**September 17, 2026**
Public Utility Commission of Oregon
201 High St. SE, Suite 100
Salem, Oregon 97301-3398

**RE: AR 676 Phase 2 - Track 3 Energy Advocates' Proposal on Performance Incentive Mechanisms**

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On behalf of Citizens' Utility Board, Climate Solutions, NW Energy Coalition, Green Energy Institute at Lewis & Clark Law School, Community Energy Project, Mobilizing Climate Action, Oregon Solar & Storage Industries Association, Oregon Just Transition Alliance, Verde and Multnomah County Office of Sustainability (collectively, the "Energy Advocates"), representing a diverse group of environmental justice, climate, energy, government and ratepayer advocacy organizations throughout Oregon, and at the request of Oregon Public Utility Commission (PUC) Staff, as part of the informal process of AR 676 Phase 2, Track 3, we submit the following Performance Incentive Mechanism (PIM) proposal for all stakeholders to consider. We understand Staff's intention in Track 3 to "develop targeted PIMs starting from an understanding of peer experiences and community perspectives." The following offers that starting point.

This proposal is organized to respond directly to the three questions Staff identified for Track 3 in its Phase 2 Issues List: (1) the metrics appropriate to each PIM area; (2) the thresholds that should apply; and (3) which PIMs and thresholds should be standard, industry-specific, or utility-specific. Section III provides a summary of the PIMs we propose, while the following sections further explain those PIMs.

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## I. Context & Level Setting

| AR 676 Phase 2 PIMs | |
|---|---|
| **Backstop PIMs** | **Outcome-Based PIMs** |
| Reliability | Limiting Disconnections |
| Safety | CBRE Progress/ Acquisition Targets |
| Customer Service | Asset Utilization |

PIMs are regulatory tools that tie a portion of utility earnings to specific measurable targets. They are intended to realign utility incentives with desired outcomes by providing a financial reward or penalty for the utility's performance on a specific metric. PIMs also can help motivate utilities to prioritize spending or programs that may not be wholly in the financial interest of the utility's shareholders under traditional cost of service regulation, but are in the public interest. It is crucial to us that PIMs do not contribute to increasing costs in ways that are not justified by truly improved customer and societal outcomes and benefits. Thus, we are interested in a cost-benefit analysis for any upside incentives to ensure ratepayer benefits outweigh the cost of any rewards.

On July 13, 2026, in Order No. 26-242, the Commission adopted Staff's recommended Phase 1 framework, which requires PIMs in six areas: three backstop PIMs (reliability, safety, customer service), and three outcome areas (customer disconnections, asset utilization, and CBRE progress/acquisition targets). We understand these six areas to be a required minimum rather than a full portfolio. The only PIM that does not apply to both electric and gas utilities is the Community-Based Renewable Energy (CBRE) PIM. Staff has described this as a "moderate PIM portfolio." Such a portfolio allows us to focus on the highest priority outcomes with less complexity. However, careful design is required to avoid incentive conflicts.

From our research and understanding thus far, which includes previous Staff- and consultant-led educational workshops, we understand backstop PIMs serve to keep utilities from backsliding on core customer obligations once utilities are operating under an MRP. We believe at this stage it makes the most sense to design our backstop PIMs to be downside only. This is also what Staff intended from Phase 1. We are interested in future adjustments that create upside opportunities for narrower scopes and more targeted improvements to reliability, safety, and customer service, particularly geographic or other targets to drive equitable outcomes in these areas. In the future,

depending on how long Wildfire Mitigation Plan (WMP) costs fall outside the index, we are interested in the potential for a PIM designed to prevent gold plating. The Phase 1 framework excludes the wildfire mitigation automatic adjustment clause from MRP scope "for the time being," and Staff indicated that such categories "can be considered for harmonization with the MRP cadence" once the MRP framework matures.[1] We ask that the eventual harmonization decision include consideration of such a PIM at that time.

We understand outcome-based PIMs are designed to reach beyond the confines of a specific utility program or investment, but that they may be confined to a subset of customers. Additionally, it is our understanding that for outcome-based PIMs, cost recovery is not necessarily guaranteed for qualifying utility actions. Lastly, we understand that in assessing the success of outcome-based PIMs, it can be difficult to determine if outcomes stem from utility actions or externalities.

## II. Our Considerations

At this stage, we have spent the most time determining the regulatory/policy goals and outcomes we are seeking, and possible metrics for these goals and outcomes. We have discussed what we already know and what we already track, and if desired outcomes in any way are redundant to existing policy. Based on the information available today, we have also considered if incentives should be upside, downside, or symmetrical. From our research, for PIMs that are equity-related, we understand that downside and or symmetrical PIMs are especially warranted. We have begun to ponder the pros and cons of different incentive designs generally, and, for some PIMs more than others, we have thought about how different incentive design options interact with outcomes in our current system. Finally, we thought about loopholes in our PIM ideas, and considered the need to avoid unduly rewarding or penalizing utilities. For example, some questions we have asked are:

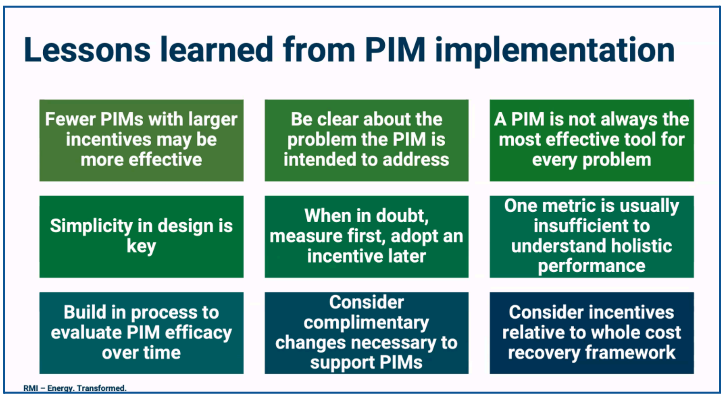
- Does the incentive conflict with other regulatory policies?
- Does this leverage the utility's ability to drive system efficiencies and cost reductions for customers?
- Is the target achievable?
- Can this contribute to capital bias?
- Can this contribute to overspending?
- Can avoided costs be inflated?
- Can utilities just avoid or alter reporting in response?
- Can there be other negative outcomes for customers?
- Can this overcompensate utilities if achieved?
- Are there unintended consequences?
- Do advocates and other stakeholders have the resources required to track the PIMs?

[1] OPUC Order 26-242: https://apps.puc.state.or.us/orders/2026ords/26-242.pdf at 2 and 17.

We have organized these considerations into a set of design criteria that we hope to apply to every PIM discussed below. The first four are Staff's own, drawn from the Phase 1 report which states that PIMs "should be measurable, within reasonable utility influence, aligned with statutory and Commission priorities, and designed to avoid duplicative rewards or penalties." We agree with these, and would add a few more:

1. A PIM should not reward a utility for meeting an obligation it already bears by statute, rule, or order. Where the concern is failure to meet an existing obligation, the appropriate tool is a backstop PIM;
2. A PIM should be verifiable by parties other than the utility, particularly Staff and parties to MRPs;
3. A PIM should not be attainable by changing how performance is defined or reported, but rather by changing performance.

Generally speaking, we are interested in simple PIM designs, which include thoughtfulness around transparency in tracking and review. Relatedly, we would like to flesh out a post-PIM evaluation and reevaluation process. We continue to consider RMI's "Lessons Learned from PIM Implementation."




We understand that Commissions around the country have generally seen PIMs as "time-bound experiments" that often have a sunset date, recognizing the importance of time to test metrics and observe performance prior to a decision to continue, redesign, or retire a PIM. Sunset dates can also allow for working toward more ambitious goals. Without an end date, PIMs require calibration for fit-for-purpose checks on a recurring basis. The Phase 1 framework supplies a natural answer: each PIM should run for the five-year MRP term, with a defined checkpoint at the mid-point of the plan (after approximately two years of data available) and a mandatory re-evaluation at the next rate case. This gives every PIM a sunset date that is aligned with the process the Commission has already adopted, avoids creating a separate review proceeding, and ensures that no PIM continues indefinitely without scrutiny over its continued value.

We also want to address reporting-only or "shadow" PIMs, because we expect this may be a central question. As we said in our May 6, 2026 comments, shadow reporting may be appropriate where genuinely new metrics require data development, but it is not appropriate where utilities already collect and report data. Where shadow reporting is used, it should be short, time-bound,

and – where useful and important to improve performance – followed by a meaningful financial mechanism on a pre-defined schedule (i.e., a backstop or outcome PIM).

From utility comments, at this stage, we generally understand that there is a desire to avoid overly complex PIMs, which we agree with. There is utility concern about duplicative PIMs or PIMs that are technology-specific. We have tried to be responsive to both concerns: where a PIM could be seen as duplicative of an existing docket or obligation, we explain below why it is not, and where a PIM could be seen as technology-specific, we propose a menu rather than a single technology. We believe that gas utilities remain skeptical, but it is important to us that they are subject to PIMs.

## III. Summary of Proposed PIMs

| PIM area | Applies to | Outcome | Metric(s)/Threshold(s) | Direction[2] | Section |
|---|---|---|---|---|---|
| **Reliability** | Electric | CAIDI, SAIDI, SAIFI, MAIFI<br><br>Second phase - worst-performing circuits & highest energy-burdened communities | Historic averages, adjusted for statistical confidence levels and grid work | Downside/ penalty. Fixed amount or basis points, measured annually | Section IV |
| **Reliability** | Gas | Average time to reconnect following a utility-mandated disconnection for reasons other than non-payment | Historic averages | Downside/ penalty. Fixed amount or basis points, measured annually | Section IV |
| **Safety (audit)** | Electric | Violations per hour as measured by PUC audit | Historic PUC performance data and what PUC has considered fair performance | Downside/ penalty. Fixed amount or basis points, | Section IV |

[2] A note on downside PIMs and ESMs: If PIM rewards and penalties are included within the earnings band used to calculate earnings sharing, a penalty imposed on the utility would be partly shared back to customers and an upside payment would be partly clawed back. That could substantially weaken every penalty PIM in this proposal. We ask that the Phase 2 concept state explicitly that PIM adjustments are applied outside the ESM calculation, so that penalties are borne by shareholders and rewards are not offset. We also ask that Staff model the combined effect on authorized returns of the full PIM portfolio together with the ESM before setting incentive levels.

| PIM area | Applies to | Outcome | Metric(s)/Threshold(s) | Direction[2] | Section |
|---|---|---|---|---|---|
| | | | in previous audit years | measured annually | |
| **Safety (performance)** | Electric | Timely correction of "immediate hazards" as defined by existing PUC safety audits | PUC timelines for correction. | Downside/ penalty. Fixed amount or basis points, measured annually | Section IV |
| **Safety (gas leaks)** | Gas | Response and correction time to reported gas leaks | Historic PUC performance data and what PUC has considered fair performance in previous years. | Downside/ penalty. Fixed amount or basis points, measured annually | Section IV |
| **Safety (overpressure)** | Gas | Number of events | Historic PUC performance data and what PUC and/or PHMSA consider fair or good performance. | Downside/penalty. Fixed amount or basis points, measured annually | Section IV |
| **Customer service** | Both | Percentage of customer contacts resolved on first contact with customer service resolution options within 72 hours, reflected by language, geography, and (if applicable) relevant program (e.g. community solar, BDP programs). | No established public reporting obligations. Customer satisfaction collected by utility, which could be made available to form the benchmark. | Downside/ penalty. Fixed amount or basis points, measured annually | Section IV |
| **Disconnections** | Both | Number of disconnections, supported by tracking of: customers in | Reduce disconnections by TBD% annually; keep | ROE-based. Symmetrical if authorized ROE is reduced to | Section V |

| PIM area | Applies to | Outcome | Metric(s)/Threshold(s) | Direction[2] | Section |
|---|---|---|---|---|---|
| | | arrears by zip code; customers disconnected by zip code; customers in 90+ day arrears by zip code; and customers enrolled in a bill discount program who are also disconnected and enrolled in a payment arrangement. | disconnections under TBD per year; without raising arrearages. Targets, deadband, and incentive level.. | accommodate ROE-based PIMs; otherwise downside only. Deadband applies. | |
| **Asset utilization (Reporting Only)** | Electric | Data Collection and Reporting on: System throughput, System performance during peak and minimum load periods, and Asset and reliability risk. | N/A | N/A | Section V |
| **Asset utilization (NWA, Electric Option 1)** | Electric | Total Cost: Total cost of NWA projects deployed by the utility or acquired through a customer program or competitive procurement | N/A | Shared savings approach on Net Cost Savings on the NWA compared to a grid upgrade. | Section V |
| **Asset utilization (DER Interconnection, Electric Option 2)** | Electric | Average time needed to secure an approved interconnection permit. | Reduce the time needed to interconnect DER projects.<br><br>*Need a baseline and benchmark before setting a target.* | Symmetrical. Rewards improvement in interconnection timeline, penalizes delays. | Section V |
| **Asset utilization (DER** | Electric | Grid Services Utilization: total incremental MW of | N/A | Shared savings PIM based on | Section V |

| PIM area | Applies to | Outcome | Metric(s)/Threshold(s) | Direction[2] | Section |
|---|---|---|---|---|---|
| **Effectiveness, Electric Option 3)** | | DER systems capable of providing grid services. | | MWh of DER deployed during peak periods. | |
| **Asset utilization Op (Strategic Electrification, Gas Option 1)** | Gas | Program Participation: # and % and types of customers participating in targeted electrification programs | TBD | Upside, Tiered reward where the utility gets a graduated incentive related to the scale of customer electrification or lines capped. | Section V |
| **Asset utilization (NPA, Gas Option 2)** | Gas | Total Cost of the pipeline project less the total cost of Non-Pipe Alternative | N/A | Shared savings approach based on the Net Cost Savings of the NPA compared to a pipeline project. | Section V |
| **Asset utilization (Reporting Only)** | Gas | Data/Reporting on distribution infrastructure fixed costs compared to number of customers, at the branch circuit level of detail. | N/A | N/A | Section V |
| **CBRE Option 1: per MW growth** | Electric only | MW of qualifying CBRE reaching commercial operation in the year, measured against an annual procurement trajectory. Multiplier for projects with community ownership, peak reduction capability, or the ability to displace traditional | No established annual CBRE acquisition target. Trajectory to be built, with statutory reporting of SSRs, CSP deployment data as two inputs to consider. | Upside per MW above the trajectory, potentially paired with a penalty for falling behind it. Structured either as fixed annual MW goals or as tiered performance levels with | Section V |

| PIM area | Applies to | Outcome | Metric(s)/Threshold(s) | Direction[2] | Section |
|---|---|---|---|---|---|
| | | generation investment. Qualification vetted by the CBIAG, or benefits pre-identified jointly by the CBIAG and energy justice advocates. | | increasing incentives. | |
| **CBRE Option 2: Shared Savings/Net Benefits** | Electric only | Net benefits and/or savings produced by the utility's CBRE investments, measured relative to the utility's reasonable alternative for meeting the same system or customer need. Rewards value created rather than MW procured. | Would require a method for evaluating benefits. Avoided energy and capacity costs and peak reduction are reasonably quantifiable; resilience, local economic development, community ownership, and benefits to underserved communities are harder to value, and microgrids may deliver several simultaneously without double counting. | Upside. Utility retains a predetermined share of the net benefits. Our proposal considers an overall incentive cap or other ratepayer protections so the incentive stays proportionate to benefits produced. | Section V |

| PIM area | Applies to | Outcome | Metric(s)/Threshold(s) | Direction[2] | Section |
|---|---|---|---|---|---|
| **CBRE Option 3: Efficiency carryover** | Electric only | Benefits produced by a CBRE over time, with incentive value earned in one year carrying forward into subsequent years –recognizing that a solar-plus-storage project or microgrid continues to reduce peak, provide grid services, and deliver resilience well beyond its commercial operation date. | Requires determining which benefits qualify for carryover, how long they are recognized, and how changes in project performance or operating conditions affect the incentive. | Upside, earned across multiple years. Requires safeguards against double counting benefits also reflected in other PIMs, programs, or planning processes, and a limit on total incentive earnable from a single project. | Section V |

## IV. Backstop PIMs

### A. Reliability

#### *Electric Utilities*

Energy Advocates want to ensure that electric utilities maintain reliable transmission and distribution systems in their territories. The PUC already requires electric utilities to report on specific reliability metrics: customer average interruption duration index (CAIDI); system average interruption duration index (SAIDI); system average interruption frequency index (SAIFI); and momentary average interruption event frequency index (MAIFI).[3] PGE and PAC issue annual reports for these metrics from the prior year and trends from the past several years of reporting.[4] This data gives the Commission a reliable baseline from which to implement reliability-focused PIMs for electric utilities. Building upon these existing systems and data should allow the Commission, utilities, and advocates to establish PIMs for each of the reliability metrics.

For the initial phase of this proposed reliability PIM, electric utilities would be required to maintain specific thresholds for CAIDI, SAIDI, SAIFI, and MAIFI across their territory. By the next multi-year rate plan period, Energy Advocates propose implementing a second phase of the

[3] OAR 860-023-0151.
[4] See PGE's reports and PAC's reports.

reliability PIM specifically focused on the worst-performing circuits in the utilities' territories as well as on communities with the highest energy burdens. This more targeted approach would ensure that well-performing parts of the utilities' territories are not skewing the results of the reliability of the system. It would also ensure that communities already challenged with high energy burdens are not further impacted by less reliable service. In order to achieve this second phase of the reliability PIM, it may be necessary for electric utilities to update their data collection and reporting for reliability metrics to be more granular or to overlay with data on energy burden. Implementing this version of the PIM at a future date gives electric utilities the time to make these necessary changes and establish a baseline.

**Proposed PIM Details:**

- **Applicability**: Electric
- **Incentive Type**: Downside/Penalty
- **Incentive Structure**: Fixed Amount or Basis Points
- **Reliability Metrics**: CAIDI, SAIDI, SAIFI, MAIFI
- **Measured**: Annually
- **Thresholds**: Based upon historic averages, adjusted for statistical confidence levels and grid work.
- **Example PIMs**: NC's SAIDI PIM (RMI PIM #114); NC's SAIDI PIM (RMI PIM #23.1); HI's SAIDI/SAIFI PIM (RMI PIM #18.1)

### *Gas Utilities*

Unlike electric utilities, gas utilities are not subject to the pre-established grid reliability metrics of CAIDI, SAIDI, SAIFI, and MAIFIE. Therefore, finding reliability PIMs that are applicable to gas utilities is not as straightforward as with electric utilities. Advocates propose exploring two potential PIMs that would be applicable to gas utility reliability. First, gas utilities could be required to achieve a reliability metric for the time to reconnect gas utility customers following a utility-mandated disconnection for reasons other than non-payment (e.g., after disconnection due to wildfire). Second, gas utilities could be required to achieve a reliability metric for the time to repair pipelines following gas leakage events. Since these metrics may not have pre-established baselines for gas utilities, a potential first phase for the PIM would focus on establishing the metric and reporting requirement, while a subsequent phase would define the threshold and penalty mechanism.

**Proposed PIM Details:**

- **Applicability**: Gas
- **Incentive Type:** Downside/Penalty
- **Incentive Structure**: Fixed Amount or Basis Points
- **Reliability Metrics**: Average time to reconnect or time to repair
- **Measured**: Annually

- **Thresholds**: Based upon historic averages
- **Example PIMs**: N/A

### B. Safety PIMs

The purpose of this backstop is to ensure that utilities continue to invest resources into effective safety programs and responses. For safety PIMs, energy advocates recommend beginning with the data and metrics that are already collected by and reported to the Commission. From conversations with PUC staff, we understand that both gas and electric IOUs report safety information to the PUC and are subject to safety-related auditing and regulations that can be captured through a PIM. Advocates recognize that there is room for evolution in these metrics, particularly if and when wildfire costs are brought into the indexed MRP.

#### *Electric Utilities*

The following electric system safety PIMs represent our current thinking on backstop PIMs based on conversations with PUC staff about the data currently available on safety performance. Our priority for safety PIMs is to ensure that utilities are incentivized to successfully prevent and correct safety issues, beyond what is required under business-as-usual, and adequately budget for the safety needs of the system. PIMs should not incentivize box-checking over action and outcomes.

**Proposed Safety Audit PIM:**

- **Applicability**: Electric
- **Incentive Type:** Downside/Penalty
- **Incentive Structure**: Fixed Amount or Basis Points
- **Safety Metrics**: Violations per hour as measured by PUC auditing
- **Measured**: Annually
- **Thresholds**: Based upon historic performance data from PUC and what PUC has considered fair performance in previous audit years

**Proposed Safety Performance PIM:**

- **Applicability**: Electric
- **Incentive Type:** Downside/Penalty
- **Incentive Structure**: Fixed Amount or Basis Points
- **Safety Metrics**: Timely correction of "immediate hazards" as defined by existing PUC safety audits
- **Measured**: Annually
- **Thresholds**: Percentage of "immediate hazards" that are corrected within the PUC-defined timeline (30-90 days depending on hazard type)

### *Gas Utilities*

For gas system PIMs related to safety, advocates highlight the options below based on information from other states and our understanding of information that is tracked by the utility and/or Commission already.

**Proposed Gas Leak Safety PIM:**

- **Applicability**: Gas
- **Incentive Type:** Downside/Penalty
- **Incentive Structure**: Fixed Amount or Basis Points
- **Safety Metrics**: Response and Correction time to reported gas leaks
- **Measured**: Annually
- **Thresholds**: Based upon historic performance data from PUC and what PUC has considered fair performance in previous years

**Proposed Gas Overpressure Safety PIM:**

- **Applicability**: Gas
- **Incentive Type:** Downside/Penalty
- **Incentive Structure**: Fixed Amount or Basis Points
- **Safety Metrics**: Number of over pressure events
- **Measured**: Annually
- **Thresholds**: Based upon historic performance data from PUC and what PUC and/or PHMSA consider fair or good performance
- **Examples from other States:** California (SoCalGas)[5]

## C. Customer Service

It will be important to monitor and evaluate utility performance to ensure they do not eliminate or reduce important customer service and satisfaction programs in an environment of cost-cutting pressures. Customer satisfaction is a traditional area where regulators have historically tracked utility performance. With the adoption of HB 2021, the legislature underscored the importance of the customer experience when it directed electric utilities to include in their biennial reports, completed after consultation with the Community Benefits & Impacts Advisory Group (CBIAG), a description of "customer experience, including a review of annual customer satisfaction surveys [and] actions to encourage customer engagement[.]"[6] The gas utilities have also created

[5] 2025 Safety Performance Metrics Report Of Southern California Gas Company (U 904G), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/2025-socalgas-spmr-_040126.pdf

[6] ORS 469A.425(2)(a)(F) and (G).

community equity advisory committees to inform and track the gas utilities' progress in reaching underserved communities with energy assistance and support.

Given that the PUC and our utilities are committed to ensuring high customer satisfaction for all customers, and given that existing tracking and surveying mechanisms are already uncovering the need to continue to reach underserved members of our population, we propose a PIM that holds utilities accountable to high levels of customer satisfaction, at all income, geographic, and program levels.

For example, PacifiCorp's CBIAG Biennial Report reflected on its 2023 Clean Energy Benefits Survey, and noted the CBIAG's request that the number of Spanish-language survey respondents be increased in future survey outreach efforts.[7] During an April 2025 CBIAG meeting, and again in an April 2026 meeting, PacifiCorp reported on its low-income discount (LID) recipient survey results.[8] Although satisfaction among LID participants was high, recipients noted the need for customer service providers to inform customers about the program–and these are customers who are already enrolled in the program. Reaching Spanish-language customers, and ensuring that customers know about LID programs as early as possible, are key indicators of customer satisfaction.

PGE's CBIAG report similarly includes recommendations from CBIAG members that PGE continue to improve outreach to rural and non-English-speaking customers.[9]

NW Natural, Cascade, and Avista each have voluntarily created analogous community & equity advisory or low-income advisory groups. These groups discuss similar topics, per participant read-outs, but the agendas from the past year do not include details.

- **Applicability**: Gas and Electric
- **Incentive Type:** Downside/Penalty
- **Incentive Structure**: Fixed Amount or Basis Points
- **Customer Service Metrics**: Percentage of customer contacts that are resolved on the first contact with customer service resolution options within a period of 72 hours, reflected by language, geography, and (if applicable) relevant program (e.g., community solar, LID programs, etc.)
- **Measured**: Annually

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[7] PacifiCorp CBIAG Biennial Report, at 51 of 72 (2024), https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificorp/energy/cbiag/PacifiCorp_2024_Community_Benefits_Biennial_Report_12_30_24_fnl.pdf.

[8] Pacific Power Community Benefits & Impacts Advisory Group for Oregon Tribal Nations Public Notes (Apr. 25, 2025); Pacific Power CBIAG Public Notes, at 15-16 (April 16, 2026), https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/community/or-cbiag/2026/OR-CBIAG_Meeting_2026-04_April_Public_Notes.pdf.

[9] Portland General Electric CBIAG Biennial Report, at 39 (June 2025), https://downloads.ctfassets.net/416ywc1laqmd/1FstHLLzSlCcAFxSICRWdu/76e6d22fc98af9058b343d970762c810/267950_CBIAG_Biennial_Report_FNL_Single__1_.pdf

- **Thresholds**: No established public reporting obligations. Customer satisfaction collected by utility, which could be made available to form the benchmark.
- **Example PIMs**: Illinois, Massachusetts

Importantly, anecdotal evidence points to concern with the customer service experience of low-income customers contacting their utility when at risk of disconnection, as well as the experience of Spanish-speaking customers. Several organizations under the umbrella of the energy justice advocates have heard community member stories about dismissive, inconsistent, or demeaning experiences with utility customer service representatives (CSRs) and about needing to specifically ask for programs in order for the CSR to assist them. Energy Justice Advocates have flagged those concerns to utilities, Staff, and Commissioners when they have come up. The customer stories that Jackson County Fuel Committee filed in Docket No. UM 2211 also point to concerns.[10]

While today we do not have the data to request a PIM that would specifically address the quality of customer service experience by customers, let alone those subsets of customers, it is important that we identify avenues to begin sharing such data. Understanding and improving the experience of customers with heightened vulnerability should be a goal of this process. We suggest as a starting point developing a metric based on surveys of community action agencies and other organizations that directly engage with customers with low-incomes or who do not speak English in their capacity as utility customers (e.g. Community Energy Project, St. Vincent De Paul, Jackson County Fuel Committee, etc.). The goal would be to begin collecting data to eventually develop a PIM that seeks to improve the experience of these communities.

## V. Outcome PIMs

### A. Disconnections

We have been concerned about rising disconnections for Oregon families for years, particularly since 2024 when they were the highest since reporting began in 2018. Energy Justice Advocates have worked hard with Staff and utilities to try to reduce the number of disconnections, and to ensure appropriate limits on disconnections for non-payment on days when the disconnection would put community members' health and safety at risk. These protections are especially important as climate change worsens, as has been extensively discussed in UM 2211 and other dockets.

While progress has been made, tens of thousands of households are still being disconnected each year. Energy Justice Advocates seek to ensure families can afford their bills and are also safe and comfortable in their homes, without having to navigate the cascading effects of disconnections.

[10] https://edocs.puc.state.or.us/efdocs/HAC/um2211hac337189026.pdf; https://edocs.puc.state.or.us/efdocs/HAC/um2211hac339061035.pdf.

Other states have or have had goals to reduce disconnections annually. Oregon should pursue a similar path.

- **Applicability: Gas & Electric**
- **Proposed Outcome/Threshold:** *Reduce number of residential disconnections for non-payment by at least TBD % annually, while keeping disconnections under TBD a year, without raising arrearages.*[11]
- **Our proposed design for this PIM depends on how the "baseline" ROE is set in the context of the MRP. If the baseline ROE is set lower due to having multiple ROE incentive PIMs, we propose a symmetrical ROE. If that is not the case, we propose a PIM with a downside only.**
- **Deadband –** we propose that the deadband and the numeric targets be utility-specific, set from each utility's own baseline, while the metric definition and the arrearage gates are standardized in rule.
- **Variance in quantitative targets depending on utility**

Positive outcomes for low-income families can be achieved through a PIM like this one. An outcome-based PIM gives a utility flexibility on how to achieve the intended result. It is key that a utility meeting the outcome would not cause households to accumulate arrearages, which we seek to address through at least two of our proposed metrics. Examples include: attention to bill discount program enrollment rates, increased and targeted outreach for weatherization/energy efficiency benefits, expansions of customer service and existing income-qualified programs, such as use of autoenrollment, ensuring CSRs are using opportunities with BDP customers to do re-enrollment to preserve families staying enrolled in the program, more flexible payment plans, using text reminders, finding better ways to spot, track, and refer at-risk accounts, or a caseworker-type approach.

In Illinois, this PIM metric focuses on disconnection reductions in the historical Top 20 Most Disconnected Zip Codes (2017-2019) in a utility's territory. This coincided with research that found serious racial disparities related to who was being disconnected more often. We are interested in this narrower approach but discussed its possible drawbacks.

Generally, we believe that we have sufficient data available to us, much of which is already publicly available, to formulate the targets and benchmarks. **We anticipate at least the following metrics:**

1. Track number of customers in arrears by ZIP code
2. Track number of customers disconnected by ZIP code
3. Track number of customers in 90+ day arrears by ZIP code
4. Track number of customers enrolled in a bill discount program who are also disconnected and enrolled in a payment arrangement

[11] The cap would be calibrated per utility.

Importantly, we need to further explore how Illinois stakeholders developed their targets and decisions about the deadband and the appropriate financial incentive. It could be helpful to invite them to a PIMs workshop.

### B. Asset Utilization

The Advocates understand asset utilization to be a goal of right sizing assets and investments to correspond with throughput and customer growth and/shrinkage. Electric asset utilization therefore means increasing the annual electric load served by existing assets divided by the maximum load carrying capacity of a geographic component of a distribution or transmission grid. The group developed the following PIMs proposal under this interpretation. Asset utilization, as a performance metric and PIM, has the potential to serve multiple goals of this PBR process. By making more efficient use of existing assets, utilities have the ability to avoid unnecessary expenditures, holding down costs for customers while allowing needed investments to proceed without unduly burdening ratepayers.

It is important to note that the challenge of asset utilization, and the measures needed to contain costs and improve efficiency, are different for electric and gas utilities. On the electric side, demand is growing for both residential and industrial customers. This growing demand is being paired with investments needed to meet HB 2021 targets. Asset utilization for the electric utilities is therefore about how to right-size investments to efficiently manage a growing and changing grid. Additionally, while peak utilization is very high, non-peak utilization is much lower. Therefore, there is significant headroom during non-peak times to serve load with existing transmission assets.

On the gas side, demand is stalling and in some places declining,[12] while the gas distribution system remains largely the same size. Trends in gas utilization are expected to continue to decline, as more heat pumps displace or replace gas space and water heating, and as the gas utilities may choose to reduce throughput to meet their obligations under the Climate Protection Program. This presents an opposite asset utilization challenge to that faced by Oregon's electric utilities. Gas customers are paying more and more for less and less from their gas utilities. This asset utilization challenge will not be solved by increasing demand for the existing gas system, as this is incompatible with meeting the gas utilities' emission reduction obligations cost-effectively. Therefore, the only way to improve the asset utilization of our gas system is to reduce the footprint of the distribution system commensurate with declining utilization.

[12] Doug Piper, Ashland Climate Collaborative, *Gas is Shrinking* (Aug. 27, 2026) (installation of gas meters peaked in Ashland in 2020, decreasing CO2 by 15,190 mt and NOx by 12.8 mt, shifting $1.1 million from Avista to City of Ashland Electric Department). In NW Natural territory, growth is sharply declining. Meter installations grew on average 11,549 between 2017 and 2022, and is now increasing by on average 5,042 per year for the last three years. NW Natural Annual Reports, 2017-2025, https://ir.nwnaturalholdings.com/financials/annual-reports/default.aspx.

To sum up, asset utilization metrics for the electric system are about smart management of growth to maintain affordability as demand grows and as investments in clean infrastructure are made. For the gas utilities, asset utilization is about smart management of a declining system, to incentivize forward-looking planning to manage that decline so low-income customers are not stranded.

### *Electric Utility Asset Utilization PIMs Proposals*

In line with the "crawl, walk, run" approach discussed by stakeholders and staff in relation to PIM design, advocates envision a phased approach to electric asset utilization PIMs. To truly understand the current utilization of our grid and incentivise more efficient management, we need more information from utilities, we therefore recommend a shadow reporting mechanism to help inform future targets, PIM design and/or other workflows related to asset utilization. However, we believe there is sufficient experience with several PIMs related to asset utilization, including Non-Wires Alternatives and Peak Demand Reduction that can serve as immediate no-regrets PIMs as we collect and analyze the new asset utilization data.

### *Shadow Reporting for Asset Utilization*

In order to devise future comprehensive performance incentives for asset utilization, we recommend collecting metrics from electric utilities on recent distribution and transmission system utilization and subsequently requiring submission of an action plan for engaging or deploying underutilized assets for overall improvement of system utilization.

<u>Phase 1</u>

We recommend the following grid utilization metrics be reported for each of the preceding three years:

1. System throughput, including:
    1. Total MWh delivered;
    2. Total potential deliverable MWh; and
    3. System losses.
2. System performance during peak and minimum load periods, including:
    1. MW delivered;
    2. Potential deliverable MW;
    3. Duration of peak and minimum load periods; and
    4. Identification of system constraints.
3. Asset and reliability risk, including:
    1. Number of assets operating outside normal operating conditions or design criteria; and
    2. Frequency and duration of abnormal operating conditions for such assets.

Phase 2

Electric utilities will submit a comprehensive action plan that details a strategy for engaging or deploying underutilized assets to improve overall transmission and distribution system utilization. Brattle released a study in March 2026 entitled 'The Untapped Grid'.[13] The authors identified several tools for improving grid utilization, including the following:

1. Batteries
2. HVAC controls
3. EV charging controls
4. Smart panels
5. Time-varying rates
6. Flexible interconnection policies
7. Targeted energy efficiency
8. Grid-Enhancing Technologies
9. Data center flexibility
10. Improved system planning

We recommend providing a 'menu' of tools, including but not limited to those listed above, for electric utilities to consider in devising their action plans.

### *Electric Utility Asset Utilization PIMs*

While the data collection and reporting above will enable us to design future PIMs to more holistically incentivize efficient asset utilization, there is also room to incentivize near-term actions which shift demand, reduce peak, and improve asset utilization. Below is a menu of options for PIMs which could incentivize more efficient use of the existing grid. We believe some of these should be implementable using existing information and data, while others may require more information like the metrics suggested above.

The importance of cost efficiency in the electric utility sector is only growing. A surge of new spending will be needed in the coming years to decarbonize electricity supply, increase system resilience in the face of more extreme weather, replace aging infrastructure, accommodate increased demand due to beneficial electrification, and power our increasingly digital and data-intensive society. To keep rates affordable through this transition, it is critical that utility spending is focused on increasing the utilization and resilience of existing assets.

Utilization of electric system assets can apply to both the transmission network and the distribution network. We are initially focused on the distribution network. Distributed energy resources (DERs) are proven technologies and systems that support affordability and resilience

[13] Ryan Hledik et al., *The Untapped Grid: How Better Utilization of the Power System Can Improve Energy Affordability*, Brattle (Mar 2026), https://www.brattle.com/wp-content/uploads/2026/03/The-Untapped-Grid-Mar-2026.pdf.

by integrating generation and storage into the existing distribution system network, and managing these resources to flatten peak loads and increase system utilization.

Advocates examined experiences from Hawai'i, Vermont, Colorado, and other states to develop metrics and PIMs that are tailored to Oregon's situation. We suggest several different potential PIMs to inform group discussion, and believe that it may be appropriate to utilize different PIMs for different utilities based on past performance and other factors. Below, we provide a summary table of our proposed asset utilization PIMs, followed by more detailed discussion of each PIM.

| **Subject** | **Target + Metric** | **General Incentive Structure** |
|---|---|---|
| Non-Wires Alternatives (NWA) | Total Cost: Total cost of NWA projects deployed by the utility or acquired through a customer program or competitive procurement | Easy to identify and measure. Measures spending on possibly cost-effective measures.<br><br>*Existing examples use a shared savings approach on Net Cost Savings on the NWA compared to a grid upgrade.* |
| DER Interconnection | DER Interconnection time: Reduce the time needed to interconnect DER projects.<br><br>Measures the average time needed to secure an approved interconnection permit. | Symmetrical. Rewards improvement in interconnection timeline, penalizes delays.<br><br>*Need a baseline and benchmark before setting a target.* |
| DER Asset Effectiveness | Grid Services Utilization: total incremental MW of DER systems capable of providing grid services.<br><br>Measures the capacity of existing resources that are being managed to reduce peak demands | Possible shared savings PIM based on MWh of DER deployed during peak periods. |

### Non-Wire Alternatives (NWAs)

The RMI PIMs database lists several NWA example PIMs that incentivize demand response (DR), DER, and Grid Enhancing Technologies (GETs). NWA PIMs appear most suitable to large projects because some form of a wires project needs to exist that the NWA can be compared against to generate a net savings that can be shared. An appropriate threshold for this measure will need to be determined. The goal of this measure is to encourage implementation of the most cost effective measure for meeting local demand growth and freeing up transmission assets to

accept more load. Using a shared savings approach on net cost savings on the NWA compared to a grid upgrade is a known PIM.

### Interconnection Timelines

DERs and community solar are ways to minimize the strain on the grid during peaks, but adoption is currently slowed by long interconnection processes. This is an immediate problem for community solar,[14] and a PUC docket exists that is supposed to address this issue,[15] but little progress is being made to speed up the process and make the requirements more transparent to developers. Given the issues with the existing docket, we believe a PIM focused on reducing interconnection delays is needed.

The goal of the PIM would be to speed up the interconnection process for DERs and community solar, while leaving options open to utilities in the strategies they could employ for reducing interconnection times. The metric would be the reduction in the average time needed to secure an approved interconnection permit compared to a benchmark. A review of the baseline data is needed, along with some benchmarking before setting a target.

### DER Asset Effectiveness

The RMI PIMs database lists several Grid Services Utilization PIMs which measure the total MWs of DER systems enrolled in grid services programs that are being utilized to provide peak load reduction and other grid services. We are recommending a similar form of PIM. We note that the NWA PIM proposed below is designed for larger projects where a specific non-wires alternative is identified. The goal of this DER Asset Utilization PIM is to incentivize smaller DER projects, without reference to a non-wires alternative. There is enough general value in DERs reducing peak loads, and thereby reducing power purchase costs, as well as deferring possible T&D upgrades to justify a distinct PIM.

There are several potential metrics to measure DER utilization and effectiveness. We propose measuring the capacity of DER resources, through a metric of total incremental MW of DER systems capable of providing grid services. A DER that is “capable of providing grid services”, is a combination of technological capability and customer/utility management. If the device cannot be called on by the utility in some way (through enrollment in a VPP or some other program), then it is not truly capable of providing a grid service. Other potential metrics could be the number or percentage of customers enrolled in DER utilization programs (VPP, demand response, or other), or the number or percentage of customers enrolled in Time of Use (TOU) rates. While we support data collection or shadow reporting on these alternative metrics, we propose the capacity metric as the most direct measurement of the service that DERs provide.

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[14] Joe Abraham, *Initial Staff Proposal on Aligning Program Administrative Costs and Revenue*, OPUC Docket No. UM 1930 (May 12, 2026) 8, https://edocs.puc.state.or.us/efdocs/HAH/um1930hah346194039.pdf.
[15] *See generally* OPUC Docket No. AR 683, https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=24912.

In considering how to reward utility performance for this PIM, we are exploring a Shared Savings Mechanism. A broad range of DERs reduce peak loads and therefore reduce costs. Reducing peak is a tangible benefit that can be quantified by deferred/avoided distribution and transmission system investments, and avoided power purchases. This PIM would reward utility investment in DERs based on the savings that their capacity provides.

Development of these PIMs will require several definitions, including:

- What Distributed Energy Resources (DERs) contribute to improved asset utilization;
- What Supporting Tools help enable the listed DERs (e.g., Smart Panels, Time of Use rates, Flexible interconnection policies, Targeted Energy Efficiency, etc.)

### *Gas Utility Asset Utilization PIMs*

Unlike the electric system, which studies such as the Oregon Energy Strategy and others show will continue to grow significantly, the use of methane "natural" gas is expected to decline dramatically over the next 20 years; such trends mean that asset utilization takes on a different meaning in the gas utility sector. Whereas the electric system improves utilization by serving a larger portion of its growing demand with DERs, etc., the gas system faces a long decline in demand, with RNG providing limited decarbonization opportunities, which cannot delay the overall decline. Therefore, asset utilization becomes a task of managing customer loss and infrastructure decommissioning so that the fixed cost of service to remaining customers stays affordable. This will require targeted electrification (or hybridization) incentives followed by branch pruning. Non-pipe solutions are also an important metric that helps avoid the risk of stranded assets.

| **Subject** | **Metric** | **Incentive Structure** |
|---|---|---|
| Strategic Electrification | Program Participation: # and % and types of customers participating in targeted electrification programs | Tiered reward where the utility gets a graduated incentive related to the scale of customer electrification or lines capped. |
| System Investment Efficiency | Total Cost of the pipeline project less the total cost of Non-Pipe Alternative | A shared savings approach based on the Net Cost Savings of the NPA compared to a pipeline project. |
| Infrastructure Asset Effectiveness | TBD following analysis of the new data of distribution infrastructure fixed costs compared to number of customers, at the branch circuit level of detail | Shadow reporting to help identify existing infrastructure that could be decommissioned, build future metrics, benchmarks, PIMS. |

### *Strategic Electrification*

The goal of this PIM is to encourage gas utilities to develop customer participation programs in support of strategic electrification by pursuing geographically targeted electrification programs. The metric would be based on program participation, which could be the number and type of customers participating in the program. The incentive mechanism could consist of a tiered reward where the utility gets a modest incentive for electrifying single end uses for a target number of customers (reducing throughput and avoiding system costs like CPP compliance), a moderate incentive for households that fully electrify and result in capping of their line, and a larger incentive where a cluster of homes electrify and an entire main can be capped.

### *System Investment Efficiency*

The goal of this PIM is to incentivize utilities to pursue pruning projects that are cost-effective compared to business-as-usual pipeline projects. As with the electric utility NWA PIM, this incentive would be best suited to larger projects that result in capping/pruning at the level of gas mains and system branches. Gas infrastructure projects, for example, a pipeline replacement, repair, or improvement, should be compared to a Non-Pipe Alternatives (NPA) option. A shared net savings on Net Cost Savings of the NPA compared to a pipeline project.

### *Infrastructure Asset Effectiveness*

As with our electric utilities, there is more data and information that should be collected to inform future PIMs. In the long-term, we see the need for metrics to track the effectiveness of the existing gas infrastructure. A possible metric could be the ratio of distribution infrastructure fixed costs compared to the number of customers, at the branch circuit level of detail. The intent of the measure is to help identify existing infrastructure that could be decommissioned. This data could inform future metrics, targets, benchmarking, planning and PIM design. Specific data sets to be collected by gas utilities would need to be developed.

## C. Community-Based Renewable Energy

Advocates are concerned that Oregon's IOUs have shown limited to no interest in Community-Based Renewable Energy projects (CBREs)[16]: Particularly CBRE procurement mechanisms that are suitable to a broader range of projects and community benefits which are key to the environmental justice communities that led on HB 2021. We have observed utilities seeking to re-label pre-existing programs and projects as CBREs in order to satisfy their obligations without doing much else. IOUs also appear to be making planning assumptions that

[16] ORS 469A.400(2) defines a CBRE as "one or more renewable energy systems that interconnect to utility distribution or transmission assets and may be combined with microgrids, storage systems or demand response measures, or energy-related infrastructure that promotes climate resiliency or other such measures, and that: (a) Provide a direct benefit to a particular community through a community-benefits agreement or direct ownership by a local government, nonprofit community organization or federally recognized Indian tribe; or (b) Result in increased resiliency or community stability, local jobs, economic development or direct energy cost savings to families and small businesses.

disfavor CBREs. Any PIM targeting CBREs should be designed with this dynamic in mind; specifically, it should reward utilities that undertake CBRE projects *beyond* what is required in HB 2021, and in alignment with the intent and objectives of that law which were created to require the IOU to go beyond business as usual. As we transition to MRPs, designing a PIM or PIMs that effectively incentivize utilities to meaningfully consider and, where appropriate, invest in CBREs is crucial.

Discussions around CBREs in the context of developing PIMs have helped identify important considerations. For example, utilities should not be rewarded for projects that meet the definition of a CBRE and that they have an existing obligation to procure, though a backstop PIM may be appropriate to ensure that they are meeting those obligations. Additionally, upside PIMs should be designed to incentivize CBREs with benefits to environmental justice communities.[17]

**Outcome:**

Incentivize Oregon's electric IOUs utilities to more aggressively pursue and procure community-based renewable energy resources with meaningful community benefits. To qualify as a CBRE covered by a PIM, a project's benefits should be supported by the utility's community benefits and impacts advisory groups (CBIAGs) or provide benefits pre-identified jointly by the CBIAG and energy justice advocates. Projects realized through programs and funding streams in existence in 2021 should be rewarded by PIMs where the utility can establish additionality beyond what the program would have delivered absent HB 2021.

Advocates have identified three distinct possible mechanisms for structuring the PIM for CBREs. Each takes a different view of what should be rewarded and when, and each carries different implementation risk. We are not wedded to any single one at this stage and are interested in stakeholder reaction to all three approaches.

### 1. Per-MW Annual CBRE Growth

Under this approach, the utility earns incentives for every MW of CBREs (and potentially qualifying small-scale renewables and storage) that reaches commercial operation relative to an established annual procurement trajectory. The incentive could increase for projects with particularly valuable characteristics, such as community ownership or the ability to reduce peak demand or displace traditional generation investments. The mechanism could also be paired with a penalty for falling behind the trajectory of CBRE acquisition to ensure that utilities treat the CBRE objectives with the appropriate urgency. Targets could be structured as fixed annual MW

[17] ORS 469A.400(5) defines an environmental justice community as including "communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including seniors, youth and persons with disabilities."

goals or as tiered performance levels, with increasing incentives for achieving higher levels of procurement.

The primary advantage of this is its simplicity and direct connection to the desired outcome: *more high-quality CBREs, sooner.* A multiplier could also allow the Commission to place greater value on projects with particular community or system benefits without needing to create separate PIMs for each. Additionally, the multiplier would help to reduce any incentives for quantity over quality that a fixed MW target may create for utilities, as higher-quality CBRE outcomes would be rewarded commensurate with their value to communities and the system.

A critical element and potential challenge of designing and implementing this PIM framework is establishing an accurate and achievable baseline and procurement trajectory. Oregon currently lacks an established annual CBRE acquisition target or historical data for determining what level of CBRE deployment is reasonable and would amount to meaningful additionality. Given this, Staff and stakeholders would need to establish this baseline and trajectory, while also defining how certain overlapping project types interact, such as CBREs and small-scale renewables, so as to avoid double counting.

Oregon is not, however, starting from scratch. ORS 469A.210(2) could inform a compliance floor from which an annual path can be determined, and the Commission has recent deployment data from the Oregon Community Solar Program and from small-scale renewable and CBRE procurements. We recommend Staff use both, for different purposes. The statutory standard can inform a starting point. Realized deployment data could help inform what rate of incremental acquisition is realistically achievable above that line.

We urge caution in using Community Solar Program deployment (or arguably any of these deployment data points on their own) as a proxy for business-as-usual utility procurement. CSP capacity is released by the Commission in administratively-set tiers, projects are developed and financed by the third-party project managers rather than the utility, and realized capacity has been limited by interconnection delays – all of which a utility has an ability to influence. A trajectory based solely on CSP capacity could risk rewarding a utility whose own delays suppressed the number. That said, we support Staff examining CSP, small-scale renewable, and any available CBRE procurement data together, establishing an initial trajectory, and reevaluating it as we get more data over time, rather than treating current deployment rates as representative of long-term CBRE potential.

We offer these thoughts on potential inputs to set the baseline and procurement trajectory for a CBRE PIM as a starting point, and look forward to hearing additional perspectives from Staff and utilities. PGE's O&M Cost Pre-Read may offer an example as the Company included a scenario on a CBRE PIM under which the utility would receive an upside incentive if "the total

amount of executed CBRE Power Purchase Agreements (contracts) exceeds the IRP's identified CBRE goal by 2035."[18] We understand that PGE may have included the scenarios in the Pre-Read purely for illustrative purposes. Still, we rely on this example to point out a general concern with focusing on IRP action plan targets as modeling decisions that impact those targets are often solely within the utility's control.

Ultimately, our perspective is that Pacific Power has done an insufficient job on CBREs so far, and that what appears as PGE's efforts to move away from its initial assertive approach are unsatisfactory. We are interested in learning more from Staff and the utilities on what may drive improvements related to CBREs.

### 2. Shared Savings/Benefits Mechanism

Under a shared savings or net benefits approach, utilities would earn a predetermined share of the net benefits and/or savings produced from the CBRE investments, rather than receiving a fixed payment or additional basis points for generating a certain amount of MW as described above. The PIM would be tied to the value created by CBREs for the utility, communities, ratepayers, and the grid, relative to the utility's reasonable alternative for meeting the same system or customer need. This approach rewards utilities for pursuing CBREs that provide greater value rather than simply rewarding additional MW, thereby addressing the potential tension between the quantity and quality of CBRE projects. Because the incentive would be based on the value of each project rather than progress toward an established MW target, it would also avoid the need to establish the same type of baseline required for a per-MW approach.

A key challenge with this approach is determining how to value the range of benefits that CBREs can provide. Some benefits, such as avoided energy or capacity costs and reduced peak demand, may be reasonably quantifiable. Other benefits contemplated by HB 2021, including resilience, local economic development, community ownership, and benefits to underserved communities, may be more difficult to assign an accurate dollar value. This is particularly true for CBRE projects like microgrids, which may provide several benefits simultaneously, including backup power and resilience, peak reduction, distributed generation and storage, grid services, and community resources. An accurate valuation would reflect these benefits without double counting them.

Finally, once the value of a CBRE is established, the PIM would need to determine what percentage of that value the utility would be allowed to retain as an incentive. This percentage would need to strike a balance between providing a meaningful incentive for utilities to actively pursue and facilitate CBREs while ensuring that the majority of the value created remains with

[18] https://edocs.puc.state.or.us/efdocs/HAC/ar676hac348788039.pdf at 6.

customers and communities. The Commission could also consider an overall incentive cap or other ratepayer protections to prevent the incentive from becoming disproportionate to the benefits produced.

### 3. Efficiency Carryover Mechanism

A third approach would allow utilities to earn an incentive for CBRE benefits over multiple years through an efficiency carryover mechanism. Rather than establishing a fixed payment for each MW procured or calculating a one-time share of a project's net benefits, the utility would receive an incentive based on the benefits produced by a CBRE over time. Benefits achieved in one year could generate incentive value that carries forward into subsequent years, allowing the utility to continue receiving a portion of the value created by the project.

This approach could be particularly useful for CBREs because many of the benefits of these projects are not limited to the year in which the project is developed or reaches commercial operation. A solar-plus-storage project, for example, may continue to reduce peak demand and provide grid services for many years. A microgrid may provide resilience during outages while also reducing or shifting load during normal operations. Under a conventional annual PIM, much of this continuing value may not be reflected in the utility's incentive after the initial project is completed. A carryover mechanism could instead recognize that the utility's efforts to facilitate a CBRE can produce benefits over a longer period.

In order to establish such a PIM, the Commission would need to determine which benefits qualify for carryover, how long those benefits should be recognized, and how changes in project performance or operating conditions should affect the incentive. A longer carryover period could also make it more difficult to determine whether benefits remain attributable to the utility's original actions. The Commission would need safeguards against double counting benefits that are also reflected in other PIMs, programs, or utility planning processes, as well as limits on the total incentive that can be earned from an individual project.

## VI. Conclusion

Energy Advocates propose these PIMs in support of the regulatory goals outlined by Staff and supported by the Commission in Phase 1 of this proceeding. We believe these PIMs support Staff's initial goal of starting from an understanding of peer experiences and community perspectives. We plan to create a slideshow presentation to further summarize the aforementioned proposed PIMs/PIM options for the Wednesday September 30 Track 3 PIMs Workshop. Through the implementation of PIMs we hope to maintain the overall goal of cost containment and affordability for customers, improve energy equity through reduced disconnections and increased access to clean energy solutions, prevent backsliding on key utility obligations, and support utilities in achieving key statewide clean energy and climate obligations. We look forward to discussing this proposal with Staff, utilities and other stakeholders.

**Respectfully submitted this 17th day of September 2026,**

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/s/ Sarah Wochele, Citizens' Utility Board

/s/ Charlee Thompson, NW Energy Coalition

/s/ Alex Houston, Green Energy Institute at Lewis & Clark Law School

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/s/ Jamie Pang, Oregon Just Transition Alliance

/s/ Alyssa Forest, Oregon Solar & Storage Industries Association

/s/ Silvia Tanner, Multnomah County Office of Sustainability