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

DENNIS STEPHENS

APRIL 26, 2024

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I. Introduction, Purpose, Preview and Perspective

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My name is Dennis Stephens. My business address is Wired Group, PO Box 620756, Littleton, CO 80162.

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

A. I am an independent distribution grid consultant, and I work frequently on behalf of the Wired Group and its clients.

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 ASSISTANCE IN PREPARING THIS TESTIMONY?

A. Yes. PUD Witness Mr. Alvarez helped me with this testimony, and I helped him with his testimony.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. After graduating from the University of Missouri with a bachelor's degree in Electrical Engineering, I began work for Xcel Energy (then Public Service Company of Colorado) in 1976 as an electrical engineer in distribution operations. In a series of electrical engineering and management roles of increasing responsibility, I gained experience in distribution planning, operations, and asset management, as well as the innovative use of technology to assist with these functions. Positions I've held over the years have included Director, Electric and Gas Operations for the City and County of Denver Colorado; Director, Asset Strategy; and Director, Innovation and Smart Grid Investments, for all of Xcel Energy.

In 2007, I was asked to lead parts of Xcel Energy's SmartGridCity™ demonstration project in Boulder, Colorado, the first of its kind at the time, covering 46,000 customers. I developed the technical foundations for the project, including the development of all concepts presented to the Xcel Energy Executive Committee for project approval, and including the negotiations with technology vendors on their contributions to the project. As Director of Utility Innovations for Xcel Energy, I also worked with many software providers, including ABB, IBM, and Siemens, helping them develop their distribution automation ideas into practical software applications of value to grid owner/operators. I retired from Xcel Energy in 2011, and now work for the Wired Group on a part-time basis.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION PREVIOUSLY?

A. Yes. I testified on behalf of the Attorney General in Oklahoma Gas and Electric Company's most recent rate case, PUD-2021-000164,[1] as well as in Public Service Company of Oklahoma's most recent rate case, PUD 2022-000093.[2] In addition, although I did not testify, I supported Staff Witness Alvarez as he developed testimony on behalf of AARP in the proceeding in which Oklahoma Gas and Electric Company ("Company" or "OG&E")

[1] Responsive Test. of Dennis Stephens on behalf of the Attorney General, No. PUD 2021-000164, April 27, 2022.
[2] Responsive Test. of Dennis Stephens on behalf of the Attorney General, No. PUD 2022-000093, March 7, 2023.

originally requested exceptional cost recovery for grid enhancement (PUD-2020-000021).[3] Furthermore, I have testified in multiple electric distribution planning, investment, and performance measurement proceedings before utility regulators in 11 other states in the last five years. A complete list of appearances is provided in my CV, attached as Exhibit PUD-DS-1. I ask that the Oklahoma Corporation Commission ("Commission") accept my credentials and recognize me as an expert witness on behalf of PUD Staff in this proceeding.

Q. PLEASE PREVIEW YOUR TESTIMONY.

A. This testimony begins by explaining my support for Staff Witness Mr. Alvarez's primary recommendation – that Grid Enhancement capital spending for which OG&E seeks recovery in this proceeding was insufficiently targeted, and that capital spending to enhance circuits not performing in the bottom 5% of OG&E circuits be disallowed from recovery from OG&E customers. It continues with recommendations for disallowances in transmission and distribution Asset Improvement capital spending, which my experience and calculations indicate are not cost-effective for OG&E customers.

Q. DO YOU CARE TO PROVIDE ANY PERSPECTIVE FOR THE COMMISSION'S CONSIDERATION BEFORE PROCEEDING?

A. Yes. In my experience there are two types of investments that for-profit utilities make: 1) Those that utilities must make in the near-term to ensure that services are safe and reliable; and 2) those that utilities prefer to make but are not strictly necessary in the near-term for

[3] 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).

safe and reliable service. In my opinion the former type of investment requires less of a utility regulator's attention. As long as a utility has appropriate project review/authorization, equipment/software procurement, and project planning/management processes and practices in place to ensure equipment and services are procured at the lowest possible cost for customers, a regulator need only ensure that the spending was necessary for safe and reliable service. Examples of such spending include: 1) spending to repair or replace equipment that fails or is damaged (for example, by storms); 2) spending incurred to connect new customers; 3) spending to accommodate load growth (capacity), as supported by circuit- and substation-specific load growth forecasts relative to equipment capacity ratings; and 4) administrative spending (such as on customer billing software). Once a regulator is satisfied that such investments were both necessary for safe and reliable service, and implemented for customers at the lowest possible cost, a regulator can correctly determine that such investments were fair, just, and reasonable.

Regarding investments that a for-profit utility prefers to make, but that are not strictly required for safe and reliable service in the near term, a regulator's job gets more difficult. In my opinion, if an investment is not strictly required for safe and reliable service in the near term, prudence should be awarded only in instances in which the investment is likely to deliver benefits to customers in excess of customers' costs. I encourage the Commission to adopt my definition as a guideline for determining whether discretionary project spending is fair, just, and reasonable. That is, if an investment is not either: 1) necessary for safe and reliable service in the near term, or 2) cost-effective for customers, then the investment cannot be fair, just, and reasonable.

In this testimony, and in the testimony of Staff Witness Alvarez, we identify OG&E capital spending that was not necessary for safe and reliable service in the near term, and that has not delivered, and is unlikely to deliver, benefits in excess of costs to customers. Mr. Alvarez and I will recommend that the Commission disallow recovery of this capital spending from customers.

II. Support for Mr. Alvarez's Recommendation to Disallow Grid Enhancement Spending in Excess of OG&E's Worst-Performing Circuits

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

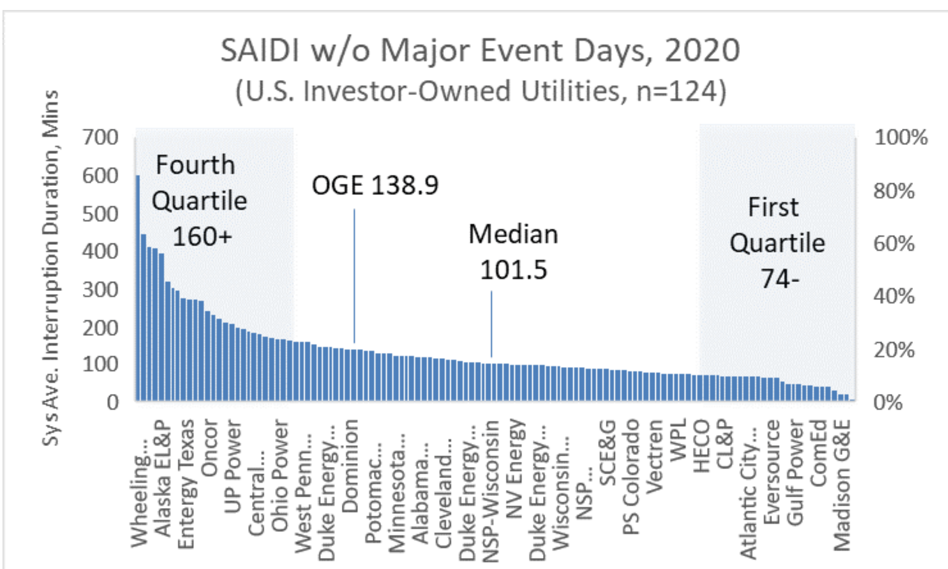
A. This section of testimony explains my support for PUD Staff Witness Alvarez's recommendation that $90.7 million of the Company's Grid Enhancement capital spending be disallowed. I will explain why I consider the Company's Grid Enhancement spending to be discretionary, and the implications of such a characterization for the Commission's prudence review. I will also reiterate the concerns I expressed in my review of OG&E's Grid Enhancement plan on behalf of the Attorney General in OG&E's most recent rate case. All of these concerns remain.

Q. OGE CLAIMS ITS GRID ENHANCEMENT SPENDING IS NECESSARY. WHY DO YOU CONSIDER IT DISCRETIONARY?

A. As indicated in the perspective section above, there are a limited number of spending types that are required for safe and reliable service. While OG&E claims its Grid Enhancement program is required to improve reliability, I fail to see why. As Mr. Alvarez noted in his testimony, customers are highly satisfied with existing reliability. Not only are OG&E

customers satisfied, I note that OG&E reliability is reasonable relative to its peers. Figure 1 below compares OG&E reliability to U.S. investor-owned utilities in 2020, when OG&E began its Grid Enhancement program. The figure depicts reliability without major event days, and I understand that the October 2020 ice storm was tough on many OG&E customers. But as Mr. Alvarez notes in his testimony, there is no assurance that enhanced circuits will weather a three-inch ice storm (or tornado, or derecho wind event) any better than other circuits. I also agree that the likelihood that the portions of the grid that will be impacted by a major storm in the next 20 years will coincide with the relatively small numbers of poles the Company is replacing and strengthening as part of Grid Enhancement will be small. In short, while OG&E has an interest in improving reliability, it also has an interest in growing its rate base, and its earnings for shareholders. OG&E is choosing to spend lots of capital to improve reliability; neither the Commission, nor PUD, nor intervenors, nor OG&E customers are forcing OG&E to do so.

Figure 1: OGE system average interruption duration vs. U.S. investor-owned utilities, 2020.



Q. DO YOU BELIEVE OG&E'S DECISION TO IMPROVE RELIABILITY IS WRONG?

A. No. Improving reliability is a worthwhile objective. However, it must be considered in the context of rate increases. The amount of utility rate increase – gas, water, or electric – Oklahoma's economy can withstand without harm is limited. OG&E capital should not be considered limitless, as customers pay for that capital. Capital limitations force utilities like OG&E to make better choices about how to deploy capital, just like all other businesses must. It is up to the Commission to ensure OG&E is motivated to govern its capital spending in a way that avoids rate increases when possible and maximizes "bang for the buck" for customers' rate increases. My concern is not with OG&E's goal; my concern is with OG&E's capital spending, and that it is not being spent wisely in pursuit of the goal.

Q. HOW SHOULD THE COMMISSION REVIEW OG&E DISCRETIONARY SPENDING?

A. If spending is not necessary for safe and reliable service in the near term, there must be some other compelling rationale for such spending. In my mind, that rationale should be benefits to customers of sufficient economic value to justify the costs customers must pay. I encourage the Commission to accept no other justification for discretionary spending.

Q. BUT OG&E USES A MODEL TO ESTIMATE THE BENEFITS OF GRID ENHANCEMENT SPENDING ON SPECIFIC CIRCUITS, DOES IT NOT?

A. It does. But as Mr. Alvarez's testimony notes, the model's outputs (benefit estimates) have not been validated against the actual results of Grid Enhancement spending to date. Now that three years have passed since OG&E applied Grid Enhancement to its first tranche of circuits in 2020, there is no excuse for OG&E's failure to validate the model. It is certainly possible that OGE has not validated its model because a new and improved version might not identify as many circuits for Grid Enhancement spending than the exiting model does. As I recommended in my testimony on behalf of the Attorney General in OG&E's last rate case, the Commission may wish to consider overseeing a study by an independent expert to quantify the benefits delivered by OG&E's Grid Enhancement programs.

Q. HAVE YOU ESTIMATED THE COSTS AND BENEFITS OF OG&E'S GRID ENHANCEMENT PROGRAMS?

A. Yes. Mr. Alvarez's testimony describes my evaluation of the benefits delivered by 11 circuits selected at random from 54 OG&E "enhanced" in 2020; in my estimation the spending will deliver reliability benefits of just $0.44 (present value over 30 years) for every $1 in Grid Enhancement spending. While I understand OG&E claims other benefits, such as O&M spending reductions and avoided future capital spending, even OG&E admits that these are of much lower value relative to reliability.[4] Further, like Mr. Alvarez, I have reservations regarding the use of fully-loaded unit costs (per truck roll or per customer call), rather than marginal avoided costs, to estimate operating cost reductions, as OG&E's model appears to do. Finally, I have never understood OG&E's claim that spending capital today to avoid future capital spending constitutes a customer benefit. To my way of thinking, deferring capital spending that will not deliver benefits in excess of costs is a great way to delay rate increases and benefit customers.

[4] PUD 2021-000164. Direct Testimony of Ms. Kandace Smith dated December 30, 2021. Table 2, page 12.

Q. HAVE YOU EVALUATED ANY OG&E GRID ENHANCEMENT PROGRAMS INDIVIDUALLY?

A. Yes. In OG&E's last rate case I evaluated the Company's $38 million deployment of TripSavers® where laterals tap into larger conductor. In my experience, laterals typically serve just a few dozen customers each. The Company is installing the devices, at an all-in cost of as much as $7,700 each,[5] in place of fuses currently installed in these locations that perform many of the same functions. The Company, under the moniker "lateral automation", claims that these devices generate reliability benefits to customers in excess of their cost through both fewer interruptions (TripSavers attempt to "reset" in response to a transient fault condition, whereas fuses will not always ride through transient faults) and fewer truck rolls (to reset fuses).

My analysis indicated that the reliability improvements provided by this spending would likely generate just $1.15 million in reliability benefits (present value to customers over thirty years), and I recommended the Commission disallow these costs as a result.[6] But the Company settled with intervenors without a decision from the Commission on the spending. Since its last rate case, the Company has spent an additional $34.4 million on TripSavers.[7] There are probably some situations in which TripSavers make economic sense to install – on laterals with exceptionally large numbers of customers, or on laterals with a high proportion of commercial customers (few), or on laterals with a relatively high proportion of transient (as opposed to permanent) faults, or most likely some combination of

[5] PUD 16-3.
[6] PUD 2021-000164. Testimony of Dennis Stephens dated April 27, 2022. From 15:6 to 19:9.
[7] PUD 15-12(a)_Att1.

all three of these.[8] But the Company does not even track these variables.[9] To blindly install TripSavers on every lateral on a Grid Enhancement circuit that meets untested criteria (such as a customer count of 30 or greater)[10] is simply not a cost-effective approach for such a costly technology. I sincerely doubt there are anywhere near $72 million dollars' worth of laterals for which TripSavers are cost-effective on OG&E's distribution system ($38 million in the last case and $34 million in the present case).

Q. DO YOU HAVE OTHER CRITIQUES OF OG&E'S GRID ENHANCEMENT PROGRAM?

A. Yes. I mentioned in previous testimony on Grid Enhancement, and repeat here, that conservation voltage reduction is conspicuous by its absence from the program.[11] Conservation voltage reduction reduces energy use for many types of customer loads. By continuously monitoring and adjusting (via software) voltage regulators and capacitor banks, a circuit's voltage can be reduced in real time without violating minimum voltage standards. In my experience, conservation voltage reduction can be cost effective on a number of circuits at most utilities, typically from 20% to 40% of circuits. OG&E has even spent $2.1 million automating capacitor banks and voltage regulators as part of Grid Enhancement since the last rate case.[12] (Capacitor and voltage regulator automation is required to maximize conservation voltage reduction.)

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[8] I am assuming here that OGE smart meters can identify transient faults through voltage limit violation reporting.
[9] PUD 16-03(c).
[10] Attachment 15-08(c)_Att2.
[11] PUD 2021-000164. Testimony of Dennis Stephens dated April 27, 2022. From 10:3 to 15:5.
[12] Attachment PUD 15-12(a)_Att1.

Yet despite OG&E's supposed interest in making Grid Enhancement cost-effective, and despite my criticism regarding the absence of conservation voltage reduction in OG&E's Grid Enhancement program, the Company has not pursued it. My guess is that the Company has no interest in pursuing cost-effective programs that reduce sales volumes, and thus Company earnings, between rate cases.

Q. PUD WITNESS ALVAREZ DESCRIBES OG&E'S GRID ENHANCEMENT SPENDING AS 'UNFOCUSED'. DO YOU AGREE?

A. Yes. As noted above, despite the availability of at least three years of data on 54 Grid Enhancement circuits completed in 2020, and more years of data available on the 14 circuits completed in Arkansas in 2018, OG&E has not validated its model. The Company's model appears to be using the same structure and assumptions to select circuits for Grid Enhancement in 2023 as it did in 2020.[13] This means that OG&E has not updated its model for actual results, nor has OG&E attempted to improve the accuracy of benefit estimates the model generates. The fact that the model OG&E uses to select circuits for Grid Enhancement has not been validated, despite the availability of at least three years of actual post-investment experience from Grid Enhancement to do so, is a big red flag for me. I find it highly unlikely that a model that has not been validated would accurately pick circuits for Grid Enhancement that would deliver benefits in excess of costs, and this would indeed lead to spending on the wrong circuits.

[13] Attachments OIEC 18-09_Att1 (2021) and OIEC 18-09_Att2 (2023).

Q. SO, YOU ENDORSE MR. ALVAREZ'S RECOMMENDATION THAT THE COMMISSION DISALLOW $90.7 MILLION IN GRID ENHANCEMENT SPENDING?

A. I do. I have always endorsed worst-performing feeder programs such as the one OG&E operates and agree that exceptional reliability improvement spending should be reserved for worst-performing circuits. Such spending should be targeted to repetitive causes identified through root-cause analyses conducted on a circuit-specific basis, with the lowest-cost mitigations applied first. OG&E's Grid Enhancement program does not appear to begin with low-cost mitigations,[14] and I am further concerned that some Grid Enhancement programs and subprograms are not cost-effective ways to improve reliability. But despite these critiques, if Grid Enhancement has any value at all, I agree that value is most likely to arise from application to worst performing circuits. I therefore concur with Mr. Alvarez that Grid Enhancement spending on the circuits not among the worst performers in 2020, 2021, and 2022 should be disallowed.

III. Asset Improvement Capital Spending Cost Disallowances

Q. PLEASE PREVIEW THIS SECTION OF TESTIMONY

A. Grid Enhancement is not the only cost-ineffective reliability improvement spending in which OG&E engages. This section of testimony addresses another cost-ineffective OG&E practice, which is the replacement of substation equipment that has passed objective diagnostic and functional tests. As with Grid Enhancement, I recommended disallowances

[14] Low-cost mitigations for worst performing circuits include completing spot vegetation management and making adjustments to equipment settings. These are not part of any Grid Enhancement circuit plans provided in discovery.

for the practice, which I call prospective equipment replacement, in my testimony on behalf of the Attorney General in OG&E's last rate case.15

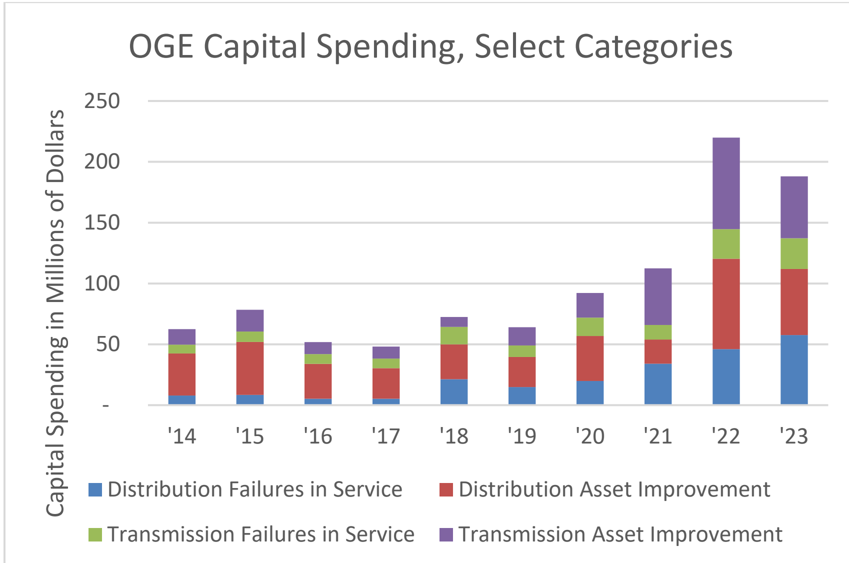
This section of testimony begins with descriptions of how OG&E, like all utilities, routinely tests the most critical substation equipment (power transformers, circuit breakers, relays, switches, etc.), and how OG&E repairs or replaces equipment that fails such tests. It then describes how OG&E's Asset Improvement program accelerates the replacement of equipment that has not failed such tests. In my opinion such replacements are not required for safe and reliable service but are discretionary. As described earlier, I believe discretionary spending must pass a benefit-cost test before it can be deemed fair, just, and reasonable. This section of testimony will conclude with a benefit-cost analysis I have completed on prospective substation equipment replacement and identify specific equipment replacement projects I recommend be disallowed. These cost disallowances amount to $7.8 million.

Q. YOU MENTION THAT OG&E ASSET IMPROVEMENT SPENDING HAS BEEN INCREASING DRAMATICALLY IN RECENT YEARS. HOW DRAMATIC HAVE THESE INCREASES BEEN?

A. In both transmission and distribution, and in both Asset Improvement and in the related category of Failures in Service, spending increases have indeed been dramatic in recent years. Figure 2 indicates just how dramatic recent increases in these categories have been, and the table that follows presents growth percentages 2019-2023. In just four years, Failure in Service and Asset Improvement spending at OGE have almost tripled.[16]

[15] PUD 2021-000164. Testimony of Dennis Stephens dated April 27, 2022. From 20:1 to 36:3.
[16] Attachments PUD 5-05(d)_Att1; PUD 5-01(e)_Att1; PUD 15-10(a)_Att1.

Figure 2: OG&E Failure in Service and Asset Improvement capital spending trends



Capital spending category	Percentage increase 2019-2023
Distribution Failures in Service	289%
Distribution Asset Improvement	120%
Transmission Failures in Service	163%
Transmission Asset Improvement	239%
Total increase in these four categories	**193%**

Q. ARE THERE ANY POTENTIAL REASONS WHY THESE SPENDING CATEGORIES COULD JUMP SO QUICKLY IN SUCH A SHORT TIMEFRAME?

A. There are several potential reasons, but none that make much sense to me. Take Failures in Service, for example. One possibility is that equipment truly is failing much more frequently than in the past. But given that OG&E's transmission and distribution systems have been built out over the past 100 years and consists of tens of thousands of pieces of equipment of incredible diversity in types, designs, manufacturers, ages, duty levels, and conditions, it is almost statistically impossible for equipment failure rates to suddenly double, triple, or quadruple in three or four years.

While I cannot explain the recent jump in Failure in Service spending, I can absolutely explain the jump in Asset Improvement spending. As with Grid Enhancement, OG&E has apparently made the discretionary decision to replace its equipment more frequently than it has in the past. As a discretionary spending decision, the Company's practice of replacing equipment that has passed its functional and diagnostic tests should pass a benefit-cost test. OG&E has not completed a benefit-cost analysis using historical equipment failure rates and service interruption data to determine if replacing equipment that has passed its tests delivers reliability improvements of sufficient customer value in excess of costs.[17]

Q. HAVE YOU PERFORMED SUCH AN ANALYSIS?

A. Yes. But before I describe the analysis I completed and explain its results, allow me to provide some background on the substation equipment testing all utilities perform on a routine, periodic basis. Substation equipment, when it fails, typically impacts large numbers of customers. A single substation transformer might serve three or four circuits, each of which might serve one thousand or more customers. As a result, traditional industry practices regarding objective testing of substation equipment have arisen over time. Key types of substation equipment, including power transformers, circuit breakers, and relays, are the subject of routine, periodic testing processes. In the case of power transformers, one of several tests performed is a test in which transformer oil is tested through dissolved gas analysis. Certain levels of certain gasses in a transformer's oil indicates an increased risk of failure. So, when those gasses are detected at prescribed levels, a transformer is scheduled

[17] PUD 02-08(c).

for repair or replacement, and design and procurement activities for the new transformer, if needed, begin promptly. In the case of circuit breakers and relays, physical testing is performed to determine if the equipment will operate as designed when called upon. As with power transformers, circuit breakers and relays that fail the physical tests are returned to service but, scheduled for near-term repair or replacement. Because these tests are objective, and highly accurate, they have traditionally been used to determine when substation equipment should be replaced.

Q. DOES OG&E HAVE SUCH A PROGRAM?

A. Yes it does. But in addition to replacing substation equipment that has failed its tests, OG&E also replaces substation equipment that has not failed its tests. The Company reports "The Company determines the need for investment on different criteria depending on the situation. Some of the criteria considered are asset condition, risk, and performance. Additionally, the Company looks to published industry standards and regulatory requirements when making investment decisions." While this sounds good, it does not meet my standards, nor do I believe it should meet the Commission's standards.

"Asset Condition" is a subjective assessment. With an objective measure like test results, subjective assessments are not necessary. "Performance" and "published industry standards" likely refer to testing and associated minimum criteria, though OG&E appears to employ "trending test histories"[18] rather than firm test result limits when making equipment replacement decisions. In my experience, dissolved gas analysis results can vary widely, and can be slowly "trending" towards dissolved gas limits for many years.

[18] PUD 15-8(b).

The Company also appears to estimate "risk" subjectively, and this is a real problem. Anyone can throw around phrases like "the risk of leaving this piece of equipment in service is high". What is truly needed is a precise quantification of risk, employing historical failure rates for equipment of that type and age; the likelihood that a failure of that piece of equipment will result in a service interruption (the vast majority of substation equipment is backed up by capacity reserved on nearby equipment and does not result in a service interruption upon failure); and the consequences to customers (counts of customers impacted, durations, and associated dollar values) should a service interruption occur. There is even an equation available to quantify the dollar value to customers of risk reductions:[19]

$$\text{Customer Benefit (\$)} = \text{Reduction in Outage Likelihood (\%)} \times \text{Consequence of Outage (\$)}$$

Q. HAVE ANY STATE UTILITY REGULATORS ORDERED THE USE OF THE EQUATION TO QUANTIFY RISK REDUCTION BENEFITS IN DOLLARS?

A. Yes. The California Public Utilities Commission became the first to order the utilities it regulates to use the equation to monetize the value of risk reductions available from investments intended to improve reliability or safety in dollars.[20] The California Commission recognized that no rigorous benefit-cost analysis is possible without quantifying risk reductions in dollars.

[19] Pascarela G et al. *Risk Analysis in Healthcare Organizations: Methodological Framework and Critical Variables*. Risk Management and Healthcare Policy. July 8, 2021. Table 1, "Quantitative Analysis" (Probability multiplied by Impact equals Risk Level). Available at https://www.ncbi.nlm.nih.gov/pmc/articles/PMC8275831/

[20] Decision 22-12-027 (*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*) at 30–35, Rulemaking 20-07-013 (Cal. Pub. Util. Comm'n, Dec. 21, 2022). Appendix A documents the formula.

Q. IS THIS EQUATION THE BASIS FOR THE BENEFIT-COST ANALYSIS YOU COMPLETED ON OG&E'S EQUIPMENT REPLACEMENT PRACTICES?

A. Yes. I estimated the likelihood of annual failures for substation transformers and circuit breakers using the Company's historical data (5 in 1,000 and 1 in 1,000 annually, respectively). I examined the Company's service interruption data to get average counts of customers impacted and interruption durations associated with these failures. Using the same avoided cost data as the U.S. Department of Energy's online Interruption Cost Estimator tool, I calculated the consequence cost of these interruptions to customers. I then multiplied the likelihoods of failure by the consequence dollars to get annual customer benefits. From there, it was a relatively simple matter to calculate the present value of those annual benefits over thirty years, enabling a comparison to average equipment replacement costs. All these key elements to the benefit-cost analysis are provided in the table below. As the reader can observe, the replacement of substation power transformers and circuit breakers that have passed their tests is not remotely cost-effective for customers.

Substation Equipment Type	Annual Failure Incidence (a)	Customer Consequence Cost (b)	Annual Risk Reduction Value (a x b)	Present Value over 30 Years	Average Replacement Cost
Power Transformer	0.005	$507,212	$2,486	$29,789	$2,449,957
Circuit Breaker	0.001	$10,003,363	$10,145	$109,815	$366,944

Q. ARE THERE OTHER WAYS TO ESTIMATE THE IMPACT OF OG&E'S ASSET IMPROVEMENT SPENDING?

A. Yes. I have reviewed the Company's distribution service interruption detail from 2020 to 2023, and in particular, service interruptions with cause code "Equipment". I looked at service interruptions with "Equipment" listed as the cause because: 1) Increases in equipment failures can help explain increases in "Failure in Service" spending; and 2) Increases in Asset Improvement spending should reduce equipment failures (and service interruptions resulting from equipment failures) over time.

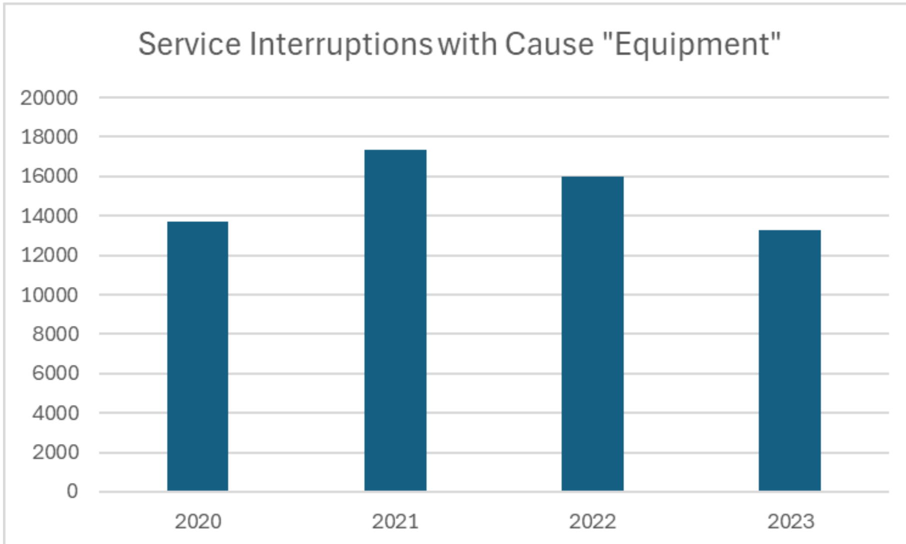
Before presenting this analysis, I must first admit that the "Equipment" cause code utilities associate with many service interruptions is a dubious measure of equipment failures. This is because, as I reported in my testimony in OG&E's last rate case, utility personnel associate many service interruptions with cause code "Equipment", that have nothing at all to do with equipment failure.[21] Examples include blown fuses (normal operation), tripped circuit breakers (normal operation), "out of adjustment," "loose connection," damage to equipment due to external causes, and many more. However, over time, I believe any such overstatement to be consistent within a utility, based on employee training, the types of cause codes available, and institutional norms. Thus, while not precise, outages listing "Equipment" as the cause can still be used as a rough approximation of changes in equipment failure counts over time.

Counts of OG&E service interruptions with "Equipment" as the cause code from 2020 to 2023 are presented in Figure 3.[22] Unfortunately, no obvious trend in service interruptions associated with "Equipment", either growth or decline, can be observed over time. This means that: 1) increases in Failure in Service spending remain unexplained; and

[21] PUD 2021-000164. Testimony of Dennis Stephens dated April 27, 2022. Page 24.
[22] Attachment PUD 02-06(b)_Att1_Conf.

2) increases in Asset Improvement spending do not appear to be reducing equipment failure rates (consistent with the benefit-cost analysis I presented above).

Figure 3: Counts of OGE service interruptions 2020-2023 with cause code "Equipment".



Q. HAVE YOU REVIEWED ASSET IMPROVEMENT PROJECTS FOR WHICH OG&E IS REQUESTING RECOVERY IN THIS RATE CASE?

A. Yes. I identified 12 transmission substation equipment replacement projects in which the only justification was equipment condition. It can be assumed that in almost every instance, the equipment in question had passed its most recent tests; otherwise, the equipment would have already been replaced (with funds from the "Failure in Service" budget) in accordance with OGE's substation equipment testing program.[23] Further, the approved Authorizations For Expenditure (AFEs) make no mention of any benefit-cost analyses completed for any of these discretionary spending projects. These projects are listed in the table below. I

[23] PUD 02-08(b).

recommend the Commission disallow costs for all of these projects, for an Asset Improvement cost disallowance totaling $7.8 million.

Project Description	AFE*	$ (000’s)^	Project Description	AFE*	$ (000’s)^
TSB-Park Place	4954	$ 149.3	TSB Type A – 38th St.	7473	15.3
TSB-Blubell Sub RTU	5671	8.1	TSB-Maysville Sub	7876	4.7
TSB-Type A North OK	7042	42.9	TSB-RP SW 5th	7369	659.9
TSB Auto-Meridian Sub	7092	3.9	TSB-Rush Creek Sub	7878	284.1
TSB Resiliency Hancock	7087	38.1	TSB-McClain	8590	1.933.0
TSB-Type A Forrest Hills	7471	66.8	TSB-Arcadia Trans Bk	8575	4,577.8
			TOTAL		**$7,783.9**

* “Authorization for Expenditure” (Attachments provided in response to PUD 15-11 (d)(i))

^ Dollar amounts from Attachment PUD 15-11(d)(i)_Att1.

IV. Unsupported Discretionary Spending Beyond Grid Enhancement and Asset Improvement

Q. PLEASE PREVIEW THIS SECTION OF TESTIMONY.

A. This section of testimony identifies a number of other discretionary projects which OG&E has not adequately supported, and for which I therefore recommend that the Commission disallow costs. These projects and their costs are summarized in the table below.

Project Description	AFE*	$ (000’s)^	Project Description	AFE*	$ (000’s)^
TLN-69kV Beeline	8174	$ 5,240.3	TSB-Glendale Upgrade	7831	1,322.1
TLN-Nation-Jamesville	8173	5,487.9	TSB-Type A – Cleo	8796	1,137.1
TLN-May Ave to 38th St.	7996	1,056.0	TSB-Type A – Reno	7458	2,258.4
			TOTAL		**$16,501.8**

* “Authorization for Expenditure” (Attachments provided in response to OIEC 01-15)

^ Dollar amounts from Attachment OIEC 01-15_Att1.

Q. PLEASE EXPLAIN YOUR REVIEW PROCESS.

A. I examined the Authorizations for Expenditure for all Transmission projects over $1 million. I identified those which were not required for safe and reliable service in the near term as "discretionary" projects. I examined these discretionary projects further, looking for other justifications, such as benefit-cost analyses indicating that the risk reduction value of the projects to customers exceeded the costs of the projects to customers, or a history of equipment malfunction, or load growth forecasts identifying violations of the Company's capacity planning criteria. The projects listed in the table are recommended for disallowance because there was: 1) no documentation that the project was requiredmalfunction, or capacity planning criteria violations.

Q. HOW WILL THE COMPANY RESPOND TO YOUR RECOMMENDATION TO DISALLOW COST RECOVERY ON THESE PROJECTS?

A. I expect the Company to respond in two ways. First, the Company will claim that these projects are indeed necessary for safe and reliable service. To this, I observe that capital for each project was authorized by management with no such evidence presented. Second, the Company will claim that following my guidance for capital spending governance represents a "run to failure" strategy, which is unacceptable from a service interruption risk perspective. This is not true; the Company maintains the testing program described earlier for all critical substation equipment; the program is designed specifically to identify equipment at high risk of failure in advance.[24] Further, as observed earlier in this testimony, the Company takes no steps to quantify service interruption risk, or to determine the level at which quantified

[24] PUD 02-08(b).

service interruption risks are considered intolerable. I ask if the Company, with capital bias, is permitted to replace equipment because the Company subjectively feels like the risk of the existing equipment is too high, what will control the limits of spending?

Q. ARE THERE ANY COMMONALITIES AMONG THE SIX PROJECTS YOU'VE IDENTIFIED FOR COST DISALLOWANCES?

A. Two of the projects are justified due to "capacity limitations", but with no data or forecasts that identify violations of the Company's capacity planning criteria. A single sentence, "Failure to complete this project leads OG&E to continue to operate in limited capacity in this area", is used to justify these two projects (AFEs 8173 and 8174) totaling $10.7 million in capital spending. I believe such a limited justification is simply unacceptable.

The other four projects appear to be justified by subjective assessments of equipment condition and associated risks of service interruptions. Again, a single sentence is used for justification, again with no data or risk quantification, and again, the equipment in question must have passed its most recent tests (otherwise, the equipment would already have been replaced).

Q. BUT, PARTICULARLY AS TRANSMISSION EQUIPMENT, WHICH COULD CONCEIVABLY IMPACT LARGE NUMBERS OF CUSTOMERS UPON FAILURE, DOESN'T THE COMPANY NEED SOME AMOUNT OF DISCRETION FOR MAKING THE INVESTMENTS IT CLAIMS IT NEEDS TO MAKE?

A. No. A utility with capital bias should not be allowed to simply invest capital because it prefers to, based on a "claim" of need. Instead, a utility with capital bias should be required to justify its decisions to make investments using data (generally known as "data-driven decision making"). Let us more closely examine the Company's transmission equipment failure history, and the service interruptions resulting from such failures. In discovery, the Company provided details on "disturbances" on its transmission grid, which it defines as "a loss of voltage", and generally known as equipment outages. Equipment outages on transmission grids must be distinguished from service interruptions, because due to back-up capacity, transmission equipment outages do not always result in service interruptions.[25]

The Company reports [redacted] "disturbances" on its transmission grid in 2023.[26] Of these, only [redacted] resulted from "Failed AC Substation Equipment" or "Failed Protection System Equipment" or "Failed AC circuit Equipment". Of these [redacted] transmission disturbances in 2023 resulting from equipment failures, only [redacted] were found on a list of transmission disturbances that resulted in a service interruption to downstream customers.[27] Of these [redacted] transmission disturbances in 2023 that resulted in downstream service interruptions to customers, a large number impacted only a handful of customers, or were 15 minutes or less in duration. The point is that OG&E's claim that a particular risk is high and requires investment should not be accepted as a given. *Risk must be quantified if it is to be considered in data-driven decisions to invest capital.* This is particularly true of discretionary investment decisions not required for safe and reliable service in the near term. To summarize, my recommendation that the Commission disallow $16.5 million from these six projects stands irrespective of the OG&E responses I anticipate.

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[25] PUD 15-01(a).
[26] Attachment PUD 15-01(b)_Att1_Conf.
[27] Attachment PUD 15-01(b)_Att2_Conf.

V. Review and Conclusion

Q. PLEASE REVIEW YOUR TESTIMONY.

A. This testimony began with my perspective on grid investment prudence. It explained that if an investment is not required for maintaining safe and reliable service in the near term, the investment should pass a benefit-cost test to be deemed prudent. This perspective is relevant to the entire testimony.

The testimony continued with my endorsement of Mr. Alvarez's recommendation to disallow $90.7 million in Grid Enhancement capital spending from cost recovery. In support of his endorsement, I agreed that the model OG&E uses to select circuits for Grid Enhancement spending is flawed, and results in unfocused capital spending. I also summarized the results of the Grid Enhancement benefit-cost analysis I prepared for Mr. Alvarez. That analysis indicates a customer reliability value of just $0.44 for every $1 in Grid Enhancement capital spent. I also reiterated some of the critiques on the Grid Enhancement program that I presented in my testimony on OG&E's last rate case, including that TripSaver devices (lateral automation) are not generally cost-effective, and that OG&E's Grid Enhancement program should include a conservation voltage reduction effort.

The third section of this testimony addressed massive increases in T&D capital spending for "Failures in Service" and "Asset Improvement". Given the extreme diversity of OG&E equipment in service (by age, service duty, type, etc.), I was unable to understand why Failure in Service spending could increase so dramatically (by factors of three or four) in such a short period (just three or four years). I identified similarly large increases in Asset Improvement spending as discretionary, thereby invoking a need for benefit-cost testing of

Asset Improvement projects and spending programs. However, given that OG&E had not completed a benefit-cost analysis of its practice of replacing substation equipment that had passed its functional or diagnostic tests, I described the approach I took to complete my own benefit-cost analysis. I explained a method for quantifying risk reductions from utility investments in dollars, which emulates the method ordered by the California PUC for the utilities it regulates. Employing that method, I found the Company's approach to making equipment replacement decisions under the Asset Improvement program to be nowhere near cost effective. I concluded the section by recommending $7.8 million in cost disallowances for 12 transmission substation equipment replacement projects for which the only justification was a subjective assessment of equipment condition.

The final section of this testimony identified additional transmission projects that were unsupported by documented need or benefit-cost analysis. I employed the Company's own data to illustrate why risk reductions must be quantified, and why the risks the Company subjectively assumes are large enough to require investment should not be accepted at face value. Beginning with hundreds of transmission system "disturbances" the Company tracked in 2023, I identified that less than 10% of these resulted from equipment failures, and that of the 10% arising from equipment failures, only 25% (2.5% of all "disruptions") resulted in a service interruption for customers (due to back-up capacity OGE builds into its transmission system). I recommended that the cost of six projects totaling $16.5 million in cost be disallowed from customer recovery due to a lack of documented need or benefit-cost analysis.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS FOR THE COMMISSION?

A. Yes. As I recommended in my testimony in OG&E's last rate case, I encourage the Commission to procure and oversee an independent evaluation of the benefits and costs of the Company's Grid Enhancement program. I also encourage the Commission to order the Company to evaluate conservation voltage reduction as a potentially valuable energy efficiency program.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS?

A. Yes. I would like to thank the Commission in advance for the time and effort it will dedicate to reviewing this testimony, and I sincerely hope the Commission finds this testimony valuable as it considers OG&E's Application.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

AFFIDAVIT OF DENNIS STEPHENS

STATE OF COLORADO)
) ss
COUNTY OF JEFFERSON)

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.

Dennis Stephens

Subscribed and sworn to/affirmed before me this 24 day of April, 2024.

TAMMERA CARROLL
NOTARY PUBLIC - STATE OF COLORADO
NOTARY ID 20224000931
MY COMMISSION EXPIRES JAN 7, 2026

Notary Public

My Commission expires on Jan 7, 2026

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Curriculum Vitae – Dennis Stephens

DS Consulting, 1153 Bergen Pkwy, Evergreen CO 80439 dstephens@wiredgroup.net
303.434.0957

Profile

Mr. Stephens has over 40 years' experience in electric and gas distribution grid planning, design, operations management, and asset management, and the innovative use of technology to assist with these functions. He spent his entire career at Xcel Energy and its subsidiary Public Service Company of Colorado, a distribution utility serving 1.5 million electric customers and 1.4 million gas customers. After a series of electrical and gas engineering and management roles of increasing responsibility, Mr. Stephens retired as the Director of Innovation and Smart Grid Investments for all of Xcel Energy's electric and gas distribution businesses in 2011. He now works for the Wired Group and its clients on a part-time basis.

Career History (all positions with Public Service Company of Colorado or its parent, Xcel Energy)

1976 -- Planning Engineer. Performed electric distribution system planning for Southeast Denver, Boulder, Front Range and Cheyenne divisions, including system protection, voltage support and distribution system design.
1983 – Senior Engineer, Electric Distribution Planning. Provided direction and guidance for junior engineers. Led special projects relating to electric distribution system reliability and design. Promoted to Supervisor of Electric Distribution Planning with a staff of 12 electrical engineers with responsibility for capacity and reliability planning.
1988 -- Manager of Operations, Colorado Front Range Division. Responsible for all electric and gas distribution operations, including a high-pressure gas system (engineering, operations, and construction).
1994 -- Manager of Operations & Maintenance Engineering, Southeast Denver. Managed the design of gas and electric distribution system replacements.
1997 -- Manager, Distribution Reliability Assessment, Xcel Energy South (CO, WY, TX, OK). Led an engineering team focused on electric distribution grid reliability and capacity.
1998 -- Director of Electric and Gas Operations, Southwest Denver Division. Responsible for all aspects of electric and gas engineering, operations, and construction in the Southwest Denver Division.
1999 -- Director of Operations, City and County of Denver Division. Responsible for all aspects of electric and gas engineering, operations, and construction for Division, including downtown Denver. Promoted to Director, New Construction of electric and gas systems for the entire metro area.
2001 -- Director Electric Distribution Asset Strategy, Xcel Energy. Developed and implemented asset management strategies for all electric distribution assets in Xcel Energy's 8-state service area.

2005 -- Director of Utility Innovations and Smart Grid Investments. Led Xcel Energy's Utility Innovations department, developing and implementing new technologies and business processes in multiple electric and gas distribution functional areas. Advanced the concept of an Intelligent Network at Xcel Energy, and led several aspects of the SmartGridCity® demonstration project in Boulder, Colorado. Department secured a national Edison Award for Innovation in 2006. Retired in 2011.
2016 – Senior Technical Consultant, Wired Group.

Noteworthy Projects

Smart Grid Solutions Development, 2010. Worked with several large solution providers to develop and implement technical distribution grid solutions and innovations, including IBM, ABB, and Siemens.
DER Integration Strategy and Roadmap Development, 2009. Established DER integration strategy and road-maps for Xcel Energy, including technology and capability roadmap for high DER penetration geographies in Boulder, Colorado.
SmartGridCity™ Project Development, 2008. Developed the technical foundations for the SmartGridCity project in Boulder, Colorado (46,000 customers).
Distribution Automation Design, 2007. Worked with ABB Corporation to design software to identify and locate failures in underground cable. The ABB Smart Analyzer™ was programmed with three traps to capture detailed information using Oscillography/Digital Fault Records (O/DFR).
Utility Innovations Program Development, 2006. Led the development of Xcel Energy's Utility Innovations program, for which Mr. Stephens' team receive a national Edison Award.
Distribution Asset Optimization Process, 2005. Taking advantage of SPL's Centricity Outage Management Program and Itron's Real Time Performance Management system (RTPM), developed a Distribution Asset Optimization process by mining AMI meter data and asset utilization information in the development of an enhanced asset loading forecasting process. The process took advantage of the systems' abilities to forecast sudden changes in usage patterns to take proactive mediation of equipment overloading.
Distribution Asset Optimization Software Development, 2004. Worked with Itron on the development of a Distribution Asset Optimization software program.
Fixed AMI Communications Network Development, 2003. Worked with Itron to pilot one of the first applications of a fixed wireless radio network to collect data from customer meters.
Electric Asset Management Strategy Development, 2002. Developed Xcel Energy's Electric Distribution Asset Management Strategy
Automated Switching System Deployment, 2001. Worked with S&C Electric Corporation to deploy its Intelliteam™ devices on Xcel Energy's distribution grid to reduce the number of customers impacted by an outage by isolate faults through automated switching routines.
High Pressure Gas Pipe Replacement Program, 1988. Initiated and managed the renewal and replacement of 26 miles of high pressure gas pipe, over a 5 year period, reducing the likelihood of seam failures as outlined in an "Alert Notice" issued by the Department of Transportation's Office of Pipeline Safety. Project roles included

community engagement, government and regulator relations (PUC, DOT, EPA), and contractor management. Project completed 1 year ahead of schedule and 14% under budget.

Regulatory Appearances

Evaluate National Grid's historical spending and multi-year rate plan. Panel testimony with Paul J. Alvarez 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 Paul J. Alvarez 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 Paul J. Alvarez 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 Paul Alvarez 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 Paul Alvarez on behalf of the Attorney General in Illinois Commerce Commission 22-0487. May 11, 2023.

Evaluate the Technical Justifications for Public Service Oklahoma's $450 million Grid Enhancement and Resilience Plan. Testimony on behalf of the Attorney General in PUD-2022-000093. March 7, 2023.

Evaluate Georgia Power's Transmission and Distribution Spending Proposals. Panel testimony with Paul Alvarez 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 Paul Alvarez 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 Paul J. Alvarez on behalf of Public Interest Advocacy Staff. Georgia PSC 44160. May 6, 2022.

Evaluate Oklahoma Gas & Electric Company Grid Modernization Spending and Plans. Testimony on behalf of the Office of Attorney General in PUD 202100164. April 27, 2022.

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

Dominion Grid Modernization Plan Review. Testimony on behalf of Appalachian Voices/Southern Environmental Law Center. PUR-2021-00127. September 13, 2021.

Avista Utilities' Electric Distribution and Wildfire Spending, Plans, and Processes. Panel testimony with Paul J. Alvarez on behalf of Public Counsel. WUTC 200900, 200901, and 200894. April 29, 2021.

Pepco's 2021-2023 Grid Investment and Plan. Panel testimony with Paul J. Alvarez on behalf of the Maryland Office of People's Counsel. MDPSC 9655. March 3, 2021

Baltimore Gas & Electric Company's 2021-2023 Grid Investment and Operations Plan. Panel testimony with Paul J. Alvarez on behalf of the Maryland Office of People's Counsel. MD PSC 9645. Aug 14, 2020.

Review of Maryland Utilities' 2019 Annual Performance Reports. Comments of the Office of People's Counsel. MD PSC 9353. June 8, 2020

Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan. Testimony before the North Carolina Utilities Commission critiquing Duke Energy's Plan on behalf of a group of environmental and consumer advocates. NCUC E-7, Sub 1214 Feb 18, 2020 & E-2, Sub 1219 Mar 25, 2020.

Indianapolis Power and Light's proposed $1.2 billion Grid Improvement Plan. Testimony before the Indiana Utility Regulatory Commission on behalf of the City of Indianapolis critiquing Indianapolis Power and Light's proposed $1.2 billion Grid Improvement Plan. 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.

New Hampshire Public Utilities Commission Distribution Planning/Grid Modernization Proceeding. Comments in IR 15-296 describing a transparent, stakeholder-engaged distribution planning process.

Pacific Gas and Electric 2019 General Rate Case. Testimony in A.18-12-009 on behalf of TURN related to $270 million in proposed "Integrated Grid Platform" investments.

Southern California Edison 2017 General Rate Case. Testimony in A.16-09-001 on behalf of TURN related to $2.3 billion in proposed grid modernization investments.
Pacific Gas and Electric 2016 General Rate Case. Testimony in A.15-09-001 on behalf of related to $100 million in proposed grid modernization investments.

Notable Publications and Presentations

Alternative Ratemaking in the US: A Prerequisite for Grid Modernization, or an Unwarranted Shift of Risk to Customers? With Paul Alvarez, Kenneth Costello, and Sean Ericson. Electricity Journal. Volume 35 (October 2022).
Utility Regulation Through Legislation: A Cautionary Tale for Legislators, Regulators, Stakeholders, and Utilities. With Paul Alvarez and Sean Ericson. 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 Paul J. Alvarez 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 to be published September, 2020.
The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Paul Alvarez & Sean Ericson. Accepted for publication by Public Utilities Fortnightly. Anticipated publication June, 2019.
Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Paul Alvarez for GridLab. January 31, 2019
Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Paul Alvarez for GridLab. October 5, 2018.
DistribuTECH 2010, Tampa, Florida. "Realizing the Benefits of DER, DG and DR in the Context of Smart Grid"
OSI 2008 User's Conference, Denver, Colorado; DistribuTECH 2007, San Diego, California. "Smart Grid City: A blueprint for a connected, intelligent grid community"
ABB 2007 World Conference, Jacksonville, Florida. "Use of Distribution Automation Systems to identify Underground Cable Failure"
North American T&D Conference 2005, Toronto, Canada; Itron 2005 User Conference, Boca Raton, Florida. "Xcel Energy Utility Innovations and Distribution Asset Optimization"
DistribuTECH 2005, San Diego, California. "How Advanced Metering Technology is Driving Innovation at Xcel Energy"

Education

Bachelor of Science Degree in Electrical Engineering, 1975, University of Missouri at Rolla.

Awards

Led Xcel Energy team that received a National Edison Award for Utility Innovations, 2006.

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:

William L. Humes
OKLAHOMA GAS AND ELECTRIC COMPANY
PO Box 321, MC 1208
Oklahoma City, OK 73101
humeswl@oge.com
reginfor@oge.com

Deborah R. Thompson
Kenneth A. Tillotson
THOMPSON TILLOTSON PLLC
P.O. Box 54632
Oklahoma City, OK 73154
deborah@ttfirm.com
kenneth@ttfirm.com

Thomas P. Schroedter
HALL, ESTILL, HARDWICK, GABLE, GOLDEN & NELSON, P.C.
521 East 2nd St., Suite 1200
Tulsa, OK 74120
tschroedter@hallestill.com

Adam J. Singer
J. Eric Turner
DERRYBERRY & NAIFEH, LLP
4800 N. Lincoln Blvd.
Oklahoma City, OK 73105
asinger@derryberrylaw.com
jeturner@derryberrylaw.com

Rick D Chamberlain
P.O. Box 21866
Oklahoma City, OK 73156-1866
rick@chamberlainlawoffices.com

Lesli R. Newton, Maj USAF
Federal Executive Agencies Attorney
139 Barnes Dr., Suite 1
Tyndall AFB, FL 32403-5317
Leslie.newton.1@us.af.mil

A. Chase Snodgrass
K. Christine Chevis
Ashley N. Youngblood
OFFICE OF THE ATTORNEY GENERAL
313 N.E. 21st Street
Oklahoma City, OK 73105
chase.snodgrass@oag.ok.gov
christine.chevis@oag.ok.gov
ashley.youngblood@oag.ok.gov
utility.regulation@oag.ok.gov

J. David Jacobson
JACOBSON & LAASCH
212 East Second St.
Edmond, OK 73037
Jdj8788@aol.com

Jack G. Clark Jr.
CLARK, WOOD & PATTEN, P.C.
3545 N.W. 58th St., Suite 400
Oklahoma City, OK 73112
cclark@cswp-law.com

Ronald E. Stakem
CHEEK & FALCONE, PLLC
6301 Waterford Blvd., Suite 320
Oklahoma City, OK 73118
rstakem@cheekfalcone.com

Jeremy E. Melton
Paul D. Trimble
TRIMBLE LAW GROUP, PLLC
5510 N. Francis Avenue
Oklahoma City, OK 73118
jmelton@trimblelawgroup.com
ptrimble@trimblelawgroup.com

Mary Ellen Sanders

Mary Ellen Sanders, Legal Secretary
OKLAHOMA CORPORATION COMMISSION