BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	CASE NO. PUD 2023-000087
AUTHORIZING APPLICANT TO MODIFY ITS	)	
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

RESPONSIVE TESTIMONY

OF

PAUL J. ALVAREZ

APRIL 26, 2024

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INTRODUCTION, PURPOSE, AND PREVIEW

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My name is Paul J. Alvarez. My business address is Wired Group, PO Box 620756, Littleton, CO 80162.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I lead the Wired Group, a small consultancy focused on distribution planning, investment, and performance that works primarily for consumer, business, and environmental advocates in state utility regulatory proceedings.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Public Utility Division Staff ("PUD").

Q. DID YOU HAVE HELP IN DEVELOPING THIS TESTIMONY?

A. Yes, PUD Witness Mr. Stephens assisted me in developing this testimony, and I assisted Mr. Stephens in the development of his testimony.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received an undergraduate degree in finance and marketing from Indiana University's Kelley School of Business in 1983, and a master's degree from the Kellogg School of Management at Northwestern University in 1991. My first role in the electric utility industry, beginning in 2001, was as a product development manager with Xcel Energy. I oversaw the development of new demand-side management ("DSM") programs, as well as programs and rates in support of voluntary renewable energy purchases and renewable portfolio standard compliance.

After seven years with Xcel Energy, I was hired by sustainability consulting firm MetaVu to develop its utility industry practice. While at MetaVu I utilized my DSM evaluation, measurement, and verification ("EM&V") experience to lead two comprehensive evaluations of smart grid deployment performance, including both grid and meter modernization. The first was an evaluation of the SmartGridCity™ deployment in Boulder, Colorado, completed for Xcel Energy in 2010, and the second was an evaluation of Duke Energy's Cincinnati-area deployment completed for the Ohio Public Utilities Commission in 2011.

I started the Wired Group in 2012 to focus exclusively on distribution utility planning, investment, performance measurement, and economic value creation. 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). In addition to leading the Wired Group, I 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 and present at conferences on distribution utility planning, investment, and performance measurement.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION PREVIOUSLY?

A. Yes. I submitted testimony on behalf of AARP in which Oklahoma Gas and Electric Company ("Company" or "OG&E") originally requested exceptional cost recovery for grid modernization (resulting in the Grid Enhancement Mechanism, or GEM).[1] I also testified on behalf of the Attorney General in OG&E's most recent rate case,[2] and in Public Service Company of Oklahoma's most recent rate case.[3] In addition, I have testified in multiple electric distribution planning, investment, and performance measurement proceedings before regulators in 15 other states since forming the Wired Group. A complete list of appearances is provided in my CV, attached as Exhibit PUD-PA-1. I ask that the Commission accept my credentials and recognize me as an expert witness on behalf of PUD in this proceeding.

Q. PLEASE PROVIDE A PREVIEW OF YOUR TESTIMONY.

A. This testimony begins with some perspective for the Commission's consideration on OG&E's transmission and distribution capital spending generally, and on the Company's Grid Enhancement spending specifically. I present the results of these spending increases (reliability improvements, or lack thereof) in relation to their size, and provide some history on transmission and distribution capital spending details, including the Company's Grid Enhancement program. I also present the results of a compelling analysis indicating that the Company's Grid Enhancement program does not deliver reliability improvement benefits to customers sufficient to exceed customer costs. The analysis examines the reliability improvements on 11 circuits with at least three years' performance post Grid Enhancement spending (meaning, work completed by December 31, 2020), and finds they

[1] Responsive Test. of Paul J. Alvarez on behalf of AARP, *Okla. Gas & Elec. Co. Grid Enhancement Plan*, No. PUD 202000021 (Okla. Corp. Comm'n Aug. 25, 2020).
[2] Responsive Test. Of Paul J. Alvarez on behalf of AG, No. PUD 2021-000164. April 27, 2022.
[3] Responsive Test. Of Paul J. Alvarez on behalf of AG, No. PUD 2022-000093. March 7, 2023.

deliver just $0.44 in customer reliability improvement value for every $1 in Company capital spending.

The third section of this testimony describes some potential explanations for the Company's failure to deliver reliability improvements given massive increases in distribution capital spending in recent years. The law of diminishing returns is presented as one potential generic explanation, while a distinct lack of focus associated with the Company's Grid Enhancement spending is presented as a more specific factor. The section concludes with a recommendation that Grid Enhancement capital spending on anything other than the Company's worst-performing circuits 2020-2021 be disallowed. Most of the circuits on which Grid Enhancement capital was spent since the last rate case were not among the worst-performing 2020-2021. Grid Enhancement spending on circuits not among the worst-performing 2020-2021 amounts to a disallowance of $90.7 million.

In Section IV I address the Company's request to increase vegetation management spending. While my calculations indicate an increase is likely warranted, I believe the Company's requested increase to be far too high. I therefore recommend a reduction in the size of the increase OG&E requested from $28 million to $8.8 million. I also recommend PUD closely monitor the amount of circuit miles OG&E clears of vegetation annually, so that any increase the Commission authorizes does not artificially increase profits through potential OG&E choices to curtail vegetation management. Finally, I recommend the Commission reject the Company's request to record vegetation management spending in excess of O&M budgets as a regulatory asset, as such an approach is not in customers' interest.

CONCERNING PERSPECTIVE ON COMPANY'S TRANSMISSION, DISTRIBUTION, AND GRID ENHANCEMENT CAPITAL SPENDING

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF TESTIMONY.

A. This section presents perspectives on the Company's Transmission, Distribution, and Grid Enhancement capital spending that I believe the Commission will find concerning. I will describe massive growth in the Company's capital spending in recent years and present it alongside reliability performance trends. I will get into the details behind a few types of transmission and distribution spending responsible for the majority of the increases, but I reserve most of this section discussion on the Company's Grid Enhancement spending. I will summarize the program and present some financial, regulatory, and operational history. I will also present the results of a cost-benefit study completed on the program that indicates benefits of just $0.44 for every $1 in capital spent by the Company.

Q. BY HOW MUCH HAS OG&E CAPITAL SPENDING ON ITS TRANSMISSION AND DISTRIBUTION SYSTEMS GROWN IN RECENT YEARS?

A. This rate case marks a new record in the amount of transmission and distribution ("T&D") capital spending on which the Company requests recovery from customers. According to its financial statements,[4] the Company placed more than $705 million in T&D equipment into service in 2023, an amount more than double the amount OG&E placed into service

[4] OG&E FERC Form 1, "Electric Plant in Service – Additions". Q4 2023 and Q4 2019.

just five years ago ($349 million, in 2018). This begs the question: What are OG&E customers getting for all this new investment?

Q. WHAT SHOULD OG&E CUSTOMERS BE GETTING FOR ALL THIS NEW INVESTMENT?

A. The Company is responsible for providing safe and reliable electric service to all customers in its service territory who request it. In exchange, the Commission grants OG&E an opportunity to earn a rate of return on invested capital at the level the Commission authorizes (expressed as a percentage of profit on investment). Mr. Stephens and I believe capital spending in excess of that required for safe and reliable service to be discretionary, warranting additional Commission scrutiny. However, due to differences of opinion as to which OG&E projects or programs are indeed "required" for safe and reliable service, and due to information asymmetry, the Commission's job in scrutinizing capital spending is difficult.

"Information asymmetry" describes the difficulty for the Commission, PUD, and intervenors to know as much about OG&E's business, infrastructure, operations, and technologies as the Company itself knows. Due to capital bias,[5] OG&E (like all for-profit monopoly utilities) prefers to invest more than the minimum amount required for safe and reliable service. Determining how much capital spending is appropriate, and how much is excessive, is therefore extremely difficult for regulators, staff, and intervenors. Cost disallowances are one of the only tools available to the Commission for signaling

[5] Averch H and Johnson L. *The Behavior of the Firm Under Regulatory Constraint*. 52 Am. Econ. Rev. 1052 (Dec. 1962).

disapproval with Company spending, and the threat of cost disallowances is critical to encouraging utilities like OG&E to appropriately govern capital spending and avoid imprudent capital spending.

Q. HOW DOES THE COMMISSION DETERMINE WHICH UTILITY SPENDING PRESENTED FOR CUSTOMER COST RECOVERY IS PRUDENT?

A. Historically, state utility regulators have identified spending on assets (generally, equipment and software) as prudent if the equipment or software 1) is used and useful in delivering service at required levels of safety and reliability; and 2) was procured in an ethical, low-cost manner. It is the former question that can be difficult to answer, and which drives much of this testimony. There is clearly a difference of opinion as to what OG&E considers to be "required" spending for safe and reliable service, and what Mr. Stephens or I consider to be required.

For spending that truly is "required" for safe and reliable service, Mr. Stephens and I believe ethical, low-cost procurement should be adequate to determine prudence. However, for spending that a utility like OG&E makes that is discretionary, and not strictly required for safe and reliable service in the near term, Mr. Stephens and I believe a higher standard should apply. That is, discretionary spending must deliver benefits to customers in excess of cost to customers to be deemed prudent. To return to the initial question, "all this new investment" consists largely of discretionary spending, and as a result, such spending should deliver customer benefits in excess of customer costs to be prudent. I note that the Commission has a history of demanding that discretionary OG&E spending proposals deliver benefits to customers in excess of costs, from smart meters to demand side management programs.

Q. WHAT DISCRETIONARY SPENDING DOES OG&E SEEK TO RECOVER IN THIS CASE?

A. Almost all of the increase in T&D capital OG&E has been spending in recent years can be traced to increases Mr. Stephens and I would categorize as discretionary. These increases in T&D capital spending consist almost entirely of three types of spending: 1) (Equipment) Failures in Service; 2) Asset Improvement; and 3) Grid Enhancement. Before I get into too much detail, however, I wish to explore the benefits OG&E has delivered to its customers from extreme T&D spending increases in recent years.

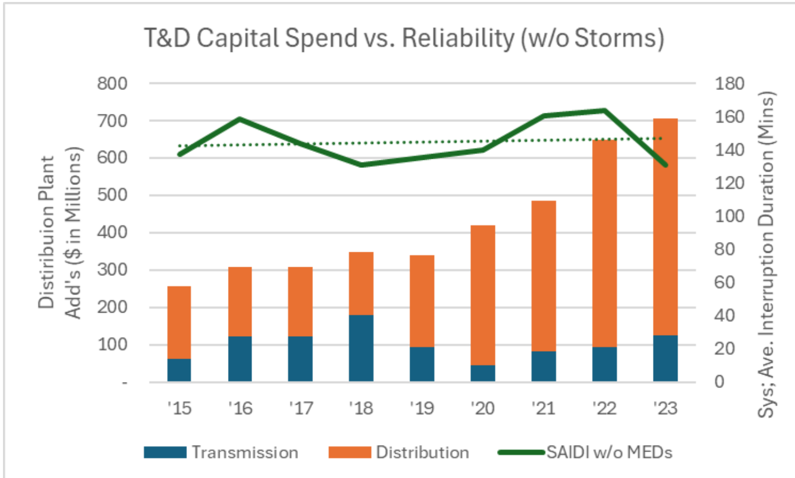
Q. WHAT BENEFITS HAS OG&E DELIVERED TO CUSTOMERS FOR T&D SPENDING INCREASES IN RECENT YEARS?

A. Not many. Figure 1 below compares growth in OG&E T&D capital spending in recent years[6] to its system average (service) interruption duration (in minutes) by year.[7] Despite doubling annual transmission spending and tripling annual distribution spending in the last five years, service interruption duration is largely unchanged. An improvement in reliability performance in 2023 is indicated, but one year's performance does not make a trend. Further, I see no evidence that a massive T&D capital spending increase in 2020 delivered any reliability improvements in 2021, nor any evidence that an additional T&D

[6] OG&E FERC Form 1. Electric Plant in Service – Additions, transmission and distribution. 2015-2023.
[7] OG&E's Annual Reliability Report to the Commission dated February 29, 2024, Figure 2, page 5 (2019-2023); OG&E's Energy Information Administration Form 861 filings, tab "Distribution Reliability" (2015-2018).

capital spending increase in 2021 delivered any reliability improvement in 2022.

Figure 1: OG&E T&D Capital Spending compared to outage duration, 2015-2023



Q. ARE THERE OTHER POTENTIAL CAUSES FOR T&D SPENDING TO INCREASE BEYOND OG&E'S DISCRETIONARY SPENDING DECISIONS?

A. There are some potential causes, but none are large enough, even in aggregate, to explain such large increases. Inflation can be a factor, but not likely larger than five or six percent or so in 2021 and 2022 (and less in 2023). Growth in coincident system peak demand is another potential explanation, though this has been relatively flat in the OG&E service area in recent years.[8] The October 2020 ice storm probably had an impact on 2020 distribution capital spending, but distribution capital spending continued to increase in 2021, 2022, and 2023. In fact, annual distribution capital spending more than tripled in the five years from 2018 ($168.5 million) to 2023 ($580.6 million). To summarize, it appears massive increases in T&D capital spending are the result of OG&E's discretionary choices.

[8] OG&E response to PUD 15-02.

Q. YOU MENTIONED T&D CAPITAL SPENDING INCREASES WERE PARTICULARLY SIGNIFICANT IN FAILURES IN SERVICE, ASSET IMPROVEMENT, AND GRID ENHANCEMENT. CAN YOU FURTHER ELABORATE?

A. Yes. Figures 2 and 3 below present the growth in capital spending in these categories in distribution and transmission, respectively. PUD Witness Mr. Stephens will cover increases in Failure in Service and Asset Improvement spending in his testimony. This testimony will address distribution capital spending increases due to Grid Enhancement.

Figure 2: Distribution capital spending increases by primary components.

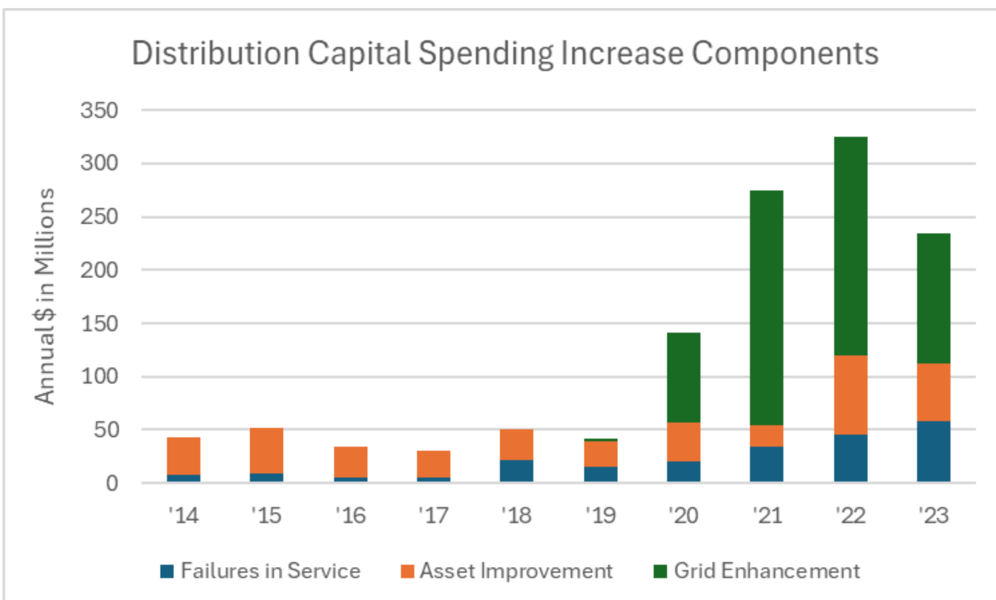
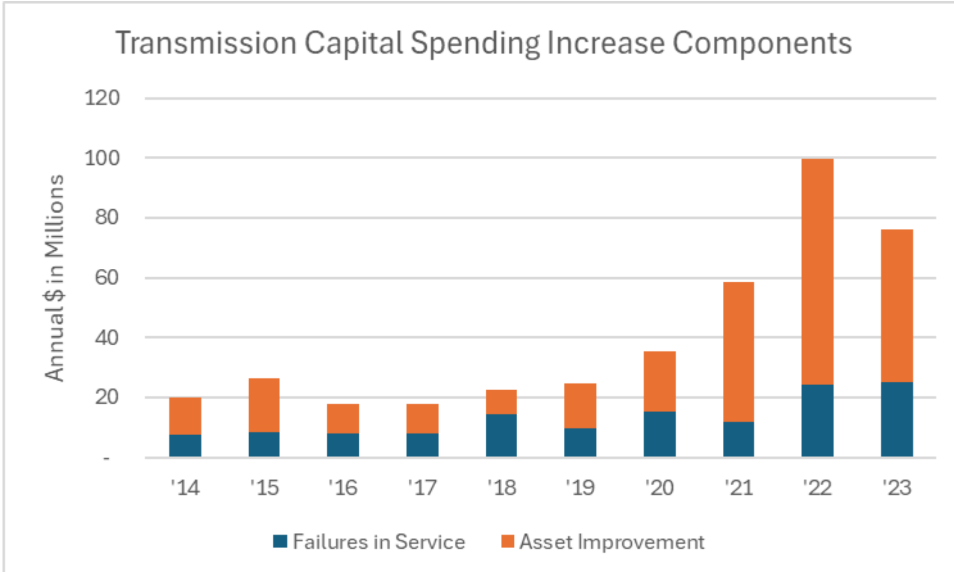


Figure 3: Transmission capital spending increases by primary components.



Q. PLEASE SUMMARIZE OG&E'S GRID ENHANCEMENT PROGRAM

A. OG&E first presented Grid Enhancement as a five-year, $810 million capital spending program to improve reliability and resilience early in 2020.[9] The proposal was part of OG&E's 2020 rate case and included a request for rider cost recovery (the Grid Enhancement Mechanism, or "GEM" rider). The program initially appears to have incorporated accelerated substation equipment replacements, but this spending appears to have been moved to Asset Improvement spending (without corresponding reductions in the size of the Grid Enhancement plan, as far as I have been able to discern). Additional spending was planned for grid automation (including both substation and distribution line components, as well as distribution lateral automation), grid hardening (including pole replacement, pole strengthening, and overhead and underground cable and equipment replacements/upgrades), and technology platforms and applications (including field data

[9] PUD 2020-000021. Testimony of Ms. Andrea Dennis on behalf of OG&E dated February 24, 2020 at 3.

communications capabilities).

Updates to proposed 2020-2021 Grid Enhancement program spending were provided late in the rate case, in July of 2020, along with a benefit-cost analysis. The $164.9 million 2021 investment plan was anticipated to reduce O&M spending by $108.4 million over time, while the combined 2020-2021 spending of $245.7 million was to have reduced overall SAIDI with storms by 71.8 minutes by the end of 2021.[10] As I indicated in my testimony on behalf of AARP at the time, I believed both reliability improvements and O&M savings estimates to be dramatically overstated.[11] Ultimately, intervenors reached a settlement with OG&E that authorized the GEM rider through October 2022, but limited it to a revenue requirement of $7 million annually.[12]

Q. IN ITS NEXT RATE CASE, OG&E UPDATED ITS GRID ENHANCEMENT PLAN AND REQUESTED A GEM RIDER EXTENSION, CORRECT?

A. Correct. In its most recent rate case, OG&E requested a prudence determination for Grid Enhancement projects placed into service through March 31, 2022. The Company also requested an expanded and extended GEM rider. The Company reiterated the benefit estimates from its previously-completed Grid Enhancement program benefit-cost analysis, and also hired Burns & McDonnell, a leading provider of electrical engineering services to investor-owned utilities,[13] to complete an "independent" benefit-cost analysis.

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[10] PUD 2020-000021. Testimony of Ms. Kandace Smith on behalf of OG&E dated July 31, 2020 at 4:1.
[11] PUD 2020-000021. Testimony of Paul J. Alvarez on behalf of AARP dated August 25, 2020.
[12] PUD 2020-000021. Joint Stipulation and Settlement Agreement filed October 5, 2020. Page 2.
[13] In April 2023, the Engineering News Record ranked Burns & McDonnell the top provider of engineering services to the electric power industry world-wide for the eighth consecutive year. Available at https://www.burnsmcd.com/news/2023-enr-ranking-7th-in-design-firms

Q. YOU AND PUD WITNESS MR. STEPHENS TESTIFIED IN THAT CASE ON BEHALF OF THE ATTORNEY GENERAL, CORRECT?

A. Yes. Mr. Stephens and I critiqued both OG&E's and Burns & McDonnell's benefit estimates as exaggerated in our respective testimonies. In addition, Mr. Stephens's testimony lamented the lack of conservation voltage reduction in the Grid Enhancement plan, a capability with significant, cost-effective energy efficiency potential. He also critiqued distribution lateral automation (a Grid Enhancement program) and prospective substation equipment replacement (which OG&E calls "Asset Improvement" spending) for their lack of cost-effectiveness. All these critiques remain in Mr. Stephens's instant testimony. He recommended disallowances of distribution lateral automation and Asset Improvement costs, and that the GEM rider be terminated pending a cost-effectiveness study of Grid Enhancement spending to date.[14]

In addition to critiquing OG&E's Grid Enhancement benefit-cost analyses and endorsing Mr. Stephens's recommendations, my testimony described problems with the rider cost recovery construct.[15] Specifically, when grid investment plans are presented for regulatory review in advance as part of the rider construct, I believe regulators' practical ability to disallow costs falls. Further, I believe advance investment plan review effectively shifts the burden of prudence from utilities to intervenors. Most offensively, I believe advance review of investment plans creates a moral hazard, as utilities like OG&E have nothing to lose, and everything to gain, by proposing excessive capital spending in such plans. I continue to harbor these concerns and encourage the Commission to consider them

[14] PUD 2021-000164. Testimony of Dennis Stephens dated April 27, 2022.
[15] PUD 2021-000164. Testimony of Paul Alvarez dated April 27, 2022.

when making decisions about Oklahoma utilities' rider cost recovery proposals in the future. My testimony also identified that commercial and industrial customers enjoy the lion's share of reliability benefits and criticized OG&E for failing to commit to reliability improvements or O&M spending reductions from its Grid Enhancement spending.[16]

Q. OG&E'S LAST RATE CASE WAS ALSO SETTLED, WAS IT NOT?

A. Yes, it was. In the settlement, intervenors agreed to a prudence determination for Grid Enhancement projects placed into service by March 31, 2022. The GEM rider was extended to July 1, 2025 but limited to a $6 million revenue requirement cap for each annual investment plan 2022 through 2024.[17]

Q. DID OG&E REDUCE THE SIZE OF ITS GRID ENHANCEMENT PLAN IN RESPONSE TO THE GEM RIDER LIMITATIONS?

A. No. OG&E appears intent on spending the majority of the $810 million originally projected for the Grid Enhancement plan irrespective of GEM rider limitations. OG&E appears confident that the Commission will not disallow capital spending of such significant size. It also seems that the Company is making up for the lack of enhanced cost recovery (limitations on the amount of cost recoverable through the GEM rider) through more frequent rate cases.

Q. HAS OG&E DELIVERED ON GRID ENHANCEMENT PROGRAM

[16] PUD 2021-000164. Testimony of Paul J. Alvarez dated April 27, 2022.
[17] PUD 2021-000164. Amended Joint Stipulation and Settlement Agreement dated June 30, 2022. P. 2-3.

EXPECTATIONS FOR RELIABILITY IMPROVEMENTS AND O&M SPENDING REDUCTIONS?

A. It is difficult to say for certain, as there are so many influences on both reliability performance and O&M spending to consider. Given the size of OG&E's Grid Enhancement program, a formal study completed by an independent third party on Grid Enhancement spending to date is certainly warranted. However, I provide two charts for Commission consideration which indicate that OG&E has not delivered on Grid Enhancement program expectations. Figure 4 below presents OG&E's system average interruption duration with storms from 2018-2023. Though performance for 2020 has been omitted to enhance clarity (the October 2020 ice storm durations dwarf all other years' performance), no 71.8-minute reduction in outage duration with storms included appears to have been delivered by $245.7 million in Grid Enhancement capital spending through 2021, as OG&E claimed it would.

Figure 4: OG&E System Average Interruption Duration with Storms over time.

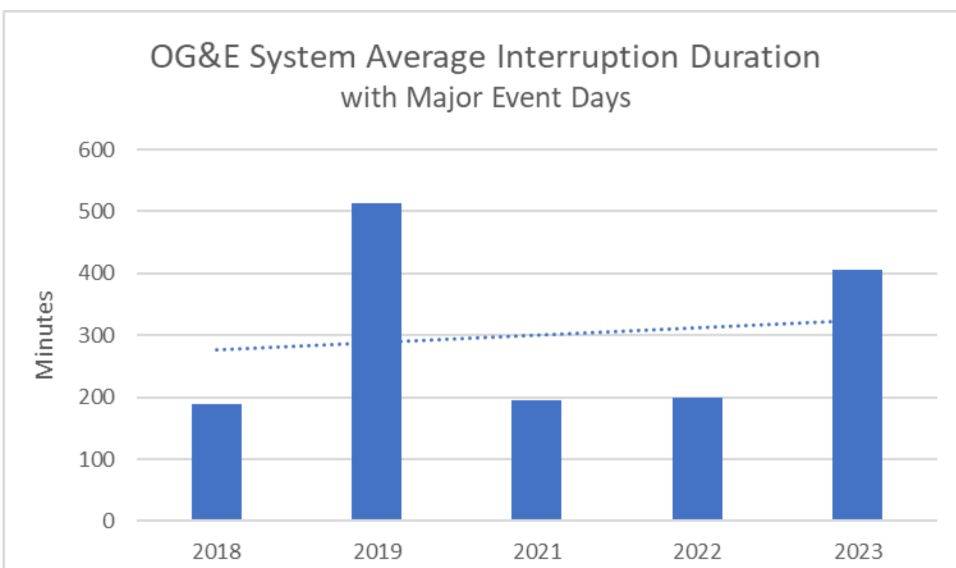
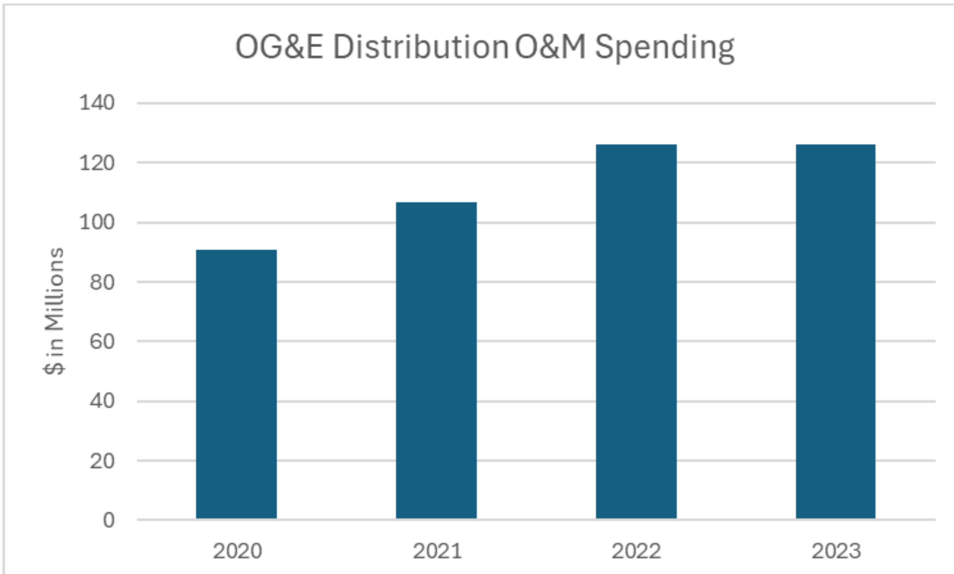


Figure 5 below presents OG&E's annual distribution O&M spending from 2020-2023. Significant annual year-on-year O&M spending increases do not make it easy to discern any O&M spending reductions from Grid Enhancement capital spending.

Figure 5: OG&E Distribution O&M Spending 2020-2023



Q. IS ANYTHING SHORT OF A FORMAL, INDEPENDENT STUDY AVAILABLE TO HELP DETERMINE THE VALUE DELIVERED BY OG&E GRID ENHANCEMENT SPENDING?

A. While a full independent study would be best, my Wired Group colleague, PUD Witness Mr. Stephens, completed as detailed an assessment of Grid Enhancement benefits as could be expected in the limited time available for discovery in this Case. In his assessment, Mr. Stephens evaluated the reliability benefits on 11 circuits selected at random from 54 circuits on which distribution circuit automation and distribution line hardening work was completed, and placed into service, during 2020.[18] Mr. Stephens selected 2020 because Grid Enhancement work placed into service that year offers the opportunity to compare three years' post-Grid Enhancement reliability performance (2021-2023) to three years' pre-Grid Enhancement reliability performance (2017-2019).

Mr. Stephens' assessment was not designed solely to quantify the reliability improvements from Grid Enhancement spending, as any utility can put a million dollars of new equipment on a circuit and improve that circuit's reliability. Instead, Mr. Stephens endeavored to determine whether the size and customer dollar value of the reliability improvements secured from Grid Enhancement exceeded the program's costs (a benefit-cost analysis).

The assessment consisted of three steps: 1) Quantifying the difference in average service interruption frequency and duration between pre- and post-Grid Enhancement on these circuits; 2) Translating the reliability difference into annual dollar values per average customer; and 3) Calculating the present value of these annual dollar values over an assumed 30-year benefit period, and comparing the present value of these customer benefits to OG&E Grid Enhancement spending (to determine the benefit-to-cost ratio).

Q. HOW DID MR. STEPHENS IDENTIFY THE DIFFERENCE IN AVERAGE SERVICE INTERRUPTION FREQUENCY AND DURATION BETWEEN PRE- AND POST-GRID ENHANCEMENT?

A. In discovery, Mr. Stephens secured detail on every service interruption on OG&E's

[18] Attachment PUD 09-02(a)_Att1

distribution system from 2017 through 2023.[19] It was a relatively simple (though laborious) matter to extract only the service interruptions occurring on the 11 circuits selected at random for detailed analysis. He found that pre-enhancement (2017 to 2019), the 11 circuits experienced 2,247 interruptions, with each interruption affecting an average of 30 customers for 4.635 hours. He also found that post-enhancement (2021 to 2023), 3,873 service interruptions occurred on the 11 circuits, averaging 32 customers and 1.95 hours. Thus, while service interruptions increased, average service interruption durations fell. Armed with this data, Mr. Stephens was able to tackle the next step: translating the reliability difference into customer dollar value.

Q. HOW DID MR. STEPHENS TRANSLATE THE RELIABILITY DIFFERENCE FROM GRID ENHANCEMENT INTO CUSTOMER DOLLAR VALUE?

A. Mr. Stephens employed the dollar values from an opportunity cost study completed by Lawrence Berkeley National Labs in 2015 (from customer research data most recently updated in 2013).[20] The dollar values by customer class (residential, small commercial, and large commercial/industrial) are the same ones used today in the U.S. Department of Energy's online Interruption Cost Estimator (ICE) tool, updated for inflation. (Mr. Stephens also updated the dollar values for inflation, applying a compound annual growth rate of 2.5% from 2013 to 2023.) While Mr. Stephens and I believe the values of service interruption opportunity cost from this ICE study are significantly exaggerated for non-

[19] PUD 2021-000164, Attachment AG 20-5_Att3 (2017-2019): Attachment PUD 02-05_Att1_Conf (2021-2023).
[20] Sullivan M, Schellenberg J, and Blundell M. *Updated value of Service Reliability Estimates for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory report LBNL-6941E. Table ES-1, page xii. January, 2015.

residential customers,[21] we note these are the most widely used values available.

By applying OG&E's overall customer class ratios (85.3% residential, 13.6% small commercial, and 1.1% large commercial/industrial)[22] to the ICE tool opportunity cost values, Mr. Stephens calculated a cost per customer per outage of $1,170 before Grid Enhancement, and $628 after Grid Enhancement – a significant customer benefit. However, this benefit was largely offset by the increase in interruption frequency on the 11 circuits. Across all service interruptions, the average customer cost of outages per circuit worked out to $2.38 million annually before Grid Enhancement, and $2.35 million annually after Grid Enhancement, an improvement of $31,000 per Grid Enhancement circuit per year.

Q. AT THAT POINT, MR. STEPHENS CALCULATED THE PRESENT VALUE OF THE ANNUAL BENEFIT OVER 30 YEARS FOR A COMPARISON TO COSTS?

A. Correct. Mr. Stephens escalated the benefits by 2% annually over 30 years to account for inflation, and then discounted the benefit stream back into today's dollars using OG&E's post-tax weighted average cost of capital (7.88%).[23] An annual $31,000 benefit over 30 years using these assumptions delivers an average present value per circuit of $433,000. Unfortunately, OG&E spent $10.8 million to enhance these 11 circuits, for an average cost of $985,000 per circuit. Mr. Stephens's analysis indicates, then, that Grid Enhancement delivered $0.44 in benefits for every $1 in Grid Enhancement capital spending on these 11 circuits ($433,000 divided by $985,000 is 0.44). I note that true benefit-cost ratio is

[21] PUD 2020-000021. Testimony of Paul J. Alvarez dated August 25, 2020. From 11:6 to 12:11.
[22] OG&E's 2022 Energy Information Administration Form 861, tab "Sales to Ultimate Customers".
[23] Schedule B - 1

something worse than that because customers actually pay $1.32 for every $1 in OG&E capital spending (owing to OG&E federal and state income taxes customers must pay).[24] Though short of a full study, Mr. Stephens's benefit-cost analysis certainly seems to indicate that Grid Enhancement capital spending is not cost-effective for OG&E customers.

Q. WHILE YOU CHALLENGE THE COST-EFFECTIVENESS OF OG&E'S CAPITAL SPENDING INCREASES, THE COMPANY CLAIMS ITS RATES ARE LOW RELATIVE TO U.S. AVERAGES.

A. I have not examined the validity of this claim. But even if true, the claim means nothing in isolation. First, OG&E rates are a combination of electric fuel costs as well as generation, transmission, and distribution costs. OG&E's generation fleet appears to consist of a relatively high proportion of coal-fired generation, and coal is a relatively inexpensive fuel. It is certainly possible that OG&E has relatively high transmission and distribution rates, which are being offset by low fuel costs. Thus, more work is needed before a conclusion that OG&E is a relatively low-cost utility can be reached.

Second, there are dramatic differences in utility labor costs by market, driven by costs of living; in one study, Oklahoma had the 2nd-lowest cost of living of any state in the U.S.25 One would therefore fully expect OG&E labor rates, and therefore OG&E's costs, to be much lower than elsewhere in the U.S. As a result, U.S. average electricity rates may not be an appropriate standard by which to judge OG&E's rates.

Finally, even if OG&E can prove it is a low-cost utility, that does not give the Company

[24] Ibid.
[25] Missouri Economic Research and Information Center, 2022.

free rein to increase transmission and distribution spending in ways that do not deliver benefits to customers in excess of costs to customers.

Q. BUT OG&E SEEMS SO CERTAIN OF GRID ENHANCEMENT'S VALUE PROPOSITIONS; ARE YOU CERTAIN GRID ENHANCEMENT IS NOT COST-EFFECTIVE?

A. As explained earlier, a formal, independent study is required to conclusively determine the cost-effectiveness of Grid Enhancement; the Ohio Public Utilities Commission has ordered its staff to solicit and oversee several such studies of utility grid modernization investment programs. Mr. Stephens's benefit-cost analysis, and the size of OG&E's Grid Enhancement program, certainly indicate that such a study is warranted. In the absence of such a study, I make several observations on Grid Enhancement spending that seem to corroborate Mr. Stephens's findings, and these are the subject of the next section of this testimony.

LIKELY EXPLANATION FOR THE LACK OF GRID ENHANCEMENT COST-EFFECTIVENESS

Q. PLEASE PREVIEW THIS SECTION OF TESTIMONY.

A. This section of testimony explores potential reasons why OG&E Grid Enhancement may not be cost-effective. Primary among these is a distinct lack of focus in OG&E Grid Enhancement spending. Grid Enhancement consists of many individual spending programs. But despite the fact that several years of post-Enhancement results are now available on many circuits, OG&E has not quantified the actual benefits delivered by various Grid Enhancement programs and subprograms. Without such an analysis, the Company cannot know which programs or subprograms h deliver the greatest benefit for the least cost. Further, no reliability improvement program is cost-effective on all circuits; a variety of drivers serve as potential indicators of which circuits are most likely to benefit from Grid Enhancement. Yet OG&E appears to us to apply Grid Enhancement to too many circuits which are unlikely to deliver benefits. I believe a lack of focus results in excess capital spending that is not as cost-effective as it could be, and this section of testimony examines this hypothesis. The law of diminishing returns will be introduced to lend credence to the hypothesis, and details of how I arrived at a cost disallowance of $90.7 million in Grid Enhancement spending will be provided.

Q. YOU STATE THAT OG&E DOES NOT KNOW WHICH GRID ENHANCEMENT PROGRAMS OR SUBPROGRAMS DELIVER BENEFITS IN EXCESS OF COSTS. HOW CAN THAT BE?

A. As described earlier, "Grid Enhancement" consists of multiple technologies and approaches. OG&E has defined approximately six types of programs within Grid Enhancement, including substation automation, circuit automation, lateral automation (TripSavers), circuit hardening (which OG&E also calls "grid resilience"), technology platforms, and highway crossings.[26] These definitions seem to ebb and flow over time, presenting a challenge to benefit-cost analysis development and validation over time. For example, prospective substation equipment replacement, which was initially proposed as

[26] Attachment OIEC 18-09_Att5.

part of Grid Enhancement, now seems to be part of Asset Improvement spending, a capital spending category completely external to Grid Enhancement.

In addition, some Grid Enhancement programs contain multiple subprograms. For example, ATO (automatic throw over, a type of switch) automation and capacitor automation have been added as subprograms within circuit automation,[27] and circuit hardening appears to consist of at least seven different types of efforts, including pole/crossarm replacements, pole structural strengthening, lightning arrestor replacements, animal guard installations, transformer capacity upgrades, overhead conductor replacements, and underground cable replacements.[28] As all of this spending appears to be discretionary, Mr. Stephens and I believe all Grid Enhancement programs and subprograms should be the subject of their own individual assessments of benefits actually delivered. Only then can OG&E understand which programs and subprograms are contributing to, rather than detracting from, cost-effective reliability improvement, and under which conditions or circumstances.

Q. NOW THAT SOME OF THESE GRID ENHANCEMENTS HAVE BEEN IN PLACE FOR A FEW YEARS, CAN OG&E COMPLETE A REVIEW TO DETERMINE THE ACTUAL BENEFITS DELIVERED BY INDIVIDUAL PROGRAMS AND SUBPROGRAMS?

A. No, I do not think that is possible. This is because every circuit (and downstream lateral) has received multiple Grid Enhancement program and subprogram applications. There is

[27] Ibid.
[28] Multiple Grid Enhancement circuit plans provided in response to PUD 09-06(b).

almost no way to isolate the impact of any individual program or subprogram because no individual circuit can be employed as a pure example of the application of a single program or subprogram to study. It is also likely that OG&E completed vegetation management on Grid Enhancement circuits, constituting yet another variable that may contribute to enhanced reliability performance which cannot be claimed as a result of Grid Enhancement spending. (Vegetation management is typically required for many types of circuit hardening work, but the Company claims it cannot identify which circuits were cleared of vegetation in 2020.)[29]

Q. IS IT APPROPRIATE TO SPEND HUNDREDS OF MILLIONS OF DOLLARS ON GRID ENHANCEMENT PROGRAMS AND SUBPROGRAMS FOR WHICH BENEFITS AND COSTS ARE UNKNOWN?

A. No, it is not. But the Grid Enhancement spending is even more poorly focused than has been described thus far, as individual circuit characteristics drive the benefits available from various Grid Enhancement programs and subprograms. A program or subprogram that might be cost-effective on one circuit or lateral might not be cost-effective on a different circuit or lateral.

Q. CAN YOU PROVIDE ANY EXAMPLES?

[29] Response to PUD 15-4(a). However, from detail provided by OG&E in its Annual Reliability reports, it is clear that significant vegetation management (more than 8 miles cleared) was completed in 2021 and 2022 on 29 of the 54 circuits on which Grid Enhancement was completed in 2020. This certainly helped to improve the reliability of these circuits in Mr. Stephens and my analyses of the impact of Grid Enhancement on these circuits from 2021-2023.

A. In Mr. Stephens and my experience completing benefit-cost analyses on multiple grid technologies, we have identified multiple drivers of cost effectiveness that vary by circuit. For example, drivers of circuit automation benefits include counts of customers served, types of customers served,[30] service interruption history (many vs. few), service interruption cause types (equipment vs. vegetation), and fault characteristics (permanent vs. transient). The benefits of lateral automation are also driven by these characteristics, which vary by lateral. OG&E appears to consider some of these variables through a model it uses to project circuit-specific benefits and claims to select circuits for Grid Enhancement using the model's outputs.[31] But such an approach is only as good as the model and its inputs, and I maintain serious reservations about both.

Q. WHAT ARE YOUR CONCERNS WITH THE BENEFIT ESTIMATION MODEL OG&E USES TO SELECT CIRCUITS FOR GRID ENHANCEMENT?

A. My biggest concern is that OG&E has not updated its model for actual results delivered by Oklahoma Grid Enhancement work to date. The input assumptions the model employed to select circuits for Grid Enhancement in 2023[32] are exactly the same as the assumptions the model employed to select circuits for Grid Enhancement in 2021.[33] Given that three years' actual results from Grid Enhancements implemented in 2020 are now available, this is concerning. It means that OG&E has not validated its model by examining how accurate the model is at predicting the actual benefits Grid Enhancement will deliver when applied

[30] Commercial and industrial customers incur higher opportunity costs from service interruptions than residential customers, and thus secure greater benefits from avoided service interruptions than residential customers.
[31] Attachment PUD 15-08(a)_Att1.
[32] Attachment OIEC 18-09_Att3.
[33] Attachment OIEC 18-09_Att1.

to a circuit. If OG&E were truly interested in selecting only circuits on which Grid Enhancement is likely to be cost-effective for capital spending, the Company would continuously adapt the model and its inputs to make the model's benefit estimates more and more accurate over time. There is no evidence of such adaptation. Many of the model's most critical inputs appear to be best guesses with no validation whatsoever.

Q. CAN YOU PROVIDE SOME EXAMPLES OF THE MODEL'S USE OF BEST GUESSES THAT HAVE NOT BEEN VALIDATED?

A. Yes. OG&E's model assumes that minor storm restoration costs will fall 50% after Grid Enhancement;[34] that number seems to be a guess. OG&E's model assumes that service interruptions and service interruption durations will fall 60% after Grid Enhancement;[35] that number seems to be based on a single year's worth of results from grid enhancement spending on 14 of the Company's Arkansas circuits in 2018. I first critiqued this assumption in testimony on behalf of AARP before the Commission when the Company first proposed its Grid Enhancement program in 2020. My concerns with the 60% reduction assumption now are the same as the concerns I described then: 1) One should not base a reliability improvement assumption on a single year's results; and 2) The 60% reduction was calculated without storms, though the model applies the same reduction to all historical interruptions, with storms included (resulting in significant benefit estimate overstatement).[36]

[34] OIEC 18-09 (a)_Att 3.
[35] Ibid.
[36] PUD 2020-000021. Testimony of Paul J. Alvarez dated August 25, 2020. From 7:12 to 8:16.

My 2020 testimony describes other concerns with the OG&E circuit benefit estimate model that I continue to maintain today. I am concerned that the U.S. Department of Energy's online Interruption Cost Estimator (ICE) tool exaggerates the customer benefits of avoided service interruptions;[37] the same $1.9 billion major storm benefit assumption that the model employed in 2019 is still in use today. I am also concerned that O&M savings assumptions are based on fully-loaded costs per activity rather than estimates of employee/contractor headcount and overtime reductions that might be available (marginal cost avoidance);[38] the same benefit assumptions of $500 per truck roll avoided and $5.16 per customer call avoided that the model employed in 2019 are still in use today. To summarize, the model the Company uses to select circuits for Grid Enhancement spending cannot be relied upon, and no efforts to make it reliable, or to validate the benefits the model estimates, appear to be underway.

Q. IS THERE ANY EVIDENCE THAT OG&E'S CIRCUIT BENEFIT ESTIMATION MODEL RESULTS IN POOR CIRCUIT SELECTION?

A. Yes, there is. As indicated above, OG&E completed circuit automation and circuit hardening work on 54 circuits in 2020. I compared the average interruption duration for each of these circuits in 2019 to OG&E's system-wide average interruption duration in 2019 (512.95 minutes with storms, and 134.39 without storms).[39] Of the 54 circuits OG&E selected for Grid Enhancement in 2020,[40] 33 (61%) had storm SAIDI better than average

[37] Ibid, from 11:6 to 12:11.
[38] Ibid, from 14:4 to 14:25.
[39] Attachment PUD 02-01(b)_Att1.
[40] Attachment PUD 09-02(a)_Att1.

in 2019, and 25 (46%) had non-storm SAIDI better than average in 2019.[41] Spending significant Grid Enhancement capital on circuits that are already above-average performers is no way to target such spending. Unfocused spending does not put OG&E capital – capital for which OG&E's customers must pay – to its highest and best use. In fact, OG&E's worst-performing feeder program ("WPF"; the terms "feeder" and "circuit" are synonymous) does a much better job of focusing spending. The WPF program examines the circuits performing in the bottom 5% of all circuits annually in an attempt to identify low-hanging opportunities to improve reliability. My educated guess is that the cost-effectiveness of OG&E's WPF program is much greater than the cost-effectiveness of OG&E's Grid Enhancement program due solely to differences in the level of focus between the two programs.

Q. HOW WOULD THE COMPANY RESPOND TO YOUR CRITIQUE THAT CIRCUIT SELECTION IS POOR, LEADING TO UNFOCUSED SPENDING?

A. The Company has already responded to my critique in discovery, stating that worse-than-average reliability performance is not "the only consideration given to select a circuit for investment in the Grid Enhancement Program."[42] Yet the Company has continued to describe its Grid Enhancement program as "needed . . . to improve reliability and resiliency."[43] I argue that Grid Enhancement spending was discretionary, not "needed", and that the reliability and resilience improvements secured from the spending have been insufficient to justify customer costs.

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[41] Attachment PUD 02-04_Att1, 54 circuits (from Attachment PUD 09-02(a)_Att1) selected.
[42] PUD 15-08 (a).
[43] Testimony of Mr. Kimber L. Shoop, January 2024. From 4:24 to 5:4.

Q. HAVE YOU OBSERVED THAT THE LACK OF FOCUS IN CIRCUIT SELECTION DELIVERS SUBOPTIMAL RELIABILITY IMPROVEMENTS?

A. Yes. Using the 54 circuits to which Grid Enhancement work was placed into service in 2020,[44] I compared the average interruption duration for each circuit 2019-2020 to the average interruption duration for each circuit 2021-2023, both with and without storms.[45] With storms, circuit average interruption duration went up on 13 of the 54 circuits (24%); of these 13, all but one were the circuits selected for Grid Enhancement in 2020 for which 2019 performance with storms was already better than average. Without storms, circuit average interruption duration went up on 26 of the 54 circuits (48%). Of these 26, 16 were the circuits selected for Grid Enhancement in 2020 for which 2019 performance without storms was already better than average.[46] These results indicate to me that OG&E is wasting capital on circuits that do not need the help.

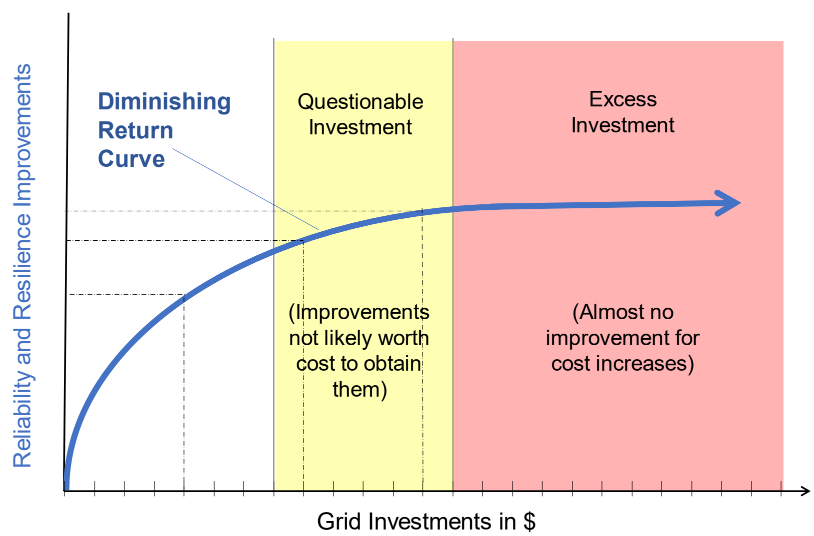
Q. YOU MENTIONED THE LAW OF DIMINISHING RETURNS. WHAT DOES THAT HAVE TO DO WITH OG&E'S GRID ENHANCEMENT SPENDING?

A. The law of diminishing returns, more properly known as the law of diminishing marginal returns, is a fundamental economic principle. It was first documented by an 18th century French administrator, Anne Robert Jacques Turgot, one of the founding fathers of modern economics. He observed that doubling the amount of time and capital input into a field (literally, as in agriculture) does not necessarily double the output. He notes "as the soil

[44] Attachment PUD 09-02(a)_Att1.
[45] Attachment PUD 02-04_Att1, 54 circuits (from Attachment PUD 09-02(a)_Att1) selected.
[46] Ibid.

approaches the point where it yields as much as it can produce, a very large outlay can only increase the product slightly."[47] What he describes eventually becomes the diminishing marginal returns curve, presented in Figure 6 below, but applied to electric grid reliability.[48] As the chart implies, and as Turgot noted, every incremental unit of input (in this case, a dollar of capital) delivers a bit less reliability improvement than the dollar most recently spent. At some point, called the point of diminishing return, the value of the incremental improvements is less than the dollars added. While a business operating in a competitive industry would never invest past the point of diminishing return, a for-profit monopoly with capital bias, like OG&E, absolutely will.

Figure 6: The Law of Diminishing Return applied to grid reliability and resilience.



Q. CAN YOU POINT TO ANY EXAMPLES?

[47] Turgot, AR. *Observations on a Paper by Saint-Péravey on the Subject of Indirect Taxation*. 1767.
[48] Alvarez P, Stephens D, Costello K, and Ericson S. *Alternative Ratemaking in the US: A Prerequisite for Grid Modernization or an Unwarranted Shift of Risk to Customers*?, 35 Electricity J. 107200 (2022).

A. Yes. Spending Grid Enhancement capital on circuits that are already performing better than the average circuit is certainly an example of spending beyond the point of diminishing return. But another strong example is available. OG&E reports that the first tranche of 128 circuits selected for Grid Enhancement[49] were responsible for about 38.5% of system-wide service interruption duration in 2018 (per Figure 1 of Mr. Huckabay's testimony).[50] The next tranche of 139 circuits selected for Grid Enhancement were responsible for only about 23.1% of system-wide service interruption duration in 2018.[51] This indicates the law of diminishing returns in action. The more circuits on which OG&E spends Grid Enhancement capital, the smaller the reliability improvements that can be expected. An $810 million spending plan allows for a lot of circuits to receive Grid Enhancement capital, and in my opinion virtually guarantees that spending past the point of diminishing return will occur. The benefit-cost analysis Mr. Stephens completed indicates that OG&E has already spent capital beyond the point of diminishing return.

Q. BUT CERTAINLY, POLE REPLACEMENTS AND HARDENING ARE WORTHWHILE GRID ENHANCEMENT INVESTMENTS GIVEN OKLAHOMA'S TORNADOS, WINDSTORMS, AND ICE STORMS, IS IT NOT?

A. I would not make that conclusion. I examined one year's worth of Grid Enhancement circuit plans covering 65 circuits.[52] These plans called for 5,377 pole replacements and

[49] Response to PUD 02-11(b).
[50] Testimony of Mr. Brian C. Huckabay, December 29, 2023. (Hereinafter, "Huckabay Testimony"). P. 5.
[51] Response to PUD 15-06(b).
[52] Sixty-five Grid Enhancement circuit plans provided as attachments in response to PUD 9-06(b).

152 pole upgrades. Assuming a cost of $4,500 per replacement and $1,500 per upgrade, that amounts to a $24.4 million pole capital spending plan.

OG&E estimates it maintains 735,500 wood poles.[53] Thus, for $24.4 million, OG&E's Grid Enhancement program is only addressing an additional 0.75% (7.5 in 1,000) poles per year.[54] I also note that in a typical year, such as 2023, OG&E might replaces 2,400 poles due to storms,[55] or about 0.32% (3.2 in 1,000) of poles. The notion that the 0.75% of poles OG&E is replacing annually through Grid Enhancement will coincide with the 0.32% of poles storms will destroy in a year is fanciful. The portion of OG&E's service area hit by storms varies every year. Even over 30 years, equivalent to replacing 22.5% of OG&E's poles as part of the Grid Enhancement program (30 years X 0.75% per year), the coincidence likelihood remains small. Furthermore, there is no guarantee that a relatively new or upgraded pole will survive a tornado, or falling tree, or three-inch ice storm any better than a 40-year-old pole that has passed its most recent inspection. Finally, poles are replaced in the routine course of business all the time, for example due to road widening projects, or circuit capacity expansions, or OG&E's existing pole inspection program. The idea that an increase in pole replacement rates will deliver reliability improvements of customer value in excess of costs cannot be assumed, and can only be determined through a formal benefit-cost study.

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[53] PUD 15-13 (d).
[54] 5,529 poles divided by 735,500 poles. I assume that OG&E's long-standing pole inspection program, which sometimes results in pole replacement and/or hardening, has continued alongside the new Grid Enhancement circuit hardening program.
[55] Huckabay testimony at 9:15. 3,600 poles replaced over 18 months is equivalent to 2,400 poles in 12 months.

Q. BUT WHAT OF CUSTOMER SATISFACTION? CERTAINLY, RELIABILITY IMPROVEMENTS IMPROVE CUSTOMER SATISFACTION.

A. Yes, there is a relationship between OG&E reliability and OG&E customer satisfaction. There is also a relationship between OG&E rates and OG&E customer satisfaction. Of the two, I note that OG&E's customers are overwhelmingly satisfied with the Company's reliability performance. No aspect of OG&E service measured in its satisfaction surveys is rated more highly by customers than OG&E's reliability.[56] Thus, OG&E's decision to spend hundreds of millions of dollars in capital to improve reliability and resilience was the Company's own. The decision was not dictated by customer dissatisfaction with existing reliability.

Conversely, OG&E's customers are overwhelmingly dissatisfied with OG&E rate increases. Regardless of customer class, no aspect of service OG&E measures is rated lower by the Company's customers than rates.[57] Further, OG&E research indicates that only a minority of customers[58] would be willing to incur rate increases for more reliable service. In light of this research, one could easily conclude that by choosing to increase capital spending (and rates) to improve an aspect of service (reliability) with which customers are already highly satisfied, OG&E is prioritizing shareholder needs over customer needs.

[56]Confidential attachment PUD 02-10(c)_Att1_Conf. Slides 22, 27, and 32.
[57]OIEC 7-20(Attachment "Escalent_2023YearEnd_ResBus_Industry_Redacted". Slides 10 (Residential) and 32 (Business).
[58] Confidential attachment PUD 02-10(c)_Att2_Conf.

Q. WHAT ARE YOUR OVERALL RECOMMENDATIONS TO THE COMMISSION REGARDING OG&E'S GRID ENHANCEMENT PROGRAM?

A. As a preliminary matter, I encourage the Commission to consider commissioning an independent study of benefits delivered by OG&E Grid Enhancement spending to date before considering GEM rider expansion or extension. Mr. Stephens recommended this in his testimony on behalf of the Attorney General in O&GE's last rate case,[59] and I agree it is a good idea.

As far as formal recommendations are concerned, I recommend that the Commission disallow $90.7 million in Grid Enhancement capital costs from customer recovery. The justification for the disallowance is a lack of focus in the Company's circuit selection. To determine this figure, I examined the list of 192 circuits on which Grid Enhancement was completed (placed into service) since the last rate case.[60] I also examined lists of the Company's worst-performing circuits in 2020, 2021, and 2022, consisting of 137 circuits.[61] I would have liked to have seen OG&E concentrate its Grid Enhancement spending on these 137 worst performing circuits. To my dismay, of the 192 circuits on which Grid Enhancement capital was spent since the last rate case, only 43 appeared on the list of worst-performing circuits 2020-2022. Due to a lack of focus, I recommend the Commission disallow $90.7 million in Grid Enhancement capital that was spent on the 149 circuits that were not on the worst-performing circuit list 2020-2022.

[59] PUD 2021-000164. Testimony of Dennis Stephens dated April 27, 2022.
[60] Attachment PUD 15-12(a)_Att1.
[61] Attachment PUD 15-09(b)_Att1.

OG&E'S VEGETATION MANAGEMENT PROPOSALS

Q. PLEASE PREVIEW THIS SECTION OF TESTIMONY.

A. This section of testimony addresses OG&E's vegetation management proposals, including 1) A proposal to nearly double the annual vegetation management budget from $30 million to $58 million; and 2) A proposal that the Company track, as a regulatory asset, vegetation management spending in excess of the annual budget for subsequent recovery from customers (to include a rate of return for the Company on such spending). Regarding the first proposal, though I recommend an increase, I will present data indicating that the increase should be much smaller than what the Company is requesting. I will then present arguments opposing OG&E's proposal to capitalize vegetation management budget overspending as a regulatory asset, which I recommend the Commission reject.

Q. WHY DOES THE COMPANY PROPOSE SUCH A SIGNIFICANT INCREASE IN ITS VEGETATION MANAGEMENT BUDGET?

A. The Company presents data indicating that the hourly rates it pays to its vegetation management contractors has increased dramatically in recent years. The Company's data indicates an average hourly wage increase of 63% since 2015, spread over four different contracting companies and three different labor classes. The Company cites vegetation management labor supply (constrained) and demand (high) as contributors to wage growth. The Company also cites increases in customer tree trimming requests and a need to increase substation vegetation management.[62]

[62] Direct Testimony of Mr. Robert Shaffer dated December 29, 2023, from 6:13 to 8:13.

Q. WHAT IS YOUR IMPRESSION OF THESE JUSTIFICATIONS?

A. I have several concerns. First, an average labor cost percentage increase means little on its own, as the 63% is a simple average. The 63% average is not weighted by relative billings by contracting company or by relative use of various labor types, nor is labor the only type of cost OG&E sees from its vegetation management contractors. Further, options are available to the Company to shift work from higher-cost contractors to lower-cost contractors, and from more experienced labor to less experienced labor. Additionally, options are available to the Company for increasing the supply of vegetation management labor. We are aware of at least one utility (DTE) that has established a vegetation management recruiting and training program. Regarding customer-requested tree-trimming, many of these projects would have been completed as part of routine line-clearing activity anyway; I consider this to be more a matter of cost timing (for example, this year versus next year) than cost amount. Regarding substation vegetation management, no trees are allowed to grow in substations, making this one of the least costly types of vegetation management to complete. Further, OG&E reports no service interruptions due to equipment contact with vegetation in substations.[63]

Q. IS THERE A BETTER WAY TO DETERMINE AN APPROPRIATE LEVEL OF VEGETATION MANAGEMENT SPENDING?

A. Yes. In my opinion, the best way to determine an appropriate vegetation management budget is to determine the average cost to clear one mile of overhead line, and then to multiply that average cost by the number of line miles that must be cleared in a year to

[63] PUD 13-03.

ensure that 100% of overhead line miles are cleared every four years.[64] A historical inflation rate (compound annual growth rate, or "CAGR") can be applied to translate recent activity and costs into an appropriate test year amount.

Q. DID YOU APPLY THAT APPROACH IN THIS CASE?

A. Yes. From 2019 to 2022, OG&E's average cost to clear one mile of distribution line grew from $4,701 per mile to $5,893 per mile, for a CAGR of 7.8%. OG&E's average cost to clear one mile of transmission line grew much more slowly, from $2,389 to $2,425 (a CAGR of 0.5%), over the same period.[65] I note that these increases are nowhere near the average 63% wage rate growth OG&E uses to justify doubling its vegetation management budget. Using the 2021 miles cleared as targets (4,681 miles for distribution and 2,437 miles for transmission – both high water marks in recent years), simple multiplication results in unadjusted 2022 spending (had 2022 miles cleared been the same as 2021) of $27.583 million for distribution and $5.911 million for transmission. From there, it is a relatively simple matter to apply the historical CAGR (7.8% for distribution and 0.5% for transmission) to the 2022 values to get an appropriate test year value. Finally, I add the Company's request for non-cycle trimming and substation trimming costs. These calculations can be found in the table below.[66]

($ in million)	2022 unadjusted	Apply CAGR to get	Add OG&E	Add OG&E request for substations	Total Test Year Vegetation Mgmt. Budget

[64] Commission Rule 165:35-25-15(c) states "Each utility shall, at a minimum, perform vegetation management on a 4-year cycle, unless needed otherwise or unless otherwise ordered by the Commission."
[65] Dollar amounts from attachment OIEC 08-13_Att1; Miles cleared from attachment PUD 16-05 (a) Att2.
[66] Neither this testimony nor these calculations reflect the reductions in the Company's requested vegetation management increase shown in the Company's updated response to AG 16-12 ($1.6 million reduction in requested distribution increase and $2.5 million reduction in requested transmission increase).

		2023 (TY) $	request for non-cycle		
Distribution	$27.583	$29.741	$1.805	$0.868	$32.414
Transmission	5.911	5.940	-	0.473	6.413
	Totals	$35.681	$1.805	$1.341	$38.827

Q. WHILE NOT AS LARGE AS OG&E'S REQUEST, YOUR RECOMMENDATION STILL REPRESENTS A 39% INCREASE OVER THE EXISTING VEGETATION MANAGEMENT BUDGET. IS YOUR RECOMMENDATION TOO GENEROUS?

A. I do not believe it is. Vegetation management is one of the most cost-effective ways a utility like OG&E can maintain reliability performance. An appropriate budget ensures the Commission that the revenue requirements reflected in the Company's rates are sufficient to provide a reasonable opportunity for the Company to earn its authorized rate of return. However, I caution that establishing an appropriate vegetation management budget is only part of the Commission's ongoing vegetation management responsibility. The other part of the Commission's responsibility is to ensure that the Company actually clears 25% of its overhead line miles every year. If the Commission approves a $38.8 million annual vegetation management budget, but the Company only spends $28.8 million of that budget (as an example), the Company increases its earnings by $10 million while simultaneously increasing the likelihood of service interruptions (by not clearing close to 25% of overhead line miles annually). If the Commission agrees with my recommendation by approving the 39% increase in the vegetation management budget I recommend, the Company must do its part by committing to clearing close to 25% of overhead line miles annually. I recommend PUD diligently enforce compliance with its line clearing regulation annually, employing OG&E's annual reliability reports as an opportunity to do so. When OG&E

fails to comply with the line clearing regulation, I encourage the Commission to order whatever disciplinary and remediation actions it deems appropriate.

Q. HAS OG&E NOT BEEN CLEARING ITS OVERHEAD LINES IN A TIMELY MANNER IN THE PAST?

A. No, it has not. For example, OG&E reports clearing just 4,246 miles in 2022, and just 1,379 overhead distribution line miles in 2023.[67] These amounts are just 91% and 30% of the highwater mark of 4,681 distribution line miles cleared in 2021. The Company is falling behind on its vegetation management responsibilities, and clearly has some catching up to do. It occurs to me that instead of spending tens or hundreds of millions of dollars annually on distribution automation and lateral automation – Grid Enhancement technologies designed in part to reduce the outages associated with transient (as opposed to permanent) faults, which are most often caused by vegetation contact – OG&E should instead be meeting its annual line-clearing obligations. Of course, as vegetation management is an O&M expense, and Grid Enhancement represents capital spending on which a return can be earned, it is incumbent upon the Commission, PUD, and intervenors to ensure OG&E keeps up with its line clearing obligations, and to ensure OG&E capital spending is not justified by problems of the Company's own making.

[67] OG&E Annual Reliability Reports dated February 28, 2022, February 28, 2023, and February 29, 2024.

Q. DO YOU BELIEVE OG&E'S NEED TO "CATCH UP" ON VEGETATION MANAGEMENT HAS ANYTHING TO DO WITH ITS PROPOSAL TO ESTABLISH A REGULATORY ASSET FOR VM BUDGET OVERSPENDING?

A. Yes. I believe the timing of OG&E's proposal to establish a regulatory asset for budget overspending has everything to do with the Company's need to catch up on vegetation management. But before proceeding, let us examine the Company's proposal in greater detail.

To be fair, the Company proposes a symmetrical approach to vegetation management spending which varies from its annual budget. That is, the Company proposes to establish a regulatory asset for any spending over the annual vegetation management budget, and also to establish a regulatory liability for any spending below the annual vegetation management budget. While the symmetrical approach the Company proposes provides the appearance of an equitable arrangement, in practice, such an arrangement is not equitable. This is because if the Commission permits OG&E to earn a return on vegetation management overspending (via a regulatory asset), the likelihood that OG&E will overspend its vegetation management budget is dramatically greater than the likelihood that OG&E will underspend its vegetation management budget.

Q. BUT YOU JUST DESCRIBED OG&E'S INCENTIVE TO UNDERSPEND ITS VEGETATION MANAGEMENT TO HIT EARNINGS TARGET.

A. Yes, I did. Under the current arrangement (no regulatory assets or liabilities), the Company can increase earnings in one year by deferring vegetation management spending to future years. But under the current arrangement, the Company cannot profit in future years by doing so. Under the current arrangement, any deferred vegetation management spending will harm Company earnings in future years, when overspending is required to catch up on deferred vegetation management. Assuming OG&E eventually does catch up, I think this anticipated penalty is a good thing, as it helps discourage vegetation management deferrals that harm reliability in the first place.

Under the proposed arrangement, the Company will benefit from overspending, because the regulatory asset will earn a rate of return for the Company when it is amortized in a future rate case. Thus, under the proposed arrangement, the Company can benefit in two ways by manipulating the amount of line miles cleared annually. First, in any one year, the Company can increase earnings by deferring vegetation management spending.[68] Though this would result in a regulatory liability owed to customers, in a future year, when "catch-up" vegetation results in over-spending, the associated regulatory asset can be used to offset the regulatory liability. Thus, OG&E's proposal allows the Company to benefit from vegetation management deferral but ensures OG&E incurs no penalty in future years from such deferrals. Second, to the extent the size of regulatory assets (overspending) over time exceeds the size of regulatory liabilities (underspending) over time, the Company will be able to earn a return on the excess of regulatory assets over regulatory liabilities. To summarize, the Company's proposal allows OG&E to benefit from underspending its vegetation management budget when it chooses while simultaneously encouraging OG&E to significantly overspend its budget periodically.

[68] The requirement that the Company establish a regulatory liability for any underspending under the Company's proposal does not affect the improvement to earnings from any such underspending. Underspending vegetation management in any one year will still improve the Company's earnings in that year, even though the Company would be required to establish a regulatory liability for the underspending.

Over time, given OG&E's profit motive, it is much more likely that overspending/regulatory assets will exceed underspending/regulatory liabilities than the other way around. That is a big downside to the Company's proposal from customers' perspectives, but there are at least two more. First, when the Company defers line miles cleared based on its earnings situation, customers suffer from reduced reliability. Second, Oklahoma's two investor-owned utilities are so large as to dominate the market for vegetation management labor.[69] The Company's proposal, which appears likely to result in wide swings in line miles cleared from year to year, is likely to create boom and bust cycles in the vegetation management labor market. In every bust cycle, experienced laborers will be laid off. Many will find other work and never return. This creates shortages in the supply of vegetation management labor which must be addressed in boom cycles through increased labor rates, resulting in the very contractor cost escalation OG&E blames in its request for a large increase in its vegetation management budget.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION REGARDING OG&E'S VEGETATION MANAGEMENT PROPOSALS?

A. In my opinion, vegetation management is too critical to reliability to be subjected to dramatic year-to-year fluctuations. My recommendation is that the Commission establish a budget that allows OG&E to clear 25% of its line miles annually, and that the Commission closely monitor miles cleared annually to ensure the Company does not fall

[69] In its recent application for a rate increase, Public Service of Oklahoma (PSO) duplicates OG&E's proposal for regulatory asset tracking for vegetation management overspending, though unlike OG&E, PSO does not propose regulatory liability tracking for any underspending. See PUD 2023-000086, Direct Testimony of Ms. Jennifer R. Ellis, January 2024, from 4:18 to 5:18.

behind on its line-clearing obligations. As described above, my calculations indicate that a $38.8 million annual vegetation management budget will enable OG&E to clear 25% of its line miles annually. My second recommendation is for the Commission to reject OG&E's proposal to track vegetation management overspending or underspending through regulatory assets and liabilities, because such an approach is in shareholders' interest, not customers' interest.

REVIEW AND CONCLUSION

Q. PLEASE REVIEW YOUR TESTIMONY.

A. This testimony began by presenting concerning perspectives on OG&E's transmission and distribution capital spending increases generally, concluding that reliability improvements to date resulting from massive capital spending increases have been insufficient to justify those increases. I also presented the results of my Wired Group colleague, PUD Witness Mr. Dennis Stephens, regarding the results to date from Grid Enhancement work completed on 11 circuits in 2020. The analysis indicates Grid Enhancement work on these circuits delivered just $0.44 in reliability improvement benefits for every $1 in capital spent.

The next section of this testimony described some potential explanations for the lack of cost-effectiveness of the Company's capital spending, and of its Grid Enhancement program specifically. OG&E's lack of awareness as to the cost effectiveness of various Grid Enhancement program components and sub-components, combined with a lack of focus on the Company's worst-performing circuits, were identified as likely explanations for the cost-ineffectiveness of the Grid Enhancement program. The law of diminishing returns was introduced to lend credence to my hypothesis. Customer research indicating high satisfaction with existing OG&E reliability and low satisfaction with OG&E rates was also presented, along with information exposing the fallacy that grid resilience spending now can avoid storm capital spending in the future. The section concluded with the recommendation that $90.7 million in Grid Enhancement spending on circuits not among the Company's worst-performing 2020-2022 (the bottom 5% annually) be disallowed.

The final section of this testimony addressed the Company's vegetation management proposals. I recommended an increase in the annual vegetation management budget, from $28 million to $38.8 million, though this increase is dramatically less than the 93% increase OG&E requested. I also encouraged PUD to strictly enforce its 4-year vegetation management cycle rule on an annual basis. Finally, I provided support for my recommendation that the Commission reject OG&E's proposal to capitalize vegetation management spending in excess of the annual budget as a regulatory asset, explaining why such a proposal was not in customers' interest.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS?

A. I would like to thank the Commission in advance for its careful consideration of this testimony. This testimony was developed to optimize the balance between customer and shareholder interest that for-profit monopoly regulation has been designed to maintain. (As I described in detail in my testimony in OG&E's last rate case, advance regulatory review of grid investment plans, as occurs with rider cost recovery, fundamentally alters the balance of interest in shareholders' favor.) I sincerely hope the Commission finds this testimony of value as it weighs the merits of the Company's Application.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

I state, under penalty of perjury under the laws of Oklahoma, that the foregoing is true and correct to the best of my knowledge and belief.

Paul Alvarez

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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 National Grid's historical spending and multi-year rate plan. Panel testimony with Dennis Stephens on behalf of the Attorney General in Massachusetts DPU Case 23-150. March 29, 2024.

Evaluate Pepco's Second Multi-Year Rate Plan. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel in Maryland PSC Case No. 9702. December 15, 2023.

Evaluate BGE's Second Multi-Year Rate Plan (Electric Distribution Components 2024-2027) and Electric Distribution Spending 2021-2022. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel in Maryland PSC Case No. 9692. June 20, 2023.

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 Duke Energy's Peak-time Rebate Pilot Results. Testimony on behalf of the Attorney General in 2022-00251. November 9, 2022.

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.

Evaluate 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.

Evaluate 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

Evaluate 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

Evaluate 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

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.

Evaluate 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

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018.

Measuring Distribution Performance? Benchmarking Warrants Your Attention. With Sean Ericson. Electricity Journal. Volume 31 (April, 2018), pages 1-6.

Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked. With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

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Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014; also International Confederation of Energy Regulators Chronicle, 3rd Ed, March, 2015

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

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 Annual Meeting. *Alternative Ratemaking: Unintended Consequences and Recommendations for Consumer Advocates.* Charlotte, NC. November 7, 2023.

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.

CERTIFICATE OF ELECTRONIC SERVICE

This is to certify that on the 26th day of April, 2024, a true and correct copy of the above and foregoing was electronically served via the Electronic Case Filing System to those on the Official Electronic Case Filing Service List, or via electronic mail to the following persons:

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