OLSON, BZDOK & HOWARD

June 14, 2023

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

Via E-Filing

RE: MPSC Case No. U-21297

Dear Ms. Felice:

The following is attached for paperless electronic filing:

Corrected Direct Testimony and Exhibits of Paul Alvarez on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (Exhibit MEC-17 through MEC-22); and

Proof of Service.

Please note that the only correction is the addition of page numbers to Mr. Alvarez's testimony.

Sincerely,

Digitally signed by Christopher M. Bzdok
DN: cn=Christopher M. Bzdok, o=Olson, Bzdok & Howard, PC, email=chris@envlaw.com, c=US
Date: 2023.06.14 12:13:16 -04'00'

Christopher M. Bzdok
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xc: Parties to Case No. U-21297

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE ELECTRIC COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	U-21297

CORRECTED

TESTIMONY OF PAUL J. ALVAREZ

ON BEHALF OF

ATTORNEY GENERAL DANA NESSEL

AND

MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL,
SIERRA CLUB, AND CITIZENS UTILITY BOARD OF MICHIGAN

June 13, 2023

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I. INTRODUCTION, QUALIFICATIONS, PREVIEW AND PERSPECTIVE

Q. Please state for the record your name, position, and business address.

A. My name is Paul J. Alvarez. I lead the Wired Group, a small consultancy dedicated to the needs of consumer, environmental, and business advocates in state utility regulatory proceedings. My business address is P.O. Box 620756, Littleton, CO 80162.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of a group of parties, including the Attorney General, Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), Sierra Club (SC), and Citizens Utility Board of Michigan (CUB), collectively referred to as "AG-MNSC".

Q. Please summarize your experience in the field of utility regulation.

A. I have been actively involved in the electric utility industry for almost 22 years. After a series of finance, marketing, and product management roles in large corporations operating in competitive markets, my utility industry experience began in 2001 as a product development manager with Xcel Energy. At Xcel Energy I oversaw the development of new demand-side management ("DSM") programs, and became familiar with the various types of cost-effectiveness tests that are applied to such programs as standard practice. In 2010 and 2011 I led teams that completed the first two independent evaluations of smart grid investment program benefits as the utility practice leader for a boutique sustainability consulting firm.[1] I started the Wired Group in 2012 to focus exclusively on distribution

[1] Colorado PUC 11A-100E. *Smart Grid City Demonstration Project Evaluation Summary*. Xcel Energy report filed as Exhibit MGL-1, Direct Testimony of Michael G. Lamb. December 14. 2011. Also Ohio

utility planning, investment, performance measurement, and regulation. I wrote "Smart Grid Hype and Reality: A Systems Approach to Maximizing Customer Return on Utility Investment" in 2014, and updated it with a 2nd edition in 2018. I occasionally teach a graduate course at the University of Colorado's Global Energy Management Program, and occasionally teach regulators and Staff at Michigan State University's Institute of Public Utilities. I also publish papers and present at conferences on distribution utility planning, investment, performance measurement, and regulation. Regarding education, I received an undergraduate degree in finance and marketing from Indiana University's Kelley School of Business in 1983, and a master's degree in management from the Kellogg School of Management at Northwestern University in 1991.

Q. Have you testified before this Commission or as an expert in any other proceeding?

A. While I have not previously submitted testimony, I am known to the Michigan Public Service Commission ("Commission") and Staff. Working with my Wired Group associate Dennis Stephens, we helped the Association of Businesses Advocating for Tariff Equity ("ABATE") develop several sets of Commentary ABATE filed in recent years. In U-20147, we helped ABATE develop Comments regarding (1) The development of five-year distribution plans in Michigan generally (September 11 and November 18, 2019); (2) Five-year distribution plans and storm performance (October 1, 2021); (3) Consumers Energy's Distribution Infrastructure Investment Plan (June 23, 2021); and (4) DTE Electric Company's Distribution Grid Plan (September 29, 2021). We also helped ABATE develop Comments in U-21122 (Summer 2021 reliability performance and distribution planning,

PUC 10-2326-GE-RDR. *Duke Energy Ohio Smart Grid Audit and Assessment*. Staff report filed June 30, 2011.

September 24, 2021). Mr. Stephens and I also gave a presentation on distribution planning and utility proposal cost-effectiveness testing, to include risk-informed benefit-cost analysis and risk-informed investment decision support, in a Staff-led workshop on distribution plan development held August 14, 2019.

In addition, I have testified on behalf of consumer, business, and environmental advocates in proceedings related to electric distribution utility planning, investment, performance, and regulation before 17 state utility regulators in the past 10 years, including California, Georgia, Illinois, Indiana, Kansas, Kentucky, Maryland, Massachusetts, New Hampshire, New Jersey, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Virginia, and Washington. A complete list of proceedings in which I've submitted testimony to state utility regulators, with proceeding numbers and dates, can be found in Exhibit MEC-17.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of AG-MNSC regarding the financial, policy, and regulatory issues presented by DTE Electric Company's ("DTE" or "Company") Distribution Grid Plan ("DGP" or "Plan"), the related strategic capital spending described in the present application, and the Company's proposal to recover related costs through a rider (the infrastructure recovery mechanism, or "IRM").

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit MEC-17: Curricula Vitae of Paul J. Alvarez

Exhibit MEC-18: MNSCDE-3.2a-b

Exhibit MEC-19: MNSCDE-3.30e

Exhibit MEC-20:	MNSCDE-3.30hi and -hii
Exhibit MEC-21:	MNSCDE-3.30b
Exhibit MEC-22:	Alvarez P, Costello K, Ericson S, and Stephens D, Alternative Ratemaking in the US: A Prerequisite for Grid Modernization or an Unwarranted Shift of Risk to Customers?, The Electricity Journal, Vol. 35: 107200 (2022)

Q. Please provide a preview of your testimony.

A. DTE supports its request for inclusion in rate base of the Strategic Capital Program expenditures presented in this case in part by reference to the DGP. In other words, the Company's case leans heavily on the claim that if a project is included in the DGP, then it is reasonable, prudent, and has the evidentiary support necessary to justify rate recovery. The Company similarly relies on the DGP to support its request for an Investment Recovery Mechanism (IRM) for distribution capital expenditures after the projected test year.

In fact, however, the inclusion of projects in the DGP is not particularly significant to a determination of reasonableness and prudence. That is because the Company's DGP was developed without an opportunity for stakeholders to critically examine the Company's DGP in a formal administrative proceeding with discovery and the other tools available in such a proceeding. While I will examine the Company's DGP as it relates to Strategic Capital Program expenditures and rider cost recovery request from financial, policy, and regulatory perspectives, my colleague Mr. Dennis Stephens, also testifying on behalf of the Attorney General and MNSC, will examine Strategic Capital Program spending from technical and timing perspectives. Our two testimonies are best considered together.

This testimony will begin with a review of the DGP, and associated spending described in the instant Application as Strategic Capital Program spending. I estimate that DTE's $3.75 billion DGP would result in a $544 million annual revenue requirement (rate) increase by 2027 – an amount equal to 25% of the Company's total revenue requirement in 2021.[2] DTE has already spent more than $1 billion[3] on Strategic Capital program in furtherance of its DGP that stakeholders did have not have d an opportunity to investigate . As affordable electricity is critical to Michigan's economic development, this section of testimony recommends that the Commission act promptly and decisively to fix distribution planning in Michigan, and to establish processes designed to identify the right balance between affordability and distribution grid development.

My testimony will then explain how distribution grid planning as currently practiced in Michigan fundamentally shifts the shareholder/customer balance of interests decidedly in shareholders' favor. For-profit monopoly regulation is specifically intended to maintain this balance, and without it, Michigan's economy will suffer from electric rates that are higher than necessary. Specifically, I will examine the unintended consequences that arise when utilities present distribution investment plans in advance. These include the loss of cost disallowance risk and the loss of information asymmetry mitigation, which in turn permits utilities to abandon capital spending governance. That is the case here with DTE's distribution plan and capital expenditures.

[2] $2.118 billion per DTE Exh. A-16, Schedule F2, p. 4.

[3] Company Exh. A-12 Schedule B5.4, p. 1. Strategic capital program spending, Actual 2021 and Projected 2022.

With an understanding of the unintended consequences of advance investment plan presentation established, my testimony will proceed to the options available to the Commission to address them. I will recommend that the Commission reject the Company's request to recover costs associated with the Strategic Capital Programs supported by the DGP through a rider. I will also recommend that capital spending governance be restored, and information asymmetry mitigated, through the implementation of a joint grid plan development process. In such a process utilities, Staff, and stakeholders can collectively identify the new capabilities and capacity additions appropriate to the right balance between affordability and other distribution grid goals, giving Michigan's economy the biggest possible bang for its buck as the state's grid transitions. Finally, I will introduce the concepts of risk-informed benefit-cost analysis and risk-informed decision support for Commission consideration. These tools are ideal for optimizing grid investment plans, and should be part of any future distribution grid investment plans developed in Michigan.

Q. Do you have any perspective to provide before proceeding?

A. Yes. Michigan's electric distribution grid is a critical state asset. The utilities may own the equipment, but the Commission must ensure that the asset is operated and developed in a way that benefits Michigan's economy. Further, customers pay for that asset, and as such, should have some say in how that asset is operated and developed.

There are some things all parties can agree on. We all want a reliable distribution grid, and we all want the grid to be "ready" for a future of electric vehicles and distributed energy resources. But beyond that lie dramatic differences. Utilities, beholden to shareholder interests, want to invest as much capital as possible as soon as possible. Customers want to keep the cost of electricity distribution service as low as possible for as long as possible. Somewhere between these two extremes is an optimum balance, but no one knows what the optimum balance is, what it looks like, or how to identify successful achievement. Worse, there are no processes in place to identify the optimum balance, to determine the best ways to secure the optimum balance; or to evaluate progress towards the optimum balance. As it stands now, stakeholders are completely and utterly reliant on the utilities' implicit claims that 1) 100% of the projects and programs proposed in multi-billion-dollar grid investment plans are required by the end of the five-year distribution investment plan span; and 2) that the projects and programs the Company has identified are the least costly way to meet the requirements. Such reliance is unacceptable.

In U-20147, the Commission required five-year distribution investment plans from the three largest investor-owned electric utilities.[4] What stakeholders have so far is just that: the *utilities*' plans for developing their grids, including how much to spend (a lot); when to spend it (sooner rather than later); and what to spend it on (hardware and software that can be capitalized). What stakeholders did not get was an opportunity to provide an informed counter to the utilities' capital-biased proposals. Stakeholders have had no procedural opportunity to investigate and challenge the utilities' distribution investment plans in a way that might enable an informed counterproposal. Given that tens of billions of dollars will be invested in Michigan's electric distribution grid in coming decades, and given utility capital bias/management's responsibility to advance shareholder interests, it is clearly unwise to leave all grid planning and related investment decisions up to the

[4] Case No. U-20147, Order dated August 20, 2020, p. 51.

utilities. I encourage the Commission to review this testimony with these perspectives in mind.

II. DTE'S DGP IS UNAFFORDABLE AND LARGELY UNJUSTIFIED

Q. Please preview this section of testimony.

A. In this section of testimony, I present a review of DTE's DGP and associated strategic capital spending as proposed in the instant Application, focusing on its size and impact on DTE customers and Michigan's economy. While my colleague Mr. Stephens provides multiple examples of unjustified spending in his testimony, this section of testimony will focus on the lack of affordability associated with the DGP and related strategic capital spending proposals. I will also present information on the effectiveness, or lack thereof, associated with recent increases in DTE capital spending. This section of testimony will also explain why a monopoly for-profit utility, absent capital spending governance, will invest capital to improve reliability in ways that are not cost-effective, as well as why such a utility will invest earlier than necessary in pursuit of grid "readiness" (for distributed energy resources, or "DER", and for electric vehicles, or "EV"). This section of testimony will conclude with a description of a typical distribution planning process that Mr. Stephens and I believe should be employed to develop distribution investment plans in Michigan.

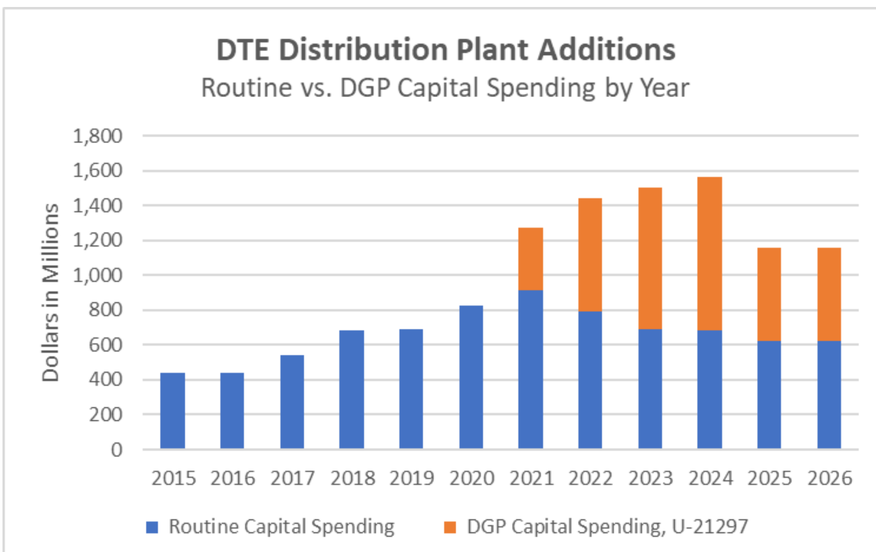
Q. Why do you believe DTE's DGP and associated capital spending to be unaffordable?

A. DTE's five-year DGP proposes $3.75 billion in capital spending on dozens of programs and thousands of projects over a five-year period.[5] The instant Application presents

[5] Exhibit A-23, Schedule M7, DTE 2021 Distribution Grid Plan from Case No. U-21047, pp. 111-13, Ex. 6.2.

substantially the same spending levels on substantially the same programs presented in the Company's DGP. Neither the DGP nor the instant Application provides any reference information that would indicate just how massive an increase over historical capital levels the Company's five-year DGP represents. As indicated in Figure 1 below, capital spending specific to the DGP alone in the six-year period ending 2026 exceeds the total amount of the Company's grid capital spending in the six-year period ending 2020.[6] By 2024, if the Commission approves the Company's proposals, annual capital spending ($1.565 billion) will be 3.5 times higher than the amount spent just 10 years earlier ($449 million in 2014).[7]

Figure 1: DTE Distribution Plant Additions, 2015-2026, Routine vs. DGP



Further, neither the DGP nor the instant Application estimates the revenue requirement associated with $3.75 billion in DGP capital spending 2021-2026, nor would the Company estimate the DGP spending revenue requirement when requested in

[6] $3.625 billion per DTE's FERC Form 1 2015-2020.

[7] DTE Energy 2014 FERC Form 1.

discovery.[8] I estimate the revenue requirement associated with the DGP capital spending, if approved by the Commission as proposed, will be $544 million annually by 2027. As cited earlier, this amount is equal to 25% of the entire distribution revenue requirement requested by the Company in 2021. The $544 million or 25% DGP rate increase by 2027 is only for DGP capital spending, and comes on top of rate increases requested in the instant Application for routine or base capital spending, and for increases in O&M spending, depreciation expense, and the Company's cost of capital, to name just a few. Further, significant electricity cost increases outside of distribution are already baked-in for DTE customers and Michigan's economy, including the significant costs associated with planned transmission capacity expansion, high fuel costs, and integrated resource plan compliance. Despite the foregoing, and despite affordability concerns expressed by multiple parties when the Company published its draft DGP, the Company made no changes in the final DGP to reduce the Plan's costs to its customers/Michigan's economy.

Q. Why is the capital spending DTE proposes in its DGP so high?

A. That is an excellent question, and one that I and other experts would have liked to have been able to explore when the Company first presented its DGP for review in 2021. There was no opportunity to get the Company to answer data requests on its DGP at that time, as it took the position that the docket in which the DGP was posted was informational, not litigated. As mentioned earlier, it is only in the Company rate cases that stakeholders have any opportunity to ask questions about the Company's DGP. This is clearly inappropriate, and unlike any distribution investment planning process I have observed in any state.

[8] Ex MEC-18, DTE response to MNSCDE-3.2 (a) and (b).

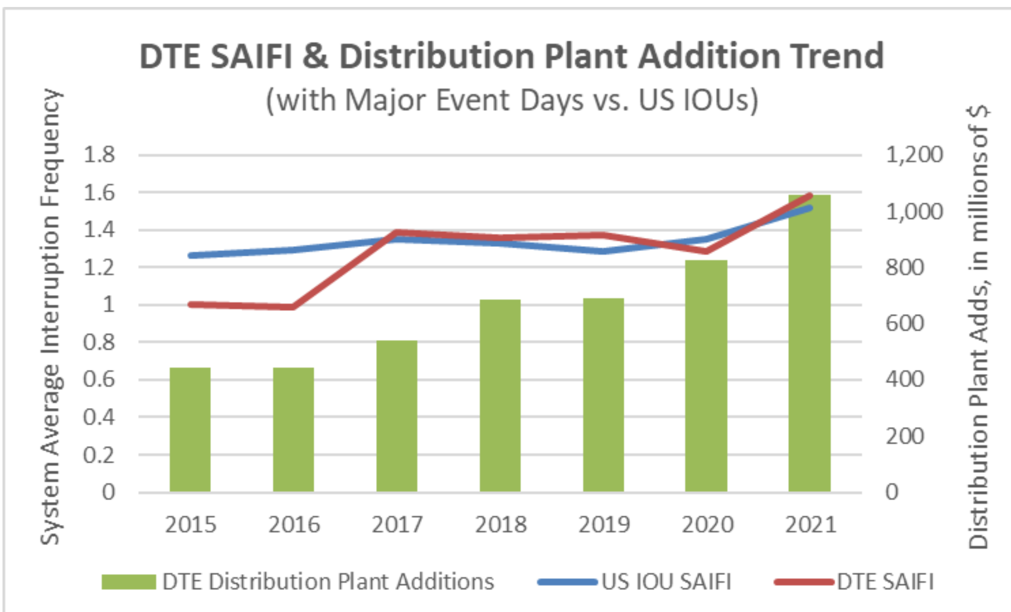
While Mr. Stephens's testimony addresses this question in considerable detail, my summary is that the Company's proposed strategic spending in furtherance of the DGP is entirely discretionary. By discretionary, I mean that considerable variation is available as to the types of capabilities and capacity added; the timing of the capability and capacity additions; and the geographic extent of the capability and capacity additions. Mr. Stephens and I would have expected specific support clearly justifying why certain capabilities and capacity expansions must be completed on specific circuits or substations by the end of the five-year DGP. Instead, support that $3.75 billion in investment is "required" by 2026 is anecdotal, supported by general observations regarding the need to improve reliability, and to make the grid "ready" for DER and EV adoption. As Mr. Stephens's testimony indicates, hard data in support of the timing and geographic extent of DGP project and program proposals is very limited.

Q. But clearly, DTE needs to invest in the grid to improve reliability, and to make the grid ready for DER and EV, does it not?

A. Perhaps to some extent, but as indicated above, strategic DGP investments are discretionary as to capabilities, timing, and geographic extent. Neither Staff nor stakeholders know what the "right" level of grid investment is. Further, this question assumes that more capital investment will deliver reliability improvements. Neither independent research nor DTE's own experience validates this assumption.

Research completed by Lawrence Berkeley National Laboratory on behalf of the U.S. Department of Energy found no correlation between investor-owned utility distribution capital spending increases and reliability improvement the following year.[9] Regarding DTE's own experience, DTE admits that more frequent tree trimming -- an O&M expense, not capital spending -- is the most effective thing DTE can do to improve reliability, stating "In areas where tree trimming has been completed, communities have experienced, on average, 60% fewer outages."[10] Finally, Figure 2 indicates that despite a 229% increase in annual distribution grid capital spending from 2015 to 2021, DTE's service interruption frequency increased 58.1%, and is now worse than the average for U.S. investor-owned utilities. More capital spending is not necessarily better than less.

Figure 2: DTE Service Interruption Frequency vs. Capital Spending Trend, 2015-2021



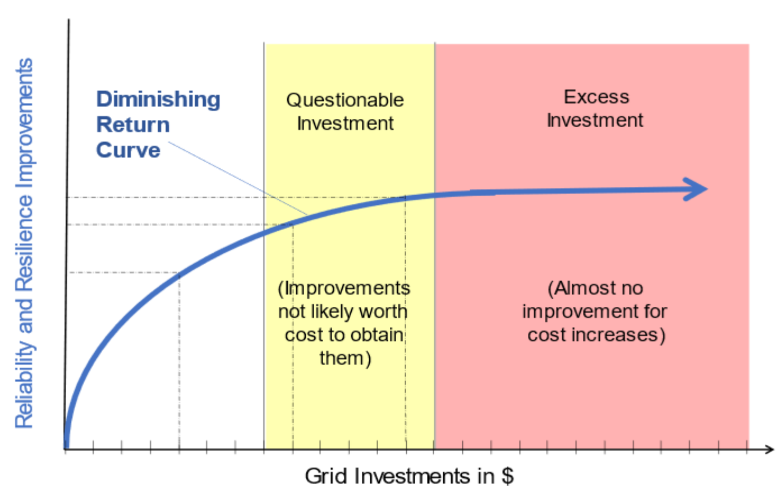
[9] Larsen PH, LaCommare KH, Eto JH, and Sweeney JL. *Assessing Changes in the Reliability of the U.S. Electric Power System*. Lawrence Berkeley National Laboratory report LBNL-188741. August, 2015. Pages 37-38. Available at: https://emp.lbl.gov/publications/assessing-changes-reliability-us.

[10] *DTE Announces an additional $70 million investment to combat extreme weather-related power outages*. DTE Energy press release. September 1, 2021. Available at https://ir.dteenergy.com/news/press-release-details/2021/DTE-announces-an-additional-70-million-investment-to-combat-extreme-weather-related-power-outages/default.aspx.

Q. That conclusion seems so counter intuitive. How do you explain it?

A. I explain it through the law of diminishing returns. The law of diminishing returns dictates that the level of incremental improvement from an activity (in this case, spending capital to improve reliability) falls ratably with each additional increment of resource input (in this case, capital dollars). This means that at some point, the value customers receive from incremental improvements in reliability will be less than the cost required to secure the improvements (known as the point of diminishing return). While a competitive business would never invest past the point of diminishing return, a utility with capital bias and no capital spending governance absolutely will. Figure 3 applies the diminishing return curve to reliability-related grid investment.[11] I believe the lack of reliability improvement resulting from DTE capital spending increases can be traced to the fact that DTE, like most U.S. investor-owned utilities, is at the upper-right of the diminishing return curve.

Figure 3: The Law of Diminishing Returns applied to reliability-related utility investments



[11] Ex MEC-22, Alvarez P, Costello K, Ericson S, and Stephens D, *Alternative Ratemaking in the US: A Prerequisite for Grid Modernization or an Unwarranted Shift of Risk to Customers?*, The Electricity Journal, Vol. 35: 107200 (2022).

Q. Are you suggesting that DTE has no effective capital spending governance?

A. Yes, that is what I am suggesting, at least when it comes to strategic DGP spending proposals. Once a grid investment plan is presented, a regulator's practical ability to exercise cost disallowance rights is severely compromised, and mitigation of information asymmetry falls too. With limited cost disallowance risk, and given information asymmetry, a utility has no reason to moderate capital spending.[12] I will return to these topics later in this testimony.

Q. But DTE must certainly invest in its grid to prepare for DER and EV, correct?

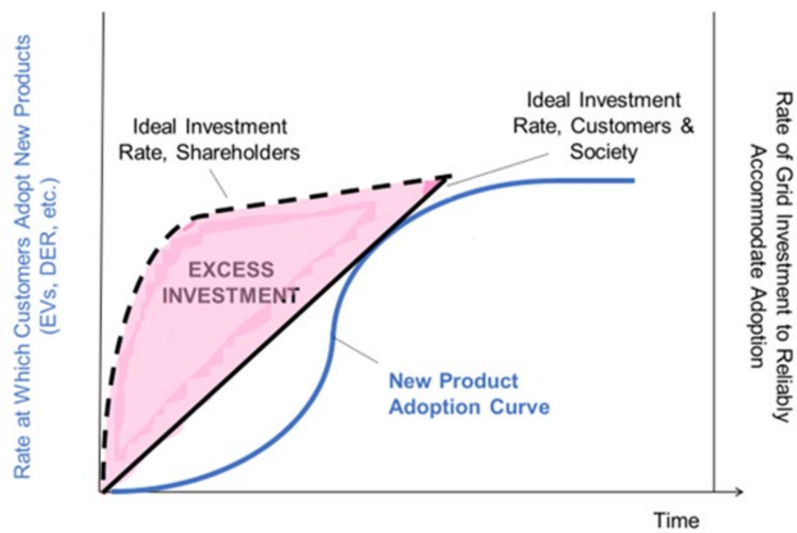
A. Correct, but in what capabilities and new capacity, over what time frames, and on what circuits and substations? Stakeholders can rely on generic utility representations of "need"; alternatively, they can demand objective documentation in support of specific capital spending requests on a circuit-by-circuit, substation-by-substation basis. If stakeholders rely only on the former, a utility is almost certain to invest more than necessary, earlier than necessary, in grid "readiness". Figure 4 illustrates how the standard "S" curve for technology adoption,[13] applied to DER and EV, is likely to require an increased rate of utility grid investment. But Figure 4 also illustrates that whatever the "right" amount of investment in grid readiness might be, an investor-owned utility with capital bias (assuming

[12] Regulatory lag also provides utilities with an incentive to control capital spending, though the Company is striving to eliminate this last remaining reason for capital spending governance through its request for rider cost recovery on DGP capital. This topic will return to this testimony later.

[13] The "S Curve" for technology adoption has been employed by product managers in consumer product companies for many decades. Regardless of technology, the curve reflects how new technologies are adopted by society – slowly at first, and then accelerating over time, until leveling off at market saturation (the point at which everyone likely to adopt a new technology already has). The adoption curve is relevant to any consumer technology, from color televisions in the 1960's to smart phones in the early part of this century. It also applies to DER and EV.

no capital spending governance) will always prefer to invest more, and earlier, than necessary to meet DER and EV needs.

Figure 4: Ideal investment rates in grid "readiness", shareholder vs. customer/societal perspectives



Q. Is it realistic to expect a utility to complete a circuit-by-circuit assessment of grid needs as part of distribution investment plan development?

A. Not only is it realistic, such a process for distribution grid planning has been common practice among utilities in the U.S for many decades. In its work on behalf of state utility regulators, the NARUC-NASEO Task Force on Comprehensive Electricity Planning documented exactly such a distribution planning process as a best practice.[14] My summary of the steps from the Task Force's "Jade Cohort Roadmap" (focusing on distribution

[14] *Jade Cohort Roadmap*. NARUC-NASEO Task Force on Comprehensive Electricity Planning. February 2021. Available at https://www.naruc.org/taskforce/resources-for-action/roadmaps/.

planning, for states that have deregulated wholesale generation) is presented in Table 1 below.

Table 1: Summary of Typical Distribution Planning Process Steps as documented by the NARUC-NASEO Task Force on Comprehensive Electricity Planning

Step	Description
Goals/Objectives	Establish goals and priorities for the grid plan, define metrics, and establish targets for metrics (objectives)
DER Forecast	Forecast DER capacity increases by circuit
Load Forecast	Forecast load growth by circuit, including loads from EV
(DER) Hosting Capacity Analysis	Quantify existing and available DER capacity by circuit, thus identifying constraints given DER forecasts. Identify any needed DER management capabilities that may be missing.
Grid Needs Assessment	Quantify existing and available load capacity by circuit, thus identifying constraints given load forecasts. Identify any needed load management capabilities that may be missing.
Identify Potential Solutions	Identify potential solutions to constraints (capacity expansion, third-party services, software, hardware, operating changes, customer programs/rates, etc.)
Evaluate Potential Solutions	Evaluate the technical, operational, and economic pros and cons of available solutions to constraints.
Select Solutions	Of the portfolio of needs and potential solutions, select solutions for implementation in the upcoming period, thus creating a grid plan and capital budgets. (We strongly encourage the use of risk-informed benefit-cost analyses to maximize customer "bang for buck" here.)
Implement Solutions	Implement the solutions selected as part of the grid plan.
Assess Results	Measure results against the targets identified in the Goals/Objectives step

Q. Do you believe Michigan utilities should follow the process steps outlined in the Task Force's Jade Cohort Roadmap when developing five-year distribution investment plans?

A. Absolutely, yes. There is really no other way for stakeholders to be assured that capital spending plans are not excessive, and that distribution planning is under control.

Q. But regarding grid readiness, does it not make sense to invest more capital than necessary under a "better safe than sorry" principle?

A. No. Utility planning has always involved prudent preparation for future needs, without spending more than will reasonably be "used and useful." While some advance spending for DER and EV readiness may be prudent, as Figure 4 above indicates, unquestioned acceptance of utility capital spending proposals is not at all appropriate. There are a great number of alternatives available for preparing the grid, with available alternatives each characterized by a wide variety of technical, operational, and financial pros and cons. This means that allowing utilities with capital bias and no capital spending governance to make unconstrained grid readiness investments is a bad idea. Further, given the information asymmetry challenge of current ratemaking practices, neither regulators, nor staff, nor stakeholders can determine how much advance preparation, in which grid technologies, in which locations, is appropriate.

I would also note that any investment in grid readiness that may be premature, unnecessary, or cost ineffective comes at a cost to Michigan's economy. Various studies indicate that employment falls between 0.0045 percent and 0.363 percent for every 1% increase in electric rates.[15] I understand that we all want the distribution grid to be ready for DER and EV in advance. But we don't want it ready too far in advance, nor do we want grid readiness to cost any more than necessary. Utility governance is needed, and the

[15] Metcalf, GE. *The Relationship Between Electricity Prices and Jobs in Missouri*, February 27, 2013, at page 3. *See also id.* at Exhibit 1 (Selected Studies of the Relationship Between Electricity Prices and Employment in the United States). Article available athttps://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936039359.

processes the Commission could use to install such governance will simultaneously help the Commission, Staff, and stakeholders reach an informed consensus on grid investments.

Q. Do the Company's proposed execution metrics help the situation?

A. No. The execution metrics the Company proposes are designed to measure how much work the Company completes (also known as "process" metrics). That the Company should be able to complete the work it has planned for the capital budgets it has established constitutes a minimum expectation. Execution metrics may help to ensure the Company completes planned programs in a cost-effective manner, but it absolutely does not ensure the Company only implements programs that are cost-effective.

To ensure the Company only executes cost-effective programs, performance metrics, not execution metrics, are required. Rather than monitor work completed, performance metrics measure the results of work completed. The act of holding a utility accountable for program performance will discourage a utility from proposing programs unlikely to deliver results. By specifying target results when a program is first proposed, the cost-effectiveness of that program can be evaluated in advance. Performance targets also allow a program's actual results to be compared to the expectations assumed at the time of approval. Without performance metrics (also known as outcomes metrics) and targets, program cost effectiveness cannot be evaluated before or after implementation.

Q. Does DTE offer any performance metrics in its DGP?

A. DTE provided reliability improvement projections in its DGP, but it will be virtually impossible for the Commission to hold DTE accountable for those improvements as presented. This is because in addition to system average interruption frequency and duration improvement estimates, DTE also presents broad bands of weather-related variation with those estimates. While DTE clearly cannot control the weather, it is also true that weather-related performance variation provides DTE with a ready-made explanation if reliability improvements fail to materialize from the $3.75 billion of spending associated with the DGP.

In recent years, DTE's storm-related reliability performance has been a clear and significant source of Commission and customer frustration. Predictably, DTE's response involves spending lots of capital. However, given the wide range of weather-induced performance variation in which DTE couches its reliability performance improvement projections, it is entirely possible that no significant improvement in reliability at all will be secured from the $3.75 billion of spending in the DGP. A review of the reliability improvement projections DTE provided in its DGP indicates that at the top band of weather-related performance variability, service interruption frequency and duration might only improve by imperceptible amounts after the $3.75 billion of DGP spending is implemented.[16]

Further, as presented in Figure 2 earlier, DTE's track record of delivering reliability improvements from capital spending increases is terrible. That $1 billion has already been spent[17] by a Company with a terrible track record, towards implementing a $3.75 billion Plan with limited metrics and no stakeholder discovery, are sure signs that DTE capital spending and distribution planning in Michigan generally, is not under control. It is unlike

[16] Ex A-23, Sch M-7, 2021 DGP. Exhibits 5.3.1 and 5.3.2 on page 101.

[17] Company Exh. A-12 Schedule B5.4, p. 1. Strategic capital program spending, Actual 2021 and Projected 2022.

any distribution planning process we have observed in any state. The Commission must act promptly and decisively to address these issues.

Q. What do you believe the Commission should do to address distribution planning processes and DTE strategic capital spending you believe to be out of control?

A. While I do have significant recommendations for Commission consideration, I have yet to present my diagnosis of Michigan's current distribution planning process. My testimony to this point, and Mr. Stephens's testimony, describe the symptoms of distribution planning problems in Michigan, not the root causes. Before offering recommendations, I wish to fully diagnose the root causes. The next section of testimony will explain exactly how advance grid investment plan presentation practically eliminates cost disallowance risk and information asymmetry mitigation, resulting in utility abandonment of capital spending governance. In DTE's case, this means an unaffordable and unjustified Distribution Grid Plan and the resulting capital expenditures proposed in this case, particularly in discretionary strategic programs.

III. THE UNINTENDED CONSEQUENCES OF ADVANCE GRID INVESTMENT PLAN PRESENTATION THREATEN MICHIGAN'S ECONOMY

Q. Please preview this section of testimony.

A. In this section of testimony, I will explain exactly how the advance presentation of grid investment plans practically eliminates regulators' ability to exercise cost disallowance rights. I will also describe how the loss of cost disallowance risk reduces information asymmetry mitigation, and how the presentation of grid investment plans in advance introduces moral hazard (a lack of consequence for making unjustified capital spending proposals in a distribution investment plan). I conclude that these factors encourage utilities (including DTE) to abandon capital spending governance when it comes to developing distribution investment plans, requiring Commission intervention.

Q. Your testimony to this point has frequently employed the term cost disallowance risk. Can you please explain cost disallowance risk and its role in ratemaking?

A. Cost disallowance risk is the possibility that a state utility regulator might prevent a utility from recovering the costs it has incurred for a certain program or project from customers in rates. Cost disallowances are severely consequential to a utility's profits, and utilities have historically gone to great lengths to avoid them.

Cost disallowances arose in the earliest days of cost-of-service ratemaking (a ratemaking construct that almost all state utility regulators, including this Commission, employ to this day). Cost-of-service ratemaking does a good job of controlling utility *profitability*; that is, the ratio of profits to capital invested in the grid in percent. Early on, however, it was recognized that cost-of-service ratemaking does a poor job of controlling utility *profit amounts*, in dollars. To raise earnings in dollars, all a utility must do is raise capital spending. Ten percent profit on $1,000 of capital invested ($100) is much greater profit in dollars than ten percent on $100 of capital invested ($10).

To address this problem, state utility regulators reserved for themselves the right to *disallow costs* from recovery from customers. A regulator can impose a heavy economic penalty on shareholders by disallowing cost recovery for a project or program deemed not used, or not useful (representing excess capital spending), in the provision of safe and reliable service. Cost disallowance risk thus encourages utilities to moderate distribution grid capital spending, and to invest conservatively in their grids.

Q. How did utilities respond to cost disallowance risk?

A. The utilities adopted the processes employed by businesses operating in competitive markets to keep their capital spending to the minimum required for safe and reliable operations. These businesses apply risk-informed benefit-cost analyses to projects and programs in a portfolio of potential investments. The businesses select for implementation only those projects and programs which appear likely to deliver economic benefits in excess of costs. In some instances, these businesses defer for future consideration projects and programs which delivered only small benefits in excess of costs. These decisions are typically made due to a lack of capital, or out of a concern for potential benefit variation and the need for a "margin of error" in project or program benefit projections.

Utilities could not adopt these processes entirely; the "obligation to serve all customers" in a defined service area, part of the regulatory compact between regulators and utilities, required utilities to make some investments regardless of the results of a benefit-cost analysis. Examples of these include the cost to connect customers to electric service, or the cost to repair or replace equipment that fails or is damaged. But other investments proposed by utility employees or departments, known as discretionary investments, were required to pass through a strict vetting process enforced by utility management. Known generally as *capital spending governance,* these processes were designed to reduce (if not eliminate) the risk that a project or program would be found not used or useful by a state utility regulator. Benefit-cost analyses and rigorous assessments of adverse event likelihoods and consequences are commonly employed as part of capital spending governance processes, and I will return to these concepts later in this testimony.

Q. How did regulatory staff and stakeholders respond to cost disallowance risk?

A. Cost disallowance risk is critically important to sound regulation of monopoly distribution utilities. Not only does cost disallowance risk encourage capital spending governance, it mitigates *information asymmetry*. Information asymmetry refers to the fact that it is extremely difficult for regulatory staff and stakeholders to know as much about a utility's grid, operations, and situation as the utility itself knows. The experience required to understand grid operations, engineering, technologies, planning, and asset management is typically acquired primarily through employment in utility grid functions. Without this experience, absent exceptional efforts, neither regulators, Staff, nor stakeholders are able to muster informed challenges to utility justifications for distribution grid capital spending.

Fortunately, as a result of cost disallowance risk and utility capital spending governance, neither regulators, staff, nor stakeholders have historically been required to spend time and attention on grid operations, engineering, technologies, planning, or asset management, or to mount informed challenges to proposed grid projects or programs. Instead, they have historically relied on cost disallowance risk, and the capital spending discipline it instilled, to govern utility grid capital spending.

It is difficult to overstate the value of cost disallowance risk to information asymmetry mitigation. Regulatory staff and stakeholders cannot reasonably be expected to rigorously evaluate or effectively challenge specific utility capital spending proposals because they simply do not have the information or experience needed to do so. Further, unlike generating plants that can cost hundreds of millions of dollars each, distribution grid planning cycles are characterized by literally thousands of relatively smaller grid investment decisions, making staff and stakeholder resource levels a problem too. With enough resources it might be possible, after years of experience participating in a particular utility's grid planning and investment selection processes, for staff and stakeholders to gain the information and experience needed to rigorously evaluate and effectively challenge that utility's myriad grid investment proposals. But short of that, cost disallowance risk—and the controls utilities themselves have historically applied internally to reduce that risk—has been the primary regulatory mechanism available to govern utility capital spending.

Q. How does utility presentation of grid investment plans in advance affect cost disallowance risk?

A. Regulators in all states employing any form of alternative ratemaking, including rider cost recovery as the Company has proposed in the instant Application, require utilities to submit capital spending plans in advance. Other state regulators, such as Michigan's, require distribution investment plans out of concerns regarding grid reliability and readiness (for DER and EV). Regardless of the reason, however, the advance presentation of grid investment plans makes it practically difficult for regulators to exercise their right to disallow costs from recovery from customers.

Once a grid investment plan is filed, a regulator's practical ability to exercise cost disallowance rights is severely compromised, for two reasons. First, when a utility presents its plan in advance, and without any opportunity for the investments proposed in its plan to be challenged by stakeholders, the utility ensures its plan becomes the only relevant perspective against which to evaluate programs and spending. It becomes akin to a self-fulfilling prophecy. Second, the plan once filed is likely to drive investor expectations. Due to the extremely large dollar amounts involved, cost disallowances may have a material effect on utility earnings expectations, and thus a utility's cost of capital, which customers must cover. When it comes to excess spending that may have been presented as part of a grid investment plan, a regulator's oversight become more limited. If the regulator disallows recovery of excess spending, it will face arguments that the disallowance will harm customers by increasing a utility's cost of capital. As a result, a utility regulator often does not exercise its right to disallow costs once a project or program is presented in a grid investment plan.

The unwritten understanding that a utility will indeed proceed to make the investments presented in a grid investment plan offered in advance effectively amounts to pre-approval of those investments. This, combined with the massive size of those investments, make it practically extremely difficult for stakeholders to evaluate spending and regulators to exercise their rights to disallow costs. The practical loss of cost disallowance risk when grid investment plans are submitted in advance marks a fundamental shift in the balance regulators strive to achieve between shareholder interests and customer interests, and has significant implications for the ratemaking process. Given the dollars at stake and the affordability considerations, any reduction in cost disallowance risk must be avoided.

Q. How does the presentation of advance investment plans change the ratemaking process?

A. Under traditional ratemaking, all the "action" in a rate case is in response to capital the utility has already spent (plus, in Michigan's case, the capital the utility is about to spend in a forward test year). This timing is fundamental to cost disallowance risk, and prompts the significant internal controls utilities put in place to scrutinize and govern capital spending proposed by internal business functions.

When a utility presents a grid investment plan in advance, the unwritten understanding that the utility will indeed proceed to make the proposed investments should result in a shift of time and attention (and litigation) to the plan. This has not happened in Michigan. The five-year distribution investment planning process Michigan followed in 2021 consisted of a single draft of each utility's plan, offered 60 days in advance. The informational nature of the U-20147 proceeding allowed the utilities to disregard data requests on their plans, and DTE completely disregarded all draft DGP recommendations offered by stakeholders.[18]

Information asymmetry and procedural schedules designed for rate cases that feature the capital spending governance encouraged by cost disallowance risk loom large in Staff and stakeholder review of distribution investment plans. Sixty days is woefully insufficient for stakeholders to understand massive distribution investment plans consisting of dozens of programs and thousands of projects, even with the discovery process offered in a litigated proceeding. Further, without experience as utility employees, Staff and stakeholders rarely are sufficiently qualified to surmount information asymmetry.

Q. To summarize, you believe advance distribution investment plan presentation results in the reduction or even loss of cost disallowance risk and information asymmetry mitigation, and that utilities abandon capital spending governance as a follow-on result?

A. Yes, and this is apparent in DTE's unaffordable and unjustified DGP. The concept of moral hazard figures prominently in my diagnosis. Moral hazard is the term economists

[18] There is essentially zero difference between the draft DGP DTE filed in U-20147 on August 1, 2021 and the final DGP DTE filed in U-20147 on September 31, 2021.

use to describe a situation in which a person (or organization) is protected from the consequences of an adverse event. In such instances, moral hazard predicts that a person (or organization) is less likely to take the steps necessary to avoid an adverse event when protected from its consequences. Flood insurance is typically provided as an example of moral hazard. A person who can obtain flood insurance is more likely to buy a home in a flood plain than a person unable to get flood insurance. Without adverse event consequences, a person (or organization) is pre-disposed to taking adverse event risks.

Let's apply the moral hazard concept to the advance presentation of distribution investment plans. In traditional ratemaking, when no investment plan is presented in advance, a utility makes conservative grid investments, cognizant of the high consequence associated with the potential of an adverse event (a cost disallowance). Let's compare this consequence to the consequence associated with making unjustified spending proposals in a distribution investment plan. In such a situation – assuming an adequate procedural schedule – a Commission might be persuaded to order reductions in the plan's capital spending. But there is zero economic penalty (consequence) associated with a reduction in plan size. A utility might not get to invest as much as it prefers, or to grow earnings by as much as it prefers, but these are only opportunity costs. They do not represent economic penalties (consequences) on funds already spent in the way that cost disallowances do.

Q. So grid over-investment entails the potential large consequence of cost disallowances, whereas offering a proposal containing over-investment entails no or minimal consequence?

A. Precisely, and moral hazard accurately predicts the result we see in DTE's DGP. Due to a lack of consequences for "over-proposing," a utility management team has nothing to lose, and everything to gain (rate base and profit growth), by proposing more spending in a grid investment plan than it would when cost disallowance is available. Further, information asymmetry and inadequate procedural schedules virtually guarantee that any unjustified spending included in a distribution grid plan presented in advance is highly unlikely to be identified in any event. From multiple examples provided in Mr. Stephens's testimony, I believe the Commission will conclude that the Company is indeed proposing excess capital spending in its DGP, and has relaxed DGP capital spending governance, in response to the practical elimination of cost disallowance risk and information asymmetry mitigation. These unintended consequences of advance grid investment plan presentation, combined with a lack of consequence for "over-proposing" (moral hazard), have resulted in a DGP which is much larger (unaffordable) and unjustified that it would otherwise be.

Q. What about regulatory lag? Doesn't regulatory lag serve to govern utility capital spending?

A. Yes. Regulatory lag describes the difference in time between when a utility makes a grid investment, and the time when the utility begins recovering the costs of those investments through rate increases. Regulatory lag also serves to govern utility capital spending to some extent, as it reduces a utility's ability to earn the target rate of return (profit percentages) when spending exceeds the levels the state regulator assumed when approving revenue requirements in the most recent rate case. I believe regulatory lag represents a much smaller incentive to conserve capital spending than cost disallowance risk, but I agree it is better than no capital spending controls at all. Indeed, a reduction in regulatory lag is cited by proponents as the primary driver of alternative ratemaking constructs such as the Investment Recovery Mechanism rider the Company has proposed in the instant proceeding. If the Commission approves the Company's request for rider cost recovery on DGP capital spending, the only remaining reason for the Company to moderate capital spending will have been eliminated.

IV. RECOMMENDATIONS

Q. Please preview this section of testimony.

A. In this section of testimony, I will present my recommendations for Commission consideration. In addition, I will introduce the concepts of risk-informed benefit-cost analysis and risk-informed decision support, and recommend these be employed in the development of all future distribution investment plans developed in Michigan (though these concepts have also been previously provided to Staff and the Commission). The recommendations are organized as follows:

- Reject (or severely restrict) DTE's request for the IRM rider;
- Restore capital spending governance and information asymmetry mitigation;
- Require risk-informed benefit-cost analysis, and risk-informed decision support, as part of all future distribution investment plan development.

Q. Please explain your recommendations regarding the Company's request for rider cost recovery (the Infrastructure Recovery Mechanism) on DGP investments.

A. I recommend the Commission reject the Company's request for rider cost recovery on DGP investments. As indicated earlier, for programs and projects in distribution grid investment plans presented in advance, regulatory lag is the only remaining brake on utility spending. If the Commission approves the IRM as DTE proposes, it will eliminate this only remaining brake.

Additionally, frequent rate case applications are one way in which utilities can reduce regulatory lag. As the Company seems to file a rate case annually, regulatory lag does not appear to be a problem that merits special cost recovery. In fact, I recommend the Commission establish an expectation that no rider cost recovery request will be considered from any utility on distribution investment plan spending until a distribution planning process that restores capital spending governance and mitigates information asymmetry can be implemented.

Q. Do you have an alternative recommendation in the event the Commission chooses to approve the Company's request for rider cost recovery for proposed strategic DGP investments?

A. Yes. As described in Mr. Stephens's testimony, the Company fails to justify the need or deployment speed for many discretionary or strategic DGP programs and projects. At a minimum, rider cost recovery should be restricted to the programs and projects, and to their associated deployment speeds/timeframes, Mr. Stephens recommends in his testimony.

Q. Please describe your recommendations for restoring capital spending governance and mitigating information asymmetry in the development of future distribution grid plans in Michigan.

A. I appreciate and admire the Commission's interest in ensuring the grid is ready for a future of DER and EV adoption, and that the Commission has required five-year distribution investment plans in pursuit of this goal. However, I believe the Commission should recognize the unintended consequences of advance distribution investment plan presentation that are detrimental to Michigan's economy, as explained in this testimony. Therefore, assuming the Commission continues to require five-year distribution investment plans from the utilities, I believe it must also take steps to address the unintended consequences of presenting these plans in advance, including utility abandonment of capital spending governance and the loss of information asymmetry mitigation. In my opinion, one of the best ways to restore capital spending governance while mitigating information asymmetry is to ensure that a new process is put in place for use in developing the next round of five-year distribution investment plans in Michigan, and to ensure that stakeholders are permitted to participate in every step of that new process.

Q. How do you recommend the Commission go about doing that?

A. The Commission could establish a proceeding in which Staff, stakeholders, and utilities were instructed to jointly create a process for developing five-year distribution investment plans. A series of working groups, led by Staff, could be used to create the distribution investment plan development process. The Commission's instructions could include minimum requirements for the resulting grid plan development process created, such as 1) that the process be based significantly on the Jade Cohort Roadmap process established by the NARUC-NASEO Task Force; 2) that full stakeholder participation is to be made available in every step of the process; and 3) that the process be designed to require no more than 36 months to deliver a distribution investment plan. The Commission could also establish standards for cost-effectiveness testing of plan projects and programs. Minimum requirements should be designed to ensure the resulting plans are definitive, valuable, and timely, and do not present any avoidable burdens for Staff or stakeholders.

Q. Assume for the sake of argument that the Commission adopts this recommendation. What would the execution of the distribution investment plan development process look like?

A. Mr. Stephens and I have mapped out the Jade Cohort Roadmap process with stakeholder participation, and believe it can be completed within 36 months. We expect the result of the process will be a distribution investment plan, complete with programs, projects, capital spending budgets, and timelines – similar to what the utilities produce today, but more focused, and with more details justifying specific programs and projects. I would also recommend the Commission stagger distribution investment plan development such that no more than two of the three utilities' plans are under development at the same time.

The goal of joint plan development is not to micromanage utility decisions, but to oversee and validate that projects and programs have been subjected to the evaluation and selection processes the parties have agreed to. Some processes we believe hold great promise, such as risk-informed benefit-cost analysis and risk-informed decision-making, will be described in the final part of this section of testimony.

Q. What if the parties cannot agree on a distribution investment plan?

A. I fully anticipate plans will include projects and programs on which the parties agree, and projects and programs the utility prefers to implement, but with which one or more parties disagrees. While the utility would be free to include spending on these projects and programs in its five-year distribution investment plan, these could be marked to indicate outstanding disagreement. If the utility proceeds to invest capital in projects and programs subject to disagreement, the utility would proceed with awareness that such projects and programs -- when presented for cost recovery in a rate case, or when presented in a proceeding dedicated to distribution plan evaluation -- will be subjected to much greater scrutiny, and involve much higher cost disallowance risk, relative to agreed-upon plan components. To avoid litigation, parties and utilities will be encouraged to forge consensus on as many projects and programs as possible. As a side benefit, Staff and stakeholder information asymmetry will fall over time as parties gain knowledge about distribution operations, technologies, and performance generally, as well as specific knowledge about the characteristics, idiosyncrasies, and constraints of the utility grids they are working on.

Q. Do you have a back-up recommendation in the event the Commission chooses to not to implement joint distribution investment plan development?

A. I do, but my recommendations to improve distribution planning apply with or without an order establishing a proceeding to create joint distribution investment plan development process. I recommend multiple enhancements to distribution investment planning in Michigan. First and foremost, distribution investment plans should be presented and evaluated in litigated proceedings specific to each utility, as is appropriate for the plans' critical roles in determining utility capital spending and rate increases described in this testimony. The litigated distribution investment plan proceedings for different utilities should not overlap, thereby avoiding stresses on Staff and stakeholder resources that will negatively impact their ability to successfully fulfill their roles as plan evaluators. The procedural schedules must be generous, providing sufficiently long discovery opportunities as will be required to fully understand highly technical utility justifications for scores of programs and thousands of projects that will likely be proposed in such plans.

Without these course corrections, Michigan's economy, businesses, and consumers will be doomed to a series of distribution investment plans filled with unjustified investments, as identified in Mr. Stephens's testimony. Finally, with or without joint distribution investment plan development, the Commission should take steps to restore capital spending governance and mitigate information asymmetry by ordering risk-informed benefit-cost analyses (to evaluate utility project and program proposals) and risk-informed decision support (to select the best projects and programs for inclusion in distribution investment plans while deferring others for reconsideration in future plans).

Q. Please describe risk-informed benefit cost analyses.

A. In most respects, risk-informed benefit cost analyses are the same as benefit-cost analyses: a simple comparison of the benefits of a project or program to customers over an investment's expected lifetime (depreciation period) to the costs of a project or program to customers (defined as the present value of associated revenue requirements over time). However, risk-informed benefit cost analyses recognize that "benefits" are not always easy to calculate. For example, consider the benefit of an investment that reduces service interruption risk. A risk-informed benefit calculation can be used to estimate the dollar value of such a risk reduction to customers, thereby enabling a comparison to costs.

Q. What is the risk-informed benefit calculation?

A. The risk-informed benefit calculation is simple and intuitive. To estimate the benefit (in dollars) of a reduction in the likelihood of an adverse event (i.e., a risk) delivered by an investment (let's call it investment "a"), one need only multiply the reduction delivered by investment (a) in the likelihood (percent) of adverse event (b) by the consequence (in dollars) associated with adverse event (b) if it occurs, as indicated below.

$$Benefit(a) = Reduction\ in\ Likelihood\ \%\ of\ (b)\ \ X\ Consequence\ Cost\ \$\ of\ (b)$$

Using a simple example to illustrate, assume investment (a) can secure a 5% reduction in the annual likelihood of a service outage from a particular cause. Assume that the customer consequence of the service interruption from the cause, were it to occur, is $100,000. The annual benefit associated with the investment is therefore $5,000 annually (5% X $100,000). Put another way, the customers served by this potential investment should be willing to collectively pay up to $5,000 annually in rate increases for this investment. If the revenue requirement associated with the investment is more than $5,000 annually, the investment proposal should be rejected as cost ineffective.

Q. Where do the reductions in likelihoods come from?

A. Ideally, risk reduction estimates should come from a utility's pilot of the proposed investment, or from evidence gleaned from data in a utility's operating systems. For example, if a 60-year-old piece of a particular type of equipment has a 2% annual likelihood of failure per a utility's asset management system, and a new piece of equipment of that type has a 1% annual likelihood of failure, then replacing the 60-year-old item with a new item will deliver a reduction in adverse event likelihood of 1% (2% before the replacement vs. 1% after the replacement). Industry research and studies can also be employed as sources for risk reduction estimate data.

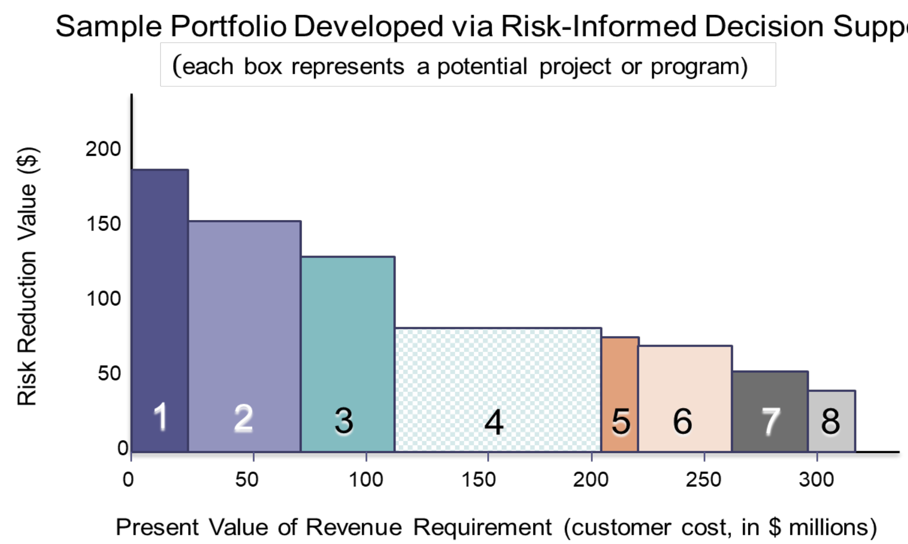
Q. Are there other advantages to using risk-informed benefit cost analyses to analyze proposed grid investments?

A. Yes. By denominating the benefits of all investments in dollars, spending to potentially be taken in pursuit of very different types of risk reductions can easily be compared to each other. Consider that a utility must manage risks of widely-differing types – service interruption risks, safety risks, the risk that growing loads or DER will not be accommodated without a delay, and many others. Further, each one of these risks can be managed through a number of potential solutions, and each potential solution offers varying degrees of effectiveness in risk reduction, and at different costs. If all benefits and costs are denominated in dollars, the capital required to reduce $100,000 in safety risk can be compared to the capital required to reduce $100,000 in service interruption risk, and to the capital required to secure $100,000 in DER accommodation delay risk.

Q. So, while risk-informed benefit cost analyses are being used to evaluate cost-effectiveness, those same analyses can also be used to compare the relative attractiveness of various risk-reduction capital spending options to each other?

A. Exactly! We believe it is best to develop various risks and available mitigations into a portfolio of potential combinations of risks to manage and solutions to manage them. By comparing the risk reduction benefits (in dollars) available from various mitigations, the portfolio can be optimized to secure the greatest risk reductions of various types of risk for the least cost. Figure 5 below presents this portfolio approach, which forms the basis of an investment plan optimization approach known as risk-informed decision support, or RIDS.

Figure 5: Sample portfolio of potential distribution investment plan projects or programs evaluated using risk-informed benefit-cost analysis as part of risk-informed decision support



Q. What is risk-informed decision support?

A. Risk-informed decision support (RIDS), also known as risk-informed decision making (RIDM), is an approach to optimizing the selection of alternatives from a number of available options under resource constraints. RIDS was initially conceived by the National Aeronautics and Space Administration (NASA) and the U.S. Nuclear Regulatory Commission (NRC). As specialists in risky activities, these organizations recognized that the law of diminishing return makes it financially infeasible to reduce the risk of any endeavor or activity to zero. As presented earlier in this testimony in the context of service interruption risk, the first risk reductions ("low hanging fruit") always involve the least costly and most impactful mitigations. But as risk falls, the mitigations available to secure each incremental unit of risk reduction become ever more costly. Thus, RIDS has always served as a means to optimize the selection of mitigations to implement from a portfolio of available risk mitigation options. An entire field of study, known as Decision Sciences, has evolved in recent decades with RIDS as the centerpiece.

Q. What does RIDS mean for distribution investment plan development?

A. By employing the results of risk-informed benefit-cost analyses, RIDS presents the opportunity to select, for inclusion in a distribution investment plan, the projects and programs from among a portfolio of potential spending options that deliver the biggest risk reductions per dollar (in layperson terms, "maximizing bang for the buck"). In so doing, risk-informed decision support, properly implemented, also identifies the projects and programs that can be deferred to the next distribution investment plan at low risk (also known as determining the level of risk deemed appropriate to tolerate).

Q. Using Figure 5, can you please provide an example of how to optimize a distribution investment plan using RIDS?

A. Figure 5 ranks a portfolio of potential projects and programs by their ability to reduce risk (measured in dollars). However, as the reader can see, the cost of each project or program varies. Project/program 1 provides almost $200 million in risk reduction value for just $25 million and is a no-brainer to select for a distribution investment plan. Project/program 4 provides about $80 million in risk reduction value, but costs $90 million, and therefore should be rejected. The four projects presented after it will cost about $150 million, but will deliver about $240 million in risk reductions, thus representing much better risk reduction value than project/program 4. Using a portfolio-based RIDS approach, it is clear this distribution investment plan could be improved by eliminating project/program 4 in favor of projects/programs 5, 6, 7, and 8.

Importantly, the portfolio approach also allows utilities, regulators, staff, and stakeholders to make *informed trade-offs* when developing a distribution investment plan. For example, assume for the sake of argument that affordability dictates a maximum capital spend in our example distribution investment plan of $160 million. Given this constraint, it appears that selecting projects or programs 1, 2, 3, 5, and 6 delivers the optimal distribution investment plan, as this combination of projects/programs delivers the greatest risk reductions for $160 million. The utility, regulators, staff, and stakeholders would be making a conscious choice to defer projects/programs 4, 7, and 8, and to reconsider them when the next distribution investment plan is being developed. In doing this they are determining both a capital spending level and the level of risk they are willing to accept (also known as risk tolerance). As indicated earlier, risks can never be reduced to zero, and the opportunities to spend capital on the grid are virtually limitless, so determining the appropriate level of risks to accept while simultaneously determining the optimum level of projects/programs/capital investment to include in a distribution investment plan is a valuable and important task.

Q. How does RIDS compare to DTE's Global Prioritization Model?

A. There really is no comparison. First, DTE's Global Prioritization Model (GPM) assigns risk reduction values (scores) to projects and programs that are entirely subjective. Each project/program is subjectively assigned a risk score for each of seven "impact dimensions" (generally, different types of risk, such as safety, reliability, etc.). There are no research-supported sources for project- or program-specific risk reduction percentages for various types of risk,[19] and scores aren't even denominated as risk reduction percentages. From there, each impact dimension score is weighted by a set of subjectively determined weights to develop an overall risk score for a project or program. The GPM assigns safety scores a weight of 10, and reliability scores a weight of 3, with no apparent research to support

[19] Ex MEC-19, DTE response to MNSCDE-3.30(e).

the different weights. Subjective risk scoring results in highly malleable decisions regarding which projects/programs to include in a distribution investment plan.

Second, risk reduction benefits are not quantified in dollars, precluding any kind of benefit-cost analysis. Despite the Company's characterization of benefit scores (not benefit dollars) divided by costs as a benefit-cost ratio,[20] in discovery, the Company admits the GPM does not measure cost-effectiveness.[21] Instead, "benefit-cost scores", another term the Company uses, are nothing more than the subjectively-determined benefit score divided by costs.

Third, the Company defines "costs" as the Company's costs, not costs customers must pay;[22] in my experience, the present value of revenue requirements (the cost customers must pay over time, discounted back to today's dollars) is typically 25%-35% higher than a utility's capital costs, resulting from customer payment of utility profits, utility interest expense, and utility taxes. Thus, the GPM understates the customer costs that should be compared to benefits in dollars (not subjectively assessed benefit scores). To summarize, while the GPM may have limited value in prioritizing potential projects/programs against one another, its value in making risk-informed decisions about what projects/programs to include in a distribution grid plan, and which to defer to the future at low risk, is essentially zero. Further, unlike risk-informed benefit-cost analyses, the GPM offers no value in identifying projects/programs that are not cost effective.

[20] Direct Testimony of Allen J. Kryscynski, pp. AJK-4 at 19 and AJK-7 at 5.

[21] Ex MEC-20, DTE response to MNSCDE-3.30(h)(i) and (h)(ii).

[22] Ex MEC-21, DTE response to MNSCDE-3.30(b).

Q. What are your recommendations regarding risk-informed benefit-cost analysis and risk-informed decision support?

A. I recommend the Commission order that risk-informed benefit-cost analyses be completed on any distribution investment plan project or program with capital spending in excess of $100,000, and to include those analyses in plan workpapers. I also recommend the Commission order that risk-informed decision support be used to select the projects and programs for a distribution investment plan from a portfolio of potential investments. These workpapers, including documentation of the recommended risk tolerance level, and identifying the projects/programs deferred to a future plan as a result, should also be required to accompany distribution investment plans.

Q. Have any other state utility regulators required risk-informed benefit-cost analysis and risk-informed decision support in distribution investment plans?

A. Yes. Late last year, the California PUC[23] ordered the utilities it regulates to employ these techniques to evaluate, and justify the selection of, capital spending projects and programs for distribution investment plans.[24]

[23] The California PUC first began approving multi-year rate plans in the mid-1980s, and was the first state utility regulator to do so. (Advance distribution investment plans are an essential component of multi-year ratemaking.)

[24] Cal. Pub. Util. Comm'n Decision 22-12-027 & Appendix A, *Phase II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in Decision 18-12-014 and Directing Environmental and Social Justice Pilots*, issued in Cal. Pub. Util. Comm'n Rulemaking 20-07-013, *Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities*, decided December 15, 2022 and issued December 21, 2022. Available at https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=500014668.

V. REVIEW, SUMMARY, AND CONCLUSION

Q. Please review the first section of your testimony.

A. This testimony began with a review of the Company's Distribution Grid Plan (DGP), which the Company began implementing in 2021 and proposes to continue implementing through 2026 (a six-year period). Key findings included:

- The $3.75 billion strategic capital programs in the DGP, which the Company plans to implement from 2021 to 2026 (six years), is a bit larger than the entire amount of capital the Company invested in its grid during the six-year period 2015-2020. DGP strategic capital spending is incremental to routine distribution grid capital spending, which will of course continue.
- I estimate the revenue requirement associated with the strategic capital spending in the DGP at $544 million annually by 2027 – an amount equal to 25% of the 2021 revenue requirement ($2.1 billion).
- The Company had already invested more than $1 billion in its DGP.
- If the Commission approves continued investment in accordance with the instant application, DTE estimates grid capital spending will be 3.5 times higher in 2024 ($1.565 billion) than grid capital spending just 10 years ago ($449 million in 2014).
- Despite a 229% increase in annual distribution investment 2015-2021, DTE's service interruption frequency increased (got worse) by 58% over the same period.
- The NARUC-NASEO Task Force on Comprehensive Electricity Planning documented a process (Jade Cohort Roadmap) that would be helpful in developing future five-year distribution investment plans.

- DTE's $3.75 billion strategic spending programs in the DGP includes minimal performance targets, and the Commission will find it difficult to hold the Company accountable for storm-related reliability performance improvements due to weather variability.
- Electric rate increases outside of distribution that are already planned, including transmission capacity expansion and integrated resource plan compliance, increase the need to control distribution service rates for the good of Michigan's economy.

I conclude that the discretionary or so-called "strategic" aspect of DTE's DGP is unaffordable, and upon consideration of my colleague Mr. Stephens's testimony, largely unjustified. I also conclude that distribution investment planning and spending in Michigan is out of control, and that the Commission should take prompt and decisive action to restore balance between customer and shareholder interests.

Q. Please review the second section of your testimony.

A. In the second section of this testimony I identified and explained the unintended consequences that arise when distribution investment plans are presented in advance, and how these unintended consequences shift the balance between customer-shareholder interests decidedly in shareholders' favor. Key observations include:

- Cost disallowance risk provides critical regulatory functions, including 1) the encouragement of utility capital spending governance; and 2) the mitigation of information asymmetry.
- Once presented, there is an unwritten expectation that a utility will implement the projects/programs proposed in a five-year distribution investment plan. This expectation makes it practically impossible for a regulator to disallow costs, as

- A utility resist opposition to the Plan/Projects/Programs and it will be impossible for challengers to present credible alternative plans; and
- Plan capital spending will drive utility and investor expectations, and it is so large, such that disallowances will trigger increases in a utility's cost of capital, which customers must pay in any event.

- Regulators' reluctance to disallow investment plan costs when presented in advance and "supported" by a plan reduces or even removes cost disallowance risk, resulting in the loss of utility capital spending governance and information asymmetry mitigation.
- There is no consequence associated with proposing excess capital spending in a distribution investment plan, a situation economists call "moral hazard". With no consequences and outsized rewards (rate base and earnings growth), moral hazard predicts utilities will propose much greater investment in a distribution investment plan than they otherwise would.
- Mr. Stephens's testimony identifies multiple examples of unjustified programs/projects in DTE's strategic program in the DGP, confirming what moral hazard predicts.
- Regulatory lag, though a much smaller penalty relative to cost disallowances, does remain to encourage utility capital spending governance. However, the Company's request for DGP rider IRM, if approved, will largely eliminate regulatory lag.

I conclude that the unintended consequences of advance grid investment plan presentation as has been done in Michigan, combined with a lack of consequence for "over-proposing" grid investments (moral hazard), have resulted in a DGP which is much larger (unaffordable) and much less justified that it would be had no opportunity to present a distribution investment plan existed.

Q. Please summarize the recommendations you provide for Commission consideration.

A. Recommendations I provide for Commission consideration include:

- Fully reject the Company's request for an Infrastructure Recovery Mechanism (rider), as it is the only inhibitor remaining to encourage DGP capital spending governance.
- If the Commission rejects this recommendation, I recommend restricting the use of the rider as Attorney General and MNSC Witness Stephens describes.
- Order a proceeding to create a process by which future distribution investment plans will be jointly developed by Staff, stakeholders, and utilities, with such proceeding to be completed with sufficient time to implement the new process for the next round of five-year distribution investment plans.
- If the Commission rejects this recommendation, I recommend the Commission order multiple enhancements to distribution planning in Michigan in advance of the next round of five-year distribution plans. The proceedings in which utilities present future distribution investment plans should be litigated; specific to each utility; and staggered over time; with generous provisions for discovery.
- The Commission should require that risk-informed benefit cost analyses be completed on all projects/programs larger than $100,000 in future distribution grid investment plans.

- The Commission should require that risk-informed decision support be employed to select projects/programs for inclusion in future distribution investment plans, and to select projects/programs to defer for consideration in follow-on planning cycles.

Q. Do you have any concluding thoughts to share?

A. I commend the Commission, Staff, and stakeholders for their foresight and efforts in requiring and procuring five-year distribution investment plans from for-profit utilities in Michigan. It was a step in the right direction. But now it is time to recognize the unintended consequences associated with the presentation of such plans in advance, and to recognize the harmful effects of these unintended consequences on Michigan's consumers, businesses, and economy. It may be too late to address premature, unnecessary, or cost-ineffective programs and projects on which capital has already been spent, but there is still time to improve distribution planning in Michigan before the next set of five-year distribution plans is developed. I encourage the Commission to take the next steps I recommend, and I thank the Commission for considering my perspectives, ideas, and recommendations.

Q. Does that complete your testimony at this time?

A. Yes.

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

Wired Group, PO Box 620756, Littleton, CO 80162. palvarez@wiredgroup.net 303-997-0317

Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed conflicts between ratemaking and benefit maximization. Since 2012 Mr. Alvarez has led the Wired Group, a boutique consultancy serving consumer, business, and environmental advocates, and regulators in matters of distribution planning, investment, and performance measurement.

Appearances and Research Projects in Regulatory Proceedings

Evaluate DTE Energy's Request for Strategic Capital Plan Cost Recovery and Infrastructure Recovery Mechanism Rider on behalf of the Attorney General and a group of environmental and consumer advocates in Michigan PSC U-21297. June 13, 2023.

Evaluate Commonwealth Edison's Multi-year Grid Plan. Panel testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission 22-0486. May 22, 2023.

Evaluate Ameren Illinois Corporation's Multi-year Grid Plan. Panel testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission 22-0487. May 11, 2023.

Evaluate Public Service Oklahoma's $450 million Grid Enhancement and Resilience Plan and Request for Rider Cost Recovery from a Policy Perspective. Testimony on behalf of the Attorney General in PUD-2022-000093. March 7, 2023.

Evaluate Georgia Power's Transmission & Distribution Spending Proposals. Panel testimony with Dennis Stephens on behalf of Public Interest Advocacy Staff. Georgia PSC 44280. October 20, 2022.

Evaluate Pacific Gas & Electric's 2023-2026 Multi-year Rate Plan. Panel testimony with Dennis Stephens on behalf of AARP. California PUC A.21-06-021. June 10, 2022.

Evaluate the Distribution Business Components of Georgia Power Company's Integrated Resource Plan. Panel testimony with Dennis Stephens on behalf of Public Interest Advocacy Staff. Georgia PSC 44160. May 6, 2022.

Evaluate Policy Issues and Precedents Associated with Oklahoma Gas & Electric Company's Grid Modernization Factor. Testimony on behalf of the Office of Attorney General in PUD 2021000164. April 27, 2022.

Evaluate Grid Modernization and Advanced Metering Proposals by Massachusetts Utilities. Panel testimonies with Dennis Stephens on behalf of the Office of Attorney General in D.P.U. 21-80, 21-81, and 21-82. January 19, 2022.

Evaluate Dominion's Grid Transformation Plan. Testimony on behalf of Appalachian Voices/Southern Environmental Law Center. Virginia SCC PUR-2021-00127. September 13, 2021.

Investigate Avista Utilities' Electric Distribution and Wildfire Spending, Plans, and Processes. Panel testimony with Dennis Stephens on behalf of Public Counsel. WUTC 200900. April 29, 2021.

Evaluate Kentucky Utilities/Louisville Gas & Electric's CPCN to Install Advanced Meters. Testimony on behalf of the Attorney General. Kentucky PSC 2020-00349/00350. March 5, 2021.

Examine Potomac Electric Power Company's Electric Distribution Spending and Plan. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel. MD PSC 9655. March 3, 2021.

Determine If Customer Interest Is Served by Smart Meter Stipulation. Testimony before the Ohio PUC on behalf of the Office of Consumer Counsel. Ohio PUC 18-1875-EL-GRD. December 17, 2020.

Critique Public Service Electric & Gas Company's Smart Meter Deployment Plan. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Rate Counsel. NJ BPU EO18101115. Aug. 31, 2020.

Examine Oklahoma Gas and Electric's $800 million Grid Enhancement Plan. Testimony before the Oklahoma Corporations Commission on behalf of AARP. PUD 202000021. August 25, 2020.

Examine Baltimore Gas and Electric's 2021-2023 Grid Investment and Operations Plan. Panel **t**estimony before the Maryland Public Service Commission with Dennis Stephens on behalf of the Office of People's Counsel. MDPSC 9645. August 14, 2020.

Critique of Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan. Testimony before the North Carolina Utilities Commission on behalf of a coalition of consumer and environmental advocates. NCUC E-7, Sub 1214 February 18, 2020, and E-2, Sub 1219 March 25, 2020.

Critique of Investment in Traditional Meters (Equipped with AMR). Testimony before the New Hampshire Public Utilities Commission recommending rejection of cost recovery. DE 19-057. December 20, 2019.

Critique of Smart Meter Benefits Claimed by Puget Sound Energy. Testimony before the Washington Utility and Telecom Commission recommending rejection of cost recovery pending demonstration of benefits in excess of costs. UE-190529 and UG-190530. November 22, 2019.

Critique of Smart Meter Benefits Claimed by Rockland Electric Company. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Consumer Advocate recommending rejection of cost recovery pending demonstration of benefits in excess of costs. ER19050552. October 11, 2019.

Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light. Testimony before the Indiana Utility Regulatory Commission recommending reductions in the size of the plan ($1.2 billion) based on benefit-cost analyses of plan components. Cause 45264. October 7, 2019.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

Investigation into Grid Modernization. Comments to the New Hampshire Public Utilities Commission recommending a transparent, stakeholder-engaged distribution planning process. IR 15-296. September 6, 2019.

Arguments to Reduce and Re-prioritize Grid Modernization Investments Proposed by Pacific Gas & Electric. Testimony before the California Public Utilities Commission. A.18-12-009. July 26, 2019.

Evaluation of Xcel Energy's Request for an Advance Determination of Prudence Regarding Natural Gas Generation Plant Purchase. Testimony before the North Dakota Public Service Commission. PU-18-403. May 28, 2019.

Critique of Smart Meter Replacement Program Implied by Proposed Duke Energy Ohio Global Settlement Agreement. Testimony before the Public Utilities Commission of Ohio on behalf of the Office of Consumer Counsel. Numerous cases including 17-0032-EL-AIR. June 25, 2018.

Support for Considering Duke Energy Grid Modernization Investments in a Distinct Proceeding. Testimony before the North Carolina Utilities Commission on behalf of the Environmental Defense Fund. E-2 Sub 1142, October 18, 2017 and E-7 Sub 1146, January 19, 2018.

Evaluation of Southern California Edison's Request to Invest $2.3 Billion in its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network. A16-09-001. May 2, 2017.

Evaluation of Kentucky Utilities/Louisville Gas & Electric Smart Meter Deployment Plan. Testimony before the Kentucky Public Service Commission on behalf of the Kentucky Attorney General in 2016-00370/2016-00371. March 3, 2017. Also in 2018-00005 May 18, 2018

Evaluation of National Grid's Massachusetts Smart Meter Deployment Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General in 15-120. March 10, 2017. Also Unitil in 15-121 and Eversource in 15-122/123, March 10, 2017

Evaluation of Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Recommendations on Metropolitan Edison's Grid Modernization Plan. Testimony before the Pennsylvania Public Utilities Commission on behalf of the Environmental Defense Fund in R-2016-2547449. July 21, 2016.

Arguments to Consider Duke Energy's Smart Meter CPCN in the Context of a Rate Case. Testimony before the Kentucky Public Service Commission on behalf of the Attorney General in 2016-00152. July 18, 2016.

Evaluation of Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research and report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research and report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

Noteworthy Publications

Alternative Ratemaking in the US: A Prerequisite for Grid Modernization, or an Unwarranted Shift of Risk to Customers? With Kenneth Costello, Sean Ericson and Dennis Stephens. Electricity Journal. Volume 35 (October, 2022).

Utility Regulation Through Legislation: A Cautionary Tale for Legislators, Regulators, Stakeholders, and Utilities. With Sean Ericson and Dennis Stephens. Electricity Journal. Volume 34

(August, 2021).

Florida Storm Protection Plans: A Bonanza for Utilities, a Bust for Consumers and the State. Whitepaper co-authored with Dennis Stephens for AARP-Florida. October 5, 2020.

Challenging Utility Grid Modernization Proposals. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 September, 2020.

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. July 8, 2019. Pages 116+

Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Dennis Stephens for GridLab. January 31, 2019

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Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities

Fortnightly. December, 2009.

Notable Presentations

NASUCA Electricity Committee Meeting. *Alternative Ratemaking and Grid Modernization: Considerations for Consumer Advocates.* With Dennis Stephens and Ken Costello. December 7, 2022.

NASUCA Annual Meeting. *Reinventing Distribution Planning in New Hampshire.* With D. Maurice Kreis, Executive Director, Office of Consumer Advocate. San Antonio, TX. November 19, 2019.

National Council on Electricity Policy Annual Meeting. Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

NASUCA Annual Meeting. *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

Illinois Commerce Commission, NextGrid Working Group 7. *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

NARUC Committee on Electricity. *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2. *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

NASUCA Mid-Year Meeting. *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators***.** Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando, FL. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando, FL. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us*. Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators*. St. Louis, MO. November 13, 2011.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 2011.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Finance, Marketing.

Certifications

New Product Development Professional. Product Development and Management Association. 2007.

MPSC Case No: U-21297	
Requester: MNSC	
Question No.: MNSCDE-3.2a	
Respondent: K. Vangilder	
Page: 1 of 1	

Question: Refer to the Company's response to Request No. MNSCDE-3.1, immediately above. Using all the same assumptions employed to determine the test year revenue requirements in the Company's present Application (for example, cost of capital, taxation, etc.), please estimate revenue requirements in year 2027 associated with

a. Strategic Capital Spending proposed 2024-2026 in the Application to be recovered initially through rider IRM if approved.

Answer: DTE Electric objects for the reason that the request is unduly burdensome, overly broad, oppressive and calculated to cause unreasonable expense to DTE Electric and its ratepayers. DTE Electric also objects to the requested information for the reason that the request seeks information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence in this proceeding. Without waiving these objections, but subject to them, the Company responds as follows:

The Company has not calculated the requested revenue requirement for 2027.

Attachment: None

Co-Respondent: Legal

MPSC Case No: U-21297
Requester: MNSC
Question No.: MNSCDE-3.2b
Respondent: K. Vangilder
Page: 1 of 1

Question: Refer to the Company's response to Request No. MNSCDE-3.1, immediately above. Using all the same assumptions employed to determine the test year revenue requirements in the Company's present Application (for example, cost of capital, taxation, etc.), please estimate revenue requirements in year 2027 associated with

b. Strategic Capital spending proposed 2024-2026 in the Application to be recovered in the Company's next base rate case (excluding Strategic Capital Spending to be recovered initially through rider IRM if approved).

Answer: DTE Electric objects for the reason that the request is unduly burdensome, overly broad, oppressive and calculated to cause unreasonable expense to DTE Electric and its ratepayers. DTE Electric also objects to the requested information for the reason that the request seeks information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence in this proceeding. Without waiving these objections, but subject to them, the Company responds as follows:

The Company has not calculated the requested revenue requirement for 2027.

Attachment: None

Co-Respondent: Legal

MPSC Case No: U-21297	
Requester: MNSC	
Question No.: MNSCDE-3.30e	
Respondent: J. Kryscynski	
Page: 1 of 1	

Question: Refer to Witness Kryscynski's testimony, Table 4 on page AJK-11, as well as to Mr. Kryscinski's statement regarding the Global Prioritization Model (GPM), page AJK-7 at 3, "Detailed analyses based on historical data, engineering assessments, and field feedback were used to quantify each investment's benefits within each impact dimension. The quantified benefits were then compared to the investment's costs to derive benefit-cost ratios" and to his statement on page AJK-8 at 4, "Each program's benefit-cost score for each impact dimension is indexed to a base range of 0-100. Projects scoring exceptionally high, above the 95th percentile, will receive a score above 100."

e. Refer to the Company's response to subpart (d) above. Provide all "detailed analyses based on historical data, engineering assessments, and field feedback" or other support materials (for example, cited standards for Regulatory Compliance) to determine each impact dimension score for each program and project listed in Table 4.

Answer: DTE Electric objects to the request for the reasons that the request is over broad and unduly burdensome, seeks excessive detail, seeks information involving CEII (either critical energy infrastructure information or critical electric infrastructure information), North American Electric Reliability Corporation (NERC) NERC-CIP (including but not limited to BES Cyber Asset information subject to protection under the Information Protection Program pursuant to NERC Reliability Standards CIP-003-6 and CIP-011-2), as the request seeks sensitive loading data. As such the data is not being provided nor is the model itself, as it contains substation loading data. Discovery of this substation loading data could be used to reveal system vulnerabilities.

Attachment: N/A

Co-Respondent(s): Legal

MPSC Case No: U-21297	
Requester: MNSC	
Question No.: MNSCDE-3.30hi	
Respondent: J. Kryscynski	
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Question: Refer to Witness Kryscynski's testimony, Table 4 on page AJK-11, as well as to Mr. Kryscinski's statement regarding the Global Prioritization Model (GPM), page AJK-7 at 3, "Detailed analyses based on historical data, engineering assessments, and field feedback were used to quantify each investment's benefits within each impact dimension. The quantified benefits were then compared to the investment's costs to derive benefit-cost ratios" and to his statement on page AJK-8 at 4, "Each program's benefit-cost score for each impact dimension is indexed to a base range of 0-100. Projects scoring exceptionally high, above the 95th percentile, will receive a score above 100."

h. Please provide the index of base ranges that incorporates all Strategic Capital programs and projects proposed in this Application for

i. cost recovery in this rate case; Indicate the point in the index of base ranges provided below which projects were deferred for future consideration and not included in this Application. Explain how the Company chose the indicated point in the index to be the most appropriate and cost-effective stopping point for programs and projects to be included in this Application.

Answer: As quoted above, within each impact dimension the base range is 0-100. Benefit-cost ratios are indexed to score within the 0-100 range for projects with a benefit-cost ratio at or below the 95th percentile of all projects scored.

All the projects and program proposed by the Company provide valuable system improvements. While the strategic investment plan is driven by the GPM, there are other considerations that impact capital allocation and project timing.

The GPM does not weigh cost effectiveness, that is done at a project and program level. The GPM weighs relative cost vs benefits for each project across 5impact dimensions (the "regulatory compliance" and "load relief" dimensions receive a score of between 0-100and cost is not a factor). Every project considered by the GPM is needed to address a unique set of identified distribution system needs. Because the GPM model does not measure cost-effectiveness, the Company did not choose an "indicated point" to be a "cost-effective stopping point", and therefore cannot answer that part of the question.

Attachment: N/A

Co-Respondent(s): N. Foley

MPSC Case No: U-21297	
Requester: MNSC	
Question No.: MNSCDE-3.30hii	
Respondent: J. Kryscynski	
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Question: 30) Refer to Witness Kryscynski's testimony, Table 4 on page AJK-11, as well as to Mr. Kryscinski's statement regarding the Global Prioritization Model (GPM), page AJK-7 at 3, "Detailed analyses based on historical data, engineering assessments, and field feedback were used to quantify each investment's benefits within each impact dimension. The quantified benefits were then compared to the investment's costs to derive benefit-cost ratios" and to his statement on page AJK-8 at 4, "Each program's benefit-cost score for each impact dimension is indexed to a base range of 0-100. Projects scoring exceptionally high, above the 95th percentile, will receive a score above 100."

h. Please provide the index of base ranges that incorporates all Strategic Capital programs and projects proposed in this Application for

ii. cost recovery via the proposed IRM rider; and indicate the point in the index of base ranges provided below which projects were deferred for future consideration and not included in this Application. Explain how the Company chose the indicated point in the index to be the most appropriate and cost-effective stopping point for programs and projects to be included in this Application.

Answer: As quoted above, within each impact dimension the base range is 0-100. Benefit-cost ratios are indexed to score within the 0-100 range for projects with a benefit-cost ratio at or below the 95^{th} percentile of all projects scored.

All the projects and program proposed by the Company provide valuable system improvements. While the strategic investment plan is driven by the GPM, there are other considerations that impact capital allocation and project timing.

The GPM does not weigh cost effectiveness, that is done at a project and program level. The GPM weighs relative cost vs benefits for each project across 5 impact dimensions (the "regulatory compliance" and "load relief" dimensions receive a score of between 0-100 and cost is not a factor). Every project considered by the GPM is needed to address a unique set of identified distribution system needs. Because the GPM model does not measure cost-effectiveness, the Company did not choose an "indicated point" to be a "cost-effective stopping point", and therefore cannot answer that part of the question.

Attachment: N/A

Co-Respondent(s): N. Foley

MPSC Case No: U-21297	
Requester: MNSC	
Question No.: MNSCDE-3.30b	
Respondent: J. Kryscynski	
Page: 1 of 1	

Question: Refer to Witness Kryscynski's testimony, Table 4 on page AJK-11, as well as to Mr. Kryscinski's statement regarding the Global Prioritization Model (GPM), page AJK-7 at 3, "Detailed analyses based on historical data, engineering assessments, and field feedback were used to quantify each investment's benefits within each impact dimension. The quantified benefits were then compared to the investment's costs to derive benefit-cost ratios" and to his statement on page AJK-8 at 4, "Each program's benefit-cost score for each impact dimension is indexed to a base range of 0-100. Projects scoring exceptionally high, above the 95th percentile, will receive a score above 100."

b. Confirm that "costs" means the capital costs for a program or project. If this cannot be confirmed, please explain how the GPM calculates the costs of a program or project.

Answer: Confirmed.

Attachment: *N/A*

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

ABSTRACT

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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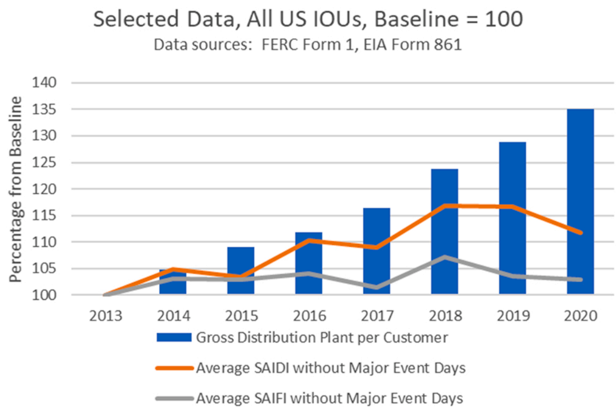

Fig. 1. Reliability Performance Relative to Distribution Plant per Customer, U. S. Investor-Owned Utilities, 2013–2020. (Higher system average interruption duration and frequency indices, SAIDI and SAIFI, indicate deteriorating reliability.).

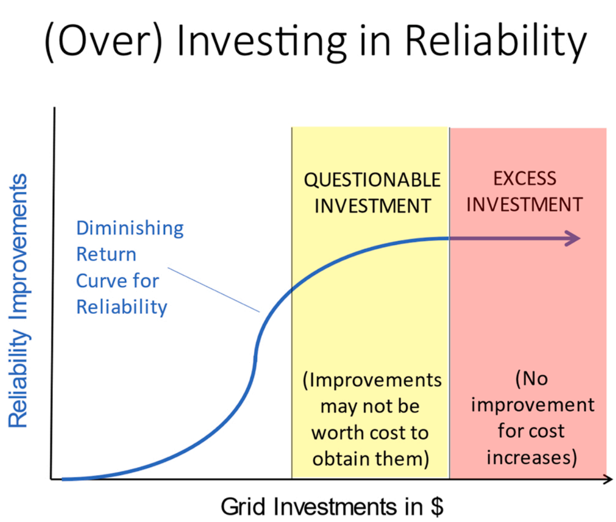

Fig. 2. The Law of Diminishing Returns Applied to Distribution Grid Reliability and Investment.

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.

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.

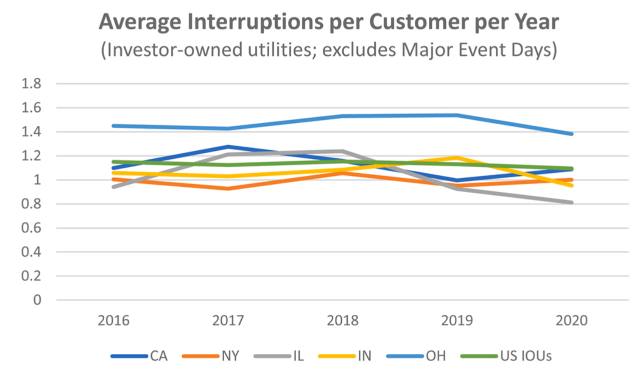

Fig. 3. Average Interruptions per Customer per Year without Major Event Days, 2016–2020, Customer of Investor-Owned Utilities in CA, NY, IL, IN, and OH compared to the average for U.S. investor-owned utilities.

[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).

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]

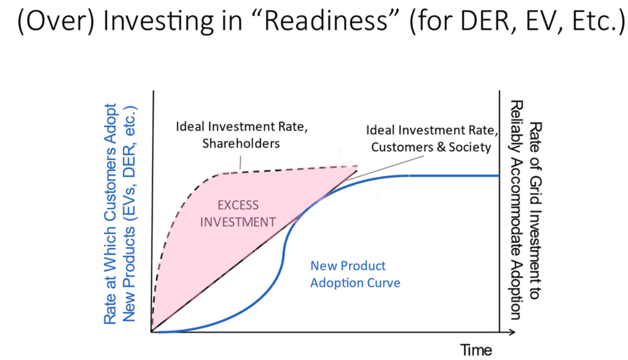

Fig. 4. Illustration of the difference between a grid investment level required to be "Ready" for customer technology adoption vs. the level of investment that for-profit utilities prefer as a regulated profit growth strategy.

[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-groundbreaking-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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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	U-21297

PROOF OF SERVICE

On the date below, an electronic copy of **Corrected Direct Testimony and Exhibits of Paul Alvarez on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (Exhibit MEC-17 through MEC-22)** was served on the following:

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[signature page to follow]

The statements above are true to the best of my knowledge, information, and belief.

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Date: June 14, 2023

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