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VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
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Salem, Oregon 97308

Re: AR 676 — Rulemaking to Establish Multi-Year Rate Plan Framework (HB 3179 & SB 688 Implementation), Phase 2, Track 3 — Reply to Energy Advocates' Performance Incentive Mechanism Proposal

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), hereby files a joint response on behalf of NW Natural, Avista Corporation, dba Avista Utilities ("Avista"), and Cascade Natural Gas Corporation (collectively referred to herein as the "Gas Utilities") in response to the Performance Incentive Mechanisms ("PIM") proposal filed by the Energy Advocates ("Advocates") on September 17, 2026, in Phase 2, Track 3 of this rulemaking.

At the outset, the Gas Utilities agree with the statement in Commission Order No. 26-242 that "PIMs should be measurable, within reasonable utility influence, aligned with statutory and Commission priorities, and designed to avoid duplicative rewards or penalties."[1] These criteria are important guiding principles for determining whether a proposed PIM is appropriate and workable. A PIM that does not distinguish utility performance from customer behavior, weather, economic conditions, emergency circumstances, or regulatory constraints may incentivize a utility for outcomes it did not cause. Where these conditions are not met, reporting, service quality standards, safety rules, prudence review, and enforcement remain the better tools. Shadow reporting may also be appropriate when parties need time to evaluate a metric before determining whether it warrants a financial incentive.

The Gas Utilities appreciate the effort reflected in the proposal and the Advocates' willingness to put a complete portfolio in front of stakeholders ahead of the September 30 workshop. These comments address only the proposed PIMs that apply to gas utilities.

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[1] Public Utility Commission of Oregon, *Order No. 26-242, In the Matter of Rulemaking to Establish Multi-Year Rate Plan Framework (HB 3179 & SB 688 Implementation), Docket AR 676* (July 13, 2026), Appendix A, 31.

The Gas Utilities' comments rest on three principles. First, PIMs for gas utilities must stay within the Commission's authority under HB 3179, which permits incentives for efficient utility operations, not penalties. Second, a PIM should address an identified performance gap or a demonstrated risk of deterioration, supported by baseline data rather than assumption. Third, a PIM is a tool for implementing policy, not for making it. Applying those principles, the Gas Utilities are open to backstop PIMs for reliability, safety, and customer service, but the metrics as proposed are not workable, and the Gas Utilities offer alternatives. The Gas Utilities oppose the proposed outcome PIMs for residential disconnections and gas asset utilization.

PIMs Must Not Exceed the Commission's Statutory Authority*:* The Commission must recognize that its legal authority to establish PIMs for electric utilities is much broader than its corresponding authority for gas utilities. SB 688 permits the Commission to "provide incentives and penalties to induce *electric companies* to bring *electric utility* operations in line with the public interest," but this authority does not extend to gas utilities.[2] If the Commission already had this authority over all utilities it regulates, SB 688 would be meaningless. In the past, the Commission has stated:

> The PUC cannot require utilities to accomplish societal objectives that are outside the scope of utility regulation and that impose costs that the Legislature has not required utilities and their customers to bear.[3]

In this case, the Legislature has determined that the costs that utilities and customers must bear in the form of incentives and penalties under SB 688 should only apply to electric utilities, not gas utilities. That said, HB 3179 does permit the Commission to "[p]rovide for incentives for efficient utility operations," but this authority is narrower than the Commission's authority under SB 688.[4] HB 3179 is limited to incentives (not penalties) and only applies to making utility operations more efficient. As such, Staff should ensure that any PIM it proposes to apply to gas utilities be limited to what is permissible under HB 3179 and not rely on the Commission's authority under SB 688, which applies only to electric utilities.

PIMs Should Address an Identified Need: A PIM should begin with a clearly identified performance gap or a demonstrated risk that performance will deteriorate under a multi-year rate plan. Where a utility is already performing well, a financial incentive adds cost and earnings volatility without improving customer outcomes. Determining whether a gap exists requires data. Before adopting a financial incentive, the Commission should establish a baseline using existing reporting where available, shadow reporting where it

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[2] Senate Bill 688, 83rd Oregon Legislative Assembly, 2025 Regular Session, (available at: https://olis.oregonlegislature.gov/liz/2025R1/Downloads/MeasureDocument/SB688/Enrolled) (emphasis added).
[3] Commission Report on SB 978, "Actively Adapting to Changes in the Electric Sector," (available at: https://www.oregon.gov/puc/utilities/Documents/SB978LegislativeReport-ExecSummary.pdf).
[4] House Bill 3179, 83rd Oregon Legislative Assembly, 2025 Regular Session, (available at: https://olis.oregonlegislature.gov/liz/2025R1/Downloads/MeasureDocument/HB3179/Enrolled).

is not, and comparisons to peer utilities where circumstances are comparable. Without that record, targets and incentive levels would be set by assumption rather than evidence.

Backstop PIMs: The Gas Utilities are open to backstop PIMs that meet the Commission's criteria and advance clearly defined objectives such as the proposed backstop PIMs for reliability, safety, and customer service, which address core utility obligations. The Advocates' proposal was a good starting point for discussion, but the proposed PIMs do not meet the Commission's requirements noted above or require further development to establish clear, measurable metrics that are within the utilities' reasonable control and support sound policy.

Outcome PIMs: The Advocates' outcome PIMs should not be adopted. The Gas Utilities do not support PIMs that would attach financial consequences to results driven either by economic conditions that are outside of the utilities' control or by establishing new or contested policy objectives through PIMs.

A PIM is a performance tool, not a policy-making tool. It is well suited to sharpening performance against an objective the Commission has already adopted, and poorly suited to selecting the objective in the first place. That distinction matters most with the Advocates' proposed asset utilization PIMs. The proposal states plainly that "the only way to improve the asset utilization of our gas system is to reduce the footprint of the distribution system commensurate with declining utilization,"[5] and builds its gas incentives around that premise. That premise rests on untested and unexplained assumptions about gas system operations, costs, energy use, electric grid capacity, the most cost-effective ways to reduce carbon emissions, and customer preferences. More fundamentally, whether the gas distribution system should contract is a significant policy, legal, and economic question with direct consequences for the customers who remain on the system, for the utilities' obligation to provide service upon request, and for the costs ultimately borne in rates. That question cannot be decided indirectly, through a PIM formula, in a rulemaking meant to set the structure of multi-year rate plans.

Reliability PIMs

- Average time to reconnect customers following a utility-mandated disconnection for reasons other than non-payment.

The Gas Utilities support reliability as a backstop area but cannot support this metric as drafted, for three primary reasons.

First, the Advocates' proposed direction of "downside/penalty" exceeds what is permissible under HB 3179, as explained above.

[5] *AR 676 Phase 2 - Track 3 Energy Advocates' Proposal on Performance Incentive Mechanisms* published on September 17, 2026, page 17.

Second, utility-mandated disconnections for reasons other than non-payment are exceedingly rare. The metric would rest on a handful of events across a multi-year plan, which is too thin a record to establish a credible baseline or to distinguish performance from circumstance in any given year.

Third, and more significantly, restoring gas service is not analogous to restoring electric service. Reconnection of gas service requires a technician to enter the customer's home to relight and verify that appliances are operating safely. The pace of that work is therefore governed by when the customer is available and willing to provide access — not solely by the Company's crew deployment or prioritization. A metric that measures elapsed time to reconnection would wrongly attribute customer availability to the utility. An elapsed-time metric would also send the wrong operational signal. Field personnel must retain discretion to isolate facilities, investigate conditions, complete repairs, test the system, purge lines, and relight equipment without financial pressure to shorten necessary safety steps. Any reliability measure should include clear start and stop points and exclusions for circumstances outside the utility's control and should not place speed and safety in tension.

The Gas Utilities offer a workable alternative that captures the spirit of this metric. The Gas Utilities already report to the Washington Utilities and Transportation Commission on the "average and median length, in minutes, from notification to arrival of a field technician in response to a natural gas system emergency." It is already defined, collected, and reported to another commission, making it a readily accessible metric to deploy in Oregon. The Gas Utilities recommend this metric as the basis for a reliability and safety response PIM.

Safety PIMs

- The proposed metrics would measure 1) Response and correction time to reported gas leaks and 2) the number of overpressure events.

Safe operation is the Gas Utilities' first obligation, and safety should be included as part of the backstop portfolio.

Before specifically addressing each of the Advocates' proposed safety PIMs, the Gas Utilities cannot support the PIMs as drafted because the Advocates' proposed direction of "downside/penalty" exceeds what is permissible under HB 3179, as explained above.

***Leak response and repair**:* The Gas Utilities cannot support the metric as written. Two definitional problems need to be resolved before the measure would be workable. First, not every odor call results from a leak on the system; some involve a customer-side equipment leak or they reveal no leak at all. A metric based on all reported calls would therefore attribute outcomes outside the Gas Utilities' systems to their performance. Second, correction time also appropriately varies with the grade of the leak. Federal classification standards direct immediate repair for hazardous leaks and scheduled or monitored remediation for lower-grade leaks. A single average repair-time figure would

treat a correctly scheduled repair for such lower grade leaks as underperformance. Notably, the Gas Utilities already report on measures of this type to the Commission on an annual basis, and any PIM should incorporate that existing reporting rather than create a parallel definition.

***Overpressure Events**:* The Gas Utilities object to this metric. Overpressure events on the distribution system are exceedingly rare, and every such event is already reported to the Commission. A count-based metric over a small number of years would produce a skewed result, driven by whether a single event occurred, not by any observable difference in performance.

Customer-side overpressure is particularly unlikely because the regulator installed at each customer meter set is designed to protect downstream customer facilities, and protective equipment on the distribution system is designed to minimize the effect of any event. There is no identified performance gap for this PIM to resolve. The appropriate objective is zero overpressure events, but that objective does not make a financial PIM useful. A PIM based on rare events would add earnings volatility without establishing a stable baseline, a meaningful performance trend, or a clear causal relationship between management action and the annual result.

In both areas, the Gas Utilities raise the following issues with their design. These metrics are already governed by comprehensive federal pipeline safety regulations administered in Oregon through the Commission's pipeline safety program,[6] and both are already subject to inspection, audit, and civil penalty authority.[7] Clear legal standards already govern these types of issues. A PIM should not create duplicate financial consequences about the same facts.

Instead of the safety related PIMs proposed by the Advocates, the Gas Utilities instead suggest that the Commission establish a PIM related to measuring timely response to natural gas emergencies, provided the Commission uses a clear definition and measures the portion of the response process within utility control. An average emergency response-time measure is more workable than a metric based on total correction time because it can be measured from customer notification to the arrival of a field service technician. The Commission would need to define a natural gas system

[6] The Commission has been certified by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) to inspect and enforce the federal pipeline safety code with respect to intrastate natural gas pipelines. *See* 49 U.S.C. §§ 60105–60106 and ORS 757.039; *see also* OPUC, Natural Gas Pipeline Safety, https://www.oregon.gov/puc/safety/Pages/Gas-Pipeline-Safety.aspx (describing the Commission's Pipeline Safety Program, which applies the standards of 49 C.F.R. and is carried out through education, inspection, enforcement, and investigation of complaints, incidents, and accidents).

[7] *See* OAR 860-031-0005 (inspection of gas pipeline operator facilities); OAR 860-031-0010 and -0015 (verbal and written notice of probable violation); OAR 860-031-0035 (civil penalties, based on the gravity of the violation and the operator's past violations); ORS 757.991 (civil penalty for noncompliance with gas regulations, in an amount established by Commission rule and not to exceed the amount set forth in 49 C.F.R. 190.223).

emergency before adopting the measure.

Customer Service PIMs

- The percentage of contacts resolved on first contact within 72 hours, disaggregated by language, geography, and program.

Before specifically addressing the Advocates' proposed customer service PIM, the Gas Utilities cannot support the PIM as drafted because the Advocates' proposed direction of "downside/penalty" exceeds what is permissible under HB 3179, as explained above.

The Gas Utilities do not object to customer service being part of the backstop PIM portfolio. Ensuring that cost discipline under a multi-year rate plan does not come at the expense of the customer experience is a legitimate purpose for a backstop PIM mechanism, and the Gas Utilities share the objective the Advocates are pursuing. The Gas Utilities' low-income and community advisory work demonstrate that the experience of income-qualified and limited-English-proficiency customers matters, and the utilities are prepared to be accountable for that experience.

The Gas Utilities question what conduct the Advocates' proposed customer service PIM would incentivize. A first-contact closure rate measured against a fixed window captures how a contact is handled and recorded rather than whether the customer's underlying need was actually met. The proposal also does not define resolution, explain how a first-contact measure would interact with a 72-hour resolution period, or establish how contacts would be attributed to the listed programs and demographic or geographic categories. Many customer inquiries legitimately take more than one step, such as field work, billing research, or eligibility documentation. Counting those as failures would not separate avoidable transfers from necessary follow-up, and segmenting results could produce small, inconsistent samples.

If a customer service PIM were to be pursued, more established options would give clearer definitions and more reliable data. Examples include:

1) Grade of service, measured as the percentage of customer calls answered within a certain number of seconds, with an annual target.
2) Customer satisfaction survey results that measure satisfaction with telephone service provided by the contact center.
3) The number of complaints filed per 1,000 customers.

The Commission should not adopt the proposed first-contact resolution PIM without a complete metric specification and a period of shadow reporting. If the Commission were to pursue a customer service measure, it should select a measure with a clear denominator, consistent data, defined exclusions, and an outcome that the utility can directly influence. The Commission should first evaluate baseline performance and the relationship between the measure and customer benefit.

Residential Disconnection PIM

- ROE-based PIM tied to annual reductions in residential disconnections for non-payment.

Before specifically addressing the Advocates' proposed residential disconnection PIM, the Gas Utilities cannot support the PIM as drafted because the Advocates' proposed direction of "downside" exceeds what is permissible under HB 3179, as explained above. Further, while the Advocates present this proposed PIM as potentially "symmetrical," the theorical upside would be undercut by the Advocates' qualifier that such purported upside would only be possible if the utility's "authorized ROE is reduced to accommodate ROE-based PIMs." In other words, Advocates are presenting two versions of a downside penalty, which exceeds what is permissible under HB 3179 as explained above.

The Commission should not establish a PIM that requires annual reductions in residential disconnections for non-payment. Disconnection volumes move with unemployment, weather, energy prices, and the availability of federal and state assistance funding, among other things. A utility can influence outreach, enrollment, payment arrangement flexibility, and the quality of its customer interactions — and the Gas Utilities do, through its bill discount program and its arrearage relief or management program— but it cannot control the economic conditions that determine the result that the metric records. Tying a return adjustment to that result would penalize the Gas Utilities for the condition of the economy in a given year.

A uniform annual reduction target would also assume that all utilities begin from a similar baseline. Disconnection rates vary across utilities due to differences in customer demographics, service territories, economic conditions, climate, customer assistance program design, and historical collection practices. For a utility that already maintains low disconnection rates and high participation in assistance programs, further reductions become increasingly difficult to achieve and may not reflect meaningful improvement in customer outcomes. Performance in this area follows a diminishing-returns curve rather than a linear path. For utilities that already perform well, maintaining low disconnection levels may be the appropriate measure of success. The proposed requirement to reduce disconnections while preventing growth in arrearages also does not account for the relationship between those two measures. A utility that relaxes its collection activities will generally experience fewer disconnections but higher outstanding balances, and a utility focused on minimizing arrearages may experience more disconnections. These metrics should not be treated as independent measures of utility performance.

Disconnection rates are actively under Commission supervision. Disconnection protections have been developed and refined in UM 2211 and related rulemakings, and the bill discount framework established under HB 2475 is in place and expanding. Adding a return-based penalty on top of active regulatory oversight creates the potential

for inconsistent direction without adding additional customer protection. To the extent the Commission wishes to strengthen expectations in this area, the Gas Utilities' view is that the existing UM 2211 docket and workspace are the better instrument to do so.

This PIM also implicates an issue that remains unresolved in Phase 2. The measures that are to some degree within a utility's control—bill discount enrollment and re-enrollment, arrearage management, flexible payment arrangements, targeted outreach, and the customer service resources needed to support these efforts—are all customer program activities. The Advocates identify substantially the same list when they describe how a utility would achieve the outcome, citing auto-enrollment, expanded income-qualified programs, more flexible payment plans, text reminders, and caseworker-type approaches. Those activities are demand-driven and enrollment-driven. Their costs do not move with a general inflation index, and they tend to rise precisely when economic conditions push disconnections upward — that is, exactly when the PIM would be applying pressure in the opposite direction.

A mechanism that would penalize a utility for an outcome while constraining the spending that produces the desired result would work against itself. The Gas Utilities raise this point because it directly impacts the treatment of customer programs under the index. If the Commission were to adopt a PIM in this area, the customer programs that drive the measured outcome should be recovered outside the revenue cap index, whether through the current deferral mechanisms, or a reopener.

The Commission should continue discussions concerning whether and how a disconnection-related PIM could be structured before adopting a specific metric or financial mechanism. Those discussions should recognize material differences among utilities, including existing disconnection rates, customer characteristics, and participation in energy assistance and affordability programs. And rather than requiring annual reductions, the Commission should consider whether maintaining low disconnection levels represents successful performance. For utilities that already perform well, the public policy objective may be to prevent deterioration in customer outcomes rather than require continued improvement from an already favorable baseline. A maintenance-based approach would better recognize differences among utilities and avoid creating unattainable performance expectations.

Gas Asset Utilization PIMs

- The three gas asset utilization proposals raise significant concerns for the Gas Utilities and should not be adopted.

As a threshold matter, gas distribution systems are planned and operated to meet safety, reliability, and peak demand requirements, not to maximize annual throughput. Each gas utility must maintain sufficient capacity and system configuration to serve customers during design-day winter conditions even when annual throughput declines. Annual use can change because of weather, conservation, economic conditions, building activity, equipment choices, and public policy, and none of these factors

establish when a facility is unnecessary. Retirement decisions require location-specific engineering analysis, operational review, cost analysis, and consideration of the customers who remain connected. A system-wide utilization measure cannot determine whether an individual facility remains needed.

Strategic electrification. The proposal would pay a gas utility a graduated incentive scaled to the number of customers who reduce or eliminate gas service. Setting aside the policy and legal questions addressed above, the fixed costs of the distribution system do not disappear when a customer leaves it. Those costs are spread across the customers who remain and who may not be able to afford to convert, who rent, or who live in buildings where conversion is impractical. A PIM of this design would have remaining customers fund any cost to electrify, a financial PIM, the remaining fixed costs of the system, and the residual cost of a stranded assets that the incentive created.

Participation in electrification is also primarily a customer decision. Customer economics, equipment replacement cycles, building characteristics, contractor availability, tax incentives, public programs, and customer preferences drive whether a customer electrifies, so a participation-based incentive would measure customer and market behavior more than utility performance. Program enrollment alone also does not establish a net customer benefit. A valid measure would need to account for program costs, incremental electric-system impacts, avoided gas-system costs, emissions effects, remaining and exiting customers' energy burdens, and other effects on customers who remain on the gas system.

Those electric-system impacts are significant. The Pacific Northwest already faces a growing resource adequacy gap. A 2026 regional study by Energy and Environmental Economics (E3), sponsored by most of the region's electric utilities, including Portland General Electric and Avista, projects a shortfall of roughly 9 GW of effective capacity by 2030, growing to 14 to 18 GW by 2035, and identifies extended winter cold snaps during low-water conditions as the region's primary reliability risk. The study also finds that the region is not on track to close that gap, given long development timelines for new generation and transmission and limited capability to deliver power into the I-5 corridor load centers. Those same winter cold events are when gas space- and water-heating load is highest. Shifting that load to the electric system would add to a winter peak the region is already struggling to serve, requiring new generation, transmission, and distribution capacity paid for by electric customers, while the fixed costs of the gas system remain with the customers who stay on it. A PIM that rewards customer departures from the gas system without accounting for the total costs and risks is counter to the Commission's and utilities' missions of ensuring safe and reliable energy service.

Non-pipe alternatives. The Gas Utilities evaluate alternatives to pipeline projects where they are technically and economically viable, and the prudence of those decisions is reviewable in a general rate case. A shared savings payment measured

against a hypothetical project that was not built would require the Commission to value a counterfactual and would give the gas utility a financial interest in how that counterfactual is characterized. Safety-driven and compliance-driven work should be scoped by engineering and regulatory requirements, not by an incentive available for an alternative.

The appropriate regulatory objective is not to maximize deployment of non-pipe alternatives, but to identify the least-cost, least-risk solution that reliably meets the underlying system need. A PIM that favors one solution type over another could distort planning decisions and undermine technology-neutral resource evaluation. A shared savings calculation would also depend on assumptions about project scope, timing, load forecast, escalation, contingency, risk, and the treatment of costs that are deferred rather than avoided, inviting disputes over the counterfactual rather than producing a transparent measure of performance.

An alternative approach is to neutralize any perception of bias between capital and O&M. A pipeline project is a capital investment that earns a return, while geographically targeted energy efficiency and demand response are generally treated as operating expenses that do not. Allowing utilities to capitalize the cost of geographically targeted energy efficiency and demand response used to defer or avoid an identified system need would neutralize the choice between capital and operating solutions. The utility would then have no financial reason to prefer one solution type over another, and the decision could turn on cost, risk, and reliability. This approach advances the same objective as the Advocates' proposal without requiring the Commission to value a counterfactual project or reward one technology over another, and the resulting investment would remain subject to prudence review in a general rate case.

Infrastructure Asset Effectiveness. The proposal describes the purpose of this reporting as helping "identify existing infrastructure that could be decommissioned" and as a foundation for future metrics, benchmarks, and PIMs. The Gas Utilities do not support a data collection exercise in service of forcing customers from the gas system.

Response to the Advocate's Statements Regarding Gas Demand

The proposal cites NW Natural meter installation data in support of its premise of system decline, noting that installations averaged 11,549 per year between 2017 and 2022 and have averaged 5,042 per year over the last three years. NW Natural offers the clarification that these data show continued growth at a slower rate, not contraction. NW Natural is adding customers. Moreover, Portland General Electric also notes slower residential customer growth as "Oregon experienced slower population growth and residential new construction are at all-time lows as the Oregon economy continues to lag the national economy."[8] This statement indicates that slower residential customer growth is not limited to the gas system, but rather reflects general economic conditions.

[8] In the Matter of Portland Gen. Elec. Co., Request for a General Rate Revision, Docket No. UE 473, Direct Testimony of Angelica Espinosa, PGE/100 at 9.

Forecasts of long-run demand differ among parties and are properly examined in resource planning, where assumptions can be tested.

Conclusion

The Gas Utilities support a workable PIM framework and intend to continue to participate constructively in its design. A workable framework rests on three principles. First, PIMs for gas utilities must stay within the Commission's authority under HB 3179, which permits incentives for efficient utility operations, not penalties. Second, a PIM should address an identified performance gap or a demonstrated risk of deterioration, supported by baseline data rather than assumption. Third, a PIM is a tool for implementing policy, not for creating it; a PIM should drive performance toward objectives the Commission has already adopted.

Applying those principles, the Commission should reject proposed PIMs that duplicate existing regulatory obligations, depend primarily on external conditions or customer decisions, rely on undefined or unstable metrics, or create conflicts with safety, reliability, affordability, and prudent system operation. A recurring challenge across many of the proposals is that they seek to incentivize outcomes rather than utility actions. The further a metric moves from utility action toward customer or market outcomes, the more difficult it becomes to design a fair and effective incentive mechanism.

The Gas Utilities are open to backstop PIMs for reliability, safety, and customer service because they address core utility obligations that customers experience directly. The metrics as proposed, however, are not workable. The Gas Utilities instead recommend an emergency response-time measure already defined and reported in Washington and, for customer service, established measures such as grade of service, customer satisfaction, or complaint rates, with shadow reporting to establish a baseline before any financial incentive is attached.

The Gas Utilities' most substantive objections are to the outcome PIMs. The disconnection PIM would penalize the utilities for economic conditions they do not control and constrain the customer program spending that drives the result; for utilities that already perform well, maintaining low disconnection levels may be the appropriate measure of success. The asset utilization PIMs would use rate plan design to unilaterally decide energy system planning decisions and contested policy questions.

The Gas Utilities appreciate the opportunity to provide these comments and look forward to continuing active participation in this rulemaking process.

Sincerely,

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