized net cost of capacity $168.93 2027$
Resources from PacifiCorp 2025 IRP. Final recommendation confirmed by PacifiCorp and PUC Staff after review.

Year	Marginal capacity resource based on IRP Preferred Portfolio	Fixed Cost of Capacity Resource ($/kW-yr)	Net Cost Adjustment 1 ($/kW-yr)	Net Cost Adjustment 3 ($/kW-yr)	Net Cost Adjustment 4 ($/kW-yr)	Effective Load Carrying Capability (ELCC)	Avoided net cost of capacity ($/kW-yr)
2027	Li_ion_4hr-2028	165.21	(41.59)	(64.34)	(8.26)	73%	69.88
2028	Li_ion_4hr-2028	168.81	(42.50)	(0.06)	(0.66)	73%	172.00
2029	Li_ion_4hr-2028	172.49	(43.42)	(2.52)	(0.43)	73%	172.72
2030	IronAir_100hr-2030	252.84	(75.42)	(39.94)	(0.00)	99%	138.86
2031	IronAir_100hr-2030	258.35	(77.06)	(41.04)	(0.04)	99%	141.62
2032	IronAir_100hr-2030	263.98	(78.74)	(36.82)	(3.67)	99%	146.20
2033	IronAir_100hr-2030	269.74	(80.46)	(31.27)	(1.72)	99%	157.86
2034	IronAir_100hr-2030	275.62	(82.21)	(58.83)	(1.67)	99%	134.24
2035	IronAir_100hr-2035	263.42		(43.66)	(2.13)	99%	219.84
2036	IronAir_100hr-2035	269.16		(44.13)	(1.60)	99%	225.68
2037	IronAir_100hr-2035	275.03		(41.36)	(2.19)	99%	233.82
2038	IronAir_100hr-2035	281.03		(36.13)	(1.22)	99%	246.14
2039	IronAir_100hr-2035	287.15		(45.77)	(1.12)	99%	242.69
2040	IronAir_100hr-2035	293.41		(2.42)	(0.03)	99%	293.90
2041	IronAir_100hr-2035	299.81		(3.71)	(0.04)	99%	299.06
2042	IronAir_100hr-2035	306.34		(6.42)	-	99%	302.95
2043	IronAir_100hr-2035	313.02		5.34	-	99%	321.58
2044	IronAir_100hr-2035	319.85		12.58	-	99%	335.78
2045	IronAir_100hr-2035	326.82		(4.14)	-	99%	325.94
2046	IronAir_100hr-2035	333.94		(4.23)	-	99%	333.05

PGE Option A
20-year levelized net cost of capacity $438.40 2025$, $/kW-

Year	Resource	Fixed Cost of Capacity Resource ($/kW-yr)	Tax Credit ($/kW-yr)	Energy Value ($/kW-yr)	Flexibility ($/kW-yr)	Effective Load Carrying Capability (ELCC)	Avoided net cost of capacity ($/kW-yr)
2027	4-hour Battery	$205	($51)	($11)	($15)	32%	$ 399
2028	4-hour Battery	$205	($51)	($11)	($15)	32%	$ 399
2029	4-hour Battery	$205	($51)	($11)	($15)	32%	$ 399
2030	4-hour Battery	$190	($48)	($10)	($20)	32%	$ 354
2031	4-hour Battery	$190	($48)	($10)	($20)	32%	$ 354
2032	4-hour Battery	$184	($46)	($10)	($20)	32%	$ 338

2033	4-hour Battery	$184	($46)	($10)	($20)	32%	$ 338
2034	4-hour Battery	$184	($46)	($10)	($20)	32%	$ 338
2035	4-hour Battery	$184	($46)	($10)	($20)	32%	$ 338
2036	4-hour Battery	$184		($10)	($20)	32%	$ 482
2037	4-hour Battery	$184		($10)	($20)	32%	$ 482
2038	4-hour Battery	$184		($10)	($20)	32%	$ 482
2039	4-hour Battery	$184		($10)	($20)	32%	$ 482
2040	Pumped Hydro	$349		($18)	($17)	52%	$ 604
2041	Pumped Hydro	$349		($18)	($17)	52%	$ 604
2042	Pumped Hydro	$349		($18)	($17)	52%	$ 604
2043	Pumped Hydro	$349		($18)	($17)	52%	$ 604
2044	Pumped Hydro	$349		($18)	($17)	52%	$ 604
2045	Pumped Hydro	$349		($18)	($17)	52%	$ 604

PGE Option B

20-year levelized net cost of capacity $284.16 Real-levelized 2025$, $/kW-yr

Year	Marginal capacity resource based on IRP Preferred Portfolio	Fixed Cost of Capacity Resource ($/kW-yr)	Tax Credit ($/kW-yr)	Integration Cost ($/kW-yr)	Energy Value ($/kW-yr)	Flexibility ($/kW-yr)	Effective Load Carrying Capability (ELCC)	Avoided net cost of capacity ($/kW-yr)
2027	Portfolio-Blended						43%	$249
2028	Portfolio-Blended						43%	$254
2029	Portfolio-Blended						43%	$259
2030	Portfolio-Blended	$245.83	-$69.20	$3.36	$59.92	$7.17	43%	$265
2031	Portfolio-Blended						43%	$270
2032	Portfolio-Blended						43%	$275
2033	Portfolio-Blended						43%	$281
2034	Portfolio-Blended						43%	$287
2035	Portfolio-Blended						43%	$293
2036	Portfolio-Blended						43%	$299
2037	Portfolio-Blended						43%	$305
2038	Portfolio-Blended						43%	$311
2039	Portfolio-Blended						43%	$317
2040	Portfolio-Blended						43%	$324
2041	Portfolio-Blended						43%	$330
2042	Portfolio-Blended						43%	$337
2043	Portfolio-Blended						43%	$344

Loss of Load Probability Heat Map Input Electric

PacifiCorp

Source and page #: Results developed from the LOLP values shown are presented in the 2025 IRP Volume II, Appendix K, pages 180-181

Source Link or File Name: CONF Fig K1-2 LT155264 Stochastic Summary LOLP.xlsb

Source Notes: The 12x24 summary reflects loss of load events from the 2025 IRP preferred portfolio from CY2025-2045

WEEKDAYS & WEEKENDS

Count	31	28	31	30	31	30	31	31	30	31	30	31
Hr Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	-	-	-	-	1%	-	0%	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	0%
8	-	-	-	-	-	-	-	-	-	-	-	3%
9	-	-	-	-	-	-	-	-	-	-	-	0%
10	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	0%	-	-	-	-
17	-	-	-	-	-	-	1%	2%	0%	-	-	5%
18	-	-	-	-	-	1%	3%	2%	0%	-	-	6%
19	-	-	-	-	-	1%	3%	7%	1%	-	-	5%
20	-	-	-	-	-	2%	5%	13%	0%	-	-	4%
21	-	-	-	-	-	1%	2%	2%	0%	-	-	5%
22	-	-	-	-	-	-	1%	2%	0%	-	-	5%
23	-	-	-	-	-	-	1%	2%	-	-	-	3%
24	-	-	-	-	-	-	0%	2%	-	-	-	3%

Note: This information is provided to Energy Trust to identify peak definitions.

PGE

Source and page #:

Source Link or File Name: LOLH_winter_summer_2030_IRP_update

Year: 2030

WEEKDAYS & WEEKENDS

Count	31	28	31	30	31	30	31	31	30	31	30	31
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.01
2	0.00	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.01
3	0.00	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.01
4	0.00	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.01
5	0.01	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.01
6	0.01	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.01
7	0.01	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.02
8	0.01	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.02
9	0.01	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.02
10	0.01	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.02
11	0.01	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.02
12	0.01	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.02
13	0.01	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.02
14	0.01	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.02
15	0.01	0.00	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.02
16	0.01	0.00	0.00	-	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.03
17	0.01	0.00	0.00	-	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.03
18	0.01	0.00	0.00	-	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.03
19	0.01	0.00	0.00	-	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.03
20	0.01	0.00	0.00	-	0.00	0.00	0.01	0.02	0.00	0.00	0.00	0.03
21	0.01	0.00	0.00	-	0.00	0.00	0.01	0.02	0.00	0.00	0.00	0.03
22	0.01	0.00	0.00	-	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.03
23	0.01	0.00	0.00	-	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.02
24	0.01	0.00	0.00	-	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.01

Note: This information is provided to Energy Trust to identify peak definitions.

Global Assumptions Natural Gas

		Avista	Cascade	Northwest Natural
Avoided Cost Element	**Units**	**Value**	**Value**	**Value**
Discount Rate (Company's Real after-tax weighted average cost of capital (WACC)	Percent	4.42%	4.24%	3.87%
Inflation Rate	Percent	2.17%	2.91%	2.45%
Regional Act Credit	Percent	10.00%	10.00%	10.00%
Forecast Period Calendar Start Year	Year	2026	2026	2025
Real Dollar Base Year	Year	2024	2025	2024
System Peak Definition	Calendar Month/Day/Hour	February 28th & December 20th	Day	Day for Gas Supply, Hour for Distribution System Planning
System Peak Coincident Day Factor (if needed)	Peak Day/Annual Load Ratio	0.011137	0.0086	
System Peak Coincident Hour Factor (if needed)	Peak Hour/Annual Load Ratio	0.000696	0.0005	

Avista

2025 Natural Gas IRP (Avista)

Values reflect the cost of procuring physical commodity (natural gas, alternative fuels), cost of transporting physical commodity (reservation cost (fixed), flow cost (variable)), and cost of storing physical commodity (cost of carry) per dekatherm of consumed energy without consideration for compliance with emission caps.

Gas Commodity and Transportation/Storage Costs - (Nominal $/Dth)

Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2027	$3.92	$4.23	$4.07	$3.92	$4.62	$5.75	$7.41	$6.74	$5.78	$4.47	$4.11	$4.08
2028	$4.09	$4.30	$4.20	$3.99	$4.78	$5.83	$7.52	$6.84	$5.75	$4.36	$4.35	$4.14
2029	$4.10	$4.41	$4.27	$3.91	$4.65	$5.74	$7.44	$6.66	$5.64	$4.32	$4.12	$4.14
2030	$4.10	$4.46	$4.52	$4.21	$4.80	$5.82	$7.41	$6.71	$5.63	$4.27	$4.29	$4.11
2031	$4.02	$4.19	$4.25	$4.23	$5.03	$6.09	$7.72	$7.02	$5.92	$4.62	$4.39	$4.32
2032	$4.18	$4.21	$4.33	$4.43	$5.27	$6.27	$7.98	$7.30	$6.25	$4.82	$4.68	$4.56
2033	$4.42	$4.63	$4.71	$4.75	$5.59	$6.62	$8.38	$7.65	$6.44	$4.98	$4.84	$4.68
2034	$4.63	$4.77	$4.82	$4.94	$5.80	$6.86	$8.63	$7.90	$6.69	$5.19	$5.01	$4.81
2035	$4.77	$4.83	$4.96	$5.02	$5.90	$7.09	$8.77	$8.12	$6.90	$5.37	$5.18	$4.91
2036	$4.81	$4.93	$5.06	$5.22	$6.15	$7.24	$9.16	$8.37	$7.11	$5.55	$5.30	$5.14
2037	$4.98	$5.06	$5.18	$5.32	$6.20	$7.34	$9.40	$8.44	$7.24	$5.69	$5.43	$5.18
2038	$5.09	$5.26	$5.37	$5.43	$6.39	$7.54	$9.56	$8.61	$7.47	$5.81	$5.69	$5.41
2039	$5.24	$5.40	$5.49	$5.53	$6.52	$7.69	$9.76	$8.74	$7.53	$5.90	$5.82	$5.52
2040	$5.31	$5.71	$5.80	$5.81	$6.82	$8.07	$10.19	$9.13	$7.94	$6.28	$6.14	$5.76
2041	$5.58	$5.83	$5.88	$5.93	$6.97	$8.15	$10.35	$9.27	$8.08	$6.39	$6.21	$5.99
2042	$5.69	$5.97	$6.08	$6.07	$7.14	$8.41	$10.43	$9.44	$8.20	$6.51	$6.38	$6.01
2043	$5.81	$6.04	$6.12	$6.13	$7.21	$8.49	$10.62	$9.67	$8.41	$6.61	$6.45	$6.15
2044	$5.85	$6.23	$6.37	$6.30	$7.39	$8.74	$10.92	$9.85	$8.64	$6.83	$6.60	$6.29
2045	$6.02	$6.38	$6.49	$6.44	$7.55	$8.98	$11.15	$10.03	$8.84	$7.04	$6.25	$6.04

Cascade

Commodity Cost Calculation Workbook.xlsx - Sourcing data from IRP LT Price Forecast 2025-10-01.xlsm

Cascade's 10/1/2025 commodity cost forecast

Gas Commodity and Transportation/Storage Costs - (Real 2025$/Dth)

Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2027	$6.46	$5.58	$3.64	$2.60	$2.49	$2.63	$3.22	$3.30	$3.23	$3.01	$4.56	$6.59
2028	$6.88	$5.90	$3.60	$2.59	$2.49	$2.62	$3.17	$3.24	$3.20	$3.07	$4.55	$6.34
2029	$6.53	$6.03	$3.82	$2.42	$2.40	$2.53	$2.97	$3.03	$3.01	$3.05	$4.70	$5.67
2030	$5.33	$4.88	$3.94	$2.28	$2.24	$2.35	$2.69	$2.75	$2.71	$2.79	$4.52	$5.18
2031	$5.05	$4.70	$4.12	$2.20	$2.21	$2.32	$2.65	$2.73	$2.70	$2.77	$4.38	$4.96
2032	$5.30	$4.93	$4.28	$2.11	$2.09	$2.21	$2.57	$2.64	$2.61	$2.70	$4.23	$4.82
2033	$5.15	$4.78	$4.22	$2.08	$2.11	$2.22	$2.59	$2.64	$2.61	$2.67	$4.26	$4.82
2034	$5.13	$4.79	$4.25	$2.15	$2.19	$2.28	$2.64	$2.68	$2.69	$2.76	$4.27	$4.83
2035	$5.16	$4.82	$4.45	$2.42	$2.40	$2.41	$2.65	$2.70	$2.71	$2.77	$4.40	$4.86
2036	$5.08	$4.81	$4.60	$2.57	$2.56	$2.57	$2.81	$2.85	$2.86	$2.93	$4.43	$4.74
2037	$4.92	$4.67	$4.53	$2.50	$2.49	$2.49	$2.73	$2.78	$2.79	$2.85	$4.35	$4.67
2038	$4.95	$4.70	$4.56	$2.53	$2.52	$2.52	$2.77	$2.81	$2.82	$2.89	$4.39	$4.70
2039	$4.99	$4.74	$4.60	$2.56	$2.55	$2.56	$2.80	$2.85	$2.85	$2.92	$4.42	$4.74
2040	$5.03	$4.78	$4.63	$2.60	$2.58	$2.59	$2.83	$2.88	$2.89	$2.95	$4.45	$4.78
2041	$5.07	$4.82	$4.67	$2.63	$2.61	$2.62	$2.87	$2.91	$2.92	$2.99	$4.49	$4.81
2042	$5.12	$4.86	$4.71	$2.66	$2.65	$2.66	$2.90	$2.95	$2.96	$3.02	$4.52	$4.85
2043	$5.16	$4.90	$4.74	$2.70	$2.68	$2.69	$2.93	$2.98	$2.99	$3.06	$4.56	$4.89
2044	$5.20	$4.94	$4.78	$2.73	$2.72	$2.73	$2.97	$3.02	$3.03	$3.10	$4.60	$4.93
2045	$5.24	$4.98	$4.82	$2.76	$2.75	$2.76	$3.01	$3.05	$3.06	$3.13	$4.64	$4.97
2046	$5.28	$5.02	$4.86	$2.80	$2.79	$2.80	$3.04	$3.09	$3.10	$3.17	$4.67	$5.01

Northwest Natural

2025 IRP PLEXO model outcome for the reference case

Gas Commodity and Transportation/Storage Costs (Real 2024$/Dth)

Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2027	$ 5.95	$ 4.07	$ 3.88	$ 3.29	$ 2.85	$ 2.73	$ 2.40	$ 2.62	$ 3.04	$ 2.97	$ 3.88	$ 5.35
2028	$ 5.20	$ 3.92	$ 4.15	$ 3.74	$ 2.60	$ 2.96	$ 3.03	$ 3.02	$ 3.09	$ 2.95	$ 3.68	$ 4.62
2029	$ 4.13	$ 3.18	$ 3.23	$ 2.94	$ 2.96	$ 2.76	$ 2.96	$ 2.43	$ 2.81	$ 2.97	$ 3.92	$ 4.28
2030	$ 4.17	$ 2.94	$ 3.18	$ 2.60	$ 2.62	$ 2.47	$ 2.50	$ 2.64	$ 2.43	$ 2.61	$ 3.90	$ 4.00
2031	$ 3.00	$ 3.28	$ 3.17	$ 2.82	$ 2.75	$ 2.66	$ 2.79	$ 2.60	$ 2.61	$ 2.70	$ 3.76	$ 4.21
2032	$ 3.12	$ 3.41	$ 3.37	$ 2.93	$ 3.02	$ 2.79	$ 2.90	$ 2.92	$ 2.84	$ 2.86	$ 3.69	$ 4.24
2033	$ 3.13	$ 3.37	$ 3.37	$ 3.07	$ 3.06	$ 2.81	$ 2.88	$ 2.89	$ 2.86	$ 2.88	$ 3.68	$ 4.23
2034	$ 3.19	$ 3.40	$ 3.54	$ 3.22	$ 3.09	$ 2.96	$ 3.07	$ 3.09	$ 3.06	$ 3.08	$ 3.83	$ 4.36
2035	$ 3.50	$ 3.53	$ 3.71	$ 3.39	$ 3.28	$ 3.43	$ 3.33	$ 3.36	$ 3.13	$ 3.15	$ 4.16	$ 3.93
2036	$ 4.58	$ 3.54	$ 3.66	$ 3.23	$ 3.27	$ 3.37	$ 3.42	$ 3.42	$ 3.31	$ 3.35	$ 4.15	$ 4.65
2037	$ 4.62	$ 3.68	$ 3.81	$ 3.58	$ 3.50	$ 3.52	$ 3.63	$ 3.65	$ 3.35	$ 3.37	$ 4.23	$ 4.68
2038	$ 4.72	$ 3.80	$ 3.93	$ 3.53	$ 3.55	$ 3.66	$ 3.77	$ 3.79	$ 3.50	$ 3.52	$ 4.04	$ 4.60
2039	$ 4.63	$ 3.72	$ 3.93	$ 3.70	$ 3.67	$ 3.70	$ 3.73	$ 3.75	$ 3.47	$ 3.49	$ 4.08	$ 4.61
2040	$ 4.60	$ 3.77	$ 3.88	$ 3.57	$ 3.49	$ 3.60	$ 3.66	$ 3.64	$ 3.40	$ 3.42	$ 4.23	$ 4.71
2041	$ 4.69	$ 3.77	$ 3.97	$ 3.64	$ 3.46	$ 3.57	$ 3.67	$ 3.68	$ 3.41	$ 3.43	$ 4.13	$ 4.56
2042	$ 4.34	$ 3.73	$ 3.90	$ 3.76	$ 3.65	$ 3.72	$ 3.74	$ 3.77	$ 3.43	$ 3.44	$ 4.22	$ 4.29
2043	$ 4.63	$ 3.83	$ 3.92	$ 3.71	$ 3.65	$ 3.79	$ 3.81	$ 3.81	$ 3.57	$ 3.60	$ 4.40	$ 4.27
2044	$ 4.72	$ 4.00	$ 4.09	$ 3.81	$ 3.79	$ 3.85	$ 3.92	$ 3.93	$ 3.64	$ 3.64	$ 4.24	$ 4.02
2045	$ 4.44	$ 4.07	$ 4.08	$ 3.87	$ 3.86	$ 3.96	$ 4.02	$ 3.95	$ 3.75	$ 3.78	$ 4.35	$ 4.00
2046	$ 4.48	$ 3.96	$ 3.99	$ 3.95	$ 3.88	$ 3.97	$ 3.87	$ 3.98	$ 3.74	$ 3.83	$ 4.46	$ 4.31
2047	$ 4.69	$ 4.23	$ 4.21	$ 4.13	$ 4.01	$ 4.10	$ 4.12	$ 4.01	$ 3.76	$ 3.79	$ 4.39	$ 4.62
2048	$ 4.30	$ 4.25	$ 4.19	$ 4.10	$ 4.05	$ 4.08	$ 4.14	$ 3.88	$ 3.82	$ 3.84	$ 4.43	$ 4.19
2049	$ 4.67	$ 4.10	$ 4.11	$ 4.23	$ 4.08	$ 4.21	$ 4.23	$ 3.97	$ 3.84	$ 3.86	$ 4.36	$ 4.64
2050	$ 4.19	$ 4.21	$ 4.22	$ 4.05	$ 4.06	$ 3.93	$ 3.71	$ 4.19	$ 3.77	$ 3.89	$ 4.45	$ 4.12

Environmental Compliance Natural Gas - Carbon Intesity (MTCO2e/Dth)

	Avista		Cascade		NW Natural	
Year	Compliance Resource	Cost (Nominal $/Dth)	Compliance Resource	Cost (Real 2025 $/Dth)	Compliance Resource	Cost (Real 2024 $/Dth)
2027	N/A	$6.809	RNG - LFG-5	$10.300	CCI	$8.122
2028	CCI	$7.035	RNG - LFG-5	$10.560	Near-term RTC Purchase	$20.240
2029	CCI	$7.267	RNG - LFG-5	$10.850	Near-term RTC Purchase	$20.257
2030	RNG - LFG 4	$7.501	RNG - LFG-5	$11.190	LFG-Mid	$14.014
2031	RNG - WW 5	$7.740	RNG - LFG-5	$11.570	LFG-Mid	$14.032
2032	RNG - LFG 3	$7.982	RNG - LFG-4	$14.120	LFG-Mid	$17.359
2033	RNG - LFG 4	$8.232	RNG - LFG-4	$14.630	LFG-Mid	$17.376
2034	RNG - LFG 4	$8.490	RNG - LFG-4	$15.220	LFG-Mid	$17.254
2035	RNG - LFG 4	$8.756	RNG - LFG-4	$15.800	LFG-Mid	$17.271
2036	RNG - LFG 4	$9.029	RNG - LFG-4	$16.360	LFG-Mid	$17.333
2037	RNG - LFG 4	$9.311	RNG - LFG-4	$16.950	LFG-Mid	$17.355
2038	RNG - LFG 5	$9.601	RNG - LFG-4	$17.590	SM-Biomass	$20.868
2039	RNG - LFG 5	$9.899	RNG - LFG-4	$18.270	SM-Biomass	$20.890
2040	RNG - LFG 4	$10.208	RNG - LFG-4	$18.950	SM-Biomass	$21.022
2041	RNG - LFG 4	$10.523	RNG - LFG-4	$19.700	SM-Biomass	$21.040
2042	RNG - LFG 4	$10.850	RNG - LFG-4	$20.420	SM-Biomass	$21.117
2043	RNG - LFG 4	$11.187	RNG - LFG-4	$21.140	SM-Biomass	$21.134
2044	RNG - WW 5	$11.535	RNG - LFG-4	$21.880	SM-Biomass	$21.341
2045	RNG - LFG 3	$11.892	RNG - LFG-4	$22.650	SM-Biomass	$21.359
2046			RNG - LFG-4	$23.460	SM-Biomass	$21.491
2047					SM-Biomass	$21.513
2048					SM-Biomass	$21.676
2049					SM-Biomass	$21.698
2050					SM-Biomass	$21.850

Environmental Compliance Risk Reduction Value

	Avista	Cascade	NW Natural
Year	Nominal $/Dth	Real 2025 $/Dth	Real 2024 $/Dth
2027	$0.000	$0.036	$2.752
2028	$0.000	$0.036	$3.573
2029	$0.000	$0.041	$5.950
2030	$0.298	$0.045	$5.405
2031	$0.435	$0.049	$4.954
2032	$0.382	$0.068	$4.946
2033	$0.304	$0.070	$4.975
2034	$0.307	$0.075	$4.738
2035	$0.311	$0.079	$4.577
2036	$0.319	$0.084	$3.914
2037	$0.327	$0.088	$3.669
2038	$0.273	$0.091	$2.702
2039	$0.283	$0.095	$2.754

2040	$0.354	$0.101	$2.837
2041	$0.354	$0.106	$2.606
2042	$0.357	$0.111	$0.904
2043	$0.364	$0.115	$1.301
2044	$0.603	$0.120	$1.269
2045	$0.503	$0.124	$1.249
2046		$0.129	$1.810
2047			$1.780
2048			$1.773
2049			$1.905
2050			$1.814

Infrastructure Costs Natural Gas

	Avista (Nominal)			Cascade			Northwest Natural (Real 2024$)		
Year	Supply ($/ Dth/Day)	Distribution Peak DAY ($/ Dth/Day)	Distribution Peak HOUR ($/ Dth/Hour)	Supply ($/ Dth/Day)	Distribution Peak DAY ($/ Dth/Day)	Distribution Peak HOUR ($/ Dth/Hour)	Supply ($/ Dth/Day)	Distribution Peak DAY ($/ Dth/Day)	Distribution Peak HOUR ($/ Dth/Hour)
2027	$0.014	$0.053	$0.003	Company left blank			$0.182	N/A	$0.306
2028	$0.014	$0.055	$0.003				$0.182	N/A	$0.306
2029	$0.015	$0.057	$0.004				$0.182	N/A	$0.306
2030	$0.015	$0.060	$0.004				$0.182	N/A	$0.306
2031	$0.016	$0.062	$0.004				$0.182	N/A	$0.306
2032	$0.016	$0.065	$0.004				$0.182	N/A	$0.306
2033	$0.017	$0.068	$0.004				$0.182	N/A	$0.306
2034	$0.018	$0.070	$0.004				$0.000	N/A	$0.306
2035	$0.018	$0.073	$0.005				$0.000	N/A	$0.306
2036	$0.019	$0.075	$0.005				$0.000	N/A	$0.306
2037	$0.020	$0.078	$0.005				$0.000	N/A	$0.306
2038	$0.020	$0.081	$0.005				$0.000	N/A	$0.306
2039	$0.021	$0.085	$0.005				$0.000	N/A	$0.306
2040	$0.022	$0.088	$0.005				$0.000	N/A	$0.306
2041	$0.023	$0.091	$0.006				$0.000	N/A	$0.306
2042	$0.024	$0.095	$0.006				$0.000	N/A	$0.306
2043	$0.024	$0.098	$0.006				$0.000	N/A	$0.306
2044	$0.025	$0.101	$0.006				$0.000	N/A	$0.306
2045	$0.026	$0.105	$0.007				$0.000	N/A	$0.306
2046							$0.000	N/A	$0.306
2047							$0.000	N/A	$0.306
2048							$0.000	N/A	$0.306
2049							$0.000	N/A	$0.306
2050							$0.000	N/A	$0.306

Risk Reduction Value Natural Gas

	Avista	Cascade	Northwest Natural
Year	Risk Reduction Value ($/Dth)	Risk Reduction Value (Real 2021$/Dth)	Risk Reduction Value (Real 2024$/Dth)
2027	Company left blank	$0.014	$0.874
2028		$0.012	$0.875
2029		$0.012	$0.976
2030		$0.012	$1.008
2031		-$0.011	$1.042
2032		-$0.011	$1.121
2033		-$0.014	$1.096
2034		-$0.043	$1.085
2035		-$0.052	$1.249
2036		-$0.053	$1.266
2037		$0.030	$1.357
2038		$0.036	$1.361
2039		$0.107	$1.395
2040		$0.142	$1.443
2041		$0.208	$1.387
2042		$0.173	$1.481
2043		$0.205	$1.512
2044		$0.297	$1.438
2045		$0.332	$1.564
2046		$0.397	$1.541
2047		$0.220	$1.551
2048		$0.153	$1.549
2049		$0.092	$1.589
2050		$0.033	$1.830

Note: Negative values will be applied as zero.

End Use Load Profiles Natural Gas

This information is provided for Energy Trust to have available. Energy Trust determines what source to use for load profiles.

Avista

2025 Natural Gas IRP (Avista)

Monthly values based on load forecast by end use provided by AEG for Oregon territory in 2026. This is for firm customers in residential, commercial, and industrial classes. Peak values reflect gross energy demand in 2026 in the PRS by end use, specific to the peak day for each end use (DSM is not removed from these values).

End Use Profiles	**Monthly Share of Normal Weather Annual Load**												
End Use	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Residential Space Heating	0.194	0.155	0.113	0.084	0.043	0.018	0.001	0.005	0.016	0.060	0.129	0.182	4,193,635
Residential Secondary Heating	0.194	0.155	0.113	0.084	0.043	0.018	0.001	0.005	0.016	0.060	0.129	0.182	41,863
Residential Water Heating	0.085	0.077	0.085	0.082	0.085	0.082	0.085	0.085	0.082	0.085	0.082	0.085	836,846
Residential Appliances	0.085	0.077	0.085	0.082	0.085	0.082	0.085	0.085	0.082	0.085	0.082	0.085	245,212
Residential Miscellaneous	0.085	0.077	0.085	0.082	0.085	0.082	0.085	0.085	0.082	0.085	0.082	0.085	14,256
Commercial Space Heating	0.189	0.156	0.104	0.084	0.041	0.019	0.001	0.012	0.024	0.071	0.123	0.176	1,923,986
Commercial Water Heating	0.085	0.077	0.085	0.082	0.085	0.082	0.085	0.085	0.082	0.085	0.082	0.085	762,756
Commercial Food Preparation	0.085	0.077	0.085	0.082	0.085	0.082	0.085	0.085	0.082	0.085	0.082	0.085	460,028
Commercial Miscellaneous	0.085	0.077	0.085	0.082	0.085	0.082	0.085	0.085	0.082	0.085	0.082	0.085	146,978
Industrial Space Heating	0.026	0.023	0.016	0.013	0.011	0.027	0.215	0.059	0.194	0.197	0.184	0.034	2,279
Industrial Process	0.075	0.064	0.072	0.072	0.081	0.083	0.085	0.098	0.110	0.092	0.083	0.084	50,949
Industrial Miscellaneous	0.075	0.064	0.072	0.072	0.081	0.083	0.085	0.098	0.110	0.092	0.083	0.084	3,017
Total	1,399,072	1,151,827	892,023	725,311	474,675	320,314	220,496	258,536	321,166	606,960	989,022	1,322,403	8,681,806

This information is provided for Energy Trust to have available. Energy Trust determines what source to use for load profiles.

Cascade left this submission blank for 2027 avoided costs

Northwest Natural

Tables 5.2 and 5.3 for peak day and peak hour ratios in Chapter 5 of the 2025 IRP.

	Monthly Share of Normal Weather Annual Load											
End Use	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Residential Space Heating (Including Hearths and Fireplaces)	0.204	0.145	0.123	0.070	0.033	0.006	0.000	0.001	0.008	0.062	0.129	0.218
Commercial Space Heating	0.204	0.145	0.123	0.070	0.033	0.006	0.000	0.001	0.008	0.062	0.129	0.218
Water Heating	0.101	0.096	0.092	0.088	0.083	0.079	0.073	0.068	0.069	0.073	0.081	0.095
Cooking	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083
Process Load	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083

End Use	**Peak Day**	**Peak Hour**
Residential Space Heating (Including Hearths and Fireplaces)	0.01767	0.00092
Commercial Space Heating	0.01767	0.00106
Water Heating	0.00330	0.00018
Cooking	0.00356	0.00028
Process Load	0.00274	0.00011