**May 6, 2026**
Public Utility Commission of Oregon
201 High St. SE, Suite 100
Salem, Oregon 97301-3398

**RE: AR 676 - Energy Advocate Joint Comments on Workshop #4**

On behalf of Oregon Just Transition Alliance, Sierra Club, Green Energy Institute at Lewis & Clark Law School, Mobilizing Climate Action Together, NW Energy Coalition, Climate Solutions, Oregon Citizens' Utility Board, Verde, and Multnomah County Office of Sustainability (collectively, the "Energy Advocates"), we submit these comments and attached table on ratemaking framework decision points. Together, we represent a diverse group of environmental justice, climate, energy, and ratepayer advocacy organizations throughout Oregon. These comments respond to Staff's proposed principles, goals, and outcomes framework, and address the key design decision points identified in the Workshop 4 worksheet. We also respond to positions taken by utilities in their prior comments, which, taken together, would not produce the strong, customer-protective MRP framework that Oregonians need and was intended with HB 3179 (2025), the FAIR Energy Act, and by SB 688, the Performance-based ratemaking bill.

We want to start by grounding these comments in the same context we have raised throughout this proceeding: *residential customers are paying more, but they aren't getting more*. The traditional cost-of-service model rewards capital spending and has allowed disproportionate costs and risks to flow to ratepayers without meaningful utility accountability. In the spirit of the FAIR Energy Act, this proceeding is an opportunity to change that — but only if the framework is designed with real discipline. The legislature's intent, and the social imperative behind this process, is not simply to make rate increases more predictable. It is to create a different incentive structure altogether.

## I. Feedback on Staff's Proposed Principles to Guide MRP and PBR Process

Staff's proposed principles are a reasonable place to start, but the ordering and framing matter. Leading with "contain and smooth customer rate impacts," with little focus on the "contain" component – and then treating utility financial stability as a co-equal concern – does not reflect where the weight of this process should fall. **We urge Staff to reframe the principles so that meaningful cost containment is the threshold objective**, with rate stability understood as a consequence of genuine cost discipline rather than a goal in its own right.

The MRP should function as a budget within which utilities must operate, prioritize, and find creative solutions – not a floor that adjusts upward to recover whatever costs the utility incurs. Where genuine opportunities exist to reduce costs through non-capital solutions, operational efficiencies, or avoided infrastructure investment, those savings should be incentivized. The utility comments filed in this proceeding reflect the opposite instinct: maximum flexibility, maximum capital investments, minimum financial consequences, and preservation of the existing web of automatic adjustments that have driven customer costs upward for years. The

Commission should use this as an opportunity to establish clear design parameters that serve customers.

On the financial stability principle specifically, we do not dispute that utilities have an *opportunity* to earn a reasonable return and the right to earn a reasonable return on investment. **But a utility's financial stability cannot mean a revenue requirement that outpaces inflation.** At the same time, those utility charges must be reasonable and just in order to be lawful. That is a recipe for continued energy (in)security disparities and unaffordability. Further, for some utilities, financial stability may not mean growth at all, but a decrease in revenue. For electric utilities facing major capital investment cycles and continued growth, some revenue growth may be warranted. For gas utilities, however, the financial stability principle must be understood in the context of a system that is likely to serve fewer customers over time–with serious considerations that, under the status quo, those left on the system are likely to be those with the least resources. Electrification trends, building codes, and the Climate Protection Program (CPP) mean that gas throughput and customer counts should decline (unless a different business model is implemented). A revenue requirement designed to hold flat -- let alone grow -- in that environment risks locking vulnerable, captive customers into subsidizing an oversized system, which is ultimately worse for utility financial stability as it accelerates customer defection and stranded asset risk. The joint comments from the gas utilities so far in this docket are notably silent on this reality.

Despite extensive discussion of regulatory efficiency and utility financial health, the gas utilities' comments contain no meaningful engagement with system trajectory, the risk of stranded assets, or how capital investment decisions should be made in light of declining sales and a declining customer base. Instead, they frame their situation primarily as a problem of chronic under-earning, and use that framing to argue the MRP must ensure utilities have a realistic opportunity to earn their authorized returns. This framing assumes a stable or growing gas system -- an assumption that is increasingly difficult to defend, and one the Commission should not embed in the MRP design.

A more sustainable approach is an MRP designed to allow the gas system to right-size over time. If a gas utility's revenue requirement decreases modestly as its system shrinks, and those savings are passed to remaining customers, per-customer costs can be held stable or even reduced as the customer base contracts. The Commission should require gas utilities to engage directly with system trajectory in their MRP proposals -- including how they plan to manage capital investments in light of declining throughput and a declining customer base, and how they will protect remaining customers, many of whom are likely to have lower incomes, from stranded asset risks.

We therefore recommend that Staff revise its principles to: (1) **elevate cost containment** explicitly in addition to naming specific cost-containment tools, framing the MRP as budget discipline that creates incentives to reduce costs, not merely pass them through more smoothly; (2) qualify the financial stability principle to make clear it **does not guarantee unwarranted revenue requirement growth**, and that for gas utilities a declining revenue requirement may be the appropriate outcome; (3) **make the burden explicit** -- where financial stability and cost

containment conflict, utilities must demonstrate that cost increases are unavoidable and prudent, not simply that they support earnings; and (4) affirm, as is consistent with the spirit of the FAIR Energy Act, that the Commission, not utilities, is in the driver's seat regarding the core design parameters of this framework.

## II. Feedback on Staff's Proposed Goals and Outcomes Framework

The goals and outcomes framework that Staff proposed is broadly consistent with what we have called for throughout the proceeding, and we appreciate Staff's effort to find common ground between stakeholders. That said, we have some observations about how this framework could be strengthened.

### A. The "Affordable, High-Value Service" Goal

We generally support this goal with one caveat. Staff identifies customer satisfaction, reliability, and rate stability as the key outcomes. These are reasonable, but, as written, the framework treats affordability primarily as a function of rate predictability -- customers will have "greater predictability in their utility rates." **Predictability in rate increases is not the same as affordability.** A utility can deliver perfectly predictable 8% annual rate increases and still price customers out of essential service. **We urge Staff to add explicit affordability outcomes**, and below we offer suggestions on this front**.**

### B. The "High-Performing Utility" Goal

We support cost containment and investment efficiency as outcomes here, and they are where MRP design does the most work. But we want to flag a tension in the "**asset utilization**" outcome as written. Our understanding of this outcome is that it means that utilities should learn to better utilize their existing resources – spreading costs for those resources/assets (which ratepayers have already paid or are paying for) over a higher sales volume. On the electric side, we agree that greater asset utilization is critical for cost containment, as local and national examples show.[1]

[1] PGE announced in October 2025 that they had unlocked 80 megawatts of capacity on the existing system using AI tools. In Virginia, a law adopted in the 2026 legislative session, HB 434, requires vertically integrated utilities to provide more data to regulators on asset utilization. See https://www.utilitydive.com/news/virginia-grid-utilization-bill-dominion/816888/.

The Virginia law requires reporting on the ratio of peak system load to capacity, the ratio of delivered load to total potential deliverable load, distribution losses by percentage, an analysis of constrained distribution circuits and an evaluation of the system performance during peak periods. Energy regulators in Virginia will be required to regularly report its own findings on the utilities' grid utilization metrics and analyze how "non-wires alternatives" — such as energy storage, distributed generation, synchronous condensers, flexible transmission and power quality monitors — can increase utilization. A similar approach is needed in Oregon.

On the gas utility side, we caution that even indirectly suggesting that we are trying to reach a higher sales volume or maximize use of gas system assets could be in conflict with Oregon's climate policy. To avoid that risk, **we therefore recommend that asset utilization be characterized differently for gas utilities**, perhaps by reframing it to reward efficient management of a declining system. An approach that weighs new capital investments in gas distribution system maintenance against alternatives like 'strategic electrification' should be considered. The Regulatory Assistance Project report, *Under Pressure: Gas Utility Regulation for a Time of Transition*, offers practical tools that the Commission should consider.

Additionally, we want to see the capex/opex equalization outcome reflected in MRP design from the outset. The current system's bias toward capital spending is one of the primary drivers of utility rate increases. A PBR framework that does not actively correct for this bias -- through total expenditure (totex) accounting, targeted PIMs, and other tools -- will reproduce it. Approaches like totex, which is used in the United Kingdom, should be considered. We also want to note that, while wanting to correct for capex bias, we do not simply want to over-incentivize operational expenses (i.e., without reducing capex) – instead, we want to really scrutinize where and how we're correcting for this bias. We are interested in a deeper dive to understand the benefits and challenges of its potential application in Oregon.

### C. The "Achievement of Societal Goals" Goal

In a later phase, we look forward to addressing what happens when utilities fail to achieve the clean energy, distributional equity, and resilience outcomes identified by Staff, or when utility investment decisions actively conflict with the outcomes.

*On clean energy development*: Staff's explanation notes that "efficient procurement and interconnection of least-cost and lowest-risk resources can ensure development provides the greatest system and customer value." We agree, but want to see this framing be strengthened. **HB 2021 and the Climate Protection Program are legal requirements, not aspirational targets**. The MRP framework must include backstop PIMs with real financial consequences for failure to meet these obligations, not just metrics and scorecards that document non-compliance without consequence. PacifiCorp's comments argue at length that HB 2021 compliance costs are potentially unaffordable and that Oregon should calibrate the pace of procurement to what customers can "reasonably afford." We are sympathetic to genuine compliance affordability concerns, but the solution is not to build a ratemaking framework that makes non-compliance easier, or that ignores or forgives lost opportunities. The solution is to design an MRP that creates strong incentives for utilities to find the most cost-effective path to compliance, likely including the deployment of demand-side resources, non-wires alternatives, and distributed energy resources that can reduce system costs while accelerating decarbonization.[2]

*On distributional equity:* Staff lists distributional equity as an outcome under "Achievement of Societal Goals," describing it as "access to the benefits of the energy system by all

[2] Oregon has made progress requiring utilities to pursue least cost resources like Grid Enhancing Technologies and small scale renewables. MRPs can push utilities to look for similar cost efficiency strategies across the system.

Oregonians." We support this framing, but want to be specific about what it requires. We also understand that the bulk of this outcome will be further fleshed out in a future AR 676 phase. Access to benefits means customers with low incomes or who are part of other environmental justice communities can fully access the benefits of a clean energy transition, including the financial benefits of clean energy programs, rather than seeing energy burden reductions only through bill assistance. Access to benefits also means that utilities meaningfully consider and procure resources that benefit communities, like community-based renewable energy resources with meaningful impacts on community benefit indicators.

Distributional equity requires that communities that have historically borne the greatest environmental burdens are prioritized for clean energy investment and any needed weatherization to support this. It means the transition does not leave behind households that cannot afford to electrify without targeted support. In forthcoming phases, we will continue to recommend that distributional equity metrics include clean energy deployment in low-income and environmental justice communities–which includes weatherization and energy efficiency upgrades, participation rates in clean energy programs by income level, and equity in reliability performance across customer populations.

*On resilience:* we support its inclusion and want to note its particular relevance for communities in or near high-fire-risk zones, where reliability and safety outcomes are most consequential. The framework should explicitly connect resilience investments to communities most at risk rather than treating it as a system-wide average.

### D. On the Gas Utility Goals and Outcomes

Staff's proposed goals for gas utilities **contain no outcome related to managed decline, system right-sizing, or protecting remaining customers from stranded asset risks as the gas system contracts.** Such an addition is necessary because gas utilities in Oregon are facing declining throughput, increasing customer attrition due to electrification, and legal obligations to reduce emissions under the Climate Protection Program. **We recommend that Staff add an explicit outcome for gas utilities related to responsible system planning in the context of declining demand** -- one that rewards utilities for making capital investment decisions that minimize long-term stranded-asset risks and protect customers as the system transitions.

## III. Feedback on the Ratemaking Framework Decision Points

### A. Type of MRP

**We strongly support an index-based attrition relief mechanism**.[3] The alternative, a forecasted MRP, gives utilities significant control over their own revenue requirement through assumptions that non-utility stakeholders cannot easily scrutinize in real time due to information asymmetry. PacifiCorp's comments acknowledge that all forecasts are inherently inaccurate, but then draw from this the conclusion that utilities need more flexibility to deviate from plan targets. We draw the opposite conclusion: **since utility forecasts are often inaccurate and have consistently led to dramatic rate increases, they should not be the primary mechanism for setting customer rates over a multi-year period**. An index-based cap anchors annual adjustments to benchmarks that are external to the utility, such as the Consumer Price Index (CPI).

We also note that the choice of MRP type and the scope of adjustments cannot be separated. PGE proposes a K-bar capital factor (capital expenditure adjustments based on historical spending), broad Z-factors (adjustments for unexpected events), and special trackers alongside an index-based cap. An index-based cap with an expansive set of carve-outs is not meaningfully different from a forecasted MRP -- it just obscures how little cost is actually subject to the cap.

### B. Plan Duration

Per third-party expert recommendations,[4] **we support a five-year stay-out period for electric utilities and a three-year stay out period for gas utilities**, but for different reasons than utilities have argued. A longer stay-out for electric utilities creates stronger cost-containment incentives and reduces the frequency of expensive rate proceedings. A shorter-term period for gas is appropriate not because gas utilities need flexibility, but because locking in a revenue requirement for five years creates real risk of *over-recovery* as public policy develops and throughput and customer counts are likely to decline. A shorter term gives the Commission more regular opportunities to right-size the gas revenue requirement as conditions change.

### C. Scope

The cost-containment value of a revenue cap depends entirely on what costs are actually subject to it. The gas utilities want existing trackers and deferrals to continue operating alongside the MRP. PacifiCorp wants to preserve and expand Automatic Adjustment Clauses (AACs) and Renewable Adjustment Clauses (RACs). PGE proposes K-bars (capital expenditure adjustments based on historical spending), broad Z-factors (adjustments for unexpected

[3] The question of whether to do a revenue cap or price cap came up in Workshop #4. Based on our current understanding, a revenue cap ties allowed revenue to an external index benchmark, decoupling utility financial health from sales volume, whereas a price cap controls only the per-unit rate charged to customers, and leaves utilities dependent on sales volume to recover their cost. We would be concerned that a price cap could create pressure for utilities to defend or grow throughput rather than support efficiency and electrification programs and otherwise aim for cost containment. For gas utilities facing declining throughput, this dynamic could be particularly risky: as customers exit, per-unit costs rise to recover fixed costs, which can accelerate further customer defection and fall hardest on captive, lower-income customers least able to electrify. However, we are interested in discussing the differences between these index-based approaches further, if Staff thinks that would be helpful.

[4] As explained in the December and January workshops.

events), and special trackers. **These positions are counter to the purpose of the legislation and this proceeding, allowing utilities to selectively pursue the most favorable mechanisms without any incentive to control costs.**

We want to be clear about what we are and are not arguing here. Not all cost recovery mechanisms outside the base rate are the same, and some serve important customer-protective functions that should be preserved. Oregon's fuel cost adjustment mechanisms -- the Power Cost Adjustment Mechanism (PCAM) for electric utilities and the Purchased Gas Adjustment (PGA) for gas utilities -- are among the best-designed in the country precisely because they share the risk of genuinely volatile, largely uncontrollable costs between utilities and customers in a structured, reviewable way. The PCAM's deadband in particular functions as a meaningful ratepayer protection, requiring utilities to absorb modest cost variances before pass-through is available. These mechanisms should be retained and, importantly, should not be weakened in the course of MRP design.

The category of adjustments we are concerned about is different: capital trackers, broad exogenous cost factors, and the proliferation of single-issue filings that allow utilities to recover costs outside the base rate with limited scrutiny and no meaningful cost-containment discipline. **The Commission should approach each proposed exclusion from MRP scope with a strong presumption against it.** Exclusion should require a specific showing that a cost category is genuinely volatile, material, and beyond the utility's ability to manage within a multi-year budget. Routine capital expenditures, ordinary operating cost variability, and foreseeable policy-driven investments do not meet that standard. On Z-factors specifically (adjustments for unexpected events), PGE's proposed list includes regulatory changes, supply chain disruptions, labor disputes, and accounting changes -- a category so broad that virtually any cost increase could qualify. Z-factor criteria must be tightly defined and subject to rigorous after-the-fact review, including earnings tests, not automatic pass-through.

### D. Going-In Rates

**The starting point is the most consequential design decision in the framework.** We have consistently called for a **third-party audit** before any MRP begins, and we reiterate that here. From Workshop 4, we understood from Current Energy Group that this was really important for Hawaii in its MRP process to identify areas for cutting costs. Indeed, the audit should identify cost-reduction opportunities, assess the reasonableness of current spending across both capital and operating categories, and flag costs that have been deferred or under-scrutinized. We strongly prefer a historical test year over a utility-forecasted one.

### E. Return on Equity (ROE)

The Commission recognized in UE 435, through Order 24-454, that reduced regulatory risk justifies a lower ROE. An MRP with a meaningful stay-out period further reduces risk, and that reduction must be reflected in the authorized return from the outset. The gas utilities frame their situation as chronic under-earning and argue the MRP must provide a more realistic earning opportunity -- but under-earning with cost-of-service ratemaking reflects the outcomes of

individual rate cases, not evidence that the authorized ROE is structurally too low. Any earnings above the authorized ROE during the plan period should be shared with customers through an asymmetric earnings sharing mechanism with a narrow deadband. Customers should share in excess earnings, but under-earnings should be on the utility – not passed through to customers. This is appropriate given that the MRP itself reduces regulatory risk, and it ensures that the burden of managing costs within the plan falls on the utility rather than ratepayers.

### F. Capital Funding Mechanisms

**We oppose the K-bar (capital expenditure adjustments based on historical spending) proposal put forward by PGE.** Automatically funding capital expenditures outside the revenue cap severs the connection between capital spending discipline and cost-containment incentives, and institutionalizes the capex bias this proceeding is meant to correct. Where large policy-driven investments genuinely cannot fit within an index-based cap, targeted trackers for specific pre-approved projects may be appropriate, but only after a showing that non-capital alternatives were fully considered and subject to a *meaningful materiality threshold* so that routine or modest expenditures cannot be carved out of the cap through this mechanism.

### G. Performance Incentive Mechanisms (PIMs) and Performance Metrics

The framework should distinguish between two types of PIMs that serve different functions: backstop PIMs, which enforce compliance with existing obligations and protect customers from harm, and targeted PIMs, which create affirmative incentives for utilities to pursue specific policy outcomes beyond their baseline obligations.

We understand backstop PIMs to be crucial protective compliance mechanisms. As such, backstop PIMs with real financial consequences should come first.

For example, we should prioritize backstop PIMs for failure to meet obligations like HB 2021, Climate Protection Program, and basic reliability standards. Utilities should not be rewarded for meeting obligations they already have, but they must face consequences for failing to meet them.

**Targeted PIMs should then create affirmative incentives for public interest outcomes that are not specifically driven through the MRP or existing mandates** (e.g., electrification program performance, deployment of non-wires alternatives, community-based renewable energy infrastructure, microgrids, or peak demand reduction). We look forward to digging into these further in Phase II.

An important area in which we want to see meaningful performance mechanisms – perhaps a mix of backstop and targeted PIMs[5] – relates to energy security for low-income customers. It will be important for utilities to have a greater stake in seeing meaningful reductions in disconnections, reductions in customer arrears, and a measurable reduction in energy burden

[5] Hawai'i has a mix of PIMs, both targeted and backstop, for customer affordability and equity. It may be appropriate to consider a similar mix during Phase II.

for households most affected.These are not novel metrics. Utilities already collect and report this data. The question is whether the framework will treat poor performance on these measures as consequential. We are eager to see how utility partners would engage more creatively and constructively in these conversations due to incentives or disincentives related to progress or failure on these crucial metrics. Developing performance mechanisms to give utilities more of a stake in preventing disconnections, arrears, and energy burden would prevent harm to customers most affected.

Shadow reporting (e.g., metrics, scorecards) may be appropriate where genuinely new metrics require data development, but it is not appropriate for outcomes where utilities already collect and report data as outlined above. Where shadow reporting is used, it should be short, time-bound, and followed by financial consequences on a pre-defined schedule -- *not* at the utility's discretion.

PacifiCorp argues utilities must be able to deviate from PIM thresholds without penalty when they judge it in the customers' best interest. This would make PIMs unenforceable. The appropriate remedy for a genuinely changed circumstance is a formal modification process, not unilateral utility discretion. Similarly, PacifiCorp's argument for eliminating PCAM deadbands should be rejected. Deadbands are a legitimate risk-sharing tool, and eliminating customer protections in existing mechanisms while seeking additional flexibility in new ones is a one-directional transfer of risk to customers -- which is precisely what this proceeding is meant to correct.

## IV. Conclusion

Throughout this proceeding, consistent with outside expert advice offered in workshops, we have argued that the MRP should function as a genuine budget discipline: one that gives utilities a clear framework within which to plan, innovate, and serve customers, while holding them accountable for the outcomes customers actually experience. The utilities' comments in this docket reflect a consistent effort to preserve the flexibility and cost pass-through mechanisms of the current system while adopting the form of a new one. We urge Staff and the Commission to design something better, and appreciate the many ways in which Staff has shown a commitment to an MRP that meaningfully balances the relevant principles while centering customers.

Respectfully submitted this 6th day of May 2026,

/s/ Jamie Pang, Oregon Just Transition Alliance

/s/ Charlee Thompson, NW Energy Coalition

/s/ Carra Sahler, Green Energy Institute at Lewis & Clark Law School

/s/ Pat DeLaquil, Steering Committee, Mobilizing Climate Action Together

/s/ Maleek McKenzie, Sierra Club Oregon Chapter

/s/ Claire Prihoda, Climate Solutions

/s/ Sarah Wochele, Oregon Citizens' Utility Board

/s/ Anahí Segovia Rodriguez, Verde

/s/ Silvia Tanner, Multnomah County Office of Sustainability

## For Stakeholders to Complete: Ratemaking Framework Decision Points

The following table lists MRP and PBR elements that Staff has identified could be subject to decisions in AR 676. Some are expected to be a focus of the Phase 1 Straw Proposal, because identifying these threshold design decisions will clarify the parameters of a Phase 1 interim Commission decision and provide greater focus in Phase 2. Other decision points are included that may receive some attention in a Phase 1 decision, then get fuller attention in subsequent phases of AR 676 or future rate cases. For these, a Phase 1 decision might suggest inclusion or exclusion of certain components, while adoption and design details could take place in a later phase. **Bolded ratemaking components** in the table indicate those that are anticipated to addressed in the Straw Proposal in either of these manners.

Stakeholders are invited to provide perspectives on proposed outcomes and decision points at the April 15, 2026 workshop and through written comments following the workshop. The workshop will focus on a subset of decisions or ratemaking components, while written comments are invited on other areas as well.

Where applicable, the column that lists each MRP and PBR design component includes a reference to the relevant page number in the "Multi-Year Rate Plans: Purpose and Design Considerations" report (MRP Report) from December 2025.

A description of each phase can be located in the Staff Implementation Letter filed in AR 676 in October 2025 and each phase is summarized below:

- Phase 1: Foundations and Concept Development
- Phase 2: Framework Design
- Phase 3: Formal Rulemaking
- Phase 4: Implementation

| Ratemaking Component | Options or Considerations | Recommended Approach |
|---|---|---|
| **Principles, Goals, and Outcomes** | See April 8 pre-read filed in AR 676 | Principles:<br>1) **Cost Containment.** Elevate cost containment explicitly, framing the MRP as budget discipline that creates incentives to reduce costs, not merely pass them through more smoothly<br>2) **Stability over growth**. Financial stability is fine to include but should be qualified to be clear it does not guarantee unwarranted revenue requirement growth. |

| Ratemaking Component | Options or Considerations | Recommended Approach |
|---|---|---|
| | | 3) **Burden on utilities**. Where financial stability and cost containment conflict, utilities must demonstrate that cost increases are unavoidable and prudent, not simply that they support earnings.<br>4) **Commission Authority**. In the spirit of the FAIR Energy Act the Commission, not utilities, must be driving design parameters of this framework.<br>Goals:<br>1) **Affordable High Value Service**. We generally support this goal.<br>2) **High Performing Utility.** We generally support this goal.<br>3) **Achieving Societal Goals**. We generally support this goal.<br>Outcomes:<br>1) Affordable High Value Service<br>a. More explicit affordability outcomes<br>2) High Performing Utility.<br>a. **Electric Asset utilization** is important as an affordability and cost containment solution.<br>b. Concerned about **gas asset utilization** as an outcome (see full comments)<br>c. **Capex-opex equalization**. We are very supportive of this outcome and want to see it integrated early in MRP design.<br>3) Achieving Societal Goals<br>a. **Clean Energy Development**. We agree with this outcome, but it can be strengthened with clear consequences for failure to meet requirements. |

| Ratemaking Component | Options or Considerations | Recommended Approach |
|---|---|---|
| | | b. **Distributional Equity.** We are generally supportive, but have a lot of ideas and considerations for how this should be developed and implemented (see comments).<br>c. **Resilience.** We are supportive of this outcome.<br>4) **Gas utility specific outcome.** We recommend adding an explicit outcome for gas utilities related to responsible system planning in the context of declining demand. |
| **Type of MRP (MRP Report, p. 7)** | • Index-based cap (revenue or price cap)<br>• Forecasted MRP | Index Based revenue cap |
| **Revenue decoupling (MRP Report, p. 40) or other revenue true-up mechanism** | How does the existence of decoupling, or not, relate to MRP type? | We are generally supportive of maintaining decoupling for gas utilities. |
| **Plan duration (stay-out period; MRP Report, p. 14)** | 3-7 years | 5+ years for electrics<br>3 years for gas |
| **Scope of an MRP (inc. trackers and deferrals; MRP Report, p. 11)** | Which costs and revenues are consolidated within the MRP base rates and thus subject to associated cost controls? | Generally, we believe that the MRP should be as broad to maximize cost containment and transparency.<br>The Commission should approach each proposed exclusion from MRP scope with a strong presumption against it, with the burden on the utility to justify exclusions. See comments for discussion of PCAM and PGA as customer-protective cost adjustment mechanisms. |
| Going-in rates (MRP Report, p. 17) | • What information determines the revenue requirement?<br>• Should a historical or forecasted test year be used? | [Determined in a rate case] We recommend a 3rd party audit as part of setting the going-in rates. |

| Ratemaking Component | | Options or Considerations | Recommended Approach |
|---|---|---|---|
| ROE (MRP Report, p. 19) | | • Do new risks, or mitigants, from the MRP change the ROE?<br>• What influence does authorized ROE have on MRP incentives? | [Determined in a rate case] An MRP with a meaningful stay-out period further reduces risk, so ROE should be lowered to reflect that reduced risk. We support asymmetric earnings sharing, with customers sharing in excess earnings and utilities bearing the risk of under earning. |
| **Index-based Adjustments (if applicable)** | **Inflation measure (MRP Report, p. 24)** | • GDPPI<br>• Other inflation measures or composite structures (e.g., regional indices, CPI, etc.) | |
| | **X factor (MRP Report, p. 25)** | • How to set (e.g., total factor productivity study)?<br>• Who conducts the study? | |
| | **Z factor (MRP Report, p. 29)** | • What are the criteria to trigger a Z-factor adjustment? | If allowed, should be clearly defined and subject to after the fact review. |
| | **Stretch factor (consumer dividend; MRP Report, p. 27)** | • Is a stretch factor warranted?<br>• What is the adjustment value based on? | We support efforts to push the utility to pursue efficiency and innovation through mechanisms like a stretch factor. |
| **Capital funding mechanism(s) (MRP Report, p. 31)** | | • What projects could be subject to a separate funding mechanism?<br>• What mechanism design is applicable? | We oppose K-bars.<br>Where large policy-driven investments genuinely cannot fit within an index-based cap, targeted trackers for specific pre-approved projects may be appropriate, but only after a showing that non-capital alternatives were fully considered. |
| **Earnings sharing mechanism (MRP Report, p. 20)** | | • Is it symmetric or asymmetric?<br>• Are there tiers and deadbands, and of what size? | We support asymmetric earnings sharing, with customers sharing in excess earnings and utilities bearing the risk of under earning. We support deadbands that are customer protective like the PCAM. |
| Off-ramp (MRP Report, p. 39) | | • What thresholds or criteria could trigger an off-ramp? | Limited off-ramps and reconciliations – perhaps none – to ensure meaningful cost-containment during a utility's stay-out period. |

| Ratemaking Component | Options or Considerations | Recommended Approach |
|---|---|---|
| | • How to make these unlikely, but available when necessary? | Costs would have to have been truly unforeseen, outside utility control, and significant (a good threshold could be 500 basis pts). Offramps should require commission investigation, with significant discretion and review by the commission, and the burden on the utility to justify the need to reopen rates. See Scoping Survey from CUB 12/10/25. |
| Reopener (MRP Report, p. 39) | • What thresholds or criteria could trigger a reopener?<br>• How to make these unlikely, but available when necessary? | See above. |
| Rebasing (MRP Report, p. 36) | • When does rebasing occur? Based on what information?<br>• How to avoid perverse incentives to inflate costs? | Similar to setting going-in rates, we support a 3rd party audit prior to the next multi-year rate case (similar to CT and UK). |
| Efficiency carryover mechanism (MRP Report, p. 38) | • Should an ECM be incorporated?<br>• What structure? | |
| **Capex/opex equalization (MRP Report, p. 36)** | • What approach is applicable (e.g., targeted PIMs, capitalization of opex, totex accounting)<br>• What is relationship or connections to capital funding? | |
| Metrics and scorecards (MRP Report, p. 40) | • Which outcomes are subject to metric reporting or a scorecard? | Appropriate where we have not been collecting/reporting data in COSR, but could serve to delay real action where we have already been collecting data and are ready to move to PIMs. Shadow Reporting should be short time-bound and followed by financial consequences on a pre-defined schedule. |
| Performance Incentives (MRP Report, p. 40-41) | • Which outcomes should be targeted for new or updated performance incentives? | We should prioritize backstop PIMs for failure to meet legal obligations under HB 2021 and CCP, and where the utility fails to meet basic reliability standards. |

| Ratemaking Component | Options or Considerations | Recommended Approach |
|---|---|---|
| | • What performance incentive design is most applicable to each outcome (PIMs, SSM, etc.)?<br>• How much revenue should be subject to performance incentives? | Additional PIMs may be appropriate where we have a history of data collection and tracking under COSR.<br><br>See comments for more detail. |
| The relationship between planning processes (DSP, IRP, etc.) and MRPs (MRP Report, p. 44-45) | • How do planning processes inform MRP design and revenue requirements? What timing needs to be taken into account?<br>• How to manage imperfect information or studies subject to later completion? | |