# Chapter 5. Cost Effectiveness Practice

*This section describes PGE's cost effectiveness practice. For results of the benefit cost analyses and ratios presented in the body the document, see Table 3 and Section 4.2.*

Chapter 7 of PGE's 2022-2023 Flex Load Multi-Year Plan[68] featured an in-depth discussion of benefit-cost analysis (BCA) for the resource, as well as a review of relevant National Standard Practice Manual (NSPM)[69] standards. In their conclusory report, Staff noted that they "appreciate[] PGE's efforts to evaluate cost effectiveness and look[] forward to hearing PGE's recommended changes to the methodology."[70]

The changes presented herein further that discussion, and better align PGE's cost effectiveness practice with regional, local, and industry-wide best practice. In addition to providing new perspectives on the economic value of the Flex Load resource, PGE also anticipates these changes may inform future activities such as non-wire solutions.

The following sections present current adjustments to PGE's cost effectiveness practice for Flex Load, spanning refinement of incremental costs, incorporation of a broader set of values used to assess other demand side management resources, and the time frame of analysis. The chapter then concludes with brief discussion of prospective adjustments also under consideration.

## 5.1 Current Adjustments

### 5.1.1 Current Adjustment I. Recalculate TRC Costs to Account for Energy Trust of Oregon Incentives

*Note that this adjustment **is** reflected in the benefit cost analyses and ratios presented in the body the document (Table 3 and Section 4.2).*

This adjustment to the cost effectiveness methodology of Flex Load programs addresses the treatment of incremental costs for Energy Trust of Oregon incentives and participant costs.

Historically, cost effectiveness evaluations for Flex Load programs co-deployed with external parties have not accounted for funding from those sources. Such external funding has only been accounted for in the participant cost test's (PCT) measure of direct financial benefits to a customer's household; it is missing from the total resource cost test (TRC).

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[68] PGE (2021). *Flexible Load Multi-Year Plan 2022-2023.* Retrieved from https://edocs.puc.state.or.us/efdocs/HAD/um2141had16243.pdf.

[69] The National Standard Practice Manual provides a comprehensive framework for evaluating the cost-effectiveness of distributed energy resources. It emphasizes the identification, incorporation, and documentation of benefits and costs in DER program assessments. The framework is intended to ensure that the cost-effectiveness evaluation of these resources is comparative to alternatives such as high-cost market purchases and traditional utility investments. Case studies on the application of the manual by utilities and regulatory bodies can be found at https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/nspm-application-by-state/.

[70] OPUC (2022) *Staff Report: PGE's 2022-2023 Flexible Load Multi-Year Plan*. https://apps.puc.state.or.us/orders/2022ords/22-023.pdf.

In 2018, OPUC staff provided guidance to the Trust regarding the co-mingling of incentives with specific non-PPC funds.[71] That guidance states that, where present, complementary funds should be treated as cost reductions in TRC calculations. Eligible sources of complementary funding include:

- Tax credits for energy efficiency measures
- Governmental grant programs, such as the Portland Clean Energy Fund
- Non-governmental grant programs, such as those offered by Community Based Organizations (CBOs)
- Ratepayer funds complementary to energy efficiency, such as those provided by utility demand response programs
- Low-income energy efficiency funding within specific frameworks defined in UM 2025[72]

Accounting for energy efficiency incentives and other non-DR funding makes PGE's benefit-cost analyses symmetrical with Energy Trust of Oregon's treatment of DR incentives in their valuation of energy efficiency without double counting cost credits. Adoption of this approach has a significant TRC impact for direct install programs, which bear the full costs associated with participation.

PGE has adjusted its treatment of Flex Load programs co-deployed with Energy Trust of Oregon (such as Residential Smart Thermostats and Energy Partner Smart Thermostat), now deducting Energy Trust of Oregon incentives from program costs. In the past the incentives provided by the Energy Trust were not accounted for in TRC cost calculations. Accounting for these types of incentives in the TRC results in a reduction of costs, thereby properly accounting for the benefit of non-DR incentives based on OPUC guidance.

PGE is also exploring additional adjustments to the treatment of costs for co-funded or co-deployed programs, as detailed in Prospective Adjustment III, below.

### 5.1.2 Current Adjustment II. Incorporate UM 1893 Energy Efficiency Avoided Cost Values

*Note that this adjustment **is** reflected in the benefit cost analyses and ratios presented in the body the document (Table 3 and Section 4.2).*

Current PGE demand response avoided costs consist of avoided generation capacity and line loss values, which are a subset of the input suite for energy efficiency avoided cost calculations in UM 1893.

This adjustment to cost effectiveness methodology incorporates all UM 1893 avoided cost values used by Energy Trust of Oregon including transmission and distribution deferral credits, risk reduction value, and the regional conservation credit, detailed below. PGE reviewed the application of both the transmission and distribution deferral and avoided costs in other jurisdictions, and also their calculation in the PGE Avoided Cost Study (submitted as part of the GRC). We believe the application of the T&D avoided cost value in UM 1893 should be revised to better reflect to direct impact of demand side management resources to the distribution and transmission system generally.

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[71] OPUC (2018). UM 2025, Order No. 19-232 *Memo: Guidance for Combining Funds Between Energy Efficiency Ratepayer Money and Other Sources of Money*. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-232.pdf.

[72] OPUC (2019). UM 2025, Order No. 19-232 Recommendations to Establish a Methodology for Reviewing Collaborations between Energy Trust of Oregon and Other Organizations Who Are Funding Low Income Energy Efficiency. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-232.pdf.

PGE plans to provide a new perspective and approach for review by the Commission and stakeholders in our upcoming DSP filing.

Note that this filing reflects PGE's initial application of these UM 1893 values to this resource. PGE recognizes that while demand response and energy efficiency are similarly situated customer resources, they operate differently. Therefore, PGE will, prior to the next MYP, explore the efficacy of using the T&D deferral value for this analysis and whether a different T&D deferral methodology for demand response is warranted. Should a different value arise, PGE will share it OPUC Staff.

#### 5.1.2.1 Transmission and Distribution Deferral Credits

PGE proposes incorporating transmission and distribution infrastructure deferral values to its benefit-cost testing methods. This change reflects the comprehensive value which these programs offer to the electric grid. Transmission and distribution systems constitute a significant portion of utility infrastructure costs, and any reduction or deferral in the need for these investments can result in substantial cost savings. The inclusion and use of these UM 1893 avoided cost submission values in demand response cost effectiveness analysis is in line with California Demand Response Cost Effectiveness Protocols[73], which the Commission Staff directed PGE to use beginning in 2016.[74] It is also in line with UM 1893 avoided costs, and the Northwest Power Conservation Council's 8th Power Plan[75], which incorporated regional demand response and the National Standards Practice Manual for Distributed Energy Resources.

#### 5.1.2.2 Risk Reduction Value

To align more closely with local energy efficiency avoided cost valuation, PGE is incorporating the risk premium $/MWH submitted with UM1893 avoided cost updates. This value represents demand-side management's contribution to reducing exposure to market volatility, over and above forecasted energy prices, during high load hours.

PGE will explore avenues to refine the value of avoided market purchases of energy during DR events to better define the risk reduction value of flexible load resources. PGE recognizes this potential value, as does Staff, which recently requested the historic market prices during periods where PGE's demand response portfolio was dispatched.

#### 5.1.2.3 Regional Conservation Credit

The NW Power Act credit was written with electric energy efficiency in mind but does not exclude its application to other demand side management resources.[76] Both the Regional Technical Forum's measure guidelines and UM 1893 apply the 10% credit to natural gas and electricity to incorporate difficult-to-quantify benefits associated with demand side management practices. Demand response

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[73] California Public Utility Commission (2016). *2016 Demand Response Cost Effectiveness Protocols*, *Section 3B: Avoided Costs of Supplying Electricity, pp.26-29*. Retrieved from https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/cost-effectiveness/2016-dr-cost-effectiveness-protocols---clean.docx.

[74] See Oregon public Utilities Commission Dockets UM 1708 and UM 1514 (2016)

[75] Northwest Power Conservation Council (2021). *The 2021 Northwest Power Plan*. Retrieved from https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf.

[76] Northwest Power Conservation Act of 1980 Section 839d(a)

and Flex Load are similarly situated to energy efficiency in regard to benefits of the activity, which are at present difficult to quantify.

Usage of the Power Act credit is core to Northwest Power and Conservation Council (NPCC) energy planning efforts. Several utilities and entities across the Pacific Northwest have implemented the 10% conservation credit under the Northwest Power Act. Notable examples include Bonneville Power Administration (the largest power supplier in the region), which incorporated the credit to reduce peak demand and avoid construction of new power plants and Seattle City Light (one of the largest public utilities), which heavily invested in DSM and benefits from the credit. Smaller utilities such as Clark Public Utilities and Eugene Water and Electric Board have also utilized the credit to encourage investments in efficiency. The Northwest Energy Efficiency Alliance has also played a key role in regional adoption of these measures.

The application of the regional conservation credit to demand response resources aligns with its application to other demand side management practices. A recent example of this was PGE's 2023 Integrated Resource Plan, which utilized the credit to account for unknown, unquantified benefits of DSM measures in its modeling of Community Based Renewable Energy serving vulnerable communities.

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In line with the latest UM 1893 update[78], PGE applies the regional credit to all components of the avoided costs considered in BCA.

### 5.1.3 Current Adjustment III. Time Frame of Benefit-Cost Analysis

*Note that this adjustment **is not** reflected in the benefit cost analyses and ratios presented in the body the document (Table 3 and Section 4.2). Rather it provides an additional perspective to consider when making decisions regarding incremental investment.*

This adjustment to our cost effectiveness methodology for Flex Load programs adds a forward-looking benefit-cost perspective. This change aligns with the national standard practice manual approach to valuing distributed energy resources.[79]

To date, PGE's Flex Load programs have been evaluated for cost-effectiveness solely on a "full lifecycle" methodology. Such treatment includes the net present value (NPV) of all benefit and cost streams back to the first year of a program's economic life through to its anticipated sunset. This view

[77] Portland General Electric. *2023 Clean Energy Plan and Integrated Resource Plan, Chapter 7: Resource Options.* Portland General Electric, 2023, p. 143. Retrieved from https://assets.ctfassets.net/416ywc1laqmd/3pRvjUAdaEA6Wzk8yBUEsE/cafdf75509cf7c3432773e9809074954/2023_CEP-IRP_Ch_07.pdf.

[78] Oregon Public Utility Commission. (April 24, 2024). *Staff Report on UM 1893, p.7.* Retrieved from https://edocs.puc.state.or.us/efdocs/HAU/um1893hau328091055.pdf.

[79] National Efficiency Screening Project (2020). *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*. Page 2-6. National Efficiency Screening Project. Retrieved from https://www.nationalenergyscreeningproject.org/wp-content/uploads/2019/06/NSPM-for-DERs.pdf.

is useful when comparing DR programs to other long-lived capital assets. The time horizon considered in the full lifecycle analysis is shown below in Table 43.

Table 43. Flexible Load Full Lifecycle Time Horizon Considered in Cost Effectiveness Evaluation

| Flex Load Pilot/Program | Full Lifecycle Benefit-Cost Start Year | Full Lifecycle Benefit-Cost End Year |
|---|---|---|
| Residential Smart Thermostat | 2017 | 2036 |
| Peak Time Rebates | 2019 | 2030 |
| Time of Day | 2021 | 2030 |
| Energy Partner on Demand (Sch 26) | 2017 | 2042 |
| Multi-Family Water Heater | 2018 | 2042 |
| Energy Partner Smart Thermostats (Sch 25) | 2023 | 2032 |
| Flexible Load Portfolio | 2017 | 2042 |

The addition of a forward-looking perspective accounts for the present value of benefits and costs from a base year through to the program's anticipated sunset. For this MYP submission, the base years considered in the forward-looking analysis will be the funding years 2025 and 2026.

This approach more closely mirrors Integrated Resource Plan modeling of the future costs and benefits of energy generation and acquisition, energy efficiency, and also demand reduction options.[80]

While past costs and benefits are useful to assess lessons learned and relative performance of a program over time, relying solely on a full lifecycle benefit-cost analysis has drawbacks for program decision-making. Attempts to tie specific values of portfolio costs over the full lifecycle can result in erroneous conclusions about current and potential cost-effectiveness. This is because, as a program ages, the preponderance of past costs and benefits increasingly outweigh the impact of any current design changes, which interferes with incremental investment decision-making. A forward-looking perspective provides the needed lens to make appropriate decisions regarding applicable incremental investment.

[80] IRP modeling does not generally consider past expenditures or sunk costs in decision-making, instead emphasizing the prudence and public interest of future investments.

Table 44. Additional Cost Effectiveness Perspective III: a Forward-Looking Time Frame

| Activity | Full Lifecycle TRC (2025-2026) | Forward-Looking TRC (2025-2026) |
|---|---|---|
| Residential Smart Thermostats | 3.90 | 5.00 |
| Peak Time Rebates | 1.13 | 2.41 |
| Time of Day | 2.52 | 4.40 |
| Energy Partner on Demand | 2.59 | 4.19 |
| Multi-family Water Heating | 0.29 | 0.69 |
| Energy Partner Smart Thermostat | 0.64 | 0.75 |
| Flex Load Portfolio | 2.07 | 3.45 |

Table 44, above, illustrates the impact which a "forward-looking" perspective can have on benefit cost analyses. Consider the implications for Multi-family Water Heating, where a "full lifecycle" TRC of 0.29 might indicate significant issues with the current approach and, perhaps, that the pilot be discontinued. Such a decision would have particularly dire consequences for the portfolio, as Multi-family Water Heating is one of the only offerings able to provide consistent, daily dispatch, providing capacity, intra-hour energy, and a foundation for other DR programs to offer intra-hour grid services to support reliability. When reconsidered independent of historical costs, the TRC improves to 0.69. This "forward-looking" perspective indicates improved recent performance and helps support the case for continued investment in this important resource.

Note that a "forward-looking" perspective may also benefit those activities with a "full lifecycle" TRC already greater than one. If that perspective unlocks additional incremental investment, it could allow the utility to reach hitherto untapped segments of the market, contributing to the continued growth of the resource.

PGE is also exploring additional adjustments to the level of cost effectiveness analysis, as detailed in Prospective Adjustments section, below.

## 5.2 Prospective Adjustments to Cost Effectiveness

This section outlines additional adjustments opportunities to explore the additional value Flex Load programs provide to both consumers and the grid.

### 5.2.1 Prospective Adjustment I. Level of Benefit-Cost Analysis

This prospective change to cost effectiveness for Flex Load programs addresses the level of benefit-cost analysis.

Thus far, cost-effectiveness testing has relied on forecasting all non-incentive costs to a high degree of specificity at the program level and well beyond the funding cycle of many programs. This approach can lend itself to large "swings" in the Total Resource Cost Test of individual programs. For example, a program may be carrying the cost of yearly or bi-yearly evaluations. While evaluations yearly or every six months may be initially warranted, it is financially burdensome to assume such costs will be carried similarly throughout the lifecycle of the program. Carrying the assumed costs of yearly or bi-yearly evaluations through a life-cycle cost effectiveness assessment of the program might lead one to conclude, erroneously, that the program activity is non-cost effective and should be shuttered. Administrative costs are likely to be overestimated if cost effectiveness methodologies assume said costs are not reduced on a proportional basis through program maturation.

PGE proposes to address this issue by reallocating costs not directly associated with ground-level program operation to the portfolio level, (e.g., planning and evaluation services, marketing, program administration) and redistributes them based on the avoided costs achieved by each program.

Under this approach, costs are fully accounted for whether they are evaluated at the program or portfolio level. Note that this method *does not* exclude non-specific program costs when assessing the cost-effectiveness of an individual program – such as program management contractors. This change more closely aligns with National Standard Practice Manual guidance which recommends non-variable costs be moved up within a DSM portfolio.[81]

Energy Trust of Oregon uses a similar practice, which allocates internal costs based on incentive and contractor expenses within its portfolio and programs.[82]

Figure 2, below, is an example of Energy Trust's electric efficiency internal costs following the combined contractor and incentive expenditure.

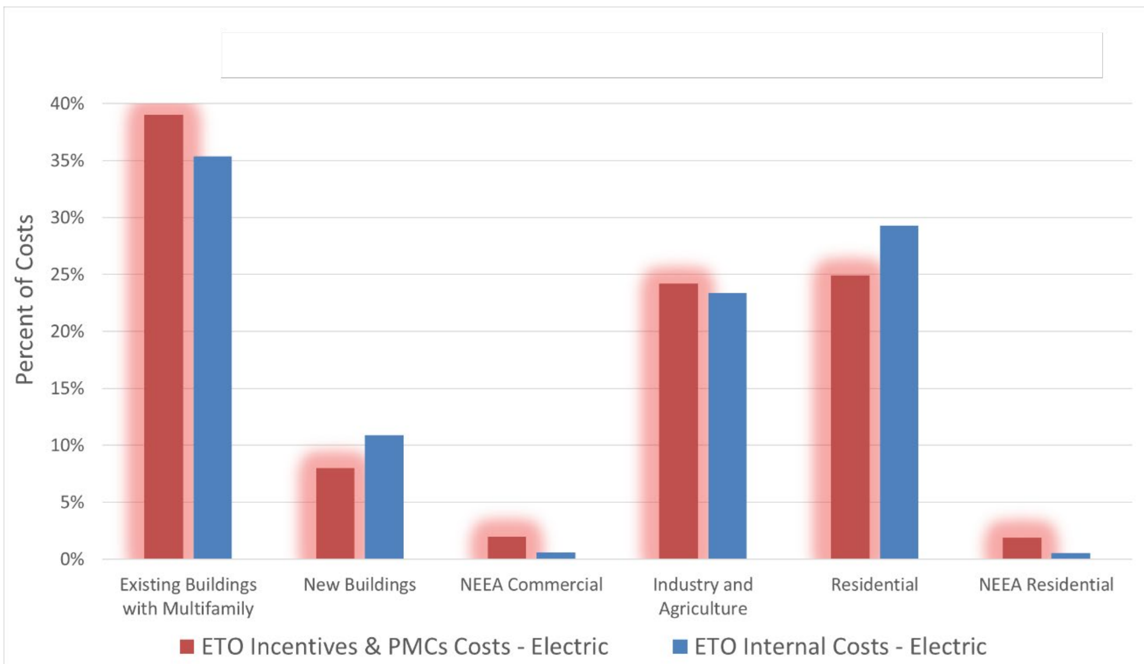


Figure 2. Expenditures by Major Program and Utility[83]

[81] National Efficiency Screening Project. *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*. Section H.1.6, page H-4. National Efficiency Screening Project, August 2020.
[82] Energy Trust of Oregon (2024). *Final Proposed Financial Reports 2024-2025*. pp 11-12. Retrieved from https://www.energytrust.org/wp-content/uploads/2023/10/Financial-Reports_2024-2025.pdf.
[83] Ibid, p.6 for examples of Energy Trust's internal costs allocated using this method.

This approach to cost allocation is in line with Staff's support to shift planning to a portfolio-level[84]. Note that PGE will continue to provide program-level cost effectiveness, which incorporates the perspective developed above.

### 5.2.2 Prospective Adjustment II. Add a Marginal One-year, Forward-looking Perspective

Consider adding marginal one-year perspectives on program benefits and costs in line with the Regional Technical Forum, and also the established budgeting practice of the Energy Trust[85]. This perspective would allow for directly comparable valuation of DSM resources between Energy Trust of Oregon and PGE, which should assist in co-deployment/co-development of measures which carry both energy efficiency and demand response benefits.

A further benefit of this approach is that the costs and benefits are well known and immediate, helping assess the viability of the near-term activity and identify miscounted benefit or costs to inform more prompt programmatic changes if need be. Note this approach also requires program cost reallocation to understand how the activity and the immediate program changes affect the total portfolio costs.

### 5.2.3 Prospective Adjustment III. Leverage the UM 1893 Energy Trust of Oregon Updated Avoided Cost Tool to Accelerate DR/EE

As noted in Prospective Adjustment I., above, assessment of potential DR offerings where devices are both controllable and more efficient than baseline, co-funding should be prioritized. This increases the value to both customers and the grid within that program design or framework (e.g., ENERGY STAR demand response-enabled room air conditioners or portable heat pumps).

Access to the UM 1893 Energy Trust of Oregon updated avoided cost tool could provide an opportunity to accelerate DR/EE co-deployment. This tool could facilitate "back of the envelope" calculations to estimate DR avoided cost value, as well as EE value by using regional approved savings, measure life, and incremental cost values (e.g., RTF, California DEER database) to identify opportunities to bridge cost gaps.

### 5.2.4 Prospective Adjustment IV. Quantifying Flex Load's Mitigation of Market Insufficiency

In addition to the values noted above, PGE is exploring real-time market risk reduction value or dispatch value of demand response. As discussed, with Current Adjustment II., this could include the creation of more precise estimates of avoided market costs during specific DR event hours.

PGE recognizes that demand response resources can help bridge periods of market insufficiency, where PGE might otherwise be forced into an emergency position or bridge these periods of market resource scarcity. While this value can be hard to quantify, recent events where resource scarcity and transmission pathway congestion nearly precipitated an emergency grid event, the demand response resource's load reduction was sufficient to mitigate the emergency, thus foregoing service disruptions. PGE is not currently capable of quantifying this value but is actively working to address

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[84] OPUC (2021). *UM 2141 – Order 21-158: Acceptance of Flexible Load Plan*, Appendix A, Page 4. Retrieved from https://apps.puc.state.or.us/orders/2021ords/21-158.pdf.
[85] See footnote 82.

this gap and will update Commission Staff on our progress through our Demand Response Advisory Group meetings.

### 5.2.5 Prospective Adjustment V. Locational Value

PGE's assessments of Non-Wires Solutions within the Distribution System Plan have surfaced the inherent locational value of distributed energy resources such as Flex Load and demand response. We look to extend this work by integrating our AdopDER model outputs with the CYME distribution system model. This integration will help PGE better understand the potential locational value signals of DER investment, and ultimately help direct DER investment.

PGE efforts to define avoided costs based on geographic areas are ongoing. This work will allow for more specific avoided costs related to targeted deployment and utilization of Flex Load and demand response. PGE expects these insights to help focus customer outreach and recruitment on those areas of the service territory which would provide greater value to the entire customer base.

### 5.2.6 Prospective Adjustment VI. Demand Response Credit towards Western Resource Adequacy Program Obligations

PGE is also exploring the value of DR contributions to Western Resource Adequacy Program (WRAP). PGE is working with the WRAP, whose obligations become a binding in 2027, to have DR resources meet some portion of PGE's WRAP obligations. As discussions mature, PGE will update Staff on the credit which demand response may receive through this process. Should demand response be granted this credit, PGE will attempt to quantify and include it in assessments of cost effectiveness.

Note that, in addition to being a compliance requirement, DR's contribution to WRAP obligations is an incremental benefit in addition to the marginal avoided generation capacity needed to meet PGE's current system peak demand.

## 5.3 Next Steps

PGE believes the above current and prospective changes to Flex Load cost effectiveness methodology represent incremental steps to more appropriately value the resource. PGE wishes to thank Staff and stakeholders for their contributions to the work and looks forward to further engagement on the issue.