ORDER NO. 26-242

ENTERED Jul 13 2026

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 676

In the Matter of Rulemaking to Establish Multi-Year Rate Plan Framework (HB 3179 & SB 688 Implementation).	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED

This order memorializes our decision, made and effective at our July 7, 2026 Special Public Meeting, to adopt Staff's recommendation in this matter. The Staff Report with the recommendation is attached as Appendix A.

As discussed at the public meeting, we expect Staff to provide at least one update at a public meeting during phase two of the informal rulemaking process. Our goal with this update is to understand phase two's developing points of consensus and disagreement among participants, and any trade-offs we may be asked to balance to further inform the development of draft rule language prior to moving to a formal rulemaking process.

Made, entered, and effective Jul 13 2026.

Letha Tawney Chair	**Les Perkins** Commissioner
	Karin Power Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

ITEM NO. RM2

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: June 23, 2026

REGULAR ___ CONSENT ____ RULEMAKING __X__ EFFECTIVE DATE ___N/A___

DATE: June 16, 2026

TO: Public Utility Commission

FROM: Michelle Scala

THROUGH: Caroline Moore and Scott Gibbens **SIGNED**

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF:
(Docket No. AR 676)
Rulemaking To Establish Multi-Year Plan Framework (HB 3179 & SB 688).

STAFF RECOMMENDATION:

The Public Utility Commission of Oregon (Commission) should adopt Staff's recommended multi-year rate plan (MRP) framework to inform the scope of rules developed in Phase 2.

DISCUSSION:

Issue

Whether the Commission should adopt Staff's recommended multi-year rate plan (MRP) framework:

1. Five-year duration (term);
2. Index-based revenue cap (MRP type) that includes the following
    a. Adjustment Factors (index formulas I-X-S+G+Z and capital funding mechanism);
    b. Revenue decoupling mechanism;
    c. Earnings sharing mechanism; and
    d. Targeted use of performance incentive mechanisms (PIMs); Initial suggestion includes PIMs in each of the following key backstop and outcome areas for examination in Phase 2:
        i. Backstop PIMs:
            1. Reliability
            2. Safety
            3. Customer Service

    ii. Outcome PIMs:
        1. Customer disconnections
        2. Asset utilization
        3. Progress on CBRE acquisition targets (electric only)
3. Comprehensive inclusion of costs in the MRP; excluding power costs, non-routine wildfire mitigation; and Energy Trust of Oregon funding (scope of MRP) for the time being.

For context, Staff also proposes to address the following in phase 2:

- Design details of Phase 1 elements, including adjustment factors, revenue decoupling, and PIMs
- Exception process
- Reopeners and off ramps
- Rebasing and efficiency carryover mechanism
- Procedural requirements

Applicable Rule or Law

ORS 757.217(2)(a) requires the Public Utility Commission to establish rules requiring an electric or natural gas company to establish a multiyear rate plan for rate revisions that subject an electric or natural gas company's return on equity to review or modification.

(b) The rules must:

(A) Include procedural and content requirements for a multiyear rate plan.

(B) Require an electric or natural gas company to file a multiyear rate plan on a regular interval that is no less than three and no more than seven years long.

(C) Establish a limit on the number of electric or natural gas companies that are allowed to request a rate increase in any given year.

(c) The rules may:

(A) Provide for incentives for efficient utility operations.

(B) Authorize refunds to customers under certain circumstances.

(C) Allow an electric or natural gas company, or third party, to request an exception to a requirement established by rule under this section on a showing of good cause.

ORS 756.046(3) authorizes the Commission to investigate, develop and adopt a framework for carrying out performance-based regulation of electric companies. The commission may use performance-based regulation to provide incentives and penalties to induce electric companies to bring electric utility operations in line with the public interest and to:

(a) Reduce the emissions of anthropogenic gases and atmospheric pollutants;

(b) Expand the use of distributed energy resources, community solar projects, microgrids, demand response programs and energy efficiency programs;

(c) Enhance the quality, reliability and resiliency of electricity service in this state;

(d) Offer flexible payment plans that reduce disconnections of electricity service for low-income customers and other programs that address the quality and affordability of electricity services for all customers; and

(e) Improve all aspects of utility operations to reduce costs and pass on savings to ratepayers.

(4) A framework that is adopted under this section must:

(a) Provide for performance standards and a baseline from which performance is measured;

(b) Provide for performance metrics that are clear, objective, verifiable and achievable for measuring an electric company's performance;

(c) Describe how the performance standards and metrics are to be carried out;

(d) Identify actions and mechanisms that an electric company may carry out or implement to meet performance standards; and

(e) Provide an electric company incentives or penalties based on an electric company's performance.

(5) In developing incentives and penalties under this section, the Commission shall take into consideration the impacts of those incentives and penalties on rates paid by ratepayers.

(6) In addition to providing for performance metrics that are subject to incentives or penalties, the Commission may establish performance metrics that are not subject to incentives or penalties but are reportable and may require each electric company to file with the commission an annual report on the electric company's performance as measured by those reportable performance metrics.

Under ORS 756.060, the Commission may adopt and amend reasonable and proper rules and regulations relative to all statutes administered by the Commission.

Analysis

Background

House Bill 3179 (2025) directs the Commission to transition Oregon's ratemaking framework for electric and natural gas utilities to multi-year rate plans (MRPs). For this purpose, HB 3179 requires the Commission to establish rules that:

- Define procedural and content requirements for MRPs,
- Require each utility to file an MRP at regular intervals of no less than three and no more than seven years, and
- Limit the number of utilities that may request a rate increase in any given year.

The statute also authorizes the Commission to provide incentives for efficient utility operations, authorize customer refunds in certain circumstances, and allow exceptions to MRP requirements on a showing of good cause.

In parallel, Senate Bill 688 (2025) lays out considerations for the development of performance-based regulations for electric utilities, emphasizing outcomes related to emissions reductions, system performance, affordability, and operational efficiency.

In October 2025, the Commission opened Docket No. AR 676 and Staff began a phased process to develop the multi-year rate plan framework as administrative rules. Staff launched Phase 1 with a scoping survey to understand stakeholders' desired outcomes, priorities, and improvements to the ratemaking framework, followed by a series of educational workshops and informal comment opportunities. Staff released a draft proposal for the Phase 1 MRP framework on May 20, 2026[1] and received comments from NW Natural, Avista Utilities, and Cascade Natural Gas Corporation (joint); Association of Western Energy Consumers (AWEC); PacifiCorp; Oregon Solar and Storage Industries Association; Oregon Citizens' Utility Board, Climate Solutions, NW Energy Coalition, Oregon Just Transition Alliance, Mobilizing Climate Action Together, Community Energy Project, Verde, and Multnomah County Office of Sustainability (Energy Advocates), Idaho Power; Renewable Northwest; and Portland General Electric Company (PGE). Staff held regular office hours throughout this process, as well.

The remainder of this report describes Staff's proposed Phase 1 framework, addresses comments and concerns raised by stakeholders, and highlights key decisions Staff anticipates in Phase 2.

Phase 1 Strategy

The Phase 1 process was designed to narrow major structural decisions necessary to efficiently and effectively develop detailed rules for the content of MRPs in Phase 2. These decisions include: plan duration, MRP type, scope, and whether specific ratemaking mechanisms should be incorporated into the framework. Detailed calibration and design questions around adjustment factors, earnings-sharing, capital adjustment mechanisms, decoupling, and PIMs will continue to be explored in Phase 2.

Staff's proposal is informed by the following principles:

- Contain and smooth customer rate impacts
- Maintain utility financial stability
- Reduce regulatory burden and improve administrative efficiency

These principles help provide a lens through which tradeoffs and design choices can be evaluated. Goals and outcomes help to operationalize these principles and facilitate a shared understanding of what success looks like. Stakeholder discussions and responses to Staff's scoping survey helped inform both the three overarching principles above and the set of goals and outcomes listed in the table below. Outcomes that support performance areas specified in Senate Bill (SB) 688 (performance incentives for electric utilities) are noted with an asterisk "*". Outcomes specific to electric utilities are noted with an "^{E}". Staff would also clarify that outcomes may be associated with more than one goal.

[1] https://edocs.puc.state.or.us/efdocs/HAH/ar676hah346341048.pdf.

Goals	Outcomes
Affordable, high-value service	Customer satisfaction*
	Reliability*
	Rate stability
High-performing utility	Cost containment*
	Investment efficiency
	Asset utilization
Achievement of key state and community goals	Efficient clean energy development and emissions reductions*E
	Distributional equity*
	ResilienceE

Staff used these principles, goals, and outcomes to evaluate how different MRP structures allocate risk, shape utility incentives, affect customer costs, and influence the practical administration of the framework. Building on this evaluation, Staff's proposed framework is grounded in discipline and predictability. Staff's strategy is to establish a clear and meaningful budget for the MRP term, while applying targeted flexibility during the budget period to facilitate utility focus on high performance and efficient progress on state and community goals.

In developing its proposal, Staff also considered how Phase 1 decision points might flow into more detailed Phase 2 design choices and eventual implementation, particularly given the diversity of growth, investment, and planning expectations among Oregon utilities. To this end, the Phase 1 framework recognizes both durability and flexibility across MRP components. "Durability" refers to the extent to which the Phase 1 MRP framework allows for Phase 2 design decisions and ongoing implementation decisions that can address different goals and utility system needs. For example, the Phase 1 framework includes adjustment factors, a decoupling mechanism, an earnings sharing mechanism, and PIMs. Throughout this report, Staff will explain how these components can be calibrated in Phase 2 and ongoing implementation to ensure that introducing a more disciplined and predictable ratemaking approach will continue to accommodate changing or unique utility system needs. Durability is also essential to sustaining the discipline the framework is designed to establish. Without a stable structure that holds over time, the expectations and incentives necessary for disciplined utility planning and cost management weaken, and the framework risks drifting toward frequent adjustments that undermine its purpose.

Staff uses "flexibility" to refer to optionality that will be built into the rules and can be implemented on a case-by-case basis in individual utility MRPs under dynamic conditions and/o to reflect differently situated utilities. Staff sought to mitigate the risks of an overly rigid framework that might restrict efficiencies, degrade outcomes, or send the wrong signals related to necessary and desirable investments. Staff intends to use targeted flexibility in Phase 2 to preserve incentives for prudent utility management, promote predictability, and advance the discipline afforded by an MRP framework. Taken together, these foundational characteristics and principled objectives formed Staff's Phase 1 strategy of discipline paired with targeted flexibility.

Staff Proposal Summary Table

Staff evaluated various framework components both individually and in conjunction with other components, considering how each component would work in an integrated process to balance affordability, predictability, utility financial stability, accountability, and administrative practicality. Staff recognizes that multiple approaches could reasonably satisfy HB 3179. The proposal presented here rose to the top based on the principles, goals, and outcomes identified through Phase 1 and Staff's assessment of how the framework would function under Oregon conditions.

MRP/PBR Component	Staff Proposal
Plan duration (stay-out period)	5-year term.
Type of MRP	Index-based revenue cap.
Scope of MRP	A comprehensive scope of utility revenues with limited exceptions, consistent with Staff's proposed principles. Exceptions include power costs, wildfire mitigation automatic adjustment clause (electric utilities), and Energy Trust of Oregon funding.

Adjustment Factors[2]	• **Include** indexing to inform the revenue cap over the plan duration and design the mechanisms in Phase 2 based on Staff's considerations.
	• **Include** the following factors in MRPs:
	  ○ Inflation measure (I)
	  ○ Productivity factor (X)
	  ○ Stretch factor (S)
	  ○ Customer Growth factor (G)
	  ○ Exogenous/Extraordinary events (Z)
	• **Include** supplemental capital funding mechanism for targeted capital and extraordinary or unforeseen expenses

Revenue decoupling	**Include** decoupling to effectuate the revenue cap and promote business efficiency (i.e., cost savings below the cap). Design of the decoupling mechanism will occur in Phase 2.
Earnings Sharing Mechanism (ESM)	**Include** an ESM. Design of ESM will occur in Phase 2.
Performance Incentive Mechanisms (PIMs)	**Include** Determination of which outcomes are subject to PIMs and design of PIMs in Phase 2. Initial suggestions include: "Backstop PIMs" (penalty-only):

2 Adjustment factors may be set to zero.

MRP/PBR Component	Staff Proposal
	• Reliability • Safety • Customer service A limited set of additional PIMs to be considered, examples below: • Customer disconnections • Asset utilization • Progress on CBRE acquisition targets[E] Concepts for more exploration into PIM metrics • Equity • Resilience[E]
Capex/opex equalization	**Include consideration** of "Totex" (total expenditure accounting) and other capex/opex equalization strategies in Phase 2 scope.
Framework Standardization	Pursue greater standardization of foundational MRP elements with continued development of targeted implementation flexibility

[E] Electric utility only

Staff Discussion

Duration

Decision Point	Primary Options[3]	Potential Benefits	Potential Risks / Limitations	Staff Recommendation
Plan Duration	3–7 years	• Shorter terms improve responsiveness and flexibility • Longer terms improve predictability, strengthen incentives, and reduce rate case administrative burden.	• Shorter terms weaken incentives, discipline and increase burden. • Longer terms risk outdated assumptions and signals and greater earnings divergence.	**Five-year term**

Staff recommends a five-year term for utility MRPs because it best balances the objectives of meaningful budget discipline, predictability, responsiveness to changing conditions, and administrative efficiency. Plan duration affects the strength of utility signals, the usefulness of the MRP as a planning and budget management/cost containment tool, and the degree to which the framework can reduce reliance on frequent rate proceedings. Less frequent rate cases allow deeper analysis and engagement on each MRP. Further discussion of alignment with utility planning processes will occur in Phase 2, but Staff expects that a five-year duration will better align with the direction of utility action plans and programmatic budgets.

Shorter terms may improve responsiveness to changing utility conditions, can signal to the utility for areas of focus, and reduce the likelihood that revenues diverge from

[3] Options are informed by stakeholder discussion and review of practices from other jurisdictions.

evolving costs or system needs. However, shorter durations also weaken incentives associated with multi-year ratemaking by reducing the period over which utilities are expected to manage within a defined revenue path or 'budget'. Shorter terms increase regulatory burden and may limit bandwidth for thorough engagement of the issues and settlement. Staff also expects shorter durations to be more difficult to align with utility planning processes.

Staff is also mindful of statutory direction that limits the number of rate cases that can be filed within a year, which could be challenging to meet if plan duration is not standardized across utilities. This standardization also provides the Commission, utilities, and stakeholders with predictability, and a longer duration permits Staff to use years between rate cases for planning and strategic analysis.

Staff's recommendation reflects a balancing of these considerations. A five-year term provides sufficient time for utilities to meaningfully manage within a multi-year budget framework while reducing the risk that assumptions become materially outdated. Staff also expects the proposed framework to include mechanisms that help accommodate changing conditions during the plan period and preserve the effectiveness of a five-year framework without depending on frequent recalibration through general rate cases.

Comments

Stakeholder comments reflect differing views regarding the appropriate balance between stronger multi-year incentives and responsiveness to changing utility conditions. Energy Advocates, OSSIA, Renewable Northwest, and CUB generally supported a five-year duration, particularly for electric utilities, emphasizing that shorter terms weaken the incentive and planning benefits associated with multi-year ratemaking. These parties generally argued that a longer duration is necessary for an MRP to function as a meaningful budgeting framework, improve administrative efficiency, and support longer-term utility planning. Several stakeholders also emphasized the importance of maintaining appropriate safeguards to address changing utility conditions over the course of a plan.

In contrast, AWEC and utilities generally supported greater flexibility within the statutory three-to-seven-year range and cautioned against prescribing a mandatory five-year term. Parties emphasized concerns regarding implementation risk, changing utility conditions, and uncertainty associated with unresolved MRP elements. AWEC supported a shorter three-year duration and emphasized the importance of retaining opportunities for rate review, particularly while key design components remain under development. Utilities, PGE, PacifiCorp, Idaho Power, NW Natural, Cascade Natural Gas, and Avista, similarly emphasized differences in utility operating conditions and capital planning needs. PGE specifically supported an initially shorter duration as parties gain experience with Oregon’s MRP framework, while gas utilities emphasized uncertainty regarding future throughput and policy requirements.

Staff Response

Staff agrees that plan duration presents meaningful tradeoffs and that implementation risks warrant consideration. However, Staff finds that a shorter default duration would weaken the advantages of moving to an MRP: discipline, predictability, strategic cost management, and reduce administrative burden. Staff recognizes the need to adjust to changing conditions, but adjustment factors and other targeted mechanisms are intended to keep the framework durable to this need. Staff intends to consider design approaches that recognize changing utility conditions during the plan period in Phase 2.

Final Recommendation

Staff recommends that each utility’s multi-year rate plan have a five-year term.

Type of MRP

Decision Point	Primary Options	Potential Benefits	Potential Risks / Limitations	Staff Recommendation
MRP Type	Index-based: Revenue Cap	• Encourages active management to a budget and cost-control • Strongest utility predictability • Removes throughput incentive[4]	• Risk of insufficient cost coverage within the cap • Risk of misaligned indexes • Requires careful design of adjustment factors	**Index-based revenue cap**
	Index-based: Price Cap	• Incentivizes the utility to reduce its cost per unit • Predictable customer prices	• Revenue volatility • Throughput incentive persists • Risk of misaligned indexes	
	Forecasted MRP	• Aligns revenues with specific costs and action plan items • Supports planned investments • Potentially less reliance on capital funding mechanisms	• Forecast bias • Weaker cost-control incentives • Higher administrative burden, increasingly difficult to review prudence of projected costs in out years	
	Hybrid	• Easier to balance predictability and flexibility • Can tailor treatment of different costs	• More complex/less transparent	

Staff recommends an index-based revenue cap for utility MRPs. The index-based MRP structure best supports a meaningful multi-year budget framework while preserving the ability to address changing utility conditions and investment needs through targeted mechanisms. To balance the increased discipline and cost containment, the revenue cap approach to indexing offers greater revenue predictability to the utility and shareholders and encourages the utility to focus on priorities beyond increasing retail sales.

MRPs can generally be structured using forecasted or indexed approaches. A forecasted MRP establishes rates based on projected utility costs and investments over the plan period. Under Staff's overall framework, this would require forecasts and initial prudence reviews of five years of projected capital and expenses and may include an ongoing forecast update process. An indexed MRP establishes an allowed revenue or

[4] Throughput incentive refers to the ability to earn more by increasing sales.

price path using predetermined adjustment mechanisms. Under Staff's overall framework, the Commission would set "going-in rates" based on a review of expected year one capital and expenses and use the index formula factors to adjust the utility's revenue over the subsequent four years of the plan duration.

Forecasted approaches may provide greater near-term precision in aligning projected costs and revenues and may more precisely capture utility spending over time. Indexed approaches place greater emphasis on utilities managing within a defined revenue path and rely less heavily on repeated updates to utility-specific cost forecasts over the course of a plan.

Both approaches can be designed to align with Oregon law, including ORS 757.355, which prohibits recovery of costs for plant or property that is not presently used and useful in providing utility service. For example, this could be accomplished by an annual process to confirm capital is in service before rates are actually adjusted. However, forecasted approaches rely more directly on forward-looking assumptions regarding future costs, investments, and system conditions. If those assumptions do not materialize as expected, forecasted approaches may limit the predictability benefits of moving to a multi-year plan and create greater tension with Oregon's used-and-useful framework without more frequent updates or reconciliation to maintain alignment with actual utility conditions.

Staff recommends an indexed approach because it better supports the core purpose of the proposed MRP framework: to establish a meaningful, disciplined budget within which utilities are expected to manage over a multi-year period. An indexed approach may strengthen incentives for cost management, operational efficiency, and longer-term planning because utilities are not reliant on forecasts of expected costs or burdensome processes to refresh forecasts. Recent MRP research, including the RMI/Synapse report discussed by stakeholders, similarly emphasizes that MRPs are more likely to support cost discipline when they rely on a stable framework with targeted flexibility rather than repeated forecast updates that weaken incentives associated with managing within a defined revenue path.[5] Staff's proposal contemplates supporting mechanisms, including adjustment factors and a supplemental capital funding mechanism, to address material changes and qualifying investments over the plan period while preserving the core discipline of a multi-year framework, subject to detailed proposals in Phase 2. Staff notes that these mechanisms can be applied to forecasted MRPs, too, but make less impact under that framework.

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5 Rocky Mountain Institute. (2025). *Fixing Multiyear Rate Plans: Building a firm foundation for utility cost control*. https://rmi.org/resources/fixing-multiyear-rate-plans/.

Staff also recommends a revenue cap rather than a price cap. Under a price cap, utility revenues remain linked to sales volumes, which can preserve throughput incentives and create tension with objectives related to energy efficiency, demand flexibility, distributed resources, beneficial electrification, and targeted electrification. A revenue cap reduces the degree to which utility earnings depend on volumetric sales and may better support optimization between operational, distributed, and traditional infrastructure solutions. This consideration is particularly relevant as utilities evaluate a broader range of approaches to reliability, affordability, emissions reductions, and changing load conditions and ultimately provides greater revenue certainty to utilities.

Comments

Energy Advocates, OSSIA, Renewable Northwest, and CUB generally supported an indexed approach and emphasized that multi-year ratemaking should meaningfully strengthen incentives for cost management, efficiency, and least-cost planning. These stakeholders generally viewed an indexed revenue cap as better aligned with reducing regulatory burden, improving predictability, and supporting alternatives to traditional infrastructure investment where lower-cost operational, distributed, or non-pipeline solutions may be available. Several parties also emphasized the importance of pairing an indexed framework with supporting mechanisms that preserve accountability and responsiveness to changing utility conditions.

AWEC generally supported an indexed approach but cautioned against prescribing specific design details in rule, including whether utilities should operate under a revenue cap or price cap and which supporting mechanisms should apply. AWEC emphasized that utility circumstances differ and argued that decisions regarding cap structure and implementation details may warrant utility-specific consideration as complementary MRP elements are further developed.

Utilities expressed greater concern regarding a prescriptive indexed framework and emphasized the importance of accommodating changing costs, capital investment needs, and differing utility operating conditions. Utility comments also supported greater flexibility to incorporate forecasted elements or utility-specific approaches as implementation matures. Electric utilities emphasized load growth uncertainty, infrastructure needs, and implementation risk associated with transitioning to a new ratemaking framework. Natural gas utilities emphasized uncertainty regarding future throughput, emissions reduction policy, and system utilization.

Staff Response

Stakeholder comments raised legitimate questions regarding how prescriptive Oregon's MRP framework should be and whether utility-specific conditions warrant greater flexibility in MRP design. Capital needs in response to policy priorities, changing load conditions, implementation risk, and differences between electric and natural gas utilities all warrant careful consideration as the framework develops.

Staff's assessment, however, is that some degree of standardization in foundational framework elements is necessary for MRPs to provide meaningful value. While forecasted and indexed approaches can both function within Oregon's statutory framework, Staff's strategy favors active budget management and optimization of spending decisions. As discussed in a later section of this Staff report, leaving core structural questions unresolved or relying too heavily on utility-specific forecast updates risks weakening the intended discipline, planning, and administrative benefits of multi-year ratemaking. With the strategic design of adjustment mechanisms and other components, the index-based revenue cap is durable to the desire to adapt to changing conditions and spending needs.

Final Recommendation
Staff recommends an index-based revenue cap for utility multi-year rate plans.

<u>Revenue decoupling</u>

Decision Point	Primary Options	Potential Benefits	Potential Risks / Limitations	Staff Recommendation
Revenue Decoupling	No decoupling; partial decoupling; full decoupling	• Supports revenue stability, predictability • Removes throughput incentive.	• Risk of misaligned indexes • Potential customer concerns regarding true-ups and bill impacts.	**Include decoupling**

Staff recommends including revenue decoupling as a component of the MRP framework with specific designs explored in Phase 2. The recommendation to include decoupling is used to effectuate a stable, predictable revenue cap and reflects the view that the effectiveness of a revenue cap depends in part on whether utility revenues remain unrelated to (i.e., decoupled from) sales volumes over the course of an MRP.

Utility revenues in an MRP may materially diverge from authorized revenues due to changes in customer usage, weather, macroeconomic conditions, electrification, distributed energy resources, or other factors affecting sales volumes. This consideration is particularly important under a revenue cap where total revenues are expected to be predictable and in a longer duration multi-year framework where rates are not reset as frequently. In the absence of revenue decoupling, utilities may face continued incentives to favor higher throughput or sales growth to grow revenue or earnings, particularly where fixed costs are recovered through volumetric rates. This incentive structure may create tension with Oregon's policy objectives and with the broader strategy underlying Staff's proposed MRP framework.

Staff notes that decoupling design presents important policy and implementation questions. In other words, the design details will be critical. For example, decoupling design affects how risk is allocated between utilities and customers and may raise concerns regarding rate volatility, customer class treatment, cost shifting, and incentives for system utilization. Questions may also arise regarding alignment with cost allocation where load growth or investment needs are concentrated among particular customers or customer classes.

Staff generally finds that these concerns can be mitigated through thoughtful mechanism design in Phase 2 and individual MRPs. Annual updates to certain billing determinants such as load forecast updates per class, decoupling true-ups, and index adjustments may help ensure that revenue requirements remain reasonably aligned with changing sales expectations and customer conditions over the course of a plan. Different decoupling structures may be needed for natural gas and electric utilities and can build off of lessons learned from previous utility approaches. Several approaches could reasonably be considered in Phase 2, including full or partial decoupling, customer class-specific treatment, deadbands, weather normalization, exemptions for certain customer classes, or alternative approaches to balancing risk and incentives. A key choice in Phase 2 is between symmetric decoupling adjustments or downward-only adjustments. One effectively makes a revenue target, while the latter (downward) enforces only the cap or ceiling.

Phase 2 should also consider how decoupling design interacts with Oregon's demand-side resource framework and whether legacy decoupling should be adapted for the transition to MRPs.

Comments

Comments focused primarily on whether decoupling is necessary within an MRP framework and how any mechanism should be designed to balance utility incentives, customer impacts, and changing load conditions. Energy Advocates, OSSIA, Renewable Northwest, and CUB supported inclusion of revenue decoupling as part of an MRP framework, particularly if the Commission adopts an index-based revenue cap. These stakeholders emphasized that decoupling is important to reducing throughput incentives and improving alignment with energy efficiency, demand flexibility, distributed resources, beneficial electrification, and least-cost planning objectives. Some stakeholders also raised concerns that decoupling may reduce opportunities to spread fixed costs over increased sales volumes, particularly where electrification or economic development contributes to load growth that could otherwise reduce rate pressure over time and emphasized the importance of avoiding unintended customer impacts through thoughtful mechanism design.

AWEC acknowledged the relationship between decoupling and a revenue cap but cautioned against prescribing a specific mechanism before other MRP elements are resolved. AWEC emphasized concerns regarding customer impacts, cost allocation, and customer class treatment, particularly for large customers whose load characteristics or investments may differ significantly from system averages.

Utilities emphasized that customer mix, sales volatility, and operating conditions differ substantially across utilities and supported flexibility regarding decoupling design. Natural gas utilities pointed to Oregon's experience with gas decoupling and uncertainty regarding future throughput, while electric utilities emphasized changing load conditions, electrification, and the importance of preserving appropriate incentives associated with customer growth and system utilization. Several utilities cautioned against extending legacy approaches to a multi-year framework without considering interactions with other MRP components.

Staff Response
Staff agrees that decoupling design warrants careful consideration and that Oregon's existing approaches may not transfer directly to a multi-year ratemaking framework. Questions regarding customer impacts, cost allocation, customer class treatment, and interactions with changing load conditions are important considerations, particularly as utilities experience differing operating conditions and evolving customer demand.

That said, Staff maintains that some form of revenue decoupling is important to the intended operation and enforceability of an index-based revenue cap. Concerns raised in comments reinforce the importance of mechanism design rather than weigh against inclusion of decoupling itself.

Final Recommendation
Staff recommends inclusion of revenue decoupling in utility multi-year rate plans, with mechanism design to be addressed in Phase 2.

<u>Scope of MRP</u>

Decision Point	Primary Options	Potential Benefits	Potential Risks / Limitations	Staff Recommendation
Scope of MRP	• Narrow scope/limited costs under cap • Comprehensive scope/everything under the cap; • Hybrid/targeted exclusions	• Narrow scope reduces utility risk (e.g., exposure to cost volatility, forecast error) and implementation complexity. • Broad scope strengthens cost discipline, predictability, and transparency.	• Narrow scope weakens incentives and increases administrative burden of rate reviews. • Broad scope may be less flexible and overexpose volatile costs to MRP risk.	**Comprehensive scope with targeted exclusions**

The scope of an MRP determines which utility costs are subject to the incentives, discipline, and flexibility created by the broader framework. A narrower scope preserves greater reliance on existing cost recovery mechanisms and may reduce risk for utilities, but it can also weaken cost containment incentives, reduce transparency, and limit the effectiveness of the MRP as a multi-year budgeting framework. A broader scope may strengthen incentives for operational efficiency and administrative efficiency by reducing reliance on trackers and frequent rate adjustments but may also increase implementation complexity and require greater attention to supporting mechanisms that address changing utility conditions over time. Staff recommends a comprehensive scope for MRPs with limited exceptions for cost categories that are highly volatile, largely outside of utility control, or already subject to separate planning and ratemaking structures that are not well aligned for integration at this time. Under Staff's proposal, the majority of utility revenues and expenses would be consolidated within the MRP and managed under the multi-year budget framework, while select categories would continue to be recovered through separate mechanisms.

Investments included within the scope of the MRP would be incorporated into the revenue cap or a supplemental capital funding mechanism.

In Scope of MRP	Recovered Separately from MRP
• Operations and maintenance (O&M) expenses • Amortization, depreciation, taxes and fees • Administrative and general expenses • Transmission system costs • Distribution system costs • Generation system costs[6] • Return on rate base • Most trackers and deferrals, except those identified for separate recovery • Customer program costs	• Power costs, including PCAM • Gas costs (including purchased gas adjustment) • Wildfire mitigation tracker *(electric utilities)* * • Energy Trust of Oregon funding *

In Staff's view, a more comprehensive MRP scope better supports cost containment, predictability, and administrative efficiency by placing a larger share of utility costs within a multi-year budget framework and reducing reliance on piecemeal ratemaking. Consolidating controllable and relatively stable cost categories within the MRP may also strengthen incentives for utilities to manage expenditures more holistically and pursue least-cost operational and investment decisions. Staff's proposal also identifies customer program costs as in scope of the MRP. This inclusion raises important considerations regarding how stronger cost management incentives may influence customer-facing and policy-driven programs. For example, programs such as bill

6 Staff still plans to comply with ORS 469A.120(2) but envisions a process that is built into the MRP process and not one that stands on its own.

assistance and demand response are often designed to increase participation or respond to customer need. Under a revenue cap, utilities could face greater pressure to manage program costs within an overall budget, which may create concern regarding whether utilities remain equally willing to market, expand, or administer programs whose success may increase expenditures over time. Index factors will capture inflationary pressures on programmatic costs, but other mechanisms may be required to capture multi-year program budgets and program growth. On the other hand, customer program costs are also areas where thoughtful cost management and efficiency matter. Including these costs within the MRP can encourage utilities to improve program administration and focus resources strategically. Staff's recommendation currently reflect the view that these costs should generally remain in scope, while recognizing that customer outcomes, participation levels, or program performance may warrant additional attention through other tools within the framework than can help drive accountability and/or performance expectations.

That said, Staff's proposal recognizes the value of certain exceptions. Specifically, the Staff proposal excludes power costs and gas costs because of their level of volatility and given that cost recovery for these expenses already include a shared savings mechanism. It also excludes wildfire mitigation and Energy Trust costs because they are already on a different multi-year budget cadence and can be considered for harmonization with the MRP cadence after these multi-year budgeting processes and/or MRP implementation is more mature.

Staff also recognizes that utilities face increasing infrastructure investment needs, particularly electric utilities experiencing load growth and major capital expansion. For this reason, Staff's proposal includes a supplemental capital funding mechanism intended to provide targeted flexibility for specific, material investment needs that may not be reasonably accommodated within the indexed framework alone. This could include significant policy-driven investments like qualifying transmission, storage, generation, or decarbonization-related expenditures. Staff also notes that the Z-Factor adjustment can be included to capture unforeseen costs, such as a new state policy that requires unexpected spending in the middle of an MRP. Staff expects Phase 2 to evaluate which specific investment categories are recovered through going-in rates, indexed adjustments, or the capital funding mechanism, as well as any guardrails around costs included or excluded from an MRP's scope. Utility-specific investment levels would be determined in GRCs and informed by existing planning processes, such as IRPs.

Comments

Energy Advocates, OSSIA, Renewable Northwest, and CUB supported a broader MRP scope and emphasized that a more comprehensive framework is necessary to strengthen cost containment incentives, improve administrative efficiency, and reduce dependence on numerous trackers, adjustment clauses, and standalone recovery proceedings. Several stakeholders emphasized that excluding too many cost categories risks weakening the effectiveness of an MRP and preserving many of the same incentive and administrative challenges the framework is intended to address.

AWEC and utilities expressed greater caution regarding scope and emphasized the importance of preserving flexibility where costs are volatile, difficult to forecast, or driven by factors outside utility control. Parties raised concerns regarding implementation risk, capital intensity, and the degree to which utilities can reasonably manage certain investment needs within a multi-year budget framework. Utilities also emphasized that some cost categories may warrant continued separate treatment, particularly where investments are large, policy-driven, or subject to changing system conditions.

Stakeholders generally supported continued separate treatment for power costs and purchased gas costs because of their volatility and limited utility control. Several parties also discussed whether emerging investment categories, including transmission, storage, wildfire mitigation, and clean energy-related expenditures, may require differentiated treatment or targeted mechanisms.

Staff Response

While Staff recognizes the need to consider capital intensity, changing infrastructure, and a level of flexibility in the framework development, a broader inclusion of costs remains important to preserving the value of an MRP. Several components of the framework including the index factors and the supplemental capital funding mechanism provide structured ways to accommodate changing utility conditions while keeping the revenue cap framework intact. If too many costs remain outside the framework, utilities may continue to rely on numerous standalone recovery mechanisms and face weaker incentives to manage expenditures holistically over time. The comments reinforce the importance of carefully defining limited exceptions and targeted flexibility for specific cost categories and objectives rather than relying on broad carveouts that could substantially weaken the effectiveness of the framework.

That said, Staff also recognizes that some programmatic cost categories such as demand response, community solar, transportation electrification, hybrid heat-pump pilots, and other multi-year customer program portfolios may not track cleanly with historical spending or with general inflation trends and may evolve through planning processes that operate on multi-year budget cycles. This can create cost trajectories that differ from typical O&M or capital spending and may offset or substitute for infrastructure investments on different timelines. For this reason, Phase 2 should evaluate whether certain programmatic portfolios may warrant additional treatment beyond pure indexing, such as limited forecasting of portfolio-level budgets, a program-or portfolio-level true-up mechanism, or other approaches that preserve accountability while accommodating legitimate multi-year program growth. This evaluation will help ensure that the framework neither constrains necessary programmatic spending nor undermines the discipline and predictability the MRP structure is designed to support.

Final Recommendation
Staff recommends a comprehensive MRP scope with limited exceptions for power costs, purchased gas costs, wildfire mitigation adjustment clauses, Energy Trust of Oregon funding, and extraordinary capital investments addressed through a supplemental capital funding mechanism.

Adjustment Factors

Decision Point	Primary Options	Potential Benefits	Potential Risks / Limitations	Staff Recommendation
Adjustment Factors	• Selection of which factors to include • Which external indices to apply (e.g., for inflation), or methods and criteria (e.g., X or S factors)	• Externally-indexed adjustments reflect market conditions • Allow revenues to adjust over term of MRP (i.e., relief from financial attrition) • Structured framework better accommodates changing conditions while preserving incentives.	• Difficulty to set adjustments that reflect utility circumstances • Information asymmetry can make reviews challenging • Overly flexible or excessive adjustments weaken cost containment discipline and can ratchet up customer rates.	**Include I–X–S+G+Z**

Staff recommends inclusion of adjustment factors as a component of the MRP framework but does not recommend specific calibrations or parameters be determined until Phase 2. Adjustment factors are the inputs to the index formula in an index-based MRP. The design of these mechanisms also influences the degree to which an MRP balances predictability, cost discipline, responsiveness to changing conditions, and administrative efficiency.

Staff recommends that MRPs include five adjustment factors: inflation (I), productivity (X), stretch (S), customer growth (G), and exogenous or extraordinary events (Z).

- **Inflation Factor (I):** The inflation factor adjusts revenues to reflect broad economy-wide changes in utility costs over time and is one of the primary tools that allows revenues to track changing conditions without repeatedly reviewing O&M and capital costs during the plan period. In practice, the inflation factor updates the revenue cap each year so that utility revenues are not fixed to year one cost conditions over a five-year term, and it can move revenues up or down, depending on the measure used. The choice of inflation index and its interaction with the other factors can meaningfully affect how closely revenues align with actual cost trends. Common measures include the Consumer Price Index (CPI), the Gross Domestic Product Price Index (GDPPI), or utility industry-specific indices.

- **Productivity Factor (X):** The productivity factor reflects expected changes in utility productivity over time and adjusts the revenue cap to account for efficiency gains or losses relative to inflation. Typically, the X-factor is estimated using total factor productivity studies, historical utility performance, and/or benchmarking against peer utilities. The X-factor may place downward pressure on annual revenue growth to reflect expected efficiency improvements or provide upward adjustment where conditions suggest productivity gains may be limited during the MRP period.
- **Stretch Factor (S):** The stretch factor applies an additional performance expectation beyond the baseline productivity assumption. Unlike the productivity factor, which typically reflects broader industry or historical trends, the stretch factor can be used to recognize utility-specific circumstances, comparative performance, and/or policy priorities. Depending on how it is calibrated, the factor may increase, decrease, or maintain the revenue path established through the broader index.
- **Customer Growth Factor (G):** The customer growth factor adjusts revenues for changes in the scale of utility operations as customer counts or system needs evolve over time. For electric utilities experiencing rapid load growth or customer additions, this factor can be used to recognize increasing service obligations and infrastructure demands that accompany system expansion. For natural gas utilities facing uncertainty regarding future throughput or declining customer usage, the factor may warrant a different approach to ensure revenue changes reasonably reflect how utility costs are changing.
- **Exogenous or Extraordinary Events Factor (Z):** The Z-factor provides a structured process for addressing significant events outside utility control that materially affect costs during an MRP. Z-factors are typically limited to well-defined, exogenous events such as changes in law, new regulatory obligations, tax changes, or other external developments that could not reasonably be anticipated when rates were established. A narrowly defined Z-factor can help preserve durability in an MRP by providing a structured means of addressing material external events without relying on reopeners or off-ramps. Conversely, overly broad terms can weaken the discipline of the indexed MRP if utilities routinely revisit costs that are more appropriately managed within the revenue cap.

Staff expects Phase 2 to evaluate the methodologies, calibration, applicability, and potential rule treatment of adjustment factors, including whether specific parameters should be standardized or addressed through utility-specific implementation. Select utility-specific decisions, such as the numeric value of a productivity factor, are expected to be subject to GRC deliberations and determined for each utility's first MRP.

Staff believes that the combination of these factors in all utility MRPs will best advance Staff's goals, but notes that the Commission will have the option to set indices at zero if a factor does not make sense on a standard basis or in individual utility MRPs.

Comments

Comments regarding adjustment factors focused primarily on how much flexibility should be incorporated into an indexed MRP framework and which mechanisms are most appropriate for addressing changing cost pressures and utility circumstances over the course of a plan.

Energy Advocates and OSSIA emphasized that adjustment mechanisms should remain limited and predictable so that an indexed MRP preserves incentives for cost management and does not devolve into frequent cost updates. Renewable Northwest emphasized the importance of ensuring that the framework can accommodate changing clean energy and infrastructure investment needs, while CUB focused more heavily on calibration, customer protections, and avoiding mechanisms that could weaken accountability or create unnecessary rate impacts.

AWEC emphasized the importance of flexibility and cautioned against prescribing specific adjustment factors or methodologies too early in the process. AWEC raised concerns regarding implementation risk, calibration, and the extent to which rule should specify adjustment factor parameters versus allowing utility-specific treatment.

Utilities supported mechanisms that better reflect changing costs, customer growth, and investment needs over the course of a plan but emphasized that utility circumstances differ substantially. Electric utilities highlighted capital intensity, load growth, and clean energy investment requirements, while natural gas utilities emphasized uncertainty regarding future throughput, system utilization, and changing customer demand. Several utilities expressed greater openness to capital-related mechanisms, including K-bar-style approaches, particularly in periods of elevated infrastructure investment.

Staff Response

Comments reflected differing views regarding how much flexibility should be embedded within an indexed MRP and whether adjustment mechanisms should be standardized or tailored to utility-specific circumstances. Staff does not view these concerns as reasons to defer consideration of adjustment factors entirely. Instead, they reinforce the importance of identifying a limited suite of tools in Phase 1 while preserving flexibility to determine requirements and flexibility in implementing the factors in Phase 2 in rule, how they should be calibrated, and where utility-specific treatment may be appropriate.

Staff also notes that well-designed adjustment factors can move revenues both upward and downward, helping ensure revenues do not remain higher than necessary, but do so more efficiently than repeatedly reviewing O&M and capital spending during the plan period. This supports discipline while still accommodating changing utility conditions. Phase 2 can further examine how the index formula and the supplemental capital funding mechanism should work together, whether indices should capture more general capital trends with a narrower capital mechanism, or whether the capital mechanism should play a larger role with more conservative index calibration, so the framework remains durable across differing levels of capital intensity. This approach may better accommodate differing utility circumstances, including the integration of other MRP components to address capital intensity, customer growth, and changing system needs, without weakening the discipline or predictability of an indexed framework. That said, the Commission may choose to defer decisions about the inclusion of specific adjustment factors until Phase 2 if it determines additional analysis is appropriate.

Final Recommendation

Staff recommends inclusion of I, X, S, G, and Z in utility multi-year rate plans, with design and calibration to be addressed in Phase 2.

Supplemental Capital Funding Mechanism

Decision Point	Primary Options	Potential Benefits	Potential Risks / Limitations	Staff Recommendation
Capital Funding Mechanism	No mechanism	• Strongest budget discipline • Simplest structure	• Cost-revenue misalignment for large capital needs • Increased risk of frequent reopeners	**Include targeted SCFM**
	Broad capital tracker	• Ensures recovery of actual capital spending • Reduces utility financial risk	• Weakens cost-control incentives • Creates ongoing administrative burden	
	Targeted supplemental mechanism	• Limits additional recovery to defined, exceptional projects • Preserves overall discipline of the revenue cap	• Requires careful eligibility criteria • Still involves case-by-case review • May not address broad capital program pressures	
	K-bar	• Predictable capital recovery tied to historical averages • Preserves some regulatory lag and cost discipline • Less incentive-eroding than broad trackers	• Can still weaken efficiency and discipline incentives if not tightly designed • Complex to implement and monitor • Misalignment if historical spending is not reflective of future needs	

Staff recommends including a supplemental capital funding mechanism as part of the MRP framework to help address a key challenge associated with indexed ratemaking: how to accommodate specific, material investment needs that may not be reasonably reflected through formulaic adjustments alone. Indexed MRPs are intended to strengthen incentives for utilities to manage within a defined multi-year budget. Staff also recognizes that utilities may face investment needs during an MRP that materially deviate from historical trends or otherwise exceed assumptions reflected in going-in rates, especially in a time of major system upgrades, transmission expansion needs, and non-emitting energy and capacity investments, or other infrastructure needed to maintain reliability, respond to aging infrastructure, changing technology, weather and peak needs, large load, electrification, and meet evolving policy obligations. Without a structured means of addressing qualifying investments, utilities may face greater pressure to reopen rates or rely on broad exceptions that weaken the predictability and administrative benefits of an indexed framework.

A supplemental capital funding mechanism also presents important tradeoffs. A mechanism that is too narrow may not provide sufficient flexibility where material investment needs arise during an MRP. A mechanism that is too broad or routinely used risks weakening incentives associated with indexed ratemaking by recreating frequent cost review, reducing utility responsibility for managing within the broader MRP budget, and eroding the intended discipline of the framework. Staff also considered whether capital-related investment needs could instead be addressed through broader capital adjustment mechanisms, including K-bar[7] approaches that provide recovery for new capital additions placed into service during an MRP. While K-bar mechanisms may provide a more straightforward means of reflecting investment growth, Staff has concerns regarding alignment with Oregon's used-and-useful standard if capital is reflected in rates before it is placed into service or without sufficient review. Staff also finds that broad capital adjustment mechanisms may weaken incentives associated with managing within an indexed framework if applied too expansively. These concerns cannot be resolved simply by adding a year-end true-up, because the purpose of this factor is K-bar is to be formulaic, rather than project-specific. A true-up would require reconciling actual capital additions each year to determine what should be reflected in rates, which functionally negates the purpose of the K-bar. In contrast, the supplemental mechanism preserves used-and-useful review and avoids routine reconciliation while still allowing targeted mid-term adjustments

Staff therefore views the supplemental capital funding mechanism as a targeted complement to formulaic adjustment factors rather than a substitute for budget discipline. Staff expects Phase 2 to evaluate the design of the supplemental capital funding mechanism including eligibility, thresholds, timing, customer protections, prudence review, and interaction with other MRP components. For example, Phase 2 will need to evaluate the extent to which the mechanism should be limited to emergency or unexpected capital needs, or whether it should also accommodate broader, discrete investment categories that may not be reasonably captured through the MRP's annual adjustment formula. This may include identifying whether investments such as transmission upgrades, storage resources, or renewable natural gas projects should be eligible for supplemental treatment rather than relying solely on indexing. Determining the appropriate balance between reliance on the index formula and the use of the supplemental mechanism will be a key decision point for the Commission in Phase 2.

Comments

Comments regarding supplemental capital funding mechanisms focused on how an indexed MRP framework should address material investment needs that emerge during a plan period without undermining the incentives associated with indexed ratemaking. Stakeholders generally supported some form of targeted mechanism to address material investments that may not be reasonably accommodated through formulaic

[7] K-bar is a capital allowance included in an annual adjustment formula for an MRP. It often relies on a historical average of expected capital investments, escalated through formulaic factors, and allows the utility to pre-fund a portion of its capital needs. Unlike a supplemental capital funding mechanism, K-bar does not reimburse actual expenditure: the utility bears any variance from the allowance, for better or worse.

adjustment factors alone. Renewable Northwest emphasized the importance of ensuring the framework can accommodate evolving resource and infrastructure needs associated with clean energy policy implementation. Energy Advocates and OSSIA emphasized that any supplemental mechanism should remain limited, transparent, and appropriately bounded so that utilities retain incentives to manage within the broader MRP budget. CUB similarly emphasized customer protections, prudence review, and avoiding routine recovery outside the MRP framework.

Other parties expressed greater caution regarding scope and implementation. AWEC raised concerns regarding calibration, transparency, and the potential for supplemental mechanisms to weaken indexed ratemaking incentives if applied too broadly.

Utility comments reflected substantial concern regarding whether an indexed framework can reasonably accommodate major investment needs without some form of capital flexibility. Electric utilities, including PGE, PacifiCorp, and Idaho Power, emphasized growing infrastructure needs associated with reliability, transmission and distribution system expansion, resource acquisition, and changing load growth expectations. Several utilities emphasized that capital needs may materially diverge from assumptions reflected in going-in rates over the course of a plan and expressed greater openness to capital-related mechanisms, including K-bar-style approaches. Natural gas utilities raised related but distinct concerns regarding uncertainty in future throughput, infrastructure utilization, and the pace of system change as customer demand evolves.

Staff Response

Staff recognizes utility concerns that an indexed MRP may not fully accommodate substantial investment needs that arise between rate cases. Electric utilities are planning for substantial infrastructure expansion, evolving resource needs, transmission development, and changing load expectations, while natural gas utilities face greater uncertainty regarding system use and customer demand. Staff also recognizes concerns raised by Energy Advocates, OSSIA, CUB, AWEC, and others that a supplemental capital funding mechanism could weaken incentives associated with indexed ratemaking if it becomes overly broad, substitutes for utility cost management, or reduces transparency and scrutiny of investment decisions.

These comments reinforce Staff's view that some level of capital flexibility is important to the durability of an indexed MRP, while also underscoring the importance of maintaining clear limits on when and how supplemental recovery is available. Staff is therefore recommending inclusion of a supplemental capital funding mechanism while expecting Phase 2 to establish guardrails regarding eligibility, review standards, customer protections, and interaction with other MRP components so that the mechanism supports significant investment needs without becoming a routine alternative to managing within the broader MRP framework.

Final Recommendation
Staff recommends inclusion of a targeted supplemental capital funding mechanism balanced with adjustment factors in utility multi-year rate plans. Design, scope, and calibration of the mechanism to be addressed in Phase 2.

Earnings Sharing Mechanism (ESM)

Decision Point	Primary Options	Potential Benefits	Potential Risks / Limitations	Staff Recommendation
Earnings Sharing Mechanism (ESM)	• No ESM • Symmetry • Deadbands	• No ESM may strengthen performance incentives. • ESM can balance risk and protect customers from over-earning while preserving incentives.	• Overly aggressive sharing weakens incentives. • No ESM may reduce customer confidence/perceived imbalance in risk allocation.	**Include ESM**

Staff recommends including an earnings sharing mechanism (ESM) to help address the possibility that realized utility earnings materially differ from expected earnings over the course of a plan. In isolation, longer-duration indexed MRPs perform well in forecasting a utility's revenue needs under typical market and planning conditions. However, in periods of load and capital investment volatility - like Oregon is experiencing now, a longer-duration index may not be sufficient on its own. Staff's proposed capital funding mechanism, decoupling mechanism, and ESM are meant to account for this by providing relief valves and adjustments to the index to account for non-standard conditions. In particular, an ESM will help provide a structured means of addressing sustained over- or under-earnings while reducing pressure to reopen rates when outcomes diverge from expectations. In the context of Staff's proposal for an indexed-based MRP with decoupling, a capital funding mechanism, PIMs, and formulaic revenue adjustments, an ESM can also help ensure that the utility maintains strong cost-management incentives without achieving sustained over- or under-earnings that do not correspond to customer value. Decoupling addresses volume risk, a capital funding mechanism adjusts revenues to account for large capital projects, while PIMs and service-quality mechanisms target specific performance outcomes. An ESM complements these tools by addressing broader financial variance, both upside and downside, that may arise when actual conditions diverge from the assumptions underlying the index formula.

That said, an ESM is not intended to function as a primary ratemaking tool or substitute for utility cost management within an indexed MRP. Staff views the mechanism as a limited backstop that may help moderate sustained earnings outcomes that fall meaningfully outside expectations while preserving the broader incentives associated with managing within a multi-year budget. Overly expansive earnings sharing can weaken incentives associated with indexed ratemaking and recreate outcomes that more closely resemble traditional cost-of-service regulation; while the absence of an ESM may increase concerns regarding persistent over- or under-earnings and place greater reliance on reopeners or frequent rate proceedings when conditions depart from expectations. Further, relying solely on reopeners or off-ramps for earnings drift weakens the stability and predictability that the MRP framework should provide. An ESM helps avoid this by providing a structured, transparent mechanism for moderating sustained earnings deviations so that reopeners and off-ramps remain tools of last resort. The Commission may also need to consider how the design and scope of a supplemental capital funding mechanism affects overall earnings variability, because that variability ultimately flows through to the ESM.

Staff recommend inclusion of an ESM in Phase 1 while leaving key design elements to Phase 2. Staff anticipates that Phase 2 will evaluate earnings bands, sharing approaches, symmetry, customer protections, and interaction with other MRP components. Staff's current thinking is that a carefully designed ESM may help support a durable indexed framework by balancing customer and utility interests without undermining the incentives associated with multi-year ratemaking.

Comments

Comments regarding earnings sharing mechanisms reflected differing views regarding how much earnings risk should be retained by utilities and the role of backstop protections within an indexed MRP framework.

Energy Advocates and OSSIA supported inclusion of an earnings sharing mechanism and emphasized the importance of maintaining accountability where utility earnings materially exceed expectations during an MRP. These stakeholders generally viewed an ESM as an important complement to a longer-duration indexed framework, particularly if utilities are afforded greater flexibility to manage within a multi-year budget. CUB similarly supported customer protections that address sustained over-earnings and emphasized transparency and appropriate sharing of benefits when utility performance materially exceeds expectations. Renewable Northwest expressed greater interest in ensuring the framework supports long-term planning and policy implementation while maintaining reasonable protections for customers.

Utilities expressed greater caution regarding earnings sharing and emphasized that an indexed MRP already increases exposure to uncertainty relative to traditional cost-of-service regulation. Several utilities cautioned that overly aggressive earnings sharing could weaken incentives associated with indexed ratemaking, reduce opportunities to retain efficiencies, or dampen investment incentives during a period of significant system transition. Utilities also emphasized the importance of considering earnings sharing alongside other MRP components, including adjustment factors, revenue decoupling, and supplemental capital funding mechanisms.

AWEC emphasized accountability and customer protections but also raised questions regarding calibration, symmetry, and the extent to which an ESM should moderate utility earnings risk without weakening incentives or increasing complexity.

Staff Response

Staff recognizes stakeholder concerns regarding both sustained over-earnings and the potential for earnings sharing to weaken incentives associated with indexed ratemaking if designed too aggressively. Staff also recognizes utility concerns that earnings outcomes should be evaluated in the context of the broader MRP framework, including adjustment factors, revenue decoupling, and other mechanisms intended to moderate risk over the course of a plan. Comments also raised important considerations regarding symmetry, the degree of earnings exposure utilities should retain, and how an ESM may influence incentives for operational performance and investment.

Staff's recommendation reflects the view that a limited ESM can help support confidence in a longer-duration indexed framework without becoming a substitute for utility cost management or a routine earnings reset mechanism. Staff expects Phase 2 to evaluate ESM design alongside other MRP components so that decisions regarding earnings bands, sharing approaches, symmetry, and customer protections are considered in the context of the broader framework and appropriately balance accountability, incentives, and risk allocation.

Final Recommendation

Staff recommends inclusion of an earnings sharing mechanism in utility multi-year rate plans, with calibration and design to be addressed in Phase 2.

Performance Incentive Mechanisms (PIMs)

Decision Point	Primary Options	Potential Benefits	Potential Risks / Limitations	Staff Recommendation
Performance Incentive Mechanisms (PIMs)	Expansive PIM portfolio	• Broad accountability across many outcomes • May better align utility incentives with policy goals • Can include exploratory, backstop, and shadow PIMs	• High complexity and administrative burden • Risk of diluted/conflicting incentives • Harder to design, calibrate and monitor	**Moderate PIM portfolio:** **Require a minimum PIM set in all MRPs and consider additional PIMs in Phase 2** **Required backstop PIM areas: reliability, safety, customer service** **Required outcome PIM areas: customer disconnections, asset utilization, CBRE progress**
	Moderate PIM portfolio	• Focused incentives on highest-priority outcomes • Lower complexity; clearer signals • Easy to integrate targeted, backstop, and shadow PIMs	• May miss opportunities outside priority areas • Still requires careful design to avoid incentive conflicts	
	No PIM portfolio	• Simple, low-risk, low-cost to administer • Shadow PIMs can support learning without stakes	• Minimal accountability • Weak alignment with policy goals • May not meaningfully influence utility behavior	

Staff recommends including a narrow set of high impact PIMs with specific metrics, targets, incentive levels, and implementation details developed in Phase 2. PIMs can help ensure that utilities managing within an indexed revenue cap do not achieve cost savings by reducing performance at the expense of customers while also meeting community, state policy, and Commission priorities.

SB 688 also helps set priorities for the use of PIMs for electric utilities and creates an opportunity to align the MRP framework with performance areas such as reliability, customer service, cost containment, investment efficiency, emissions reductions, distributional equity, and resilience. PIMs should be used carefully within that structure. They can provide accountability where transparency alone may be insufficient, but they are difficult to get right and can counteract cost discipline and predictability, increase complexity, create conflicting incentives, or impose financial consequences in areas where performance is not clearly measurable or within reasonable utility control. Staff also notes that a common response to the challenge of setting effective PIMs is an overreliance on informational performance metrics. Staff seeks to prioritize thoughtfully designed PIMs over reporting requirements that will not directly impact the success of the MRP framework at the outset of MRP implementation. As noted, more complexity can be added over time if desired.

Staff believes PIM integration should begin with a targeted, outcomes driven approach. As such, Staff also recommends that the Commission identify a minimum set of PIM areas that must be included in all MRPs. Specifically, Staff initial proposal in Phase two is that each plan should include three backstop PIMs targeted toward 1) reliability, 2) safety, and 3) customer service; and three outcome PIMs related to 1) customer disconnections, 2) asset utilization, and 3) progress on community based renewable energy acquisition targets for electric utilities. Staff's final recommendation will be informed by what can be implemented with a clear and measurable PIM.

Staff recommends that Phase 2 treat these six areas as a baseline for all MRPs and use the Phase 2 process to determine whether additional PIMs, shadow PIMs, or other performance tools are warranted. Further, Staff does not expect Phase 2 rules to necessarily prescribe detailed PIM designs. Rather, it is more likely that rules will specify the requirement to include backstop, outcome, and other types of PIMs, with specific designs and incentives adopted by Commission order. This approach maintains flexibility, minimizes premature prescriptiveness, and preserves the ability to tailor PIM structures to utility-specific conditions while ensuring a consistent, minimum accountability framework across MRPs.

Comments

Comments on PIMs reflected broad interest in accountability but different views regarding urgency, scope, and sequencing. OSSIA urged the Commission to prioritize penalty-based backstop PIMs tied to measurable progress toward HB 2021, small-scale renewable acquisition, coal transition requirements, and other clean energy obligations. OSSIA emphasized that metrics and reporting may improve transparency but may not meaningfully influence utility behavior without financial consequences. Renewable Northwest placed greater emphasis on translating investment efficiency, asset utilization, and efficient clean energy development into concrete metrics and incentive structures, including approaches that encourage better use of existing transmission and generation assets before additional infrastructure is pursued.

PGE supported further exploration of Staff's proposed backstop and outcome-based PIM categories but urged a data-driven and staged process. PGE recommended that Phase 2 focus on PIM categories and principles, with specific metrics, targets, and incentive levels evaluated in utility-specific proceedings. PGE also emphasized statutory and policy alignment, utility controllability, measurable baselines, flexibility, and demonstrated precedent as important design principles.

Utilities were more cautious about broad or immediate earnings-at-risk exposure and emphasized the need to avoid overly complex, duplicative, or technology-specific PIMs. Natural gas utilities questioned whether PIMs should be a required feature of gas MRPs, while electric utilities were more open to continued discussion of performance metrics and accountability in areas connected to SB 688 and evolving electric system needs. AWEC emphasized careful calibration and cautioned against duplicative mechanisms or incentives in areas already governed by legal obligations or existing regulatory oversight.

Staff Response

Staff agrees that PIMs should not be broad, automatic, or untethered from clearly defined outcomes. The comments identify several design constraints that should guide Phase 2: PIMs should be measurable, within reasonable utility influence, aligned with statutory and Commission priorities, and designed to avoid duplicative rewards or penalties.

Staff appreciates the emphasis on foundational service areas for consideration as limited backstop PIMs, including reliability, safety and customer service. Staff agrees these are areas where cost reductions should not come at the expense of baseline performance and where customers may be directly harmed by degradation in utility service. Staff also sees value in further evaluating several goal-oriented areas raised in comments and has reflected this in the final recommendation requiring a baseline of asset utilization and CBRE acquisition PIMs, among others. Staff expects Phase 2 will continue to explore other areas identified by stakeholders, including HB 2021 compliance, coal transition requirements, and equity and resilience outcomes. These areas raise important accountability considerations but also must account for utility controllability and other intersections with the regulatory framework.

Staff also agrees that metrics and scorecards will not always be sufficient. In areas where measurable outcomes and meaningful utility influence justify financial consequences, PIMs may be appropriate to ensure accountability. Staff's recommendation therefore preserves PIMs as part of the framework while signaling a targeted and strategic approach: establish a minimum set of required backstop and outcome-area PIMs now and use Phase 2 to determine whether these areas should be implemented as financial PIMs, shadow PIMs, or other performance tools, and to consider whether additional PIMs are warranted.

Final Recommendation

Staff recommends requiring three backstop PIMs (reliability, safety, customer service) and three outcome-area PIMs (customer disconnections, asset utilization, and CBRE *acquisition targets for electric utilities) in all MRPs, with designs and additional PIM addressed in Phase 2, and with final PIMs adopted by Commission order.*

Capex/opex equalization

Staff recommends continued exploration of capex/opex equalization as part of the transition to MRPs because the broader shift to indexed ratemaking creates an opportunity to revisit longstanding incentive structures and evaluate whether more neutral treatment of investments and operational solutions could better support least cost outcomes. Under traditional ratemaking, utilities generally have greater opportunity to earn a return on capital investments than on operating expenditures. In some circumstances, this dynamic may create incentives that favor capital-intensive solutions over operational approaches, distributed resources, non-wires or non-pipeline alternatives, or other lower-cost options that may better align with customer affordability and long-term system value. This consideration is increasingly relevant as utilities evaluate a wider range of solutions to address load growth, reliability, resilience, emissions reduction requirements, and changing customer needs.

Staff believes its proposal, inclusive of an index-based revenue cap and revenue decoupling, may partially reduce this dynamic by increasing flexibility regarding how utilities manage expenditures within a multi-year budget framework. However, Staff also finds that additional discussion may be warranted regarding whether further mechanisms should be considered to improve neutrality between capital and operational solutions and better align utility incentives with least-cost outcomes.

Staff is not recommending the Commission make a decision on the use of a capex/opex equalization mechanism in Phase 1. Potential approaches, implementation considerations, and interactions with other MRP components warrant further evaluation. Staff recommends that Phase 2 discussions explore whether additional policy changes are appropriate, the circumstances in which equalization mechanisms may provide value, and how such approaches would interact with broader MRP objectives.

Comments

Stakeholder comments acknowledged the importance of aligning utility incentives with efficient decision-making, though parties differed regarding the extent to which additional intervention is necessary to address potential capital bias.

Clean energy and consumer stakeholders generally supported continued discussion of mechanisms that improve neutrality between capital and operational solutions and reduce incentives that may favor traditional infrastructure investment where lower-cost alternatives are available. Utilities generally expressed caution regarding additional mechanisms and emphasized the importance of preserving flexibility to pursue needed infrastructure investments and maintaining financial stability.

Staff Response
Staff agrees that questions regarding capital bias and procurement neutrality warrant additional discussion but finds that further evaluation is appropriate before recommending a specific mechanism. Staff views this issue as closely related to broader MRP design choices, including revenue decoupling, supplemental capital funding mechanisms, and performance incentives. Phase 2 provides an opportunity to further evaluate whether additional mechanisms are warranted and, if so, how they may best support the Commission's regulatory objectives.

Framework Standardization

The degree of standardization built into the MRP framework will meaningfully shape how the framework functions in practice. Decisions regarding which elements are standardized in rule, which remain utility-specific, and where flexibility is preserved will influence transparency, administrative efficiency, comparability across utilities, implementation burden, and the durability of the framework over time. Staff recommends enough standardization to establish clearer expectations for a disciplined MRP design while preserving room for targeted flexibility where utility-specific circumstances warrant different treatment.

A more standardized framework may provide several advantages. Standardization can improve regulatory efficiency by reducing the need to relitigate foundational MRP design choices in each utility proceeding and may support more consistent expectations regarding utility planning, risk allocation, and performance over time. A clearer and more consistent framework may also strengthen incentives associated with multi-year ratemaking by establishing shared expectations regarding how utilities are expected to manage within a multi-year budget structure. Greater standardization may also improve transparency and comparability across utilities and support a more durable implementation.

That said, a highly standardized framework may not fully account for meaningful differences in utility operating conditions, customer mix, capital investment needs, load growth, existing ratemaking structures, or statutory obligations. Electric and natural gas utilities face different sources of uncertainty and operational expectations over a multi-year period. To this end, a more case-by-case approach may provide greater flexibility to tailor implementation to utility-specific circumstances.

Staff's recommendations throughout this report reflect an effort to balance these competing considerations. Staff has recommended a degree of standardization in Phase 1 by narrowing several foundational decision points that shape the overall structure of the framework, including plan duration, MRP type, use of revenue decoupling, inclusion of earnings sharing mechanisms, use of performance incentive mechanisms, and the inclusion of adjustment factors and a supplemental capital funding mechanism. Staff views these recommendations as important signals regarding the intended direction of Oregon's MRP framework and as a means of improving predictability, preserving discipline, and aligning implementation with the principles, goals, and outcomes identified in this proceeding.

Staff anticipates that Phase 2 discussions will provide an opportunity to incorporate targeted flexibility where warranted and evaluate how the framework should be calibrated across differing utility conditions. In Staff's view, the value of standardization is greatest where it establishes clearer expectations, improves regulatory efficiency, and reinforces the discipline associated with multi-year ratemaking. The value of case-by-case implementation is greatest where utility-specific conditions materially influence outcomes or where flexibility is necessary to preserve durability and effective implementation. Staff's recommendations therefore reflect an effort to establish a sufficiently consistent framework to guide implementation while preserving flexibility in areas where additional tailoring may improve outcomes.

Comments

Stakeholder comments reflected differing views regarding the appropriate balance between standardization and utility-specific implementation.

Utilities generally supported greater case-by-case flexibility and cautioned against prescribing foundational MRP elements in a manner that may not reflect differing utility circumstances. Several utilities emphasized differences in capital planning needs, load conditions, customer characteristics, and operational uncertainty and argued that these differences warrant utility-specific implementation decisions. Electric utilities generally emphasized changing load conditions and infrastructure needs, while natural gas utilities emphasized uncertainty regarding throughput and future demand.

Energy Advocates, OSSIA, Renewable Northwest, and several consumer and clean energy stakeholders generally supported greater standardization of foundational MRP elements, emphasizing that consistency is important to preserving accountability, improving regulatory efficiency, and ensuring MRPs produce meaningful changes in incentives and outcomes. Several stakeholders cautioned that an overly case-by-case approach risks weakening the effectiveness of the framework and recreating existing ratemaking practices through repeated relitigation of core design questions.

AWEC generally supported a balanced approach that establishes clear guiding principles while preserving flexibility to account for utility-specific differences and customer impacts. AWEC emphasized that some design choices may warrant utility-specific calibration and cautioned against prematurely locking in highly prescriptive requirements before complementary MRP elements are fully developed.

Staff Response
Staff agrees that effective implementation requires balancing consistency with flexibility and that neither a fully standardized nor entirely case-by-case framework is likely to best support Oregon's objectives. Staff also agrees that utility-specific operating conditions matter and that implementation details may reasonably vary across utilities and customer classes.

That being said, Staff finds value in establishing greater clarity regarding core framework elements during Phase 1. A framework that leaves too many foundational questions unresolved risks reducing predictability, increasing administrative burden, and weakening the incentive and discipline benefits associated with multi-year ratemaking. Staff therefore finds merit in establishing clearer direction regarding key structural components while preserving flexibility in how those components are calibrated and implemented.

<u>Reflecting differences between electric and natural gas</u>

Throughout this proceeding, stakeholders raised important questions regarding whether the MRP framework should differ between electric and natural gas utilities. These discussions reflected meaningful differences in operating conditions, policy context, planning horizons, customer expectations, and investment needs. At the same time, they also raised broader questions regarding how much differentiation is necessary to support effective implementation without weakening the consistency, predictability, and discipline sought through a multi-year framework.

Electric and natural gas utilities face different sources of uncertainty that may influence how an MRP functions in practice. As mentioned in various parts of this Staff report, electric utilities are experiencing changing load conditions associated with electrification, economic development, and large customer growth, alongside increasing infrastructure needs related to reliability, resilience, transmission, and statutory clean energy requirements. These dynamics may create significant capital investment needs and greater uncertainty regarding the timing and scale of future system demands. Natural gas utilities face a different set of challenges, including uncertainty regarding future throughput, emissions reduction requirements, long-term system utilization, and the pace at which customer demand may change over time. These differences affect how utilities experience risk and how individual MRP components may function over a multi-year term.

Staff does not find that these differences necessarily require wholly separate MRP frameworks or fundamentally different regulatory objectives. Many of the challenges identified in this proceeding, including increasing regulatory burden, concerns regarding cost management, the need for greater predictability, and interest in stronger alignment between utility incentives and policy outcomes, are relevant across utility types. The principles, goals, and outcomes identified in this proceeding also remain broadly applicable, including affordability, customer protection, administrative efficiency, investment discipline, and long-term system value.

Staff's recommendations throughout this report reflect an effort to establish a framework that is sufficiently durable to operate across differing utility conditions while preserving targeted flexibility where differences are warranted. Staff has therefore recommended greater consistency in foundational framework elements, including plan duration, MRP type, revenue decoupling, earnings sharing, and performance incentives, while recommending that calibration and implementation details occur in Phase 2. In Staff's view, this approach allows the Commission to establish clearer expectations and preserve the discipline associated with multi-year ratemaking without assuming that identical implementation is appropriate across utilities.

Phase 2 discussions will provide an opportunity to further evaluate where utility-specific differences warrant tailored approaches and where consistency creates greater value. This may include consideration of differing capital investment needs, customer class treatment, risk allocation, adjustment factors, decoupling structures, performance incentives, and interactions with utility-specific planning obligations. Staff anticipates that implementation experience will also inform whether additional differentiation becomes necessary over time.

Other Phase 2 Issues

Several additional issues will be addressed in Phase 2 that are not specific to Staff's MRP framework. Staff summarizes these issues below.

Exception process, reopeners, and offramps

Staff did not include the exceptions process, reopeners or offramps as part of the Phase 1 decision points; however, these are important components in longer-duration MRPs. Staff recommends the exploration and design of these tools occur as part of Phase 2 to ensure they support the broader strategy and provide targeted flexibility to address unforeseen circumstances without undermining the discipline and effectiveness of the MRP framework. While related, each mechanism serves a different function. The exception process, a required component under HB 3179, allows utilities to request an exception from requirements established by rule governing the MRP framework where utility-specific circumstances may warrant different treatment (e.g., out of sequence filing). Reopeners provide a structured process for revisiting specific elements of an approved MRP when predefined conditions occur or assumptions materially change. Offramps provide a path to reset rates or exit the MRP structure before the plan period is complete. In general, these mechanisms provide tools for addressing circumstances that may not be fully anticipated when an MRP is approved and can help ensure the framework remains workable over the course of a plan. That said, to maintain cost control, regulatory certainty, and other objectives of the MRP structure, these tools are typically for rate circumstances when ratepayer or utility health is at substantial risk.

Procedural requirements

HB 3179 also requires the Commission to adopt rules that include procedural requirements for MRPs. These rules will govern filing expectations, planning assumptions, evidentiary support, timelines, and processes governing updates or review during the term of an MRP. They may also address how utilities demonstrate support for adjustment factors, capital investment, earnings protections, and any utility-specific requests for exceptions under the framework. Staff recommends that procedural requirements be developed as part of Phase 2, after design choices have been established, so that filing expectations and review processes can be tailored to the final MRP framework and support more consistent implementation across utilities.

Conclusion

The transition to MRPs is an opportunity to respond to the increasing pressure from changing economic and utility conditions, growing regulatory complexity, and evolving customer and policy expectations. Utilities are navigating changing load conditions, inflationary pressures, infrastructure investment needs, and heightened expectations regarding affordability, reliability, resilience, and emissions reductions. At the same time, the frequency and administrative burden of rate proceedings has increased, creating challenges for utilities, stakeholders, and the Commission alike. These dynamics suggest value in evaluating whether Oregon's current approach remains well-positioned to support long-term planning, cost discipline, and effective regulatory oversight.

Staff's proposed MRP framework reflects a set of interconnected recommendations regarding how the Commission might structure multi-year rate plans under HB 3179. The recommendations in this report are intended to work together: a longer planning horizon, an indexed revenue cap, inclusive scope, adjustment mechanisms, revenue decoupling, earnings protections, performance accountability, and supporting flexibility mechanisms each play a role in balancing cost discipline, customer protections, and adaptability over the course of a plan.

The Commission's decisions in Phase 1 will shape the overall direction of the MRP framework. Phase 2 can then focus on translating those decisions into workable rules, metrics, thresholds, and utility-specific applications. Ultimately, Staff recommends the Commission adopt its recommended Phase 1 MRP components as the basis of an integrated framework. Collectively, they meaningfully balance the overall strategy of discipline and targeted flexibility with strong incentives to align with and accomplish the principles, goals, and outcomes established throughout this proceeding.

PROPOSED COMMISSION MOTION:

The Commission should adopt Staff's recommended MRP framework to inform the scope of rules developed in Phase 2:

1. Five-year duration (term);
2. Index-based revenue cap (MRP type) that includes the following
    a. Adjustment Factors (index formulas I-X-S+G+Z and capital funding mechanism);
    b. Revenue decoupling mechanism;
    c. Earnings sharing mechanism; and
    d. Targeted use of performance incentive mechanisms (PIMs); Initial suggestion includes PIMs in each of the following key backstop and outcome areas for examination in Phase 2:
        i. Backstop PIMs:
            1. Reliability
            2. Safety
            3. Customer Service
        ii. Outcome PIMs:
            1. Customer disconnections
            2. Asset utilization
            3. Progress on CBRE acquisition targets (electric only);
3. Comprehensive inclusion of costs in the MRP; excluding power costs, non-routine wildfire mitigation; and Energy Trust of Oregon funding (scope of MRP) for the time being.