October 1, 2026
Public Utility Commission of Oregon
201 High St. SE, Suite 100
Salem, Oregon 97301-3398

RE: AR 676 Phase 2 - Track 2 CUB & NWEC Staff Survey Responses

---

Oregon Citizens' Utility Board and NW Energy Coalition submit the following comments in response to Staff's Track 2 Optional Survey. We appreciate the opportunity to offer positions in advance of Staff's first draft concept on the various components of the forthcoming MRP framework, which includes adjustment factors, the proposed Special Capital Funding Mechanism (SCFM), and other decision components.

We opted to answer Staff's proposed questions directly, finding this to be a useful way to express our positions at this phase. However, these positions as outlined are not exhaustive due to time and resource constraints, and are open to evolving as this process moves forward. For Staff questions where our responses are absent or brief, we hope to provide additional feedback as the process goes on.

1. **What do you see as the goal of the "I" factor? For example, is it to escalate the utility's costs in a way that mirrors their cost pressures? Is it to keep customer bills stable while accounting for inflation? Is it a combination of these goals? Please explain why your proposed inflation adjustment, if you have one, would achieve your stated goal.**
    a. We understand that the I-Factor exists to balance customer bill predictability and stability with utility cost pressures and that its combination with the X-factor is crucial for ensuring rates do not spike. It is important to keep in mind that a core design feature of MRPs is to place inflation forecast risk on the utility in order to incentivize efficient operations. For example, HECO in Hawai'i came in for a $83.2M inflation true-up arguing to recover the gap in what inflation was forecasted to be and what actual inflation was.[1] We would not support this in Oregon as it is counter to the intentions of the MRP with utilities operating under a holistic budget, where we understand that there are not only costs that will be higher than the index, but costs that will be lower too.

[1] E3: *Modernizing New Jersey's Electric Utility Business Model*, July 2026: https://www.nj.gov/bpu/pdf/reports/EO26040117-%20EO%201%20Elec%20Utility%20Bus%20Model-%20Final%20Phase%201%20Report%20%287.15.26%29.pdf at 112. *See also* Alberta Utilities Commission, Decision 30274-D01-2025: FortisAlberta Inc., *2026 Annual Performance-Based Regulation Rate Adjustment*, Proceeding 30274, December 17, 2025: https://media.auc.ab.ca/prd-wpuploads/regulatory_documents/Reference/30274-D01-2025.pdf.

b. It is important to recognize that the I-factor represents a trade-off between the utility and its customers. The utility gets something that it does not have in traditional rate-of-return regulation: an annual increase in rates without having to offer evidence to support that increase. The increase is automatic. It is not subject to a disallowance or prudence review. The utility does not risk stakeholders combing through its finances and identifying offsetting savings or a lowering of its ROE. On the other side of the equation, customers get predictable rates that increase only modestly in most years, rather than the double-digit increases utilities often request. When this trade-off is well maintained both the utility and its customers can benefit from an MRP.

c. The key to maintaining this trade-off is cost discipline. It works well if the utility plans its expenditures based on the expected revenue under the cap. If the structure allows the utility too much latitude to seek rate increases in addition to the annual escalator and the utility acts on this latitude, the customer loses its side of the bargain. And, as seen in Maryland, if customers experience too much rate pressure under an MRP, that MRP can be abandoned.[2]

d. From our research we see that utilities in at least three states (Massachusetts, Hawai'i and New York) utilize GDP-PI as the I-factor for their index based cap MRPs–a measure of economy-wide output price inflation. Generally this seems more common in the US. We also found that in at least two instances, two utilities use a blended I-factor whereby a measure of industry input price inflation is used. For example, the Alberta jurisdiction is notably one of the longest-running MRPs on the continent, using an index-based *price* cap. For the I-factor, Alberta uses a mix of labor (60%) and non-labor (40%) indices.[3] For Oregon, ultimately this will also depend on the X-factor possibilities.

e. Federal Social Security uses the Consumer Price Index for Urban Wage Earners and Clerical Workers (CPI-W). Ultimately, we understand CPI to be a closer measure to where customers are, while GDP is closer to where industries are. If we are trying to hold utilities to a budget that relates to customer affordability, which is what we understand the MRP to be, we are more supportive of using CPI. Again, while the X-factor will also be an important consideration here, we are also very concerned about what is to be included under the cap and what options utilities will have for recovery outside of the index.

---

[2] Office of People's Counsel, State of Maryland. *Multi-year rate plans: A failed solution in search of a problem, People's Counsel tells Public Service Commission*, October 18, 2024: https://content.govdelivery.com/accounts/MDOPC/bulletins/3bceee5

[3] E3: *Modernizing New Jersey's Electric Utility Business Model*, July 2026: https://www.nj.gov/bpu/pdf/reports/EO26040117-%20EO%201%20Elec%20Utility%20Bus%20Model-%20Final%20Phase%201%20Report%20%287.15.26%29.pdf at 114.

2. **What is your vision for the X-factor? In your answer please discuss:**
    i. An X-factor is important to the construct. It sends a message to the utility that it is important to look for productivity gains. Currently, PGE is undertaking a multi-year effort to identify and implement efficiencies. This came, at least partially, as a response to UE 435 where, in the face of rapidly increasing customer bills, PGE had much of its requested rate increase rejected. Arguably, the rate case result sent a message to PGE that it needed to do more to control its costs and PGE responded accordingly. Allowing the utility to automatically raise rates should come with a similar message concerning the need to control costs and maintain affordability. The X-factor makes clear that utilities are expected to find ways to control costs.
    ii. If the MRP is successful and long-lasting, the X-factor will vary over time. In the 1990s, for example, the economy had significant productivity gains as businesses moved into a digital world of computing power, digit storage and internet communication. There is a possibility that Artificial Intelligence (AI) could again lead to broad productivity gains. Our initial view, which is subject to change through this stakeholder process, is that the X-factor should look to independent factors that broadly examine productivity in the economy rather than look narrowly at each individual utility and at a given time period should largely be the same for all utilities. The X-factor should be determined by the Commission, after analysis from its Staff or consultants, and input from stakeholders.

b. How often it would be updated?
    i. While we want utilities to live within a budget, and do not want to create annual proceedings, we prefer the precedent of a fixed X-factor over the MRP term.

c. **Any bounds on what the X-factor could be?**
    i. We understand the X-factor to be a productivity offset that reflects the impact of productivity growth on cost growth using broad economic trends. And that while the I-factor is updated each year, the X-factor generally remains fixed over the MRP duration. We believe that best practice for a credible X-factor begins with an analysis of economy-wide productivity growth that can be applied to specific utilities. An attempt to base this primarily on each individual utility's unique circumstance will be difficult and conflict with the S-Factor.

ii. Our preliminary research shows that in North America, regulators calibrate the X-factor to be in a narrow range, 0-1%, particularly when an ESM is present.[4]

iii. It is important to us to not set the X factor to zero. We want to encourage utilities to increase productivity. Setting the X-factor to zero says that there is no expectation for utilities to work to become more efficient. Thus, we want to set it above zero as a signal that we expect a utility to find these gains.

iv. It could perhaps be set in a manner somewhat similar to ROE. We potentially could largely look outside the utility to the broader economy to identify a reasonable range of expected productivity and choose a specific number based on an individual utility. For example, an economy wide look, may suggest that productivity gains of between 0.7% and 1.2% are expected of most businesses and based on the individual utility's circumstances, that the X-factor is set at 0.9%.

3. What is your vision for the Z-factor? In your answer please discuss:

a. What costs should be eligible for Z-factor recovery?

i. We should continue to operate under the assumption that the great majority of utility costs will fall under the indexed revenue cap. It is important to keep in mind that RMI notes in its "Fixing Multiyear Rate Plans report from 2025 states that one of the common flaws of MRPs is noted as: "Multiple avenues for cost recovery outside of base rates allow the utility to selectively pursue the most favorable cost recovery mechanisms to maximize their earnings." Staff's V1 Concept for the electric distribution system[5] appropriately flags the Z-factor as being used for unforeseen O&M costs and capital restoration costs. We agree with this, but believe even this is too broad.

ii. *The Z-factor should recognize that the utility is compensated to manage risk. Rates reflect the inclusion of subject-matter experts who are paid to manage various risks.* For example, utilities have used various hedging instruments to manage some unforeseen risks related to fuel prices and even the currency risk of Canadian exchange rates. In managing these risks the utility can come out ahead or behind. A structure that makes it simple for a utility to place unforeseen costs on customers, but difficult for customers to benefit from unforeseen gains is inherently unbalanced. *The*

[4] LBNL, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*. July 2017: https://eta-publications.lbl.gov/sites/default/files/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf at 38 & 47.

[5] Docket No AR 676, *Staff Electric Distribution Concept v1*, September 25, 2026: https://edocs.puc.state.or.us/efdocs/HAH/ar676hah349606112.pdf

Z-factor should be limited to unforeseen costs that are not within the normal range of expected utility management.

iii. It is important that the alternative pathways for recovery are clear and do not create a "menu" for utilities to select the most utility advantageous pathway in a way that games the index. We believe that this should be designed in such a way that no single cost can fall into more than one alternative pathway to recovery. Carving out clarity on the difference between the Z-factor, the SCFM, and the re-opener is crucial. The thresholds and burden of proof should help make clear these distinctions.

b. What materiality threshold should be considered – if any?

i. A materiality threshold is critical to striking a reasonable balance of interests in an MRP and in making it administratively workable. We generally think that a deadband to establish materiality and cost sharing both are essential. It is also important that it be applied to large utilities like PGE and PacifiCorp and small utilities like Cascade. Historically, the Commission has previously established this by using basis points of ROE. This ensures that the materiality threshold of a small utility reflects its size. An ROE threshold also reflects the total earnings potential of the utility which relates to its ability to absorb risk. Historically, the driver of a utility's request for a rate increase is an expectation that because of higher costs and additional investments, the utility's ROE will be reduced below a reasonable level.

ii. This is the reason that electric utility PCAMs originally had deadbands based on ROE. Those mechanisms grew out of the power cost deferral decisions that the Commission made during the Western Power crisis. *See dockets UE 121 and UM 995, with Orders 01-420 and 01-683 for examples.*

c. How frequent Z-factor adjustments should be able to be filed?

i. We believe it should not be frequent. Captive customers are essentially forced to hire the utility to manage the risk of operating a utility. When PGE proposed a hydro-only PCAM, the Commission looked at establishing something that would deal with a 1-in-10 year hydro event. There was recognition that there was a risk associated with hydro availability, but that risk was two-sided, that it was a risk that traditionally had been handled by the utility and that the utility was compensated through its ROE to manage. But it was also recognized that it was a risk that could lead to large variations that would be difficult to manage without a rate adjustment. Thinking about how often the risk would likely rise to the level of needing a rate adjustment was a good tool to use in

establishing the threshold. It should be noted that we did not propose to limit the adjustment to only being used once in every 10 years, but we tried to establish a threshold that over time, on average, was expected to trip about once per decade.

d. When the rate update should occur?

i. We are still thinking through this.

e. Whether Z-factor can be used for only one event or whether multiple events could be accumulated into a Z-factor filing?

i. We have concerns if a utility can combine multiple smaller events to overcome the necessary threshold, as the index should accommodate the smaller events. If multiple events can be combined, they should each have to meet the individual threshold for a qualifying event.

f. What the burden of proof should be in a company's Z-factor filing?

i. It is important that a utility be clear about why it could not meet its revenue needs in any other way under the index–meaning why it could not find savings elsewhere to offset the costs. A utility needs to demonstrate why a Z-factor was the only remaining option.

4. What principles should be considered when determining the S-factor? Are there particular data sources or approaches you believe should guide the S-factor?

a. We understand the S-factor to be important for looking at utility spending and overspending compared to peer utilities. One possibility to inform data sources or approaches to guiding the S-factor is looking at utility FERC Form 1 and benchmarking these.

5. What materiality threshold should apply to the G-factor? How should customer forecast accuracy and any potential loss in earnings be weighed?

a. We need more time to respond to this.

6. What is your vision for the Supplemental Capital Funding Mechanism (SCFM)? In your answer please discuss:

i. RMI warns that such mechanisms can create a self-fulfilling prophecy, "the existence of a mechanism for increased capital spending might itself enable greater-than-needed spending, especially where utilities are already operating with an incentive to seek new capital investment opportunities to increase earnings."[6] This should also be considered when designing asset utilization PIMs.

ii. For example, in Hawai'i, they utilize an Exceptional Project Recovery Mechanism (EPRM) "for project-specific cost trackers for large,

[6] RMI, *Fixing Multiyear Rate Plans*, January 2026: https://rmi.org/resources/fixing-multiyear-rate-plans/ at 18.

extraordinary projects."[7] But they have an associated mechanism–the combined shared savings mechanism– meant to encourage cost control for these projects.

iii. Large costs that are future and predictable are planned and anticipated at the beginning of an MRP plan. In other words, we should know when we implement the 5 year plan that a big investment will happen in a future plan year and that the investment is necessary to service load. Because there will be a need for a prudency review – the facts will change since the 5-year plan was adopted – this could be one of the most intensive elements of the MRP.

iv. Again, RMI warns that incremental capital funding mechanisms that dilute cost control in an MRP have become a major MRP pitfall.[8]

7. **What is your vision for decoupling? In your answer please discuss: What level of decoupling should be included (full, partial, etc.),**
   a. We need more time to respond to this.

8. **If an Efficiency Carryover Mechanism is established, what do you see as its primary goal? Are there any considerations you think should be balanced when developing an ECM? Given this, do you think an ECM should be established?**
   a. We need more time to respond to this.

9. **What considerations should be made when determining the deadbands for the Earnings Sharing Mechanism? Should the deadbands be symmetric or asymmetric?**
   a. RMI has found that ESMs are typically asymmetrical, only returning excess earnings to customers. Allowing utilities to recover underearnings can be counterproductive to MRP incentives and shifts risk from utility to customers. Afterall, it is the utilities who are responsible for forecasting and operational decisions, customers cannot influence these outcomes. Customers should not be expected nor required to backstop utility underperformance. Assurance of recovery under poor or inefficient management is not an acceptable design.

10. **Please discuss your vision for re-openers and off-ramps. In your answer please discuss:**

    a. Under what condition a case can be reopened?
       i. RMI found in its review of existing MRPs around the country at least 5 main pitfalls. One of these pitfalls is, "Off-ramp thresholds that are too

[7] *Id.* at 21.
[8] *Id.* at 18.

easily met."[9] Utilities should not be able to exit an MRP prematurely–the stay-out period is one of the defining aspects of an MRP. Utilities are meant to assume risk under an MRP and low bars to trigger an off-ramp eliminate the cost containment incentive.

ii. RMI compares Hawai'i and North Carolina's approaches to re-openers and off-ramps, noting also that off-ramp decisions are often done in the context of a reopener review. RMI suggests that Hawai'i has a stronger design because not only do utilities need to be in financial duress via a credit rating outlook that indicates a potential credit rating downgrade below investment-grade status (or "the Companies' actual ROE enters the outer most sharing tiers of the ESM (either upside or downside)")[10], but make a determination on if an off-ramp is warranted in the first place and that the utility cannot just submit a new rate case without a Commission determination.

iii. We think that consideration around a credit rating outlook indicating a potential credit rating downgrade below investment-grade status could be a reasonable trigger for a re-opener, pending further discussion as well on an ESM.

We are grateful to Staff for a thoughtful process and look forward to continuing to discuss and contribute feedback regarding the best design considerations for Oregon.

Respectfully submitted this 1st day of October 2026,

/s/ Sarah Wochele
Oregon Citizens' Utility Board

/s/ Charlee Thompson
NW Energy Coalition

[9] *Id.* at 23.
[10] *Id.* at 24.