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July 16, 2025

VIA E-MAIL TO

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

Re: Docket No. UG 520 – In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision.

Attention Filing Center:

Attached for filing in the above-captioned docket, please find Northwest Natural Gas Company's Cross-Examination Statement and Cross-Examination Exhibits (NW Natural/3800-3801)

Please contact this office with any questions.

Sincerely,

Michael Highfill
Paralegal
McDowell Rackner Gibson PC

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

UG 520

In the Matter of NORTHWEST NATURAL GAS COMPANY dba NW NATURAL, Request for a General Rate Revision.	**NW NATURAL'S CROSS-EXAMINATION STATEMENT AND CROSS-EXAMINATION EXHIBITS**

Pursuant to Administrative Law Judge ("ALJ") Sarah Spruce's February 14, 2025, Memorandum and July 15, 2025, "Memorandum Regarding Cross Examination Statements," Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), submits the following cross-examination statement.

The Company waives cross-examination of all parties to this proceeding,[1] but reserves the right to ask follow-up questions of any witness who is questioned by another party, the ALJ, or any Commissioner. NW Natural respectfully requests that the ALJ identify whether there are any NW Natural witnesses for whom the Commissioners or the ALJ may have questions, or otherwise confirm that, because the parties have waived cross-examination, the evidentiary hearing is cancelled.

NW Natural also submits the following exhibits for inclusion in the administrative record. Staff and CUB have stipulated to the admission of these exhibits, which are attached to this filing.

[1] The non-Company parties to this proceeding are Staff of the Public Utility Commission of Oregon ("Staff"), the Oregon Citizens' Utility Board ("CUB"), the Alliance of Western Energy Consumers, and Climate Solutions, the Coalition of Communities of Color, Verde, Sierra Club, and Oregon Environmental Council (collectively, the "Coalition").

Exhibit Number	Description
NW Natural/3800	Staff Responses to Coalition Data Request Nos. 1-4 (July 14, 2025)
NW Natural/3801	Docket UM 2362, CUB's Initial Comments on Portland General Electric Company's 2024 Distribution System Plan (June 13, 2025)

Respectfully submitted this 16th day of July 2025.

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Attorney for Northwest Natural Gas Company dba NW Natural

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Staff Responses to Coalition Data Request Nos. 1-4 (July 14, 2025)

EXHIBIT 3800

July 16, 2025

Date: July 17, 2025

TO:
COLE SOUDER
GREEN ENERGY INSTITUTE
10101 S TERWILLIGER BOULEVARD
PORTLAND, OR 97219
csouder@lclark.edu

FROM: Kate Ayres, Charles Lockwood, Michelle Scala

OREGON PUBLIC UTILITY COMMISSION
Docket No. UG 520 – GEI Data Request No. 1

GEI Data Request No. 1:

Please refer to Staff/2000, Ayres-Lockwood-Scala/14, lines 14-15, stating "these concerns included issues around overlapping state and federal funding for electrification." Please identify the concerns related to how state and federal funding for electrification could negatively impact the use of OLIEE funds to replace a dead or dangerous furnace with a heat pump.

OPUC Data Response No. 1:

Staff prefaces that Community Action Partner Agencies (CAP Agencies) are experts on the interplay of federal and state funding resources overlapping in this area, and Staff recommends the Coalition contact the agencies to better understand concerns. Staff continues to reiterate these technical and important policy discussions should be occurring in a dedicated space such as Docket No. UM 2211.

Nevertheless, given the breadth of potential impacts of the Coalition's electrification proposal, Staff had conversations with CAP Agency representatives, Oregon Housing and Community Services (OHCS) and the Community Action Partnership of Oregon (CAPO). These conversations were meant to understand the potential burdens placed on the agencies as they are not currently represented by an intervenor in the docket. Throughout our conversations, the representatives discussed the complexity of mixing OLIEE funds with federal funding if OLIEE funding was used for electrification. Representatives of the CAP Agency, OHCS, and CAPO all stated that US Department of Energy Funds may not be used to support fuel switching. Accordingly, to the extent OLIEE funding was used to replace the furnace with a heat pump, the use of funds from the US DOE to cover other home upgrades to ensure the house is prepared for such a switch may be impacted. Due to the intricate braiding of funding CAP Agencies currently utilize between both state and federal resources, representatives were concerned with the impacts of utilizing OLIEE funds for electrification and potential impacts. This is compounded with uncertainty at the federal level regarding the future funding levels of

Bonneville Environmental Foundation, United States Department of Energy, and the Low Income Home Energy Assistance Program.

Date: July 14, 2025

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FROM: Kate Ayres, Charles Lockwood, Michelle Scala

OREGON PUBLIC UTILITY COMMISSION
Docket No. UG 520 – GEI Data Request No. 2

GEI Data Request No. 2:

Please refer to Staff/2000, Ayres-Lockwood-Scala/14, lines 16-17, which identifies "administrative hurdles that currently exist in how CAP Agencies operate" as a concern regarding the timing and feasibility of the Coalition's OLIEE proposal. Please describe the administrative hurdles that exist.

OPUC Data Response No. 2:

Staff prefaces that CAP Agencies are experts on the administrative hurdles that currently exist in this area, and Staff recommends the Coalition contact the agencies to better understand concerns. Staff continues to reiterate these incredibly technical and important policy discussions should be occurring in a dedicated space such as Docket No. UM 2211.

Nevertheless, given the breadth of potential impacts of the Coalition's electrification proposal, Staff conversations with CAP Agency representatives, Oregon Housing and Community Services (OHCS), and the Community Action Partnership of Oregon (CAPO). These conversations were meant to understand the potential burdens placed on the agencies as they are not currently represented by an intervenor in the docket. As Staff discussed in DR Response No. 1, there are concerns with intermixing state and federal funding in that some federal funds may not be available if OLIEE funds are used for fuel switching. Additionally, Staff learned from CAPO that CAP Agencies require specific approval from Oregon Housing and Community Services (OHCS) to transition a house from natural gas to electric. The OHCS representatives reported that fuel switching is not a policy OHCS currently deploys or implements given the complexities due to federal funding requirements.

Representatives of Multnomah County (CAP Agency) noted to Staff it can be easier and faster for the CAP Agency to replace the red-tagged unit with a 90+ efficiency model and add AC if not present, rather than wait for approval for fuel switching.

Additionally, the Multnomah County (CAP Agency) representatives stated it was more time effective for the CAP Agency to alert Northwest Natural of the red-tagged appliance and have the Company switch the appliance out. Lastly, Multnomah County and OHCS representatives also noted there are several technical reviews that must occur such as how the heat pump will interact with the duct systems in the house, leading to challenging transitions.

Date: July 14, 2025

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FROM: Kate Ayres, Charles Lockwood, Michelle Scala

OREGON PUBLIC UTILITY COMMISSION
Docket No. UG 520 – GEI Data Request No. 3

GEI Data Request No. 3:

Please refer to Staff/2000, Ayres-Lockwood-Scala/14, lines 19-21, stating "Staff is particularly concerned with feedback from some CAP agencies that for some customers, heat pumps create increases in electricity bills that are higher than the customer's current bills for natural gas." Are these concerns present for NW Natural customers with an electric utility other than PGE or PacifiCorp, i.e. a COU or MOU?

OPUC Data Response No. 3:

Staff prefaces that CAP Agencies are experts on the concerns that currently exist in this area, and Staff recommends the Coalition contact the agencies to better understand concerns. Staff continues to reiterate these incredibly technical and important policy discussions should be occurring in a dedicated space such as Docket No. UM 2211.

The Commission only regulates three electric utilities, with Idaho Power Company being the only utility not listed in the Data Request who does not have an overlapping service territory with Northwest Natural. The Commission does not regulate COUs or MOUs, therefore, Staff does not have the same level of visibility into concerns for these concerns. The concerns shared with Staff were general concerns rather than a specific concern directed at any one utility.

Date: July 14, 2025

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FROM: Kate Ayres, Charles Lockwood, Michelle Scala

OREGON PUBLIC UTILITY COMMISSION
Docket No. UG 520 – GEI Data Request No. 4

GEI Data Request No. 4:

Do the same concerns about the cost of utility bills exist for a customer who is unable to replace their furnace with a high-efficiency furnace, such as customers who have a gas wall furnaces or similar ductless gas combustion units (see Coalition Intervenors/300, Apter-Prihoda/8-10)?

OPUC Data Response No. 4:

Staff prefaces that CAP Agencies are experts on the concerns that currently exist in this area, and Staff recommends the Coalition contact the agencies to better understand concerns. Staff continues to reiterate these incredibly technical and important policy discussions should be occurring in a dedicated space such as Docket No. UM 2211.

Discussion surrounding gas wall furnaces or similar ductless gas combustion units as referenced in Coalition Intervenors/300, Apter-Prihoda/8-10, was not brought into testimony until the Coalition's June 24th Reply Testimony. Therefore, Staff has not had discussions with CAP Agencies regarding these concerns. Staff defers to the CAP Agencies as experts on these issues, especially given the Commission does not regulate COUs or MOUs as referenced in Staff's Response to DR No. 3.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Docket UM 2362, CUB's Initial Comments on Portland General Electric Company's 2024 Distribution System Plan (June 13, 2025)

EXHIBIT 3801

July 16, 2025

Oregon Citizens' Utility Board

610 SW Broadway, Suite 400
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(503) 227-1984
www.oregoncub.org

June 13, 2025

Public Utility Commission
Attn: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

RE: UM 2362, CUB Initial Comments on PGE 2024 Distribution System Plan

The Oregon Citizens' Utility Board (CUB) advocates for residential customers by working to develop energy systems that are affordable, accessible, reliable, and clean. Our comments here focus on the distribution spending, which to date has been immense. Last year we saw rising disconnections because customers were already struggling to afford the increases in utility bills. Now, PGE's estimates $645 million in distribution investment in 2024 alone. This is happening in an uncertain landscape, where market conditions have increased costs and the incentives to spur DER adoption and social safety nets like LIHEAP are under attack.

Our comments here target consumer interests. These comments are intended to tie specific cost concerns of PGE's 2024 DSP to DSP guidelines, reflect on the rate impacts of distribution investments across Oregon, and encourage transparency and disciplined spending ahead of PGE's next rate case. Ultimately, as costs increase and adoption forecasts become more uncertain we ask how PGE will discipline its spending, ensure equitable allocation of costs and benefits, and share the risks between ratepayers and shareholders.

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Distribution spending must be transparent to ensure least-cost, least-risk investment strategies

The level of spending on distribution is immense. It is greater than what PGE spends on transmission and generation, which with a growing data center load is clearly needed. **Guideline 6** requires that PGE identify the biggest drivers and trends behind needed investments and operational budgets. **Guideline 8** requires that PGE include a prioritized list of investments and projected spending for which cost recovery may be sought in future rate cases. Unfortunately, this DSP does not give us much of a basis to drill down into the spending. For one thing, Tables 25 and 26 of the DSP do not reflect the full costs necessary to execute PGE's spending plans. The DSP shows 2024 costs of $383 million for business as usual for

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distribution spend and $70 million more for the VPP, for a rough total of $450 million in 2024. The Company's presentation to investors, however, showed $645 million in 2024 distribution investment. In other words, **PGE told investors it planned to spend $200 million more than what PGE presented in the DSP**.

According to PGE, $170 of the $200 reflects loaders and overhead. While the remaining $30 million is not associated with any customer-benefits or projects but approved by the PGE board to spend in 2024.[1] While CUB appreciates the clarification in the DR, at the end of the day, to execute the DSP's benefits there is an additional 50% mark up on the costs above what PGE presents in the DSP. As discussed further in this comment, CUB is concerned that the $645 million in 2024 is already unaffordable and will continue to grow.

Table 25 from PGE 2024 DSP

Table 25. Summary of distribution system investments (as of July 2024)

Project category ($M)	2024	2025	2026	2027	2028
Compliance	$148.32	$187.38	$141.53	$91.10	$72.07
Customer/Partner	$153.44	$140.55	$131.80	$135.58	$140.49
Capacity/Flexibility	$38.76	$94.64	$158.01	$132.78	$162.75
Reliability	$41.37	$70.27	$47.90	$38.62	$31.85
Operations	$1.25	$1.10	$2.26	$2.47	$2.56
Totals	**$383.15**	**$493.95**	**$481.50**	**$400.54**	**$409.72**

[1] See attached, PGE Response to CUB IR 4.

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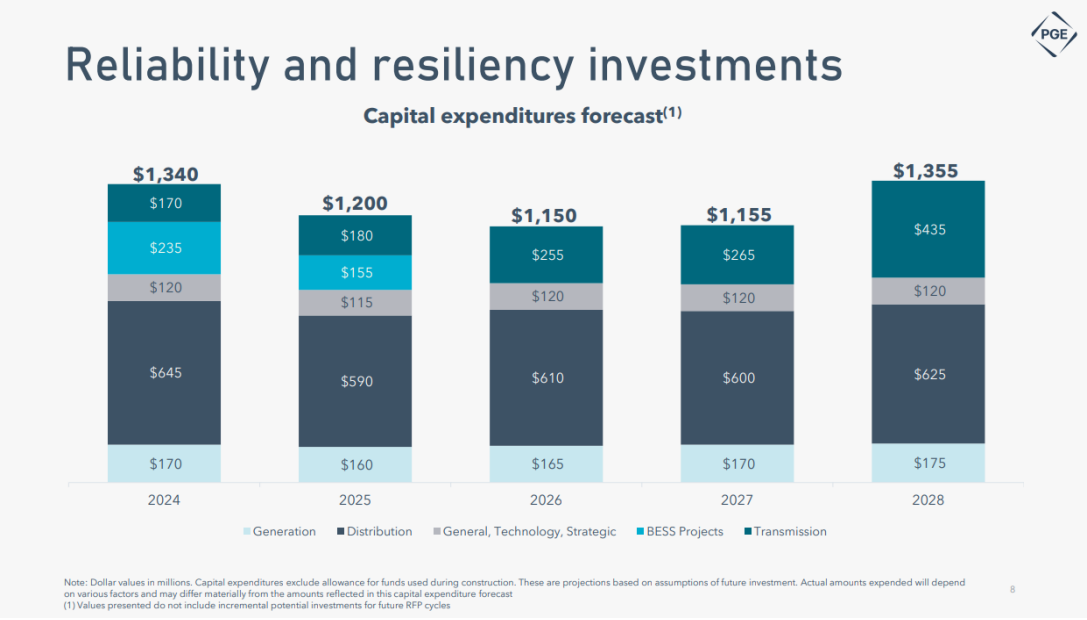
Table 26 from PGE 2024 DSP

Table 26. Summary of grid modernization investments (as of July 2024)

Project category ($ million)	2024	2025	2026	2027	2028
Grid management systems	$48.29	$37.16	$16.10	$5.50	$4.00
Integrated planning	$1.50	$0.70	$1.40	$-	$-
Sensing, measurement, and automation	$2.50	$4.05	$13.60	$35.60	$4.20
Telecommunications	$12.80	$14.16	$13.65	$9.85	$3.55
Physical grid infrastructure	$5.00	$4.84	$8.50	$8.80	$9.00
Totals	**$70.09**	**$60.91**	**$53.25**	**$59.75**	**$20.75**

June 17, 2024 PGE Investor Presentation[2]



[2] Slide 8, available at https://investors.portlandgeneral.com/static-files/44f315ac-95a0-42c9-b685-10b5b1af3c51

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Recommendations

In UE 435, PGE attempted to recover $4 million in O&M for its VPP. Staff objected to $1.5 million, concerned that PGE had not made significant progress in the development of its VPP to warrant any increase to expense included in base rates. The Commission accepted this disallowance, finding that PGE had not justified the spend for the 13 new employees.[3] Accordingly, **CUB recommends** that the Commission here direct PGE to focus on reducing these overhead and loader costs ahead of its next rate filing. For example, PGE can reduce overhead costs of its various smart grid programs and planning dockets through consolidation. PGE has several smart grid programs, such as the EV smart Charging program, the smart grid testbed, SALMON, and the smart thermostat program. PGE should look to consolidate these programs while also assessing the role of ETO, CAP agencies, local governments, and ODOE in minimizing PGE's overhead. This consolidation can limit workload duplication and reduce costs while streamlining information sharing about customer adoption and program utilization to further offset grid needs.

Similarly, **CUB recommends** the Commission direct PGE to identify opportunities across its planning dockets for one-touch distribution repairs and upgrades to further reduce duplication of overhead and labor costs. This is also an opportunity to assess what assets and grid needs established in the separate planning dockets can be utilized to meet the DSP grid needs or resolved with the DSP investments.[4]

Finally, **CUB recommends** that PGE undertake a Reliability Performance review Relative to Distribution Plant per Customer using gross distribution plant per customer and SAIDI and SAIFI scores from FERC filings. See below for example.

[3] Order No. 24-454 at 49-50

[4] For example, can the two-way communication and power flow that can provide customer level information and enable efficient use of DERs discussed in the DSP also provide visibility in high-risk fire areas and fault management such that wildfire mitigation costs are offset by the investments presented here?

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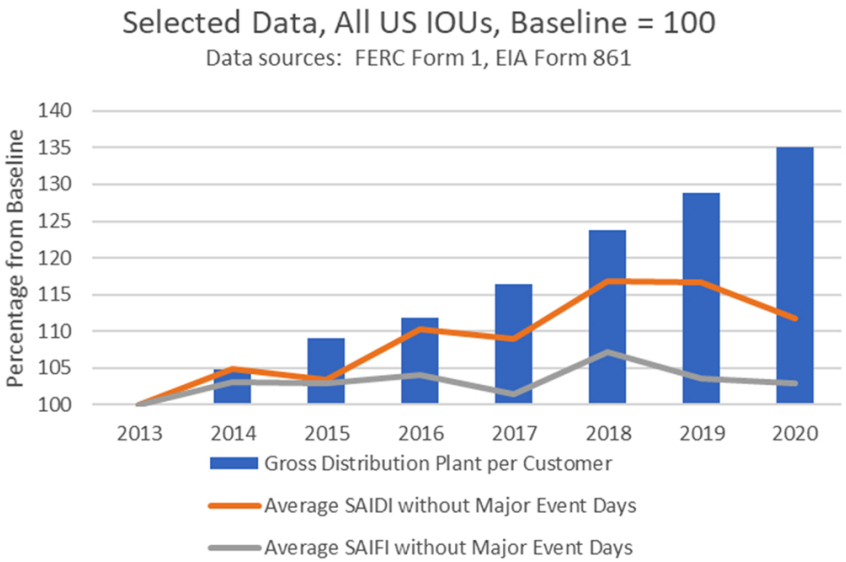

Reliability Performance Relative to Distribution Plant per Customer, U. S. Investor-Owned Utilities, 2013–2020. (Higher system average interruption duration and frequency indices, SAIDI and SAIFI, indicate deteriorating reliability.).[5]

In the above example figure, the Electricity Journal demonstrates how "the U.S. electric distribution grid has seen massive investments in recent years, and that a lack of grid performance, not a lack of grid investment, is the issue." As the authors explain,

> Despite a 35% increases in gross distribution plant per customer among U.S. IOUs since 2013, service interruption frequency has deteriorated 3%, and service interruption duration has deteriorated 12%. While everyone wants the distribution grid to be more reliable, the law of diminishing returns indicates that it is indeed possible to spend more to improve reliability than the improvements are worth to customers and state economies.[6]

[5] *P.J. Alvarez et al., Alternative ratemaking in the US: A prerequisite for grid modernization or an unwarranted shift of risk to customers? The Electricity Journal 35 (2022) 107200*, Fig. 1. See attached for full article.
[6] *Id.*

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PGE states that the Grid Needs and Grid Modernization will improve reliability and resiliency. PGE should provide the metrics and supporting documents behind these statements. This is necessary to ensure the improved grid performance is worth the investment, especially at a time when energy affordability is top of mind.

Changes in market conditions and federal policies undermine the DSP's forecasts and increase costs

The DSP is outdated. It includes cost forecasts of grid investments as of July 2024. As a result, the DSP does not articulate PGE's strategy to adapt to significant changes to market conditions and federal policies that undermine the DSP's forecasts and increase costs. For example, this past week the Trump Administration imposed a 50% tariff on steel, which will flow into rates with capital expenditures. Likewise, supply chain constraints and inflation unnecessarily increase costs that are then passed onto customers without any additional benefits. At the same time, DOE grants that were previously relied on to bring down the costs of new meters and advanced technologies are now in limbo. On the customer side, Trump's plans will further tighten home budgets and raise costs. Staffing cuts to LIHEAP and programs that have helped to weatherize and retrofit homes will both increase utility bills and slow down EE, DR, and DER adoption rates. Simultaneously, loss of the incentives in the Bipartisan Infrastructure Law and Inflation Reduction Act, including tax credits, grants, and rebates will impact forecasts of DER uptake and reduced energy usage.

These changes impact both the forecast spending as well as customers' adoption rates. In UE 435, PGE argued the incremental spending increase in its VPP was justified because customer program enrollment had kept pace with prior years. The market challenges and policy changes threaten that consistent enrollment and thereby undermine PGE's prior arguments. While CUB recognizes that Guideline 5(a)(iv) only necessitates that PGE use the most current

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and accurate sources at the time of filing. The goal of **Guideline 5** is to accurately forecast load growth to reliably meet future energy, demand, and ancillary grid service needs. By filing in December instead of April and by using nearly year-old information (accurate in July 2024), the DSP omits months of market and policy data at this critical juncture.

Recommendations

To account for the significant upheaval of market conditions and policy, **CUB recommends** that PGE file a supplemental update of adoption and cost forecasts. The update should also include an explanation of how these market and policy changes impact the DSP, changes that PGE has made in response, impacts to programs, and how PGE will buy down the cost of grid modernization.

Questions for PGE and the Commission:

1. How will PGE buy down the cost of grid modernization?
2. Will PGE invest in cheaper but lower technology options that provide upfront savings but lack the long-term or advanced benefits? And if so, will the lower tech options still have the computing power to maximize on the ratepayer benefits as predicted in the DSP?
3. Will PGE decide to delay part of the plan or otherwise allocate the investments to a longer timeline?
4. How will the risks be shared? What part of these risks and costs should shareholders bear?
5. Is it reasonable for PGE to make these investments now knowing they come with an inflated price tag?
6. Can customers afford this investment?

DSP lacks a plan for optimized DER deployment to ensure the highest value for customers' dollars

Where and when DERs are deployed determines their value and the resulting costs and benefits to customers. Strategically located DERs can reduce local congestion and improve voltage control thereby reducing power costs. But DERs located in areas where the distribution grid does not have hosting capacity to send power from behind the meter to the grid will require new distribution investments. A scattershot of adoption across PGE's service territory is

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unlikely to provide the grid benefits and savings to justify the spend. It's not clear whether PGE has identified these strategic areas for deployment and, if so, whether PGE is working alongside partners like ETO to target high-value locations. Likewise, there is no clearly articulated framework for compensating customers that could encourage adoption in these high-value areas.

To foster transparency and enable effective decision-making, **Guideline 4** requires that DSPs provide a **"**fundamental understanding of the current physical status of the utility distribution systems and equipment, progress of investment in those systems, the level of distributed energy resources (DERs) currently integrated into those systems, and management and monitoring practices of those systems." While Guideline 5 recognizes that, "as DER and EV adoption grows, forecasting must advance to better account for their impact on load, as well as the ability of these resources to productively modify load." As further explained in **Guideline 5**, the update to the DSP guidelines requires more granularity of forecasting "to improve the accuracy and granularity of existing and anticipated constraints on the distribution system." Similarly, **Guidelines 6 and 7** require details on grid needs and solutions for no and low cost. Lacking a plan that identifies high-value areas and a strategy to optimize existing DER investments and encourage further adoption in high value areas, PGE has not provided sufficient information for approval of the DSP.

Questions for PGE and the Commission:

1. Will residential battery storage primarily be used to address peak load, provide ancillary services, provide flexibility, or reduce local capacity constraints? And what metrics will PGE use to demonstrate and allocate these services?
2. What mechanisms will PGE use to compensate ratepayers for the services delivered to PGE in support of PGE's electrical system?
3. How will ratepayers' investments contribute to PGE's resource adequacy needs?
4. How will PGE address uncertainties and risks of scaling up pilot programs and who should bear the costs of buyer's remorse if the benefits do not materialize as assumed?
5. Should PGE bid aggregated DERs into wholesale markets or reserve the resources for local reliability and resiliency needs?

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6. What is the overlap in cost-effective DER deployment and freeing up idle capacity to allow for building electrification co-benefits like improved indoor air quality with direct impacts to Black, Indigenous, and other Environmental Justice communities?

Equity concerns of grid modernization

Multi-family homes and split incentives

The energy bar association recently published a law journal article finding that those in energy poverty are generally left behind in the transition to renewables.[7] Indeed, we are familiar with these types of inequities as they have presented in net metering, between those able to install solar and receive credits and those unable due to financial constraints and housing type.

Likewise, we are seeing similar inequities in the programs ETO now offers and which PGE points to as solutions in its DSP. Renters are left out of many of the direct benefits of ETO's programs. And instead they are directed to encourage their landlords to make these EE and weatherization upgrades.

This creates in unequal barrier to adoption for renters who do not have that kind of relationship with their landlord or who are concerned that upgrades to the home will increase rent and thereby force relocation to more affordable housing stock albeit now without these improvements. Because ETO's funding is paid by all residential ratepayers, there is a split incentive where single-family home owners are able to take advantage of the full suite of ETO programs, but ratepayers in multi-family buildings cannot.

CUB is concerned this split incentive will flow into PGE's DSP execution. Multi-family ratepayers, including renters and condo owners, as well as ratepayers in housing stock that cannot incorporate these new technologies into their homes, will pay to upgrade a distribution

[7] Gwendolyn Savitz, *Illuminating Inequality: Going Residential Solar Neutral to narrow the energy equity gap*

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system that they cannot access. In effect, the virtual grid will be paid for by all ratepayers, but only accessible by the few who qualify.

Low Income barriers to participation in a modernized grid

Even if the split incentive was resolved, CUB is concerned that income barriers will continue to prevent all ratepayers from participating in this modernized grid. The existing data is not encouraging. PGE's 2024 EBA notes that 50-60% of energy assistance need for PGE customers is among renters, also noting the challenge of reaching them through EE and weatherization. The 2024 EBA also noted that existing low-income EE programs serve relatively few households, noting that between ETO programs and the Public Purpose Charge, these programs reach less than 1% of the eligible population. Overall, per the EBA, across PGE's low-income customers who have been identified as having high energy burden, 38.9% of them have low energy efficiency potential and 21.9% have high energy efficiency potential. For each of its lowest-income tiered customers, respectively, PGE has identified only 27% of these customers as high energy efficiency potential, which means that the remaining 73% of low energy efficiency potential customers who primarily reside in multi-family housing, would experience little to no benefit from energy efficiency measures.

While electrification is a preferred strategy for building decarbonization, the Commission should be prepared to protect multi-family customers and LMI customers from the anticipated negative cost impacts of this immense investment in the distribution grid.

Allocating costs and benefits among the classes

A key issue that is overlooked in this DSP is that the set of customers who traditionally utilize the distribution system is different than the set of customers who receive benefits from the VPP. The DSP will allow PGE to increase the capacity of the grid in a way that lets the company sell more energy to data centers, EV drivers, and customers of electrified homes. But while the DSP points to building and transportation electrification as drivers for increased

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demand, it omits the hyperscale growth of data centers with generative AI. The capacity and ancillary services provided by the VPP and modernization generally will support these large users. Even if data centers become more efficient, the queue shows unprecedented load coming onto the system.[8]

Questions for the Commission and PGE:

1. Does strategic DER deployment share the benefits and costs across the customer classes? Are the grid needs of certain customers prioritized over others?
2. How are BTM investments in DERs providing capacity to data centers given challenges of constructing utility-scale transmission and distribution needed to serve hyperscale loads? What is the value of that capacity?
3. How are the BTM investments envisioned in the DSP providing ancillary services to industrial customers and data centers? What is the value of those services?
4. Where are there overlaps in strategic DER deployment and targeted approaches to serve PGE's most vulnerable customers?

Least Cost- Least Risk Electrification requires consistent futures across Oregon's electric and gas utilities

According to PGE, its customers are investing in fuel-switching options away from natural gas or otherwise building with electric appliances over natural gas. At the same time, NW Natural, an investor-owned gas utility whose service territory overlaps with PGE's, claims that customers are not electrifying. In its ongoing rate case, UG 520, NW Natural argues electrification will mean more emissions and higher costs for ratepayers.

These two simultaneous realities, one from an electric company and one from a gas company, diverge. And if we entertain the two realities, customers will end up paying simultaneously for the redundant distribution costs of two systems. This increase in utility bills will be on top of additional BTM investments to reduce energy consumption. Customers who

[8] Volts Podcast, *Should we put utilities in charge of distributed energy*? Interview with Pier LaFarge, CEO of Sparkfund (Dec. 18, 2024) available at https://www.volts.wtf/p/should-we-put-utilities-in-charge.

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partially electrify, such as converting appliances to electric but maintaining a gas stove or water heater, will continue to pay for NWN's gas assets.

Distribution costs are driving up the utility bills of all utilities. The distribution assets of both electric and gas utilities have long life spans, and doubling the buildout of both systems threatens stranded assets. CUB is not asking the Commission to weigh in on the NWN contested rate case in this proceeding. Rather, we are emphasizing that, under the framework of these opposing realities, customers will continue to see rising utility costs due to redundant and inefficient investment.

Recommendations

If the Commission plans to approve the DSP, **CUB recommends** the Commission provide clarity on how to approach these divergent realities and provide guidance to facilitate joint utility future scenarios to ensure beneficial electrification with least-cost, least-risk investment strategies.

Conclusion

To take a step back, we reflect on this from under the lens of beneficial electrification. As previously recognized by the Commission, "for electrification to be considered beneficial, it must meet one or more of the following conditions without adversely affecting the other two: 1) Saves consumers money over the long run; 2) Enables better grid management; or 3) Reduces negative environmental impacts."[9] In the natural gas fact finding report, the Commission found beneficial electrification necessary for a least-cost/least-risk strategy.[10] So too, CUB encourages the Commission, when reviewing this DSP, to take a page from the Report

[9] Natural Gas Fact Finding report, 4.3 FULL COST OF AGGRESSIVE DEMAND REDUCTION –LOAD SHIFT IMPACTS OF ELECTRIFICATION at 22 (citing Farnsworth, D., Shipley, J., Lazar, J., and Seidman, N. (2018, June). Beneficial electrification: Ensuring electrification in the public interest. Montpelier, VT: Regulatory Assistance Project).
[10] Natural Gas Fact Finding report, 3.2.2 *Lessons on Costs and Risks from Scenarios* at 13.

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and consider whether PGE's plan includes the data necessary and vetted assumptions to not just ensure "modernization" spending but also beneficial electrification.

Respectfully submitted,

/s/Claire Valentine-Fossum

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May 9, 2025

To: Bob Jenks
Oregon Citizens' Utility Board

From: Steven Corson
Regulatory Consultant, Regulatory Strategy and Policy

Portland General Electric Company
UM 2362
PGE's Response to CUB Information Request 001
Dated April 25, 2025

Request:

Page 125 of the 2024 Distribution System Plan has two tables. Table 25 lists distribution investments as of July 2024. Please provide an updated table that includes actual distribution investments made in 2024 and updated forecasts for 2025, 2026, 2027, and 2028.

Response:

Please see UM 2362_NONC_PGEtoCUB_IR1R_Attachment A for an updated Table 25 that includes actual distribution investments for 2024 and updated forecasts for 2025, 2026, 2027, and 2028. The dollar values are provided on an incurred basis and do not include overhead. The 2025, 2026, 2027 and 2028 forecasts are for projects identified as of April 2025.

DSP with Updated 2024-2028 (Incurred)

	2024 Actuals	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
T&D	**$ 366,378,173**	**$ 452,147,565**	**$ 470,901,782**	**$ 341,223,160**	**$ 325,358,216**
Compliance	$ 143,379,544	$ 186,042,917	$ 165,426,720	$ 109,139,183	$ 127,755,817
Customer/Partner	$ 170,747,325	$ 141,886,280	$ 113,599,103	$ 101,685,904	$ 115,944,270
Capacity	$ 29,501,080	$ 87,783,589	$ 114,785,226	$ 77,817,133	$ 36,746,392
Reliability	$ 20,284,179	$ 35,331,548	$ 76,090,733	$ 51,580,940	$ 43,711,737
Operations	$ 2,466,044	$ 1,103,232	$ 1,000,000	$ 1,000,000	$ 1,200,000

May 9, 2025

To: Bob Jenks
Oregon Citizens' Utility Board

From: Steven Corson
Regulatory Consultant, Regulatory Strategy and Policy

Portland General Electric Company

UM 2362
PGE's Response to CUB Information Request 002
Dated April 25, 2025

Request:

Table 25 of the DSP is labeled Summary of distribution investments (as of July 2024) and lists investment totals for 2024, 2025, 2026, 2027, and 2028.

a. Does this table represent projected distribution investments for the years 2024, 2025,2026, 2027 and 2028?
b. Does this table show actual investments from 2023?

Response:

a. Yes. Table 25 shows forecasted capital distribution costs for 2024, 2025, 2026, 2027 and 2028 which have been individually identified and forecasted for spend as of July 2024, as described in the paragraph below Table 25 in the DSP (page 125).
b. No. Table 25 does not show the year 2023.

May 9, 2025

To: Bob Jenks
Oregon Citizens' Utility Board

From: Steven Corson
Regulatory Consultant, Regulatory Strategy and Policy

Portland General Electric Company
UM 2362
PGE's Response to CUB Information Request 003
Dated April 25, 2025

Request:

Table 26 of the DSP is labeled Summary of grid modernization investments (as of July 2024) and lists investment totals for 2024, 2025, 2026,2027 and 2028.

a. Does this table represent projected investments for the years 2024, 2025, 2026, 2027, 2028?
b. Does this table show actual investments from 2023?
c. Are the numbers in Table 26, included in Table 25 (Is Grid Modernization a subset of Distribution Investments?)
d. If the Grid Modernization investments are not included in the distribution investments, please explain why?
e. Are there other distribution investments that are not included in the summary of Distribution Investments (Table 25)? Please list those investments and explain why they are not included in the summary of distribution investments?
f. Please point to a place in the Distribution System Plan where total forecasted distribution spending in 2024, 2025, 2026,2027 and 2028 is listed.

Response:

a. Yes, it does. Table 26 shows forecasted capital grid modernization costs for 2024, 2025, 2026, 2027 and 2028 as of July 2024.
b. No, Table 26 does not show the year 2023.
c. No, the numbers in Table 26 are not a subset of Table 25. They are separate.
d. Grid modernization investments are differentiated from more traditional distribution investments in order to ensure they are considered, evaluated and funded as a strategic priority and can effectively support customer-side or distributed resource investments (demand-side distribution), IT investments, and traditional distribution investments to meet evolving grid needs. Please see Chapter 4 of the 2024 DSP for a discussion of PGE's Grid Mod investments and strategy.[1]
e. Table 25 includes all distribution investments made by PGE except those related to Grid Modernization, which is reflected in Table 26.

[1] PGE 2024 DSP, Chapter 4, beginning page 48, https://edocs.puc.state.or.us/efdocs/HAA/haa333816025.pdf

f. Table 25 shows the total forecasted distribution spending in 2024, 2025, 2026, 2027 and 2028. The costs provided are on an incurred basis and do not include overheads or AFUDC.

May 9, 2025

To: Bob Jenks
Oregon Citizens' Utility Board

From: Steven Corson
Regulatory Consultant, Regulatory Strategy and Policy

Portland General Electric Company
UM 2362
PGE's Response to CUB Information Request 004
Dated April 25, 2025

Request:

On July 26, 2024, PGE made a presentation for investors (https://investors.portlandgeneral.com/static-files/4d92db93-648c-4390-b7de-91a61dc9f963). That presentation forecast 2024 capital investments for distribution as $645 million.

a. Please explain the $200 million difference between what is presented in the DSP and what is presented to investors.
b. $645 is more than 42% higher than $453 (the sum of the 2024 investments in Table 24 and Table 25). Please list all distribution project investments that cost more than $1 million that are included in the July Investor Presentation but are not included in table 25 or table 26.
c. Please list the total amount of all distribution project investments that cost less than $1 million that are included in the July Investor Presentation but are not included in Table 25 and Table 26 and provide a narrative that explains what those projects are intended to do.
d. If the DSP reflected 2023 actuals, please provide an update for actual 2023 and 2024 Distribution investment.
e. If the DSP reflected 2023 actuals under the column labeled 2024, please explain why PGE used 2023 actuals in the DSP and used the 2024 forecast with investors.

Response:

a. There are two main reasons driving the differences between Tables 25 and 26 with the investor slide.

   First, the dollar values in Table 25 and 26 are shown in incurred dollars and the investor slide shows dollars as incurred plus overhead. The actual 2024 labor loadings/overheads applied to projects shown in Table 25 and 26 were approximately $170 million.

   The second reason, making up the remainder of the difference, is due to different methodologies for categorizing capital expenditures and the use of different groupings of spend. The investor presentation capital expenditures table reflects the total board-approved capital expenditure authority for 2024, as of July 2024, with the total on-going

capital expenditures roughly allocated to three major categories of spend (generation, transmission and distribution and "general business and technology"). The investor relations slide is a "top-down" view of capital expenditures. Table 25 and 26 reflect specific identified projects as of July 2024, which is a subset of the expected total capital expenditures for the year.

b. As explained in part a, the investor presentation capital expenditure slide is based on total approved capital expenditures for the year allocated to major categories of spend. There is not project-specific data mapped to the investor categories to identify specific projects.
c. The projects included in tables 25 and 26 are included in multiple categories within the investor slides, not only Distribution. The amounts in the investor slides include labor loadings and allocated costs.
d. The DSP (Table 25 and 26) does not reflect 2023 actuals.
e. The DSP (Table 25 and 26) does not reflect 2023 actuals. The column labeled 2024 on the DSP is a forecast for the year 2024 at the time.

May 9, 2025

To: Bob Jenks
Oregon Citizens' Utility Board

From: Steven Corson
Regulatory Consultant, Regulatory Strategy and Policy

Portland General Electric Company
UM 2362
PGE's Response to CUB Information Request 005
Dated April 25, 2025

Request:

PGE put together a slide presentation titled, 2024 Distribution Planning Discussion, Citizen Utility Board Presentation, 03/04/2025; Follow up conversation 03/28/25. This presentation concerns a discrepancy between 2023 actual spending and the 2024 investor presentations. PGE seems to be suggesting that CUB's concern about the difference between PGE's DSP and its Investor Presentation is caused by confusion about the vintage (investment year) and loaders.

a. To the degree that 2023 actuals are part of the confusion, please explain how 2023 actuals are reflected in Tables 25 and 26.
b. The difference between the 2024 investments from Tables 25 and 26, labeled as of July 2024, and the investor presentation from July 2024 is greater than 42%. Please list all elements of loaders and explain how they can represent a 42% increase in the projected cost of a distribution investment.
c. For each element of loaders above, please state whether that element is financed by debt and/or equity.

Response:

a. 2023 is not shown in Table 25 or 26. Each table shows forecasts starting in 2024 through 2028 only.
b. Please see response to CUB IR 04 part a. and b. The reason for the differences is due to dollars being shown as incurred vs. fully loaded and due to the methodology for allocating the capital amounts to categories and the grouping differences.
c. All operations and capital expenditures are financed by debt and equity. There is no separate designation or assignment of financing for loadings.

May 9, 2025

To: Bob Jenks
Oregon Citizens' Utility Board

From: Steven Corson
Regulatory Consultant, Regulatory Strategy and Policy

Portland General Electric Company
UM 2362
PGE's Response to CUB Information Request 006
Dated April 25, 2025

Request:

When PGE presents forecasts as part of its Investor Presentations of capital investment in Generation, Distribution, Transmission, BESS and General, Technology, Strategic; do these forecasts all include loaders?

Response:

Forecasts shared in PGE's investor presentations include overhead – labor loadings and allocations.

May 9, 2025

To: Bob Jenks
Oregon Citizens' Utility Board

From: Steven Corson
Regulatory Consultant, Regulatory Strategy and Policy

Portland General Electric Company
UM 2362
PGE's Response to CUB Information Request 007
Dated April 25, 2025

Request:

Regarding PGE's Presentation titled, 2024 Distribution Planning Discussion, Citizen Utility Board Presentation, 03/04/2025; Follow up conversation 03/28/25.

a. Page 8 has a "top down" forecast of 2023 distribution spending including loaders of $600 million. Page 9 has a "bottom up" forecast of 2023 distribution spending including loaders of $757 million. Please list all projects that cost more than $1 million that are included in the bottom up forecast but not the top down.
b. CUB's understanding is that the Board of Directors' approved budget is generally aligned, or will be adjusted to be aligned with the Investor Presentations. Did the Board of Directors approve a budget that included $757 million in distribution investment including loaders in 2023? If so, when was this budget approved?

Response:

a. In general, the $600M shown as T&D category on the Investor Presentation is a subset of the Bottom Up forecast shown on Page 9. The Bottom Up forecast includes Grid Modernization and Battery projects such as Seaside and Constable. On the Investor Presentation slides, Grid Modernization is part of the 'General, Technology and Strategic' category and the Seaside and Constable projects are shown as separate categories. The $757M is part of the overall $1.475B investment in 2023 on the Investor slides.
b. The Board approved the 2023 budget in October of 2022. Per response above, the $757M is part of the overall $1.475B approved budget.

May 9, 2025

To: Bob Jenks
Oregon Citizens' Utility Board

From: Steven Corson
Regulatory Consultant, Regulatory Strategy and Policy

Portland General Electric Company
UM 2362
PGE's Response to OPUC Information Request 008
Dated April 25, 2025

Request:

For each year, from 2018 through 2024, please provide:

a. The total capital investment for the distribution system for that year, both with and without loaders.
b. The amount that was included in the BoD budget for distribution spending at the beginning of that year.
c. The amount that was included in the BoD budget for distribution spending at the end of that year.

Response:

a. See UM 2362_NONC_PGEtoCUB_IR8R_Attachment A for the responsive information.
b. See UM 2362_NONC_PGEtoCUB_IR8R_Attachment B for the responsive information.
c. See UM 2362_NONC_PGEtoCUB_IR8R_Attachment B for the responsive information.

Distribution total investment without Loadings and Overheads

	Year							
	2018	2019	2020	2021	2022	2023	2024	Grand Total
Sum of amount	$228,383,097	$243,143,410	$245,311,612	$259,386,012	$300,452,600	$459,689,453	$467,049,139	$2,203,415,322

Distribution total investment with Loadings and Overheads

	Year							
	2018	2019	2020	2021	2022	2023	2024	Grand Total
Sum of amount	$341,971,412	$370,602,574	$354,529,754	$377,514,632	$432,978,748	$585,630,438	$626,022,493	$3,089,250,052

Distribution Spend - BOD BUDGET (Fully Loaded)

	year							
	2018	2019	2020	2021	2022	2023	2024	Grand Total
Sum of Calculated Total	$331,824,504	$309,000,711	$418,202,358	$347,957,376	$401,864,740	$433,798,574	$649,337,151	$2,891,985,414

Distribution Spend - ACTUALS (Fully Loaded)

	Year							
	2018	2019	2020	2021	2022	2023	2024	Grand Total
Sum of amount	$327,571,085	$357,987,859	$356,086,574	$377,554,082	$432,525,276	$585,468,284	$597,093,196	$3,034,286,356

May 9, 2025

To: Bob Jenks
Oregon Citizens' Utility Board

From: Steven Corson
Regulatory Consultant, Regulatory Strategy and Policy

Portland General Electric Company
UM 2362
PGE's Response to OPUC Information Request 009
Dated April 25, 2025

Request:

What is the minimum sized conductor that PGE installs in its distribution system (not including the service drop to an individual house)?

Response:

The minimum conductor size PGE installs on its distribution system (not including the service drop to an individual house) is #2 ACSR (aluminum conductor steel reinforced).

May 9, 2025

To: Bob Jenks
Oregon Citizens' Utility Board

From: Steven Corson
Regulatory Consultant, Regulatory Strategy and Policy

Portland General Electric Company
UM 2362
PGE's Response to CUB Information Request 010
Dated April 25, 2025

Request:

Has this minimum size conductor in question 9 changed in the last 10 years? If so, please explain the reason for the change?

Response:

No. The minimum conductor size described in response to IR 009 has not changed in the last 10 years.

May 9, 2025

To: Bob Jenks
Oregon Citizens' Utility Board

From: Steven Corson
Regulatory Consultant, Regulatory Strategy and Policy

Portland General Electric Company
UM 2362
PGE's Response to CUB Information Request 011
Dated April 25, 2025

Request:

What is the minimum sized transformer that PGE installs in its distribution system?

Response:

The minimum transformer size PGE installs on its distribution system is rated for 25 kVA (kilovolt-ampere).

May 9, 2025

To: Bob Jenks
Oregon Citizens' Utility Board

From: Steven Corson
Regulatory Consultant, Regulatory Strategy and Policy

Portland General Electric Company
UM 2362
PGE's Response to CUB Information Request 012
Dated April 25, 2025

Request:

Has this minimum size transformer changed in the last 10 years? If so, please explain the reason for the change?

Response:

PGE interprets "this minimum size transformer" to reference the minimum size that PGE installs in its distribution system referenced in CUB Information Request 11. With this understanding, PGE provides the following response.

Yes, this minimum size transformer has changed in the last 10 years. Within the last 10 years, PGE has ceased installation of transformers on its distribution system rated for 5 kVA, 10 kVA, and 15 kVA, making 25 kVA the minimum sized transformer installed on the system. This change was made because the growing capacity needs of customers has made the smaller sized transformer impractical.

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Alternative ratemaking in the US: A prerequisite for grid modernization or an unwarranted shift of risk to customers?

A B S T R A C T

With increasing frequency, investor-owned electric utilities are requesting preferred cost recovery for "grid modernization" in multiple forms, from multi-year rate plans to riders. Utilities' claims that massive grid investment is necessary, and that exceptional investment requires exceptional cost recovery, are typically accepted by policymakers with little challenge. It is difficult for policymakers to resist the siren call of grid modernization's perceived outcomes, from improved reliability and resilience to reduced risks to safety and new customer technology adoption (electric vehicles, distributed energy resources, and more). This paper provides a contrarian viewpoint that is virtually absent as policymakers consider alternative ratemaking practices. It introduces the possibility that excess grid investment in the name of modernization is not only possible, and economically harmful, but has already occurred, encouraged by alternative ratemaking. It provides examples of common grid modernization expenditures the authors have identified as cost-ineffective in the course of their work. It also describes traditional grid planning practices with proven ability to address changing requirements over time, calling into question the need for exceptional grid modernization investment plans. Most important, the paper explains the moral hazard inherent in alternative ratemaking, and the fundamental shift in ratemaking risks and responsibilities from utilities to customers that results. The perspectives this paper presents are critical for policymakers to understand before adopting, extending, or expanding alternative ratemaking practices in their respective jurisdictions.

1. Introduction

It's hard to argue against having a "modern" grid. Legislators and regulators are agreeing with the hype and encouraging rate base growth. Multi-year rate plans (MYRP) are the latest alternative ratemaking trend.[4] Formerly restricted to California and Georgia, MYRP have expanded in recent years to New York, Maryland, Illinois, and Washington. "Modernization" riders have become increasingly popular too (Illinois, Indiana, Florida, Massachusetts, Minnesota, Missouri, Ohio, and several others). Policymakers hope these ratemaking alternatives will prompt utilities to make the massive grid investments perceived to be "required" for reliability, resilience, electric vehicles, distributed energy resources, or safety (wildfires).

Investor-owned utilities (IOUs) are only too happy to oblige, and need to grow rate bases to hit earnings targets promised to Wall Street. Investor presentations brim with claims of 7–8% compound annual rate base growth in coming years. Utility share prices and executive option payouts are climbing in anticipation of earnings growth. Yet utilities have been finding deregulation, integrated resource planning, and falling demand restrict the need for new generation. They are also discovering that long lead times make transmission a mid- to long-term growth prospect at best. For near-term earnings growth, distribution grids appear to have become the favorite destination of utility capital in recent years. A chorus of vested interests chime in, including utility suppliers and consultants; some environmental advocates; EV manufacturers; the ASCE and labor unions; and others who believe they will benefit from increasing grid investment.

But do customers and state economies benefit from alternative ratemaking and massive increases in grid investment? Is it possible that the benefits of exceptional grid investment have failed to compensate utility customers and society adequately for associated rate increases? Does the law of diminishing returns apply to grid investment? Are utilities proposing grid investments that are premature, or of the wrong type, or in the wrong places, or in the wrong capabilities? As experts to consumer, business, and environmental advocates on distribution business planning, investment, operations, and performance, we see evidence of all of these, as indicated in Fig. 1. Despite a 35% increases in gross distribution plant per customer among U.S. IOUs since 2013, service interruption frequency has deteriorated 3%, and service interruption duration has deteriorated 12%.

While everyone wants the distribution grid to be more reliable, the law of diminishing returns indicates that it is indeed possible to spend more to improve reliability than the improvements are worth to customers and state economies. A fundamental principle in economics first identified in the 1700 s,[5] Oxford defines the law of diminishing returns as "a principle stating that profits or benefits gained from something will

[4] National Conference of State Legislatures at https://www.ncsl.org/research/energy/modernizing-the-electric-grid-state-role-and-policy-options.aspx.

[5] Turgot. *Observations on a Paper by Saint-Peravy*. "Even if applied to the same [agricultural] field, it [the product] is not proportional [to advances to the factors], and it can never be assumed that double the advances will yield double the product." 1767.

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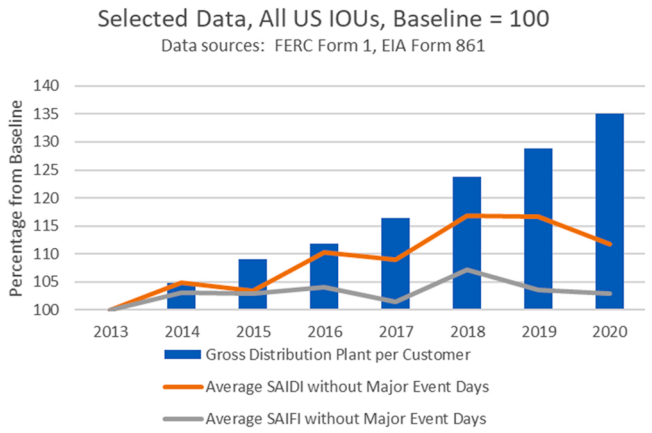

Fig. 1. Reliability Performance Relative to Distribution Plant per Customer, U. S. Investor-Owned Utilities, 2013–2020. (Higher system average interruption duration and frequency indices, SAIDI and SAIFI, indicate deteriorating reliability.).

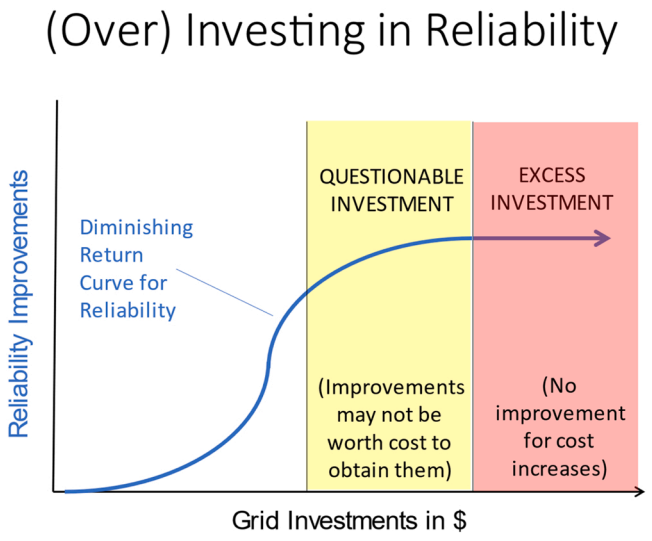

Fig. 2. The Law of Diminishing Returns Applied to Distribution Grid Reliability and Investment.

represent a proportionally smaller gain as more money or energy is invested in it." Fig. 2 applies the principle to reliability and grid investment. As discussed later in this paper, a utility under alternative ratemaking may have an incentive to over invest. One reason is moral hazard: a utility faces a return-risk calculus that is suboptimal, at least from the perspective of customers and state economies. Using grid modernization as a justification, a utility can significantly expand its rate base to increase its profits while passing through most if not all of the risks to customers.

Policymakers have generally bought utilities' pitch that as the generation, transmission, and distribution of electric energy changes, utility regulation must change with it. While this may or may not be true, controls against over-investment will continue to be a major responsibility of good regulation. While alternative ratemaking such as MYRP and riders may have some attractive qualities, moderating rate base growth is not one of them. Further, while DER and electric vehicle accommodation are important goals, reducing capital spending controls is not necessarily the best way to pursue them.

This paper argues that alternative ratemaking methods – the capital cost recovery of MYRP and modernization riders specifically– emasculate the existing controls by shifting risks and responsibilities from utilities to customers. It argues that cost disallowance risk essentially falls to zero under MYRP and "rider" ratemaking; that these constructs create a moral hazard; and that excess investment becomes inevitable. Our paper begins with examples of misplaced grid investments and planning processes that have resulted from alternative ratemaking to date.

2. The grid is not short of investment; it suffers from cost-ineffective investment

The American Society of Civil Engineers implies the U.S. energy grid has been neglected, giving it a "C-" rating in its most recent infrastructure report card.[6] Fig. 1 indicates that the U.S. electric distribution grid has seen massive investments in recent years, and that a lack of grid performance, not a lack of grid investment, is the issue. Most laypersons have trouble believing that increased grid investment fails to deliver improved grid performance, though independent research confirm this.[7] Based on the investments that typically pass for "modernization", the authors can explain the difference between the hype and the reality. Examples include smart meters, prospective equipment replacement, undergrounding of overhead lines, and advanced distribution management systems, to name just a few.

2.1. Smart meters

Exhibit number one in sub-optimized distribution investment is smart meters. Though some utility customers benefitted through reductions in manual meter reading costs, most utilities had already automated meter reading. This left just energy efficiency and demand response as the greatest potential benefits from smart meters at most utilities.[8]

Yet the throughput incentive (i.e., higher sales, higher short-term profits) makes the use of smart meters for energy efficiency, from conservation voltage reduction to improved consumer energy management tools, anathema to utilities. Demand response is antithetical to the capital bias that exists for investor-owned utilities. Why then should we be surprised that utilities are doing little to ensure the delivery of these potential benefits, as a well-known ACEEE report identifies?[9] Further, the authors observe utility claims that smart meters can markedly improve reliability are declining, as indicated by smart meter deployment proposals we have examined in the course of our work.

2.2. Prospective equipment replacement

Prospective equipment replacement is another investment that fails to deliver benefits in excess of costs, as some of the co-authors have already reported.[10] By some accounts, prospective equipment does not even constitute "modernization": it consists of replacing equipment of no or low book value (thus earning no or low profits for utilities) with new equipment of the same type. Most experts define grid 'modernization' to be the digitization of the grid through increased abilities to

[6] *America's Infrastructure Report Card (Energy)*. American Society of Civil Engineers. 2021.

[7] Larsen P, LaCommare K, Eto J, and Sweeney J. *Assessing Changes in the Reliability of the U.S. Electric Power System.* Lawrence Berkeley National Laboratory report 188741 prepared for the Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy. Pages 37–38. August, 2015.

[8] Alvarez, P. *Smart Grid Hype and Reality: A Systems Approach to Maximizing Customer Return on Utility Investment*. Second Edition. Table 18, page 159.

[9] Gold R, Waters C, and York, D. *Leveraging Advanced Metering Infrastructure To Save Energy*. American Council on an Energy Efficient Economy report U2001. January, 2020.

[10] Alvarez P, Ericson S, and Stephens D. *Asset Replacement Based on Risk Modeling: Emerging Best Practice?* Public Utilities Fortnightly. Part 1, August 2020 p.58; Part 2, September 2020, p. 72.

monitor grid conditions, analyze those conditions with software, and take appropriate action in near real-time. However some states have included prospective equipment replacement in the definition of "modernization", resulting in cost-ineffective investment.

Further, all utilities already employ objective procedures to identify assets in need of replacement before they fail in service, from substation equipment chemical and functional testing programs, to pole inspection and testing programs, to worst-performing circuit programs. Yet, because of MYRP and 'modernization' riders, prospective equipment replacement based on projections of failure due to age and subjective assessments of condition is becoming regrettably commonplace.

Given the objective testing programs all utilities have successfully employed to identify equipment in need of replacement, equipment failure "prediction" is both insufficiently accurate and unnecessary, offering extremely small reliability improvements relative to the extremely high cost of prospective equipment replacement. No research indicates that prospective equipment replacement delivers benefits relative to costs greater than those available from the practices listed above, which utilities have historically employed to identify equipment in need of replacement.

An analogy employing light bulbs can help the reader understand the failure in logic of prospective equipment replacement. Assume that the average lifespan of an incandescent light bulb is 4 years. Would the reader replace every light bulb in his or her home as it reaches 4 years of age simply because the average life was reached? Probably not.

Granted, the consequences of a failure in service of a critical piece of substation equipment are much greater than that of a light bulb. But all utilities maintain periodic testing programs that offers accurate, objective indications of failure for critical substations assets like power transformers, switches, circuit breakers, and relays. Such testing allows utilities to identify substation equipment in need of replacement in advance of a failure, thereby avoiding service outages affecting large numbers of customers. Should a utility replace a fully depreciated piece of substation equipment after it passes such tests? Probably not. Yet this is precisely how many utilities are replacing substation equipment prospectively, with little or no reliability benefit to show for it.

2.3. Undergrounding overhead distribution lines

Undergrounding overhead distribution lines is yet another extremely costly way to deliver reliability improvements. Though intuitively and aesthetically appealing, undergrounding's extreme cost – between $1 million (Florida) and $3 million (California) per mile – means it is simply not a cost-effective way to reduce reliability risk. Given that the average for-profit utility in the U.S. serves just 40 customers per distribution line mile, the reliability benefits simply cannot justify a cost of $25,000 to $75,000 per premise. Independent research confirms that even the most generous benefit definition, from a hurricane state (Texas), delivers just $0.30 in benefit for every $1 spent.[11]

Besides, undergrounding is no panacea. In the authors' experience, underground lines are more subject to outages from excavation and flooding than overhead lines. Faults in underground lines require additional time to locate and repair than faults in overhead lines. Finally, more aggressive tree-trimming and increases in right-of-way radii can deliver some of the same reliability benefits as undergrounding at a dramatically lower cost.

2.4. Advanced distribution management systems

An Advanced Distribution Management System (ADMS) is another typical component of grid modernization plans. However the authors note that it is the individual software components of ADMS, not an ADMS itself, that delivers benefits. Fault location, isolation and service restoration (FLISR); DER management systems (DERMS); grid power flow modeling; outage management systems (OMS); integrated volt-VAR control (IVVC, used to implement conservation voltage reduction); demand response management systems (DRMS); and other components are the sources of value. These are available for deployment individually; in the authors' experience, ADMS simply combines these together into a single platform. Given that needs vary greatly by utility and over time, ADMS can represent a financial boondoggle relative to the deployment of individual capabilities on an as needed basis.

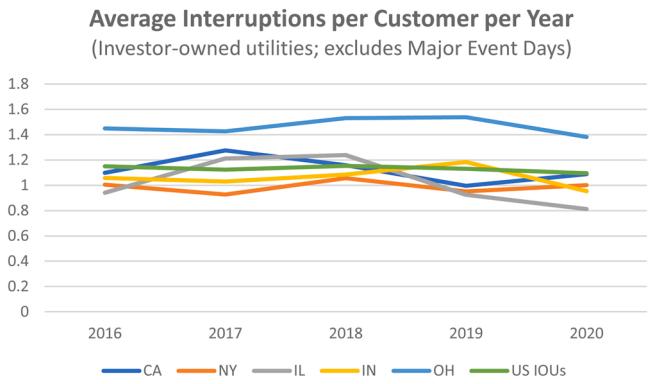

Fig. 3. Average Interruptions per Customer per Year without Major Event Days, 2016–2020, Customer of Investor-Owned Utilities in CA, NY, IL, IN, and OH compared to the average for U.S. investor-owned utilities.

Further, utilities' stated expectations that ADMS will usher in a wave of operations automation and grid optimization are unrealistic and potentially infeasible. For ADMS to operate in this manner assumes a degree of accuracy between the physical world (equipment types, locations, phases, settings, capabilities, capacities, etc.) and the virtual world (data in utilities' geographic information systems, or "GIS") that simply does not exist at any utility. In the authors' experience, herculean field organization efforts are required not just to secure such accuracy, but also to maintain it over time. As a result, "advanced" ADMS capabilities simply will not work as advertised,[12] and thus will be ignored by grid operators. ADMS investments driven by a desire to grow rate base, rather than as solutions to needs identified by grid operators and traditional grid planning practices, will be premature.

These are just a few examples. Certainly, grid planning practices can and should prepare the grid for the future, as the next section of this paper will discuss. But the track record of alternative ratemaking, and the associated increases in grid investment it encourages, is not good. Fig. 3, which shows a performance review from a few states that have had MYRP and grid modernization riders in place for several years, attests to this.[13] The states with the longest-running MYRP ratemaking, California and New York, have seen no reduction in service interruptions in recent years despite massive grid investments. The states with the longest-running grid modernization riders, including Illinois, Indiana, and Ohio, have seen marginal if any reduction in service interruptions, despite billions in grid modernization investments per state.

[11] Larsen P. *A Method to Estimate the Costs and Benefits of Undergrounding Electricity Transmission and Distribution Lines*. Lawrence Berkeley National Laboratory report 1006394. Section 4.3, page 35. October, 2016.

[12] *Voices of Experience: Insights into Advanced Distribution Management Systems*. Office of Electric Delivering and Energy Reliability, U.S. Department of Energy. February, 2015.

[13] U.S. Energy Information Administration. System Average Interruption Frequency Index by State without Major Event Days as reported by U.S. Investor-Owned Utilities, including such utilities serving customers in CA, NY, IL, IN, and OH on Form 861, 2016–2020.

3. Traditional grid planning, indistinct from modernization plans, will deliver the grid we will need

To guard against cost-ineffective grid modernization spending, most alternative ratemaking designs require advance spending plans from utilities. This has typically involved distinct plans and planning processes dedicated to "modernization" investments. But the authors caution that a separate modernization planning process abandons the traditional grid planning practices utilities have employed successfully in the past. These traditional grid practices have historically accommodated both new customer technologies and new utility technologies as they have become available over time. Yet in recent years such practices have been typically criticized as inadequate by both utilities and some stakeholders, including environmental stakeholders concerned that the grid will not be ready for electrification or DER.

3.1. Capital bias as a serious concern

In examining the utility position, we know that capital bias drives an interest in accelerating rate base growth. A distinct grid modernization planning process both 1) satisfies regulators' advance planning requirements; and 2) is likely to justify (accurately or not) greater investment than traditional grid planning practices would. Utilities thus have shown little interest in describing how traditional planning practices would ensure grid "readiness", and readily agree to a separate planning process for modernization. Regarding environmental advocates with grid readiness and planning concerns, the authors know of no such advocates with direct experience creating grid investment plans using traditional planning practices.

The authors, with extensive grid planning, investment, operations, and performance experience, including experience in geographies with relatively high customer adoption of electric vehicles and DER, present a different perspective. While some modern grid management software does make sense to deploy in advance, the traditional approach to grid planning has evolved to accomplish exactly the same goals as "modernization". That is, that the right capabilities (none extraneous) are in the right places (to no greater extent than necessary) at the right times (in advance, but no earlier than necessary). No separate planning process for modernization is needed or advisable.

3.2. No need to replace traditional planning

Traditional grid planning consists of a periodic, methodical approach to identifying and satisfying grid needs in advance through a circuit-by-circuit, substation-by-substation review. The review compares load and DER forecasts to existing capacities and capabilities, and also considers grid performance goals. This traditional grid planning process was recently documented by a joint NARUC-NASEO task force on comprehensive electricity planning in its "Jade Cohort Roadmap".[14] (The Roadmap recognized that a distinct planning process for "modernization" is an option, but does not offer an opinion on this, and the authors were not consulted.).

In the authors' experience, there is no requirement or advantage in separate planning for grid modernization. Indeed, a separate grid modernization planning process can be associated with disadvantages, such as premature or unnecessary investment. To summarize, separate grid modernization planning is an artifact of grid modernization riders, not a benefit of such riders. There is nothing unique about modern customer or utility technologies that traditional grid planning practices cannot manage in the absence of a separate grid modernization planning process.

Let's consider a few examples, starting with transportation electrification. Whether personal, or fleet, or public, electric vehicle charging overwhelmingly takes place at night, when both transportation needs and grid loads are the lowest. Time-of-use rates enabled by smart meters further encourage this beneficial charging behavior.[15] This means that capacity increases required to accommodate transportation electrification are still pretty far off. In 2021, over 96% of passenger cars sold in the U.S. were still powered solely by internal combustion engines.[16] Those vehicles are going to remain in service for the next 20–25 years; no overnight transformation is imminent.

Many observers also tout electrification of the built environment as a need for grid modernization. The authors note that billions of dollars of unpaid natural gas distribution investment exists in almost every state. In many states, this number grows by the day as safety programs dictate pipeline replacements. We note that these investments are matched by untold billions in related customer investments (natural gas furnaces, water heaters, stoves, etc.). It will take decades and decades to wean the public off this grid, even if a concerted, neighborhood-by-neighborhood planning effort were to begin in every state tomorrow. There is plenty of time for the grid to evolve to meet electrification needs.

Regarding distributed energy resource (DER) accommodation, we find policymaker and environmentalist fears that the grid will not be ready to be similarly exaggerated. The most common form of DER, photovoltaic (PV) solar panels mounted on residential and commercial building rooftops, are not a threat to grid reliability. DER located near customer loads, and in particular inverter-connected loads like PV Solar and batteries, are unlikely to cause grid issues until very high adoption levels are reached. Hawaii's experience and independent research confirms this.[17]

A circuit-by-circuit review of DER growth forecasts, incorporated into traditional grid planning practices, will be sufficient to identify and construct any associated grid accommodations that may be required in advance of need. In the authors' experience, large utility-scale DER is the type most likely to require large grid investments to accommodate; but predicting locations for such installations in advance is difficult, and preparing an entire grid for all such possible locations in advance is cost-prohibitive.

To summarize, rate base growth and resulting rate increases are being incurred for no documented benefits to date – a situation that is no doubt detrimental to both utility customers and state economies. While utilities tout the jobs created by their investments, empirical evidence shows that higher utility rates reduce overall employment.[18] But near-term economic risks from excess grid investment are not the only ones suffered by customers and state economies.

Grid investment too far in advance can be placed in the wrong locations, and are at risk for technological obsolescence. In some cases, the authors expect grid investments to become obsolete, or to be fully depreciated, before the need to employ associated capabilities actually arises. In the past, cost disallowance risk discouraged for-profit utilities

[14] NARUC-NASEO Comprehensive Electricity Planning Task Force. Blueprint for State Action, Jade Cohort Roadmap. Page 5, Jade Cohort (distribution grid) Flowchart of Idealized Comprehensive Electricity Planning Process. February, 2021.

[15] Smart J and Salisbury S. *Plugged In: How Americans Charge Their Vehicles*. Idaho National Laboratory. July 1, 2015, Figure 10, page 17. (In San Diego, where electric rates are lowest from midnight to 5 am, EV charging during this time exceeded charging relative to other times of day at an approximate ratio of 6:1.)

[16] Clifford, C. *"Electric vehicles dominated Super Bowl ads, but are still only 9% of (global) passenger car sales."* CNBC Blog Post February 14, 2022. Available via internet at https://www.cnbc.com/2022/02/14/evs-dominated-super-bowl-ads-but-only-9%-of-passenger-car-sales.html

[17] Hoke, A et al. *Maximum Photovoltaic Penetration Levels on Typical Distribution Feeders*. National Renewable Energy Laboratory preprint JA-5500–55094. July, 2012.

[18] Garen J, Jepsen C, and Saunoris J. *The Relationship between Electricity Prices and Electricity Demand, Economic Growth, and Employment.* University of Kentucky Center for Business and Economic Research Report. October 19, 2011.

from taking such risks. But with alternative ratemaking, cost disallowance essentially falls to zero, creating moral hazard, encouraging premature and unnecessary investment, and shifting investment risks and ratemaking responsibilities from utilities to customers. We now turn to a detailed explanation of why alternative ratemaking has effectuated these negative outcomes, doing harm to electricity customers and state economies in the process.

4. Alternative ratemaking creates moral hazard, shifting risks and responsibilities from utilities to customers

If alternative ratemaking such as MYRP and riders have led to misplaced grid investment and planning practices, the reader may ask why alternative ratemaking is so popular among legislators, regulators and utilities. The reader may also ask if such popularity comes at a cost to customers and state economies. The answer can be found by examining two cost controls that are the foundation of the balance of power between customers and shareholders: regulatory lag and cost disallowance risk.

4.1. Regulatory lag as a benefit

Alternative ratemaking proponents generally tout the reduction or elimination of regulatory lag on capital as a benefit of MYRPs and riders. Regulatory lag – or the timing difference between a utility's cost increases and associated rate increases – is perceived by many as discouraging utility investment at a time when grid investment needs are perceived as high. No regulator wants to author orders which could be perceived as anti-investment, anti-reliability, anti-environment, or anti-safety.

But while regulators are routinely reminded by utilities that regulatory lag discourages investment, and is therefore a bad thing, regulators must also consider the benefit of regulatory lag: that it acts as a control against premature or unnecessary investment, thereby helping to balance shareholder and customer interests. The notion that regulatory lag can be a good thing merits additional discussion.

Historically, regulators have favored, not discouraged, regulatory lag specifically because it acts as a built-in cost control. Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs.[19] The reason is that when a utility experiences higher costs, the longer it has to wait to recover those costs, thus lowering its earnings. Consequently, the utility would have an incentive to minimize its costs.

Regulators have thus historically relied on regulatory lag as a critical element in motivating utilities to act efficiently. One reason for this is that regulators recognize the difficulty of determining the prudence of investments, which requires highly technical resources whose costs are beyond the reach of most regulators. Instead, regulators came to rely heavily on regulatory lag as a mechanism to control a utility's costs. Ironically, one can therefore oppose alternative ratemaking precisely because it reduces regulatory lag, when lately the major argument in favor of alternative ratemaking is reduced regulatory lag.

4.2. Importance of balancing interests

Regulators' foci appear to have shifted from the value of regulatory lag as a legitimate and effective cost control designed to balance customer interests against shareholder interests, to encouraging grid investment. The problem is that regulators' duties should lie with balancing interests rather than encouraging investments per se. The notion that grid investment should be ever-increasing rests on a series of unreliable assumptions, including 1) that if an increase in grid investment is good (unproven), then 2) ever-increasing grid investment must be better (contradicting the law of diminishing returns), and thus 3) regulatory lag is something to avoid (an errant conclusion).

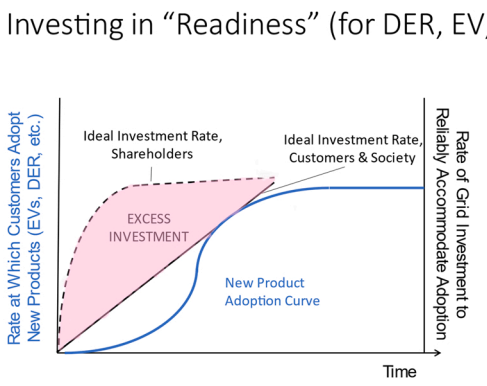

Fig. 4. Illustration of the difference between a grid investment level required to be "Ready" for customer technology adoption vs. the level of investment that for-profit utilities prefer as a regulated profit growth strategy.

Utilities are not the only parties in favor of alternative ratemaking and increasing investment. Ever-increasing grid investment is supported by an "Iron Triangle" – including not just for-profit utilities, but Wall Street and some "agenda" advocates[20] – with utility customers on the other side as skeptics. These vested interests are not concerned about the regulatory implications of alternative ratemaking (the shift in risk from shareholders to customers), nor do they have experience in grid planning or operations. Both claims these vested interests make – that massive grid investment is needed now for "readiness", and that alternative ratemaking is a prerequisite for such investment – must be rigorously challenged by regulators and legislators, who are advised to consider the motivations and qualifications of those making these claims.

The authors, who count several environmental advocates as clients, sympathize with those who want the grid to be "ready" for DER, or for electrification, and other priorities driven by climate change. The authors want the grid to be "ready" too. But we do not subscribe to the theory that controls on capital investment should be abandoned in pursuit of grid readiness. Consider Fig. 4. While acknowledging that advance investment is indeed required to prepare the grid for anticipated technology adoption, Fig. 4 also documents that for-profit utilities have an economic incentive to over-prepare. As discussed earlier, over-preparation carries the risks of premature investment and technological obsolescence – risks that are passed on to customers under alternative ratemaking practices in the form of unnecessary rate increases.

The adoption curve in Fig. 4 is a representation of a phenomenon observed for all new technologies across industries and products, from color televisions in the 1970's to mobile phones in the 1990's. Experience has shown that the diffusion of new technologies is a gradual process. The fraction of potential users that invests in a new technology typically follows an S-shaped path over time, rising only slowly at first, then experiencing rapid growth, followed by a slowdown in growth as the technology reaches maturity and most potential adopters have switched.[21]

[19] Kahn, A. *Economics of Regulation*, Vol. 2 (New York: John Wiley & Sons, 1971).

[20] For example, RMI (formerly the Rocky Mountain Institute), a prominent clean-energy advocate, has remarked that: "To support a clean yet reliable, flexible, and safe power system, utilities need to invest in new resources and technologies. PBR mechanisms, such as multi-year rate plans or other regulatory tools like cost trackers, can provide utilities with longer-term revenue certainty and more immediate cost recovery to support these more nontraditional investments." [https://rmi.org/five-lessons-from-hawaiis-ground-breaking-pbr-framework/].

[21] Jaffe A. et al., Technological Change and the Environment, RPP-2001–13 (Cambridge, MA: John F. Kennedy School of Government, October 2001), 41.

Fig. 4 also indicates that some amount of advance investment in the grid is advisable, as it may not be possible to ramp up grid investment as rapidly as required at some points of the adoption curve. The appropriate amount of advance investment is an open question, but could be guided by the concept of *real options*. Real options theory says that when the future is uncertain, it pays to have a broad range of options available, and to maintain the flexibility to exercise those options.[22] To those who claim massive investment is required now, investment at the level suggested by real options theory may represent a reasonable, and more cost-effective, alternative to massive investment as encouraged by alternative ratemaking.

Finally, Fig. 4 documents the results of utility capital bias combined with a relaxation of capital cost controls. For-profit utility investment levels result from a risk vs. reward calculus. Utility managers weigh the rewards of capital investment (earnings growth) against its risks (cost disallowances by regulators). The lower the cost disallowance risk, the lower the likelihood that a for-profit utility will incur a cost for premature, or unnecessary, or incorrect investment decisions. For-profit utilities protected from such consequences are more likely to invest prematurely, or unnecessarily, or incorrectly when the consequences of such decisions are shifted to consumers (see next).

4.3. Cost disallowance risk as a control on capital investment

Finally, while utilities obviously want to reduce or eliminate regulatory lag, another big payoff is in reducing, if not effectively eliminating, cost recovery risk. For both MYRP and modernization riders, utilities are required to present investment plans in advance. A few states, including Massachusetts and Minnesota, go so far as to "pre-authorize" or "pre-certify" grid modernization investments presented and reviewed in advance.[23] In instances when utilities present grid investment plans in advance (MYRPs and modernization riders), cost disallowance is practically impossible, for two reasons. These reasons persist despite specific legislation or regulation which preserves regulators' right to disallow costs for recovery from customers.

First, any stakeholder electing to challenge an investment after a utility has spent capital is likely to face a credible and logical utility argument. That argument is, "Ms. Stakeholder, if you had a problem with our grid investment plan, why didn't you challenge it when we provided our plan for review, before we spent capital?" Regulators will have difficulty dismissing such arguments. Second, utility grid investment plans, including modernization plans, are typically denominated in hundreds of millions if not billions of dollars. Disallowances of even small proportions of such massive investments have big impacts on utility cost of capital, and thus customer rates.

In a sense, MYRPs and riders put regulators in a Catch-22. At the end of an MYRP period, or in a rate case, utilities ask to add previously presented and reviewed investments to rate base. When presented with a grid investment that failed to deliver benefits in excess of costs, a regulator can 1) allow the investment into rate base, which harms consumers and state economies; or 2) disallow cost recovery on the investment, which increases a utility's cost of capital, thus harming consumers and state economies.

4.4. Shifting risk to customers upsets the balancing act

As a result, alternative ratemaking shifts risk to customers, jeopardizing both economic efficiency and "fairness." In their duties, regulators must acknowledge the interests of individual groups by avoiding actions that would have a devastating effect on any one group. Since regulators implicitly or explicitly assign objectives to ratemaking, logically they should evaluate mechanisms on how they advance certain objectives while not seriously impeding others that are integral to good ratemaking. For alternative ratemaking, this means that regulators should look at the incentive and equity implications as well as the financial effects on the utility.

There is also the important question of who can better absorb risk: the utility or its customers? Optimal risk sharing depends on: (1) who has control over risk? (2) who can better shoulder risk and is less risk averse? and (3) who can bear risk more cheaply? On the first point, utilities obviously have the ability to manage their costs. Utility investors would seem to be better able to shift their financial portfolio under adverse utility-financial conditions than for utility customers to switch providers when, say, utility rates rise unexpectedly high. This infers that more risk should fall on utility investors rather than utility customers.

A difficult but critical task for regulators is to translate stakeholders' interests into the public interest. This is an essential feature of the "balancing act" of regulation in which regulators try to avoid certain outcomes, notably excessive rates and suppression of utility investors.[24] Given the reductions in regulatory lag and cost disallowance risk, few people doubt that alternative ratemaking is beneficial to utilities and their investors. The tough question for regulators is how alternative ratemaking promotes the interest of utility customers. The answer is unclear.

The regulatory "balancing act" often uncovers the extreme positions of parties, whether they are utilities or intervenors. It requires regulators to tradeoff the various ratemaking objectives in deciding what best serves the public interest. For example, although alternative ratemaking tends to help the utility financially, it may expose customers to excessive risks and other costs (e.g., moral hazard) that make riders contrary to the public interest. It is somewhat puzzling then why regulators are so keen on a ratemaking mechanism that is so imbalanced in favor of utility shareholders at the expense of customers and state economies.

4.5. MYRPs and riders create moral hazard

In response to these concerns, utilities claim that regulators always maintain cost disallowance authority, and that stakeholders now have two opportunities to challenge utility investments. But do they? Stakeholders have never had access to the kinds of technical expertise required to challenge complex electrical engineering justifications for investments. Further, the limited discovery periods associated with MYRP, or rate cases, or grid modernization plan review, do not permit stakeholders to secure, let alone understand, the voluminous and complex technical information required to evaluate utility grid investment proposals. These obstacles, known commonly as information asymmetry, have always proved difficult to surmount. Instead, stakeholders have always counted on regulatory lag and cost disallowance risk to control utility capital spending. Under alternative ratemaking, these controls over utility investment are now effectively missing.

Prudence reviews try to dissuade a utility from poor decisions with the threat of financial harm to encourage more discipline in investment plan development and execution. Given asymmetric information, where a utility knows more about its operations than the regulator or stakeholders, some analysts characterize prudence reviews as a second-best mechanism to market-like incentives to reduce costs. Throughout the history of public utility regulation, regulatory lag and prudence reviews have been the most prominent instruments used by regulators to assure that rates are just and reasonable. If they go missing or are seriously weakened, as with alternative ratemaking, a course correction becomes necessary.

[22] Avinash D and Pindyck R. Investment Under Uncertainty (Princeton, NJ: Princeton University Press, 1994). Also Pindyck R, "Irreversible Investment, Capacity Choice, and the Value of the Firm," The American Economic Review, vol. 78 (December 1988): 969–985.

[23] Massachusetts "pre-authorization" described at https://www.mass.gov/info-details/grid-modernization; Minnesota "pre-certification" example available in PUC Docket No. E002/M-20–680, Order dated July 23, 2020.

[24] Costello K. "*Let's Not Forget Balancing Act of Regulation*." Public Utilities Fortnightly, October 2019: 46–9.

Others will argue "So, what has changed? Stakeholders have always had difficulty securing cost disallowances." What has changed is utilities' perception of cost-disallowance risk. While always considered by utilities as a low risk, cost disallowance risk is at its lowest point ever with MYRP and modernization riders, creating a moral-hazard situation. Moral hazard is a term economists use to describe a situation in which a market actor (in this instance a regulated utility) has no incentive to avoid risk (in this instance cost disallowance risk) because the actor is protected from its consequences (in this instance through preview of MYRP and modernization rider investment plans).

Moral hazard from MYRP and modernization riders is no different than that of the Great Recession of 2008, which was prompted in large part by mortgage makers who sold those mortgages to others, thus abdicating any accountability for making loans to people who were clearly not qualified to pay the loans back. Nor is the moral hazard created by MYRP and modernization riders any different from that created by government-paid flood insurance, which encourages people to rebuild homes destroyed by floods in flood plains. Protection from the consequences of a risk encourages greater risk taking, and utility investment is no different.

Historically, stakeholders could count on utility fear of cost disallowance risk (and to a lesser extent, regulatory lag) to help moderate utility investment levels. Utilities spent the capital required to distribute electricity safely and reliably, and bore the burden to prove prudence. Once grid investment plans are presented for review, given virtually zero cost disallowance risk, the burden shifts to stakeholders, who must identify questionable spending in advance. This would be fine if stakeholders had the information and expertise to recognize and challenge investments of questionable value or timing, from prospective equipment replacement to undergrounding, but they do not. There can be no denying that alternative ratemaking shifts risk from shareholders to customers, or that utilities are likely to take advantage of the moral hazard thus created.

4.6. Need for customer protections and performance monitoring

If the new approaches to ratemaking are to continue, regulators should require new provisions for customer protection. Ideas include (1) duration limits (for example, sunset provisions); (2) annual rate increase or investment caps; (3) deferrals/carrying charge limitations (for investments in excess of rate increase or investment caps); (4) O&M offsets or productivity offsets or specific cost savings associated with such capital spending, and any other charges in utility revenue requirements; (5) reduced rates of return (a result of lower utility financial risk); (6) excess earnings tests and customer sharing; (7) greater stakeholder participation in grid planning processes and development; (8) performance targets and benchmarks; and (9) penalties and incentives based on targets and benchmarks.

In advancing the public interest, regulation's central task is to induce high-quality performance from utilities. Achieving this requires regulators to measure a utility's performance along with reviewing utility decisions and other actions.[25] Since grid modernization programs are extremely expensive, regulators should demand that utilities demonstrate the benefits to customers from improved performance attributable to the capital expenditures recovered through alternative ratemaking.

5. Parting thoughts

We bring these perspectives to policymaker attention to encourage a re-evaluation of commonly-held beliefs that may be incorrect, including 1) massive grid investment is needed; 2) massive investment delivers reliability improvements and other benefits that justify the associated rate increases; and 3) without alternative ratemaking, utilities will not make grid investments at the required level. The reality is that no one is dictating what investments a utility should or should not make to provide safe and reliable service. Parties with vested interests are encouraging these beliefs, and policymakers are encouraged to consider them with a healthy dose of skepticism.

It is worthwhile to remember that for-profit enterprises operate as monopolies under state authority through a regulatory compact. Through the compact, legislators and regulators expect that such enterprises will make the investments required to deliver safe and reliable services, and they authorize rates of return on capital to compensate for investment risk. The prospects of load growth through electrification, or of self-service technologies such as PV solar, do not change the compact, nor this reasonable expectation. The regulatory compact has served our nation well in the past, through massive customer technology adoption (such as air-conditioning) and new utility technologies (from SCADA to solid-state circuit breakers). There is no reason to believe that it cannot continue to work well in the future.

Innovative technologies adopted by customers and utilities are not new. Indeed, it has been the status quo for the electric utility industry since the dawn of the 20th century. It is time to stop bribing distribution utilities for fulfilling basic expectations and accepting investment risks for which they are already well-compensated. Even in cases of legislated ratemaking reforms, interest in grid modernization does not relieve regulators of their responsibility to balance shareholder interests against customer interests.

It is time to question the appropriateness of increasing utility rewards, in the form of reduced regulatory lag, given increasing customer risk, in the form of reduced (if not eliminated) cost-disallowance likelihood. As in the past, regulators should expect that utilities will make the investments required to deliver safe and reliable service, in return for fair compensation opportunities through rates charged to customers. In this manner, the historical balance between shareholder interests and customer (and state) interests can be equitably maintained while the need for grid investment is appropriately pursued.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data Availability

Data will be made available on request.

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[25] Costello K. *"Performance Review of Utilities: Important but Proceed Cautiously."* Climate and Energy, April 2022: 13–8.

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