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	)	CAUSE NO. PUD 202000021
APPROVING A RECOVERY MECHANISM FOR	)	
EXPENDITURES RELATED TO THE	)	
OKLAHOMA GRID ENHANCEMENT PLAN	)	

RESPONSIVE TESTIMONY OF PAUL J. ALVAREZ

On behalf of

AARP

August 25, 2020

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I. INTRODUCTION

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 am the president of the Wired Group, a boutique consultancy engaged in electric and gas distribution system planning, investment, and performance measurement.

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

A. I am testifying on behalf of AARP. AARP, with its millions of members in all 50 States and the District of Columbia, Puerto Rico, and U.S. territories, is a nonpartisan, nonprofit, nationwide organization that helps empower people to choose how they live as they age, strengthens communities, and fights for the issues that matter most to families, such as healthcare, employment and income security, retirement planning, affordable utilities, and protection from financial abuse. AARP has 400,000 members residing in Oklahoma representing all segments of the socio-economic scale. Moreover, a substantial percentage of AARP's members live on fixed or limited incomes and depend on reliable and affordable electric service for adequate heat, cooling and lighting. Affordable and reliable electric service is required for economic security, health, and personal welfare. Older adults are particularly burdened by price increases on energy, as many of them live on fixed incomes and lack the flexibility to pay significantly higher monthly expenses, and average utility expenditures for households headed by people age 65 and older have been rising faster than inflation. More importantly, the current pandemic has left thousands of Oklahomans unemployed, struggling to make ends meet, and challenged to pay utility bills.

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 established a utility practice for sustainability consulting firm MetaVu. 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,[1] and the second was an evaluation of Duke Energy's Cincinnati-area deployment completed for the Ohio Public Utilities Commission in 2011.[2]

I started the Wired Group in 2012 to focus exclusively on distribution utility performance measurement and ratepayer 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 2016 my Wired Group colleagues and I developed the *Utility Evaluator*™, an Internet-based software program which uses publicly available operating and financial data to facilitate utility performance benchmarking. In addition to leading the Wired Group,

[1] Alvarez P et al. *SmartGridCity® Demonstration Project Evaluation Summary*. Colorado PUC 11A-1001E. Direct Testimony of Michael Lamb. Exhibit MGL-1. December 14, 2011.
[2] Alvarez P et al. *Duke Energy Ohio Smart Grid Audit and Assessment*. Ohio PUC 10-2326-GE-RDR. Staff Report dated June 30, 2011.

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 IN SIMILAR REGULATORY PROCEEDINGS PREVIOUSLY?

A. Yes. My credentials have been accepted, and I have testified in electric distribution planning, investment, and performance measurement proceedings, before regulators in 15 states. A complete list of appearances is provided in my CV, attached as Exhibit PJA-1. My associate, Dennis Stephens, an electric and gas grid engineer with 35 years' electric and gas distribution planning, investment, and asset management experience with Xcel Energy, often assists me with grid modernization plan reviews, as he did in this proceeding. Mr. Stephens's CV is also attached, as Exhibit PJA-2.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE OKLAHOMA CORPORATION COMMISSION?

A. No.

Q. DO YOU REQUEST THE COMMISSION ACCEPT YOUR CREDENTIALS AND RECOGNIZE YOU AS AN EXPERT WITNESS IN THIS MATTER?

A. I do.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony provides support for my recommendation in this case, which is that OG&E's request for a new surcharge to recover the cost of its Grid Enhancement Plan be denied. My recommendation follows from three findings: 1) Plan investments, which the new surcharge will encourage, will not deliver benefits to residential customers, or to any customers, in excess of costs; 2) OG&E's request for a new surcharge is not justified, and essentially shifts all risks to customers; and 3) There is no pending reliability, resilience, flexibility, efficiency, or other emergency for which the Commission should encourage exceptional investment through the approval of a new surcharge.

Q. YOUR TESTIMONY IS LENGTHY. ARE THERE ANY HIGHLIGHTS YOU WISH TO POINT OUT IN ADVANCE?

A. Yes. In reviewing OG&E's application, testimony, and discovery responses, and developing my recommendation, several "proof points" stood out to me. I will be presenting and citing these proof points as part of my findings as appropriate. However, to avoid losing these stand-out points in long technical arguments, I present them here as a service to the reader. All evidence will be cited later as these proof points are presented.

- While OG&E estimates residential customers will pay 60% of Plan costs, only 2% of the reliability-related economic benefits OG&E projects from its Plan will accrue to residential customers.
- OG&E's Plan will increase residential revenue requirements by more than 7% by 2024. This rate increase is only the first installment on a $3.5 billion regulated rate base growth plan OG&E recently presented to Wall Street.
- Of the five-year, $810 million Plan, OG&E is only presenting for approval its initial Annual Investment Plans ($245.7 million). While these initial Plans suffer from the same issues as the overall Plan, the issue is that future Plan spending will not be reviewed by the Commission until after Plan spending is complete and costs are being recovered from customers. At that point, disallowance will be practically impossible.
- OG&E also appears to seek only approval of the cost recovery mechanism in this docket, while claiming the Commission may review the spending after OG&E collects funds from customers.
- Except for major storm years in 2013 and 2015, OG&E's reliability with storms is in line with US Investor Owned Utility (IOU) averages, which

broadly demonstrates the Plan for extra-ordinary distribution spending is unjustified and unnecessary.

- OG&E utilizes an assumption that its Plan will deliver a 60% improvement in reliability (as measured by SAIDI and SAIFI)[3] with storms, when estimating related economic benefits to customers. However, with storms, the small Arkansas grid enhancement program on a very small number of circuits on which this assumption is based delivered only a 24% improvement in SAIDI and no improvement in SAIFI.
- With the possible exception of line pole replacements (which OG&E's Plan does not specify), I note that new equipment OG&E plans to install will be no less susceptible to weather damage than old equipment, requiring ratepayers to potentially pay twice for the same equipment.
- OG&E claims the Plan is necessary due to an increase in outages from equipment issues. However, Customer Minutes Interrupted due to equipment issues represented 34.6% of Minutes on average from 2013-2015, and only 32.1% of Minutes from 2017-2019. There is no impending reliability emergency.
- On average, from 2015 to 2019, OG&E reports that it only received 131 general complaints from customers per year regarding OG&E reliability, demonstrating the Plan is not driven by customer demand.
- The Plan would increase OG&E's distribution rate base, which took 116 years to build, by almost 20% in just five years.
- The state utility regulator in only one of the examples OG&E cited has approved extra-ordinary cost recovery for grid modernization plans. In that state (Indiana), legislation instructed regulators to do so. OG&E does not cite states (North Carolina, Virginia) which rejected grid modernization plans from Duke Energy and Dominion.

[3] SAIDI is System Average Interruption Duration Index, and SAIFI is System Average Interruption Frequency Index. Standards for measuring and reporting both reliability metrics are maintained by the IEEE in Standard 1366. For those unfamiliar with these industry standard measurements, they measure the duration of outages (the D in SAIDI) and the frequency of outages (the F is SAIFI), have reporting standards for with and without storms, and the lower the SAID and SAIFI numbers, the better.

- At normal investment levels, OG&E invested $1.4 billion in its distribution grid from 2011 to 2018 inclusive without any need for any new surcharges.

II. PLAN INVESTMENTS, WHICH THE NEW SURCHARGE WILL ENCOURAGE, WILL NOT DELIVER BENEFITS TO RESIDENTIAL CUSTOMERS, OR TO ANY CUSTOMERS, IN EXCESS OF PLAN COSTS

Q. OG&E CLAIMS ITS PLAN WILL DELIVER $1.9 BILLION IN ECONOMIC BENEFITS, COMPARED TO $810 MILLION IN COSTS. IS THIS REALISTIC?

A. No, it is not. OG&E's benefit-cost analysis exaggerates all three benefit types OG&E claims, including (a) avoided economic harms related to reliability improvements ($1.4 Billion), (b) avoided capital expenditures ($380 million), and (c) avoided O&M spending ($120 million).

A. THE MAJORITY OF OG&E'S CLAIMED BENEFITS COME FROM AN ESTIMATED $1.4 BILLION IN BENEFITS THAT ARE NOT SUPPORTED BY OG&E'S ANALYSIS

Q. WHAT ARE THE DEFICIENCIES IN OG&E'S CLAIMED AVOIDED HARM BENEFIT ESTIMATE OF $1.4 BILLION IN PRESENT VALUE TO CUSTOMERS?

A. There are multiple deficiencies resulting in a dramatically exaggerated avoided harm benefit estimate. First, OG&E bases its reliability improvements on the results of similar investments in only 14 Arkansas circuits (and associated substations). While the reliability of the Arkansas circuits reportedly improved 60% in the first year *without storms*, OG&E applied the 60% reliability improvement to historical Oklahoma reliability performance *with storms,* dramatically exaggerating reliability improvements. Second, OG&E uses the US Department of Energy's online Interruption Cost Estimator (ICE) to translate the 60% reliability improvement into avoided economic harm benefits. While OG&E discounts these benefits by 27% in its benefit-cost analysis, the Plan upgrades only a fraction of its assets and circuits. This casts significant doubt that economic benefits equal to

73% of the already-exaggerated 60% improvement in reliability are even remotely achievable. Third, even if these two deficiencies are ignored entirely, the ICE tool estimates that only 2% of the reliability-related economic benefits accrue to residential customers.[4] Given current distribution cost allocations by class, this means that OG&E's Plan offers residential customers no chance to secure benefits greater than costs. It should be noted that OG&E in no way guarantees the delivery of these improvements or benefits to customers. Finally, even if all three deficiencies are ignored, it is highly likely that the ICE tool significantly over-estimates the economic benefits to Commercial & Industrial (C&I) customers from reliability improvements.

Q. Explain why OG&E's use of the 60% improvement in 14 Arkansas circuit reliability without storms cannot be applied to historical Oklahoma reliability with storms.

A. In developing and supporting the benefits of its Plan, OG&E assumed reliability would improve 60% for those upgraded substations and circuits. The assumption is based upon the results *excluding* storms[5] of similar investments made in Arkansas.[6] OG&E input the 60% improvement in SAIDI and SAIFI into the ICE tool,[7] applying the 60% improvement to OG&E's historical SAIDI and SAIFI performance *with* storms.[8] This resulted in an ICE output of $1.9 billion in reliability-related economic avoided harm benefits, which OG&E subsequently discounted by about 23%, to $1.4 billion, in the Plan benefit-cost analysis. By applying reliability improvement percentages to non-storm reliability metrics, OG&E exaggerates reliability improvements, as reliability metrics with storms are always greater values than reliability metrics without storms. In discovery, OG&E provided

[4] OG&E response to DR AG 7-22 attached as Exhibit PJA-3.
[5] Direct Testimony of Zachary Gladhill. Chart 3, "Monthly SAIDI for Arkansas Series I". Page 13.
[6] OG&E response to DR AARP 1-6(b), "AARP 1-6_Att1.xlsx" (Arkansas enhancement investment lists).
[7] OG&E response to DR AG 3-8, "AG 3-8_Att.xlsx", tab "Oklahoma ICE (inputs) w Storms".
[8] OG&E response to DR AARP 1-5(a).

historical reliability data *with storms* for the 14 Arkansas circuits in question, which were upgraded in 2018.[9]

Table 1: SAIDI and SAIFI history for upgraded Arkansas circuits WITH STORMS

SAIDI, 6 Subs/14 Circuits, Fort Smith					**SAIFI**, 6 Subs/14 Circuits, Fort Smith				
2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
214.92	1373.02	296.82	238.66	190.47	0.91	1.59	1.14	2.11	1.42

If the aberrant year of 2016 (with SAIDI five times higher than the circuits' historical averages due to a vicious set of storms on July 14th) is removed, the 3-year average pre-upgrade SAIDI (before upgrades) is 250.13 with storms, and the 3-year average pre-upgrade SAIFI is 1.39 with storms. After the upgrades, SAIDI improved 24% relative to historical averages with storms (190.47 vs. 250.13), not 60%; SAIFI deteriorated 2% rather than improving 60% (1.42 vs. 1.39).

I am also concerned that the post-upgrade reliability metrics for Arkansas circuits reflect only a single year's performance. The reliability of any circuit for a single year is highly variable. It is possible that the 24% SAIDI improvement observed in Arkansas in 2019 was, in part, an aberration, and not the direct result of the upgrades. This is why 3-year or 5-year averages are commonly utilized in reliability analyses.

I also reviewed the 25 service outages which occurred on the Arkansas circuits in the years prior to the upgrades.[10] These 25 service outages were utilized in the Monte Carlo simulation OG&E ran to model reliability improvements; the Monte Carlo simulation was used as additional support for the 60% SAIDI and SAIFI improvement estimate. I found that only 10 of these 25 outages, or 40%, and only 52% of outage minutes, resulted from equipment deterioration. Not only is it impossible for a 60% improvement to be secured when the underlying causes represent just 40% of outages and 52% of outage minutes, OG&E's claim that

[9] OG&E Response to DR AARP 1-6, "AARP 1-6_Att2.xlsx".
[10] OG&E response to DR AARP 1-17, "AARP 1-17_att.xlsx".

equipment replacements lead to reduced outages is predicated on a notion that OG&E can accurately identify which assets will fail in the future. Unless OG&E has objective asset test results which predict failure (to be further discussed later in this testimony), or a crystal ball, this is clearly not realistic and does not provide a reliable substantive basis for the Commission to approve a new surcharge.

Q. YOU MENTIONED THAT OG&E'S DISCOUNTING OF ICE TOOL ECONOMIC BENEFITS FROM RELIABILITY, FROM $1.9 BILLION TO $1.4 BILLION, WAS AN INADEQUATE REDUCTION GIVEN THE SMALL FRACTION OF ASSETS OG&E PROPOSES TO UPGRADE IN ITS PLAN. PLEASE EXPLAIN THIS.

A. OG&E discounted the ICE tool's economic benefits output, calculated on 60% improvements in SAIDI and SAIFI, by about 27% (representing about $500 million).[11] OG&E discounted the ICE tool's benefit output as the historical outages on the circuits to be upgraded represent about 73% of OG&E's total service interruptions. However, I note that substations and circuits are made up of hundreds of assets, any one of which can fail at any time. In fact, OG&E's Plan only upgrades a tiny fraction of its assets. The details of proposed initiatives in the $810 million Plan,[12] compared to the quantities of different types of assets installed in Oklahoma,[13] delivers the following "percent of assets upgraded" results:

[11] Gladhill Direct Test., page 18, line 29.

[12] Direct Testimony of Kandace Smith, Exhibit KS-5, confidential workpaper, "Smith CapEx Detail 5-yr Plan.xlsx". OG&E redacted version in response to DR AG 1-3, "AG 1-3_Att_Supplement.pdf" attached hereto as Exhibit PJA-4.

[13] OG&E response to DR AARP 1-23.

Table 2: Percent of Assets to be Upgraded by Type per Plan

Asset Type	Number in OK	# Upgraded in Plan	% Upgraded per Plan
Distribution Transformers	247,082	4,200	1.7%
Substation Transformers	1,465	40	2.7%
Substation Breakers	2,624	200	7.6%
Substation Relays	12,049	450	3.7%
Circuits Reinforced	1,183 circuits	250 circuits	21.1%
Switches Automated	1,183 circuits	250 circuits	21.1%

Q. YOU MENTION THAT THE ICE TOOL ESTIMATES THAT RESIDENTIAL CUSTOMERS WILL RECEIVE ONLY 2% OF PROJECTED ECONOMIC BENEFITS RELATED TO RELIABILITY. HOW CAN THAT BE TRUE?

A. In ICE output details obtained in discovery, residential economic benefits from OG&E's projected reliability improvements amounted to only $42.5 million of the $1.9 billion OG&E used in its benefit-cost analysis[14] (subsequently discounted to $1.4 billion). In my informed opinion, the issue is not underestimated residential benefits; instead, the small ratio of residential benefits to total benefits is an artefact of drastically overestimated C&I customer benefits.

The "avoided harm" benefits the ICE tool calculates are based on a limited number of surveys of residential and commercial customers conducted by only a few IOUs from 1989 to 2013. The surveys asked customers about the costs per interruption, from a momentary outage (less than 5 minutes) to a sustained interruption lasting up to 8 hours. In a secondary research project in 2009,[15] updated with two more surveys collected in 2013,[16] the Department of Energy translated survey results into

[14] OG&E response to DR AG 3-8, "AG 3-8_Att.xlsx", tab "Reliability Improvement".
[15] Sullivan et al. *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory. June 2009.
[16] Sullivan et al. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States.* Lawrence Berkeley National Laboratory. January 2015.

the estimated costs per interruption the ICE tool employs today. A sample of those costs are presented below.[17]

Table 3: ICE Tool "Avoided Harm" Economic Benefit Estimates by Customer Type and Outage Duration

	Momentary	**1 hour**	**8 hours**
Large C&I (> 50 MWh annually)	$12,952	$17,804	$84,083
Small C&I (< 50 MWh annually)	$412	$647	$4,690
Residential	$3.90	$5.10	$17.20

As you can see, the residential avoided harm benefit estimates appear quite reasonable. However, I believe the C&I estimates are drastically overstated, for a variety of reasons. Drastic C&I benefit overstatements cause relatively accurate residential estimates to appear tiny by comparison. The reasons I believe the C&I avoided harm estimates are dramatically overstated, many of which the researchers themselves cite as data deficiencies,[18] include:

- The estimates are based on a limited number of surveys of manufacturing and retail customers only (now a C&I minority), conducted decades ago.
- Sampling was not representative of various types of C&I customers, nor was it representative of various US geographies.
- Survey administrator identities (IOUs) were known to respondents, so C&I customers may have provided inflated answers (dollar costs per interruption) in hopes of receiving outage-related compensation or other benefits.
- There is no consistency in how surveys/survey respondents took available back-up generation or uninterruptible power supplies into account when estimating dollar costs per interruption.

[17] Ibid, Table ES-1, page xii.
[18] Ibid, page 48.

- The definition of a “large” C&I ratepayer is very small (a bit smaller than the electric usage of 4 average OG&E-served residences),[19] increasing the count of large C&I customers to which large avoided harm benefits are multiplied in the ICE tool.

- The surveys estimated individual customer harms, not community-wide harms. Individual customer harms cannot simply be aggregated to estimate community-wide harms, as this approach ignores outage-related benefits to C&I customers near outage-impacted areas. (Consider a resident who decides to go out to dinner, or simply switches a purchase to a business with power, when faced with an electric service outage.) These offsetting C&I benefits are ignored by the ICE tool, resulting in excessive avoided harm estimates.

B. THE CLAIMED BENEFIT OF $380 MILLION IN AVOIDED CAPITAL SPENDING IS ILLUSORY

Q. OG&E’S BENEFIT ESTIMATES ALSO INCLUDE $380 MILLION IN AVOIDED CAPITAL SPENDING. IS THIS ESTIMATE EXAGGERATED TOO?

A. Yes. OG&E claims that replacing existing assets with new ones now avoids future replacement costs. I simply do not understand how accelerated capital spending can be considered a customer benefit, as customers will be paying today for asset replacements that could have waited until a future time, when justified as necessary by objective, asset-specific test results. Mr. Gladhill states it is less costly to replace an asset in advance than it is to replace an asset in an emergency, such as when its failure causes an outage.[20] However, it is impossible for OG&E to predict which assets will fail, or which assets will be taken out by a storm. As a result, it is highly unlikely that prospective replacement will reduce capital spending. The reality is that the OG&E Plan accelerates and increases capital spending.

[19] Energy Information Administration Form 861, 2018: 13.46 MWh per OG&E residential customer (8,969,308 MWh sold to 666,448 residential customers).
[20] Gladhill Direct Test., page 15, line 23.

To secure a present value benefit of $380 million in avoided capital, OG&E will need to save about $26.0 million in capital annually (nominal value).[21] I asked OG&E to provide the historical annual capital costs associated with service restorations from 2013 to 2019. The average was $37.4 million annually, including $7.4 million in non-storm capital and $30.0 million in storm capital.[22] This data causes me significant concern about the size of OG&E's avoided capital benefit estimate.

First, this data indicates OG&E's Plan will reduce annual outage-related capital spending by 70% ($26.0 million in projected capital reductions vs. $37.4 million in historical spending). Given that OG&E's Plan only replaces a small fraction of most assets, I just don't see how this is even remotely possible. Second, with the possible exception of line pole replacements, which OG&E's Plan does not specify,[23] storm-related capital spending avoidance is largely impossible. A storm that destroys a mile or two (or several miles) of distribution line is generally going to destroy those lines whether there is new equipment on those lines or not. Furthermore, even if new equipment could significantly reduce storm-related capital spending, OG&E would have to be able to predict where future storms will hit to achieve a reduction of such magnitude. OG&E would also need to have near-perfect equipment failure prediction capabilities to achieve a 70% outage-related capital reduction in non-storm situations.

Finally, prospective asset replacement actually increases OG&E's distribution capital spending. When a storm takes out a bunch of new equipment, customers continue to pay for the new equipment destroyed, and pay for the replacement equipment as well.

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[21] OG&E response to DR AG 3-4, attachment "AG 3-4_Att_Supplement.xlsx", tab "NPV Calc", cell B16, attached hereto as Exhibit PJA-6.
[22] OG&E response to DR AARP 1-2, "AARP1-2_Att.xlsx".
[23] OG&E response to DR AARP 2-1(e).

C. THE CLAIMED BENEFIT OF $120 MILLION IN AVOIDED O&M SPENDING IS EXAGGERATED

Q. OG&E'S BENEFIT ESTIMATE ALSO INCLUDES $120 MILLION IN AVOIDED O&M SPENDING. HOW IS THIS ESTIMATE EXAGGERATED?

A. OG&E exaggerates the O&M spending reduction benefit in two ways. First, it uses "fully loaded" (with fixed costs) estimates of cost per activity. For example, OG&E's benefit-cost analysis assumes that $500 will be saved every time OG&E's Plan avoids a truck roll.[24] However, $500 is not the variable cost of a truck roll. Instead, it is a "rule of thumb" value which includes many fixed costs which will not fall with a reduction in truck rolls. Fixed costs allocated to the rule of thumb value can include service center, supervisory, and management costs. The rule of thumb value may even include allocations of general and administrative overhead costs such as human resources or information technology support.

To validate this hypothesis, I asked OG&E for details behind the O&M cost reduction estimate. I prompted for details such as reductions in headcount and associated employee benefits, overtime, contract labor, vehicle costs, etc. OG&E responded that it "does not have the requested breakdown".[25] To secure a present value benefit of $120 million, OG&E will have to cut $12.8 million annually (nominal value) from its distribution spending upon full deployment.[26] This is about 3/8ths of the O&M spending on service restoration OG&E spent on average per year from 2013 to 2019 ($34 million).[27] That is a significant savings percentage to estimate with no detail as to how the savings will be achieved, particularly when OG&E's Plan replaces far, far fewer than 3/8ths of OG&E's distribution assets.

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[24] OG&E Workpaper, Witness Smith, "Oklahoma Cost Benefit Model Summary.pdf".
[25] OG&E response to DR AARP 1-8.
[26] OG&E response to DR AG 3-4, attachment "AG 3-4_Att_Supplement.xlsx", tab "NPV Calc", cell B15, attached hereto as Exhibit PJA-6.
[27] OG&E response to DR AARP 1-2, "AARP 1-2_Att.xlsx".

Second, OG&E's avoided O&M spending is exaggerated due to rate case timing. While OG&E's benefit-cost analysis shows annual O&M reductions, O&M reductions are not translated into customer rate reductions until a rate case is held. It also assumes the full O&M spending reductions projected are reflected in test year accounting records for that rate case. One feature of the new surcharge OG&E is requesting is that it lets OG&E recover Plan costs without a rate case. This is likely to reduce rate case frequency. If any O&M cost reductions result from OG&E's Plan, it may be many years before the combination of full O&M spending reductions and rate case occur simultaneously, securing benefits for customers at long last. Until such time, any such benefits are retained by OG&E's shareholders. (It is also notoriously difficult to validate the size of O&M spending reductions in test year accounting records.)

Oklahoma Staff pioneered an answer to this issue in PUD 20100002, the case involving OG&E's request for a rider to recover smart meter costs. In an innovation I cite frequently in my work, the Settlement Agreement specifies that the O&M cost reductions OG&E projected from its smart meter investment by year would be deducted from the rider's revenue requirement by year.[28] This innovation effectively held OG&E accountable for delivering O&M benefits in the amounts estimated, in the timeframes estimated (at least until the next rate case), and addressed the rate case timing issue. If OG&E is confident of the O&M reduction estimate in its Plan, it should propose deducting $12.8 million, grown by inflation annually, from its annual revenue requirement, as well as a post-deployment audit to validate the actual size of O&M spending reductions the Plan delivered.

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[28] Cause No. PUD 201000002, Joint Stipulation and Settlement Agreement dated May 27, 2010. Page 3, paragraph F. Approved by the Commission in Order No. 576595 dated July 6, 2010.

D. THERE ARE ADDITIONAL OVERRIDING ISSUES WITH THE COST-BENEFIT ANALYSIS OG&E RELIES UPON FOR ADVOCATING ITS PLAN AND ITS PROPOSED SURCHARGE.

Q. YOU'VE MADE SEVERAL ARGUMENTS THAT THE BENEFITS OF OG&E'S PLAN TO CUSTOMERS WILL NOT EXCEED COSTS TO CUSTOMERS. BUT WHAT ABOUT QUALIFIED BENEFITS? DON'T THOSE COUNT FOR SOMETHING?

A. Yes, they do. Mr. Gladhill notes qualitative Plan benefits like safety, security, and economic development benefits. I recognize that these benefits are both real, and difficult to quantify. However, in my estimation, these qualitative benefits will amount to less than qualitative costs – specifically, the cost to the Oklahoma economy of higher electric rates. Rate increases without sufficiently high corresponding benefits act as a tax on the Oklahoma economy. Governments may have to reduce services, businesses may choose to relocate operations, and consumers' discretionary spending falls. OG&E estimates a Plan rate increase exceeding seven percent for residential customers. This increase will be in addition to any routine rate increases OG&E may require, and it will persist until Plan assets are fully depreciated (20 years on average, using OG&E's benefit period as a guide, but 40 years for many assets). I recommend the Commission consider rate increases to be a precious commodity, to be reserved for occasions when truly necessary (such as for storm-related repairs or distributed energy resource accommodation), and/or justified by clear and measurable benefits. Such a philosophy will never be more important than at the present time, when pandemic-related economic dislocations may impact the Oklahoma economy for years to come.

Mr. Gladhill's testimony also notes that improved customer experience results from improved reliability, and counts this as a qualitative benefit. I note that an average of only 131 customers per year out of 800,000 complained about OG&E reliability from 2015-2019.[29] Mr. Gladhill's testimony also notes that improved grid configuration flexibility counts as a qualitative benefit. I note that OG&E's grid is

[29] OG&E response to DR OIEC 2-23.

already quite flexible, and that OG&E already makes extensive use of sectionalizing devices to isolate faults, and back-tie lines to supply power to customers located beyond a fault without having to wait for the fault to be repaired.[30,31]

Q. WHAT ABOUT OG&E'S PLAN COST PROJECTIONS? ARE THOSE OF CONCERN?

A. Yes, I do have concerns about OG&E's cost projections. One example is proposed Plan investments totaling $155 million for information technology and communications network infrastructure.[32] These assets have estimated useful lives of five to ten years. Yet, OG&E's cost estimate includes no provision for replacing these assets even once during the 30-year benefit period OG&E used in its Plan benefit-cost analysis. I am also concerned OG&E has completed no make vs. buy analysis on the $55 million communications network investment vs. service options available from AT&T or Verizon Wireless.[33]

I believe the Commission should also be concerned about the level of detail at which cost projections have been completed. For instance, OG&E estimates the $1.9 billion in total Plan benefits it expects will result from 48 different initiatives. OG&E estimates the capital cost of these initiatives to be $810 million.[34] However, these costs have only been estimated at a very high level. Only the Plan components OG&E proposes for the first Annual Investment Plan have been estimated with any degree of certainty.[35] It is very possible, if not likely, that the cost of the 48 initiatives as currently conceived will cost far more than $810 million. An alternative outcome might be that OG&E cuts the initiatives (thus lowering benefits) to stay within the $810 million budget. According to the AACE Cost Estimate Classification System, the level of detail at which OG&E has developed

[30] OG&E responses to DR AARP 1-13 and DR AARP 1-14.
[31] OG&E redacted workpaper in response to AG DR 1-3, "AG 1-3_Att_Supplement.pdf" attached as Exhibit PJA-4.
[32] Gladhill Direct Test., Table 1, page 14.
[33] OG&E responses to DR AARP 3-2(i) and DR AARP 5-2(d)
[34] OG&E redacted workpaper in response to DR AG 1-3, "AG 1-3_Att_Supplement.pdf" attached as Exhibit PJA-4.
[35] OG&E response to DR OIEC 9-8.

its $810 million cost estimate qualifies for Level 4 at best.[36] The AACE has found that Level 4 cost estimates are only accurate from -15% to +50%.[37] I also note that, absent a Commission Order to the contrary, customers will bear all cost overrun risks. (I will return to the highly unlikely prospect of cost disallowances later in this testimony).

Q. ARE THERE ANY ASPECTS OF OG&E'S PLAN WHICH, IF IMPLEMENTED PROPERLY, COULD BE BENEFICIAL?

A. There are some Plan initiatives which I believe merit stronger consideration than others. For example, primary research I have led into the cost-effectiveness of smart grid deployments indicates that the remote control of grid reconfiguration switching (generally known as FLISR, or "fault location, isolation, and service restoration") does have some reliability improvement potential, as reconfigurations can be executed from a control center (rather than having to send linemen to throw switches manually). But benefits are limited to about 20 minutes per outage, and back-up power feeds are not always available when grid damage is widespread and extensive (which is the case in severe storms). Benefits are also limited to customers beyond the isolated section of grid; customers in the immediate area of the outage must still wait for repairs. Further, the budget for the switch automation initiative is less than 5% of OG&E's $810 million Plan.[38]

As another example, I agree that improving visibility to grid conditions in real time is important for managing high levels of distributed energy resources reliably (like customer rooftop solar). However, OG&E has no substantive penetration levels of such resources.[39] Increases in grid condition visibility will be necessary someday, but when, and to what extent geographically? The gaping hole in OG&E's Plan is the complete lack of transparent comparisons of the pros and cons of various

[36] Unlike most grid modernization plans I have evaluated, OG&E did not utilize the AACE cost estimation classification system to estimate Plan costs. (OG&E response to DR AARP 1-24(a))
[37] AACE International Recommended Practice No. 18R-97. Page 2.
[38] OG&E redacted workpaper in response to AG DR 1-3, "AG 1-3_Att_Supplement.pdf" attached as Exhibit PJA-4.
[39] Gladhill workpaper "021120_EV_DG.xlsx"

spending alternatives, and a lack of customer-focused prioritization. For example, only 2% of the Plan budget is dedicated to adding remote control capabilities to capacitor banks and voltage regulators.[40] This capability is critical for implementing automated conservation voltage reduction, which has proven to deliver energy savings of at least 1-2% on most circuits (more if smart meters are incorporated). Automated conservation voltage reduction therefore offers one of the best benefit-cost ratios of any available grid capability. But its existence, let alone a plan to implement it, is completely absent from OG&E's Plan.[41] This is probably due to the fact that automated conservation voltage reduction reduces electric sales volumes between rate cases, and therefore OG&E's opportunity to earn the rate of return authorized by the Commission. But automated conservation voltage reduction is a clear example of how OG&E's Plan is suboptimal for customers, and why much work needs to be done before the Plan, let alone preferred cost recovery, merits Commission consideration.

Another example of a lack of decision support and customer-focused prioritization, related directly to reliability, is vegetation management. I observe that OG&E has a history of non-compliance with the 4-year vegetation management cycle prescribed by the Commission. It is certainly possible, if not likely, that greater spending in vegetation management will deliver more reliability improvement per dollar than OG&E's Plan. (As a large O&M expense, when earnings targets promised to Wall Street are in danger of being missed, vegetation management spending is among the first to get cut at most IOUs.) To summarize, relative to the many grid modernization plans I have evaluated, OG&E's Plan is not well-considered, fails to consider potentially less costly alternatives in pursuit of goals, and is poorly supported.

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[40] OG&E redacted workpaper in response to AG DR 1-3, "AG 1-3_Att_Supplement.pdf", attached as Exhibit PJA-4, lines 13 and 14 divided by $810 million.
[41] OG&E response to DR AARP 4-3(c).

Q. WHAT DOES YOUR VERSION OF THE OG&E PLAN'S BENEFIT-COST ANALYSIS LOOK LIKE?

A. In the table below I estimate Plan costs and benefits from a residential customer perspective. Despite the significant reservations I have described above for each benefit projection OG&E has estimated, to ensure a conservative analysis, I have ignored all such reservations. I multiplied all costs and benefits by residential customers' share of the Oklahoma jurisdictional revenue requirement (59.77%) as settled in PUD 201800140.[42] The only difference is that I use the residential portion of the reliability-related benefits determined by the ICE tool ($42.5 million), discounted by the same 23% that OG&E used to account for the fact that it's upgrading just a portion of its circuits and assets. Even if all OG&E benefit projections are accepted at face value, residential customers will secure only $0.69 in benefits for every $1 in costs. While this testimony demonstrates that Plan costs are highly certain to exceed Plan benefits for customers overall, I can state with complete certainty that residential Plan costs will exceed residential Plan benefits.

Table 4: AARP Residential Customer Benefits per Dollar of Costs Estimate

($ in millions)	**OG&E Plan Estimate**	**Non-Residential Portion**	**AARP Residential Estimate**
Avoided Economic Harm Benefits (Reliability)	1,400	(1,367)	33
Avoided Capital Spending	380	(153)	227
Avoided O&M Spending	120	(48)	72
Total Benefits	1,900	(1,568)	332
Cost	810	(326)	484
Customer benefit per $1 of cost	**$ 2.35**		**$ 0.69**

[42] Oklahoma Corporation Commission PUD 201800140. Worksheet "Okla PUD 201800140 (Settled COS).xlsx", tab "Cost of Service". Residential rate requirements ($375.237 M)/Total ($627.781M).

III. OG&E'S REQUEST FOR A NEW SURCHARGE IS NOT JUSTIFIED, AND ESSENTIALLY SHIFTS ALL RISKS TO CUSTOMERS

Q. WHAT DOES OG&E'S APPLICATION REQUEST?

A. In an unusual move, in this case OG&E is only seeking approval of a new surcharge to recover the costs of Plan investments, with actual review of the Plan investments to come at a later date. OG&E proposes that investments placed in service quarterly would result in quarterly increases in the surcharge, with documentation provided to Staff. In addition, the surcharge crafted by OG&E is unlimited in how much revenue it can collect from customers.[43] There are several reasons the surcharge OG&E proposes is not justified. Some of these are specific to this application. Other reasons relate to any request for rate increases outside of a rate case, and will be familiar to the Commission. I will address these types of issues in turn, and then finish the topic of cost recovery with a discussion on risk, and how customers in general (and residential customers in particular) essentially bear all of it given OG&E's proposal.

Q. WHAT ARE THE PECULIARITIES OF THIS SPECIFIC OG&E PROPOSAL FOR A NEW SURCHARGE?

A. I find this specific OG&E surcharge proposal troubling. Perhaps the most significant is that OG&E is asking for a surcharge on spending that has not yet occurred. Typically, OG&E requests for a surcharge relate to storm-related repairs; in those instances the costs of equipment, overtime, contract labor, mutual aid (from other utilities), etc. are known. In addition, the Commission has the opportunity to review this spending to ensure it was necessary. In this OG&E proposal, little is known about the spending or its necessity. Furthermore, as proposed, only Staff has the opportunity to review Grid Enhancement spending and such review would occur outside any proceeding before the Commission.

[43] OG&E response to DR AG 8-6 attached as Exhibit PJA-7.

Q. WHY DO YOU CLAIM LITTLE IS KNOWN ABOUT THE SPENDING? OG&E'S PLAN PROVIDES DETAILS ON $810 MILLION IN PROPOSED SPENDING, DOES IT NOT?

A. Well, yes and no. The Application includes an overview of 48 initiatives OG&E will likely undertake over five years if the Commission approves the surcharge request. OG&E's proposal is to provide a plan annually, called the Annual Investment Plan, for Staff review. As equipment is placed into operation quarterly in accordance with each Annual Investment Plan, OG&E's proposal calls for the surcharge to increase, using existing assumptions about the cost of capital, authorized rate of return, and cost of service allocations to calculate rate increases outside of a rate case. OG&E proposes to provide new Investment Plans annually to Staff, and to provide documentation of commissioned investments and surcharge increases quarterly to Staff, but notably, not to stakeholders or the Commission. The present Application, for example, only provides equipment, cost, and capability commitments for the initial Annual Investment Plans, which totals $245.7 million. The other $564 million of Plan spending is not well-defined at all.

While OG&E casts the flexibility of this approach as a benefit, it causes me significant concern. First, as described earlier in my discussion on cost concerns, customers cannot really be assured of which capabilities will be implemented, or to what geographic extent, for a specific cost. It is possible OG&E will spend more to implement promised capabilities, or, conversely, that OG&E will reduce capabilities to remain within the $810 capital spending target. It is impossible for the Commission to hold OG&E accountable for its spending or results in such a situation. Second, and perhaps more importantly, it leaves the Commission and stakeholders just two opportunities to review OG&E Plan investment: 1) the present opportunity, applicable to just $245.7 of $810 million; and 2) once all Plan capital spending is completed, in a rate case, to determine prudence. All Annual Investment Plans and quarterly surcharge increases are provided only to Staff. I find both the lack of accountability and the lack of Commission review opportunities associated with the surcharge proposal extremely inappropriate. I believe equity is also an issue. In the highly unlikely event the $810 million investment is deemed imprudent (an issue to be addressed a bit further below) in 2025 or beyond, OG&E will owe refunds of $230 million already collected.[44] Many customers who paid these funds will have moved from OG&E's service territory by the time the refunds are made, and will never get their money back. Missing a refund of significant size constitutes an inequitable situation. Customer relocations are likely to increase during the next few years because of Pandemic-related economic disruption.

Q. WHAT EVIDENCE DO YOU HAVE THAT $564 MILLION IN PLAN SPENDING IS ILL-DEFINED?

A. I could provide many examples, but here are two large ones. While the $564 million includes $55 million for communications network replacement, OG&E has yet to determine how it will upgrade its AMI network,[45] or how it will upgrade field data backhaul.[46] The fact that OG&E has estimated such costs when a replacement approach has yet to be selected does not instill confidence. As another example, the list of capital initiatives for $167.5 million in "circuit upgrades" is supported by a single assumption: that it will be adequate for 250 circuits.[47]

Q. WHAT ARE THE ARGUMENTS AGAINST THE SURCHARGE WITH WHICH THE COMMISSION IS ALREADY FAMILIAR?

A. There are at least three reasons why OG&E's request for a surcharge, to be determined outside of a rate case, is not justified. In addition to the peculiarities specific to this OG&E proposal as described above, these three reasons will be familiar to the Commission, as AARP established them as positions in PUD 201800097 (the proceeding regarding Public Service Oklahoma's request for performance-based rates).[48] First, allowing a utility to increase rates without a rate case reduces the frequency of rate cases, which thus reduces opportunities for

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[44] Workpaper "OK Grid Enhancement RR- 5yr plan – 3 RR – V2 (Rowlett Supplemental).xlsx", tab "COMBINED", Line 29 (Oklahoma Revenue Requirement, 2020-2024 inclusive).
[45] OG&E response to DR AARP 5-2(d)
[46] OG&E response to DR AARP 3-2(i).
[47] OG&E redacted workpaper in response to AG DR 1-3, "AG 1-3_Att_Supplement.pdf" attached as Exhibit PJA-4.
[48] Responsive testimony of Ron Nelson on behalf of AARP, Cause No. PUD 2018-97, January 18, 2019.

regulatory review of utility spending. Second, allowing a utility to increase rates without a rate case reduces the beneficial aspects of regulatory lag for customers. Regulatory lag offers a utility an opportunity to increase profits by reducing costs between rate cases. As noted earlier in the discussion about O&M spending OG&E claims will be avoided by its Plan, increasing the amount of time between rate cases delays the translation of any Plan-related cost reductions into customer rate reductions. OG&E has failed to include these delays in its benefit-cost analysis. Finally, using a new surcharge to recover Plan costs reduces shareholder risks. Such risk reductions merit reductions in the authorized rate of return, though a reduced rate of return related to this reduced risk is not part of OG&E's proposal. For all these reasons, I believe the surcharge as requested by OG&E in this case is not justified.

Q. BUT OG&E OFFERS SEVERAL JUSTIFICATIONS IN FAVOR OF A NEW SURCHARGE, DOES IT NOT?

A. Yes. Mr. Rowlett states that the customers have benefitted from such surcharges in the past, citing the system hardening program rider.[49,50] He also claims that OG&E's request for preferred cost recovery is similar to one the Commission approved for Public Service Oklahoma (PSO) recently.[51] Mr. Rowlett also implies that the Commission should approve the request since OG&E rates are relatively low.[52] I take issue with all these justifications.

Regarding OG&E's previous system hardening efforts, I note that OG&E has provided no evidence that the investments were cost-effective, let alone that the investments improved reliability.[53] Regarding PSO's Distribution Reliability and Safety (DRS) rider, I understand it was capped in settlement at a revenue requirement of $5 million annually, or about $9 per customer per year.[54] I note that

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[49] Rowlett Direct Test., page 6, line 16.
[50] Cause No. PUD 200800387. Joint Stipulation and Settlement Agreement filed March 20, 2009. Approved by Commission Order No. 567670, May 7, 2009.
[51] Ibid, page 9, line 8.
[52] Ibid, page 13, line 6.
[53] OG&E response to DR AARP 1-18(b).
[54] $5 million divided by PSO's customer count of 554,500 (2018 Energy Information Administration).

OG&E estimates its revenue requirement at $97.7 million annually by 2025,[55] or over $122 per average customer per year.[56] The OG&E Plan is more significant by orders of magnitude than the investments contemplated in the settlement reached in the PSO case. I also note that PSO's DRS rider was limited to extraordinary investments, whereas many OG&E Plan initiatives consist solely of accelerated replacement of traditional distribution assets. To summarize, OG&E's request for a surcharge is not similar at all to PSO's request.

Finally, I do not believe the Commission should consider the size of OG&E's rates relative to the US IOU average when making a decision regarding a new surcharge. OG&E's overall rates are relatively low due to factors unrelated to distribution rates, including fuel mix and fuel cost, and to other factors beyond OG&E's control, such as the relatively low labor costs in Oklahoma. The fact that OG&E's rates are on the low end compared to other US utilities in other parts of the country is irrelevant to the decision of whether a significant surcharge on OG&E's customers without proven benefits is appropriate.

Q. OG&E WITNESS MR. ROWLETT EMPHATICALLY DENIES THAT OG&E'S COST RECOVERY PROPOSAL SHIFTS RISKS TO CUSTOMERS.[57] IS HE MISTAKEN?

A. Yes. Mr. Rowlett's assertion is based on a single fact: that the Commission can deny or refund cost recovery in the future, which creates risk for shareholders. As a practical matter, the likelihood that the Commission would deny OG&E cost recovery on $810 million in Plan investments in a future rate case should this application be approved is virtually zero. This is due to two factors. First, it will be impossible for stakeholders to prove that Plan assets are not used and useful. The assets will be installed, and commissioned, and will distribute electricity to customers. Even if the assets deliver zero improvements in reliability, zero capital spending reductions, and zero O&M spending reductions (indicating that the

[55] OG&E response to DR OIEC 1-6, "OIEC 1-6_att_Supplement.xlsx".
[56] $97.7 million 2025 Oklahoma jurisdictional revenue requirement divided by 800,000 customers.
[57] Direct Testimony of Donald Rowlett. Page 11, line 11.

assets may not have been useful), the fact that the assets are delivering electricity will make it difficult for the Commission to justify disallowance. Furthermore, OG&E offers no cost or benefit performance measures in its Plan. This means the Commission has no way to determine if benefits projected in the Plan were delivered, or to what extent, and therefore no basis for a finding that the investments were not useful. Moreover, according to OG&E, it failed to consider or analyze any alternative cost recovery mechanism options.[58]

Second, and perhaps more importantly, a decision by the Commission in the future to deny cost recovery on such a massive investment ($810 million or more) after this case will increase OG&E's cost of capital. Increases in cost of capital result in customer rate increases irrespective of the ratepayer benefit associated with Plan cost disallowance. In effect, the Commission's hands will be tied. If it allows cost recovery on assets which provided relatively little economic benefit, rates will increase; If it denies cost recovery on those assets, rates will increase anyway (through increases in OG&E's cost of capital). Practically speaking, plan cost disallowance in the future therefore constitutes an empty threat. This fact alone should cause the Commission great concern in approving OG&E's proposed surcharge mechanism.

Q. HOW IS RISK TRANSFERRED TO CUSTOMERS?

A. Once the reality that future cost disallowance risk is virtually zero is recognized, the transfer of all risk to customers is clear and unequivocal. As discussed at length earlier, the likelihood that Plan costs will exceed Plan benefits is a certainty for residential customers. Further, customers cannot do anything to reduce performance risk; the delivery of anticipated benefits to customers relies fully on OG&E choices and actions, both pre-investment and post-deployment. This is why customers, and not shareholders, essentially bear all Plan risk. It is also reason enough for the Commission to reject OG&E's request for a surcharge.

[58] OG&E response to DR AG 6-1 attached as Exhibit PJA-8.

In addition, OG&E's Plan does not offer to share the risk of cost over-runs with customers. Nor does OG&E's Plan offer to place some of its cost recovery at risk based on the achievement of Plan benefits. Under OG&E's proposal, shareholders are virtually assured of cost recovery, with a "built-in" rate of return, while customers receive no assurances of any kind. That sure sounds like a transfer of risk to customers to me.

IV. THERE IS NO PENDING RELIABILITY, RESILIENCE, FLEXIBILITY, EFFICIENCY, OR OTHER EMERGENCY FOR WHICH THE COMMISSION SHOULD ENCOURAGE EXCEPTIONAL INVESTMENT THROUGH PREFERRED COST RECOVERY

Q. OG&E IS ASKING THE COMMISSION TO APPROVE A NEW SURCHARGE FOR ITS PLAN, IMPLYING THAT IT CANNOT INVEST TO THE DEGREE NECESSARY WITHOUT SUCH AN INCENTIVE.[59] WHAT DO YOU THINK OF THIS LOGIC?

A. I think the logic rests on a shaky foundation. First and foremost, OG&E has not demonstrated that Plan investments are necessary. The justification for the investments is based entirely on a claim that Plan benefits to customers will exceed Plan costs to customers. As indicated in the first section of this testimony, such a claim is far from solid. OG&E makes several other claims in its application which appear to convey to the Commission a sense of urgency regarding its Plan. I contend that no such urgency exists, and refute such claims in this section of testimony. Furthermore, data OG&E submitted on FERC Form 1 indicates that OG&E's distribution rate base grew by $1.4 billion from 2011 to 2018, inclusive. This indicates to me that OG&E is being adequately incented to make, and adequately compensated for making, needed grid investments.

[59] Rowlett Direct Test., page 7, lines 5-16.

Q. OG&E CLAIMS THAT OUTAGES FROM EQUIPMENT FAILURE ARE ON THE RISE,[60] IMPLYING AN URGENT SITUATION WHICH MUST BE ADDRESSED BY PROMPT APPROVAL OF PREFERRED COST RECOVERY. DO YOU AGREE?

A. No. I secured historical, detailed "outage by cause" data in discovery; the percentage of customer minutes out by cause are provided in the table below.[61] The average percentage of customer minutes out from cause "equipment" was 34.6% from 2013 to 2015, and only 32.1% from 2017 to 2019. Therefore, outages from equipment failure do not appear to me to be "on the rise", nor does there appear to be some urgent need to prospectively replace equipment.

Table 5: Customer Minutes Interrupted by Cause Code, 2013-2019

Cause	2013	2014	2015	2016	2017	2018	2019
Animals	4.2%	7.3%	5.0%	5.4%	5.8%	7.5%	5.1%
Blank	0.5%	0.1%	0.0%	0.2%	0.0%	0.0%	0.0%
Equipment	32.6%	39.0%	32.2%	32.5%	30.4%	31.9%	33.9%
Other	12.8%	7.9%	9.1%	7.6%	5.3%	7.1%	1.9%
Vegetation	12.6%	12.6%	18.6%	13.6%	19.0%	14.4%	23.4%
Weather	37.4%	33.1%	35.1%	40.7%	39.6%	39.1%	35.7%

Q. OG&E CLAIMS ITS PLAN ALIGNS WITH BEST-IN-CLASS INDUSTRY PRACTICES.[62] DO YOU AGREE?

A. No. While some parts of OG&E's Plan emulate the investments other IOUs are proposing, it does not necessarily follow that these proposals constitute best practices. Indeed, large portions of the OG&E Plan are outside best industry practices. Primary of these is what I call "Prospective Asset Replacement Absent Justification". We can already see evidence of this in OG&E's initial Annual

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[60] Direct Testimony of Patrick Dalton, page 4, line 21 and page 6, line 18; Gladhill Direct Test., page 7, line 9.
[61] OG&E response to DR AARP 1-9, "AARP 1-9_Att.xlsx"
[62] Dalton Direct test., page 5, line 17.

Investment Plan. To understand why prospective asset replacement absent justification is not standard industry practice, a quick lesson in objective asset testing is required.

As is standard industry practice, OG&E maintains programs to test substation assets (transformers, circuit breakers, and relays) on a periodic basis. When an asset fails its test (chemical, electrical, or, in the case of poles, formal inspections), the asset is replaced prospectively (i.e., before a failure in service causes a service outage). Objective test (or formal inspection) results are used to accurately identify assets in need of replacement, and this has long been recognized as a best practice for substation assets and poles.

In recent years, and particularly in the last 12 months, I have identified an increased incidence of IOUs using subjective estimates of asset health to justify prospective asset replacement. While there is no research to support that subjective estimates are superior to objective testing in correctly identifying assets likely to fail, I have observed that the use of subjective estimates results in a dramatic increase in the number of assets IOUs propose to replace in their grid modernization plans. In the table below, I compare OG&E's historical annual replacement rates for various asset types to the replacement rates OG&E proposes in its Plan.

Table 6: Historical vs. Proposed Annual Replacement Rates for Selected Asset Types

Asset Type	Average Number of Assets Replaced Annually, 2015-2019	Average Number of Assets OG&E Proposes to Replace Annually per Plan, 2020-2025[63]
Substation Circuit Breakers[64]	21	40
Substation Relays[65]	37	90

In discovery I secured the most recent test reports for many of the assets OG&E proposes to replace in the first Annual Investment Plan, including 24 substation circuit breakers,[66] 65 substation relays,[67] and 3 substation transformers.[68] Not only were no test failures noted on any of these test reports, the reports confirmed that OG&E's existing asset management processes are working well and in accordance with standard industry practices. Minor abnormalities are clearly being identified, and appropriate repairs and adjustments are being made, in accordance with existing OG&E policies and processes. I believe adherence to standard practices is part of the reason why OG&E customers enjoy adequate reliability at low rates today. There is no need for OG&E to depart from standard industry testing and inspection practices.

Q. WHAT IS YOUR OPINION OF THE VARIOUS GRID MODERNIZATION GUIDES, CITED THROUGHOUT OG&E TESTIMONY, PUBLISHED BY THE ELECTRIC POWER RESEARCH INSTUTUTE (EPRI) AND THE US DEPARMENT OF ENERGY (DOE)?

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[63] OG&E redacted workpaper in response to AG DR 1-3, "AG 1-3_Att_Supplement.pdf" attached as Exhibit PJA-4.
[64] OG&E response to DR AARP 3-1(f).
[65] OG&E response to DR AARP 2-2, "AARP 2-2_Att2.xlsx".
[66] OG&E response to DR AARP 3-1.
[67] OG&E response to DR AARP 2-2(e).
[68] OG&E response to DR AARP 4-2(e).

A. I think these organizations are more biased than one would hope. For example, more than half of EPRI's board of directors are employed by IOUs, the Edison Electric Institute, or utility suppliers. The US Department of Energy is focused on reliability (including cybersecurity) and distributed energy resource accommodation, and rightfully so. However, the DOE appears to have few if any concerns about cost effectiveness. Despite paying $4 billion in grid investment grants to utilities from 2010-2012 as part of the 2009 American Reinvestment and Recovery Act, the DOE has not conducted a single benefit-cost analysis of any utility's grid modernization plan post-deployment.

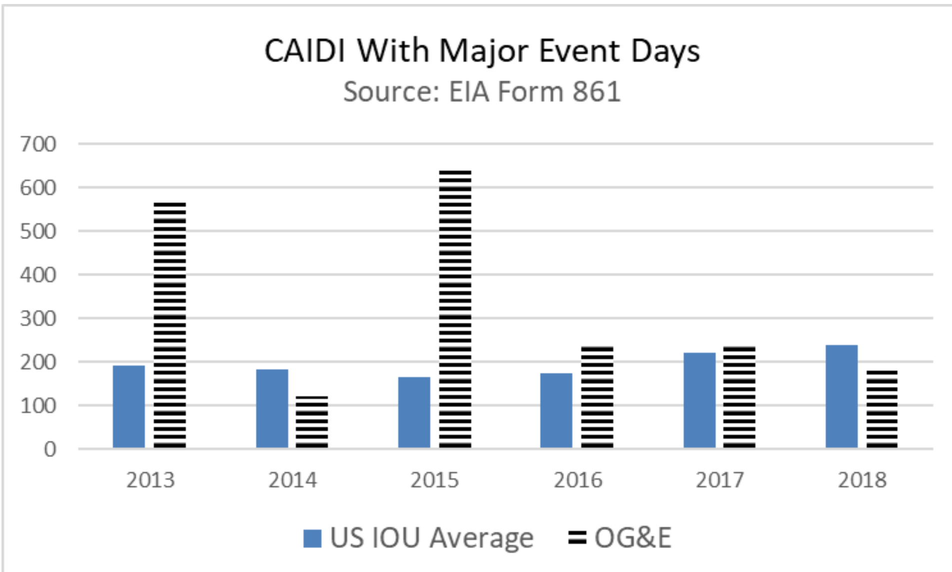
While I agree with many of the perspectives, constructs, and strategies described in various EPRI and DOE guides, I have found the practical value of such guides in making utility-specific or circuit-specific investment decisions to be extremely limited. Every IOU has a unique installed infrastructure base, and every IOU is at different levels of reliability performance, distributed energy resource capacity, and growth. High-level abstractions and theories are difficult to apply in such contexts. While the ICE tool is an exception, and attempts to serve a practical need, it suffers from the many deficiencies I described earlier in this testimony. I am also concerned by the "Least Cost, Best Fit" methodology espoused by the DOE.[69] I have observed many IOUs apply Least Cost, Best Fit in inappropriate circumstances, and strongly encourage the Commission to require benefit-cost analyses, as well as make-or-buy analyses, in as many instances as possible.

[69] Dalton Direct Test., page 23, line 7.

Q. OG&E CLAIMS THAT ITS RELIABILITY WITH STORMS IS TWICE AS BAD AS THE NATIONAL AVERAGE.[70] DO YOU AGREE?

A. No. The chart below compares OG&E CAIDI[71] with storms over the last several years to US IOU averages. Other than big storm years of 2013 and 2015, OG&E CAIDI is in line with US IOU averages. (US IOU reliability data for 2019 will not be available from the Energy Information Administration until October.)

Figure 1: CAIDI with Storms, OG&E vs. US IOU Average



Q. OG&E CLAIMS THAT CUSTOMER EXPECTATIONS REGARDING RELIABILITY ARE INCREASING.[72] DO YOU AGREE?

A. No. As indicated earlier in this testimony, out of 800,000 customers, an average of only 131 customers per year complained about OG&E reliability from 2015-2019.In fact, OG&E utilized no customer survey data, no customer input and no Oklahoma customer specific evaluation to inform a Plan it then calls customer-driven. OG&E presents no market research which indicates that reliability improvements are being demanded by customers. OG&E presents no market research which

[70] Dalton Direct Test., page 16, line 4; Gladhill Direct, page 7, line 9.
[71] Average duration of a service outage among customers who experienced one or more in a year.
[72] Dalton Direct Test., page 6, line 20; Gladhill Direct Test., page 8, lines 2-12.

indicates that customers are willing to pay more for better reliability, or which quantifies the rate increase customers are willing to accept for a given reliability improvement.[73] Such research is called “willingness to pay” research, and I encourage the Commission to conduct such research independently before approving preferred cost recovery for investments intended to improve reliability.

Q. OG&E CLAIMS THAT INCREASES IN GRID INVESTMENT WILL IMPROVE RELIABIILTY, OR AT LEAST HALT DETERIORATING RELIABILITY.[74] DO YOU AGREE?

A. No. Most laypersons are surprised to learn that there is no research or data which supports this claim. It certainly surprised the researchers from Lawrence Berkeley National Labs, who found no correlation between grid investment increases and reliability improvements among US IOUs from 2000 to 2012.[75] More recent data from US IOUs confirms this research. As seen in the chart below, IOU grid investment in recent years has far out-paced growth in peak demand, which is flat to falling. One would assume that investments in excess of the amounts required to accommodate demand growth would deliver reliability improvements. Yet, CAIDI has deteriorated. (Note that a rising CAIDI value indicates deteriorating reliability.) The exact same phenomenon can be seen from recent OG&E data in the chart which follows. I observe the same phenomenon with almost every IOU I analyze in this manner.

[73] OG&E has also failed to perform any economic or other analysis of the impact of its proposed large rate increase on its residential customers. OG&E response to DR AG 7-6 attached as Exhibit PJA-9.
[74] Dalton Direct Test., page 6, line 25; Gladhill Direct Test., page 8, line 10.
[75] Larsen P, LaCommare K, Eto J, and Sweeny J. *Assessing Changes in the Reliability of the U.S. Electric Power System*. Lawrence Berkeley National Laboratory study for the U.S. Department of Energy. August, 2015. P. 37.

Figure 2: Reliability vs. Distribution Rate Base Over Time, US IOU Averages

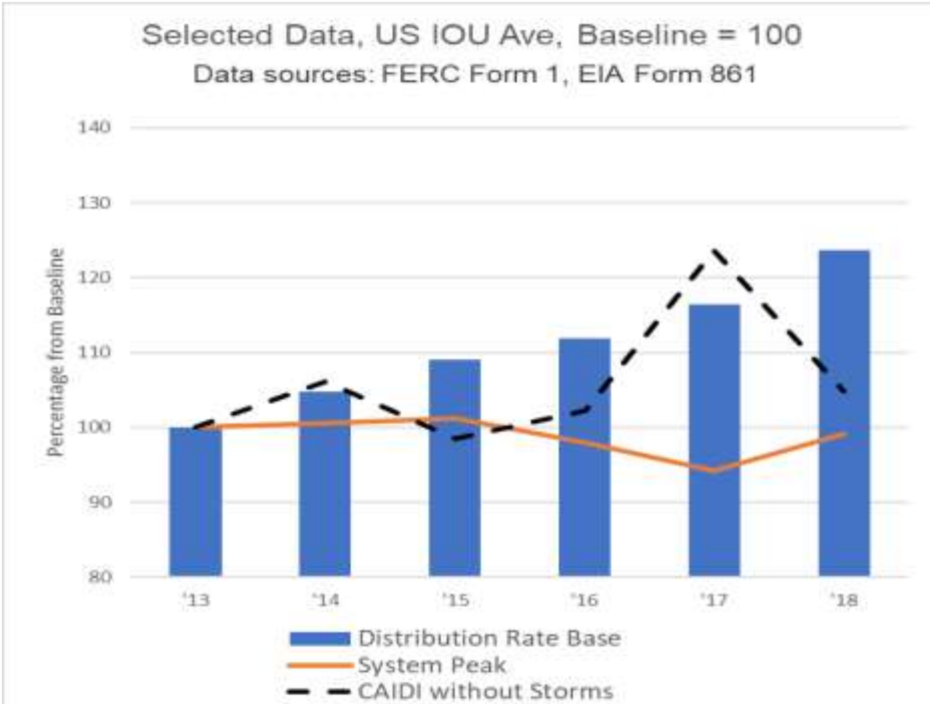
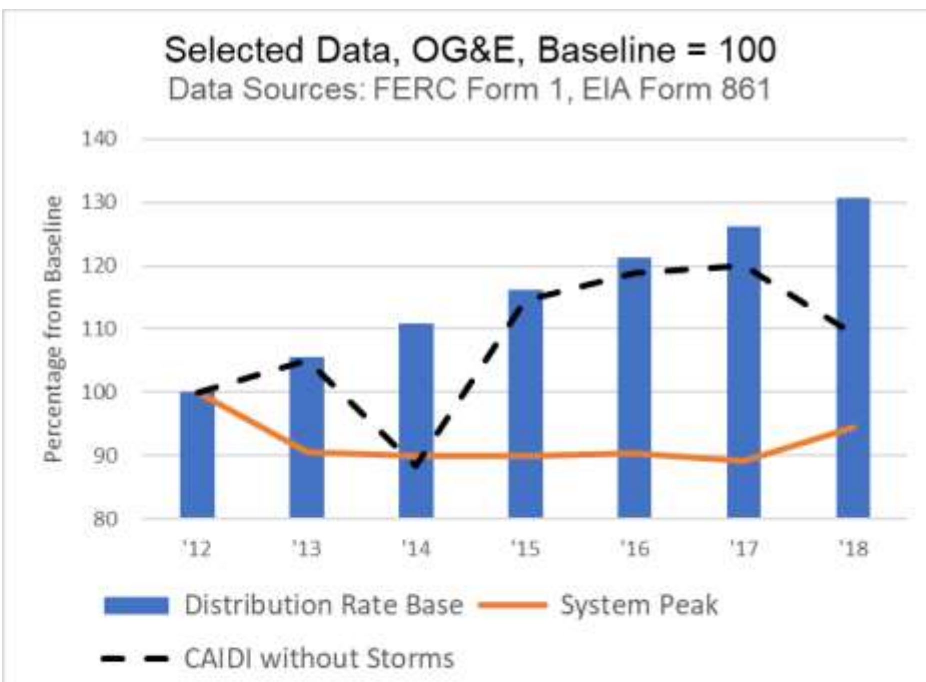


Figure 3: Reliability vs. Distribution Rate Base Over Time, OG&E



Q. OG&E WITNESS DALTON IMPLIES THAT GRID MODERNIZATION PLANS ARE BEING APPROVED BY UTILITY REGULATORS ACROSS THE US.[76] DO YOU AGREE?

A. No. Of the several states Mr. Dalton cites, only the Indiana Commission has approved IOU grid modernization plans (four of them). In Indiana, legislation essentially required the Commission to do so. The Missouri Commission has not yet reviewed Ameren's grid modernization plan. In Michigan, grid investment plans by Consumers Energy and DTE are not subject to Commission approval, as they are part of an investigational proceeding (not litigated). In fact, the Michigan Commission and Staff were so concerned with the size of the grid investment plans the IOUs submitted that they have transformed that proceeding into one focused on the development of stakeholder-engaged distribution planning processes.[77] Mr. Dalton does not cite Commissions which have rejected billion-dollar grid modernization plans, such as Virginia[78] and North Carolina.[79]

Q. OG&E CLAIMS THAT ITS PLAN IS MOTIVATED BY A DESIRE TO MAKE ITS GRID MORE RELIABLE, RESILIENT, FLEXIBLE, AND EFFICIENT.[80] DO YOU AGREE?

A. Yes, I agree. OG&E, like any utility, certainly wants its grid to be reliable, resilient, flexible, and efficient. But OG&E does not disclose that a variety of factors are making the earnings targets its executives have promised to Wall Street increasingly difficult to achieve. Across the US, IOU earnings are falling with sales volumes. New generation investments can be difficult to justify, and transmission investments require ten years of planning, approval, and construction before they can be added to rate base. With sales falling, and other investment opportunities limited, IOUs are attempting to make up the earnings shortfall by growing distribution rate bases. As indicated by the charts above, IOUs are growing

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[76] Dalton Direct Test., page 22, lines 28-30.
[77] Michigan PSC U-20147, Five-Year Distribution Investment and Maintenance Plans.
[78] Virginia SCC PUR-2018-00100. Order dated January 17, 2019.
[79] North Carolina UC E-7 Sub 1146. Order dated June 22, 2018. Pages 141-149.
[80] Gladhill Direct Test., page 4, line 18

distribution rate base despite flat to falling demand. IOU executives are highly motivated to do so, as the greatest proportion of their compensation potential comes from stock options. These stock options only payout when share prices rise. As share prices are highly correlated to earnings, the connection between distribution rate base growth and incentive compensation is clear.

OG&E's Plan is massive; its $810 million investment would grow OG&E's 2018 year-end distribution rate base, which took 116 years to build, by almost 20% in just 5 years.[81] OG&E estimates that its Plan will increase residential rates 7.3% by year 5.[82] This increase will be on top of any other rate increases OG&E may require to earn the rate of return the Commission authorizes. The 7.3% rate increase would also be additive to any other capital-intensive programs which OG&E may request. Investor Updates OG&E held in June project $3.5 billion in regulated investments from 2020-2024 (including the Grid Enhancement Plan), with only $90 million of that earmarked for Arkansas.[83] It is therefore likely OG&E will be seeking other large rate increases from its Oklahoma customers soon. To summarize, while OG&E undoubtedly wants its grid to be reliable, resilient, flexible, and efficient, OG&E's Plan is also clearly motivated by an interest in growing earnings. OG&E is certainly successful in that regard; despite the pandemic-induced recession, OG&E's 2nd quarter earnings were $0.39 per share, 5% higher than 2nd quarter earnings in 2019 ($0.37).[84]

[81] $810 million Plan divided by OG&E year-end distribution rate base, 2018 FERC Form 1 ($4.2 billion).
[82] OG&E response to DR OIEC 1-6, "OIEC 1-6_Att_Supplement.xlsx", tab "Impacts".
[83] OG&E Investor Update dated May 29, 2020. Slide 28 (https://www.ogeenergy.com/events-presentations/).
[84] OGE Energy Corp. Reports Second Quarter Results. Press release dated August 6, 2020.

V. SUMMARY AND RECOMMENDATION

Q. PLEASE SUMMARIZE YOUR TESTIMONY

A. My testimony provides evidence in support of three claims:

- The Plan investments and the proposed new surcharge and cost recovery mechanism will encourage unnecessary, uneconomic investment in OG&E's distribution system and will not deliver benefits to residential customers, or to any customers, in excess of costs; and,
- OG&E's request for a new surcharge is not justified, and essentially shifts all risks to customers; and,
- There is no pending reliability, resilience, flexibility, efficiency, or other emergency for which the Commission should encourage exceptional grid investment through the approval of a new surcharge.

Q. GIVEN YOUR TESTIMONY, WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. I recommend the Commission deny OG&E's Application for a new proposed surcharge and mechanism for its Grid Enhancement Plan cost recovery, and in addition, the Commission should reject the Plan itself as cost ineffective. Should the Commission adopt my recommendation, I encourage the Commission to consider making specific suggestions to Oklahoma IOUs regarding grid modernization proposals. These would include: 1) greater analysis and transparency in alternatives to capital investment, and the pros and cons of each; and 2) greater priority of customer needs over shareholder needs, including maximizing impact for the least amount of capital.

Q. DOES THIS CONCLUDE YOUR RESPONSIVE TESTIMONY?

A. Yes, it does.

LIST OF EXHIBITS

Exhibit PJA-1	Curriculum Vitae of Paul J. Alvarez
Exhibit PJA-2	Curriculum Vitae of Dennis Stephens EE
Exhibit PJA-3	OG&E response to DR AG 7-22 *regarding only 2% of the avoided economic harm benefits accruing to residential customers*
Exhibit PJA-4	OG&E redacted response to DR AG 1-3, "AG 1-3_Att_Supplement.pdf", Oklahoma Grid Enhancement 5 Year Plan, List of Potential Investments
Exhibit PJA-5	OG&E response to DR AG 3-8, "AG 3-8_Att.xlsx", tab "Reliability Improvement" *regarding OG&E inputs into the ICE tool, which converts reliability improvement estimates into economic customer benefit estimates*
Exhibit PJA-6	OG&E response to DR AG 3-4, "AG 3-4_Att_Supplement.xlsx", tab "NPV Calc" *regarding OG&E's estimates of avoided O&M and capital spending benefits*
Exhibit PJA-7	OG&E response to DR AG 8-6 *regarding no maximum revenue requirement recovery limit that OG&E may collect under the proposed tariff*
Exhibit PJA-8	OG&E response to DR AG 6-1 *regarding OG&E's failure to evaluate alternative cost recovery mechanism*
Exhibit PJA-9	OG&E response to DR AG 7-6 *regarding OG&E's failure to conduct any "willingness to pay" study related to proposed bill increases*

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

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

Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed the limitations of current utility regulatory and governance models. Mr. Alvarez currently serves as the President of the Wired Group, a boutique consultancy serving consumer and environmental advocates, regulators, associations, and suppliers.

Appearances and Research Projects in Regulatory Proceedings

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Books

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

Noteworthy Publications

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 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.

Price Cap Electric Ratemaking: Does it Merit Consideration? With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

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. *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.

Curriculum Vitae – Dennis Stephens EE

Wired Group, PO Box 620756, Littleton, CO 80162 dstephens@wiredgroup.net 303.434.0957

Profile

Mr. Stephens has over 35 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

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. The proceeding is still underway.

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. The investigational proceeding is still underway.

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

Pacific Gas and Electric 2019 General Rate Case. Testimony in A.18-12-009 related to $270 million in proposed "Integrated Grid Platform" investments, part of a long-term plan featuring an Advanced Distribution Management System (ADMS) implementation likely to cost as much as $644 million. As an "integration" software package of little benefit, Mr. Stephens' testimony rejected PG&E's proposal in favor of several individual ADMS components of greater value PG&E failed to propose, such as a Distributed Energy Resource Management System (DERMS) and an automated volt-VAr control system for conservation voltage reduction. A settlement agreement between the parties is under review.

Southern California Edison 2017 General Rate Case. Testimony in A.16-09-001 related to $2.3 billion in proposed grid modernization investments. Though portrayed by the Company as "required" to accommodate higher levels of distributed energy resources like photovoltaic solar panels, Mr. Stephens' testimony identified appropriate investment proposals (related to grid state monitoring, modeling, and frequent grid reconfiguration) while rejecting proposals which did not return benefits in excess of costs for customers (4kV circuit elimination and centralized, automated grid reconfiguration. as well as the systems and communications associated with centralized, automated grid reconfigurations). As a result of Mr. Stephens's testimony, the California PUC rejected $462 million in unnecessary grid investments requested by SCE.

Pacific Gas and Electric 2016 General Rate Case. Testimony in A.15-09-001 related to $100 million in proposed grid modernization investments. Though portrayed by the Company as "required" to accommodate higher levels of distributed energy resources like photovoltaic solar panels, Mr. Stephens' testimony rejected many proposed grid upgrades as either premature (due to insufficient DER on any one circuit or location) or unnecessary (due to safeguards in standard photovoltaic grid interconnection equipment). The California PUC rejected $60 million in unnecessary grid investments requested by PG&E as a result of Mr. Stephens's testimony.

Notable Publications and Presentations

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

National Edison Award for Utility Innovations, 2006.

Attorney General
Data Request AG-7
Cause No. PUD 202000021

7-22 Please refer to the Company's response to AG-OGE-3-8, which shows that approximately 2% of avoided economic harm benefits would accrue to residential customers and approximately 98% of avoided economic harm benefits would accrue to other customer classes. Did OGE evaluate the reasonableness of allocating cost recovery using current distribution and other plant allocation ratios in light of the differences in benefits accruing to various customer classes? If so, please provide the results of that evaluation. If not, please provide a detailed explanation for why OGE did not consider this issue.

Response*: OG&E did consider benefits when determining its allocation methodology. The economic harm benefits derived from the Department of Energy's ICE calculator, and referenced in OGE's response to AG 3-8, are based on the lost revenue associated with outages. Improvements in reliability, regardless of customer class, will be the same on each circuit, so all customers on enhanced circuits will receive benefit; how they monetize the benefits will differ. Since residential customers generate less revenue from their homes than a commercial or industrial customer, the total value of residential benefits will not be recognized by the ICE calculator. Residential customers' benefits will be more qualitative in nature, focusing on quality of life and the ability to stay connected. For example, in the current pandemic environment, a customer's ability to work from home has become critical in keeping businesses operating and connecting with loved ones through electronic means. Even in today's shelter in place approach, outages at residential customers' premises don't generate significant lost revenue but can have major impacts on these residents. Due to the more qualitative nature of residential benefits OG&E chose what it believes to be a reasonable allocation methodology by looking to the cost-of-service supporting the final order from its most recent general rate case proceeding and choosing the allocation results tied to the same FERC accounts as those of OG&Es Grid Enhancement program.

Response provided by:	Zachary Gladhill
Response provided on:	April 13, 2020
Contact & Phone No:	Jill Butson 405-553-3285

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Grid Enhancement 5 Year Plan

List of Potential Investments

ID	Category	System	Investment	Specific Investment	Description	Assumptions	Estimated Volume of Work	Estimated Capital Cost	Include in 2020	2020 Investment Criteria	Additional Benefits to Include in Model
1	Grid Resiliency	Substation	Animal Protection	Animal Protection	Add protective fence around substation equipment with the highest risk for outages caused by animals Add advanced cover up at substations with highest risk for outages caused by animals	[redacted]	Protective Fence @ 80 Substations Cover Up @ 40 Substations	$ 5,200,000	Yes	Areas with known snake issues Use the Distrurbance Log & Review with the Substation Operations Team	n/a
2	Grid Resiliency	Distribution Line	Conductor Upgrades	UG Cable Replacement	Replace unjacketed cable and main feeder cable with historical failures	[redacted]	1.6 million feet	$ 41,120,000	Yes	Unjacketed Concentric Neutral Cable - Prioritized by average CMI per customer	n/a
3	Grid Resiliency	Distribution Line	Conductor Upgrades	OH Conductor Replacement	Replace obsolete overhead conductor	[redacted]	390,000 feet	$ 3,900,000	Yes	Replace 8S3, 3X3, 7W3 conductor - Prioritized by Customer Count	n/a
4	Grid Resiliency	Distribution Line	Equipment Upgrades	Transformer Load Management	Replace overloaded distribution transformers	[redacted]	4,300 distribution transformers	$ 18,060,000	Yes	Peak Load as % of rating, >40 hours in duration of overloaded	n/a
5	Grid Resiliency	Distribution Line	Equipment Upgrades	Lightning Outage Reduction	Upgrade lightning outage protection on circuits	[redacted]	50 Circuits 3,750 miles OH Line	$ 8,437,500	Yes	CMI associated with lightning strikes	n/a
6	Grid Resiliency	Substation	Equipment Upgrades	Substation Breaker Replacement	Replace poor performing and obsolete substation circuit breakers (PCR, FIS, PCB)	[redacted]	200 Breakers	$ 10,000,000	Yes	Replace breakers with lack of support and parts from manufacturer (6 Types of Breakers to Replace - GEFKD, Westinghouse ESC, Westinghouse PRC, TSC, Westinghouse ES, Westinghouse ESV)	n/a
7	Grid Resiliency	Substation	Equipment Upgrades	Substation Transformer Replacement	Replace poor performing substation transformers	[redacted]	40 Transformers	$ 24,000,000	Yes	Cascade: Risk Score	n/a
8	Grid Resiliency	Distribution Line	Storm Reinforcement	Distribution Line Reliability	Survey circuits and upgrade facilities	[redacted]	250 Circuits	$ 167,500,000	Yes	Condition and Criticality	n/a
9	Grid Resiliency	Substation	Capacity Reinforcement	Mobile Substations	Add mobile substations to the distribution substation fleet. Refurbish existing mobile substations	[redacted] [redacted]	4 Mobile Substations Annual Refurbishment	$ 17,400,000	Yes	Highest need and gap in fleet first	n/a
10	Grid Resiliency	Substation	Capacity Reinforcement	Mobile Generator	Add mobile generator to the distribution substation fleet.	[redacted]	10 MW of Generation	$ 10,250,000	No	n/a	n/a
11	Grid Resiliency	Distribution Line	Capacity Reinforcement	Distribution Storage	Install distributed energy storage to support the distribution system	[redacted]	5 MW Batteries	$ 5,250,000	No	n/a	n/a
12	Grid Resiliency	Distribution Line	Conductor Upgrades	Downtown Underground Netowrk Upgrades	Replace 30's and 40's vintage conductor on the secondary network Replace obsolete primary underground cable on remaining network circuit	[redacted]	45,000 feet of secondary conductor 2,500 feet of primary conductor	$ 9,500,000	No	n/a	n/a
13	Grid Automation	Distribution Line	Smart Field Devices	Add communications to capacitors	Add communications and controls to existing capacitors	[redacted]	2 per circuit 250 circuis	$ 4,000,000	Yes	All capacitors on selected circuits	Eliminating 2 truck rolls per year for each Capacitor

Oklahoma Grid Enhancement 5 Year Plan

List of Potential Investments

ID	Category	System	Investment	Specific Investment	Description	Assumptions	Estimated Volume of Work	Estimated Capital Cost	Include in 2020	2020 Investment Criteria	Additional Benefits to Include in Model
14	Grid Automation	Distribution Line	Smart Field Devices	Add communications to regulators	Add communications to existing regulators	[redacted] [redacted] [redacted]	1 per circuit 250 circuits	$ 11,875,000	Yes	All regulators on selected circuits	Eliminating 2 truck rolls per year for each Regulator
15	Grid Automation	Distribution Line	Automated Circuit Tie Lines	Automated Circuit Tie Lines	Install automated switches on circuits	[redacted]	2.5 devices per circuit 250 circuits	$ 36,875,000	Yes	Install at N.O. Ties, Commercial & Ind Load Pockets, and behind stepdown transformers 2.5 per circuit	n/a
16	Grid Automation	Distribution Line	Automated Lateral Lines	Smart Lateral Fuses	Install smart lateral fuses on circuits	[redacted]	60 devices per circuit 250 circuits	$ 45,000,000	Yes	All laterals - excluding small load or minimal exposure	n/a
17	Grid Automation	Substation	Remote Fault Location	Fault Location SCADA Inputs	Install SCADA points at substations to allow for remote fault location analysis in the DMS system	[redacted]	220 Substations	$ 1,100,000	Yes	All selected substations without existing SCADA points	SAIDI Improvement - 20% of remaining events
18	Grid Automation	Distribution Line	Remote Fault Location	Smart Fault Indicators	Install smart fault indicators at 6 locations on 200 of the worst performing circuits to enhance remote fault location analysis in the DMS system This will reduce restoration time by 20 minutes per incident.	[redacted]	6 locations per circuit 200 circuits	$ 7,200,000	No	n/a	n/a
19	Grid Automation	Distribution Line	Smart Field Devices	Smart Sensors	Add smart sensors to circuits	[redacted]	2 devices per circuit 100 circuits	$ 6,000,000	No	n/a	n/a
20	Grid Automation	Substation	Modern Protection Relays	Relay Replacement	Replace electromechanical and poor performing relays	[redacted]	450 relays	$ 121,500,000	Yes	Parts/Replacement Unavailable, Mis-Ops, Relay Test Plans (did they pass), manufacturer technical bulletin Cascade: Risk Score	n/a
21	Grid Automation	Substation	Substation Automation	SCADA (new/upgrade)	Install/Upgrade SCADA at substations	[redacted]	125 substation	$ 31,250,000	Yes	All selected substations without existing SCADA	SAIDI Improvement - 20% of remaining events
22	Grid Automation	Substation	Substation Automation	Replace S4/AD Meters	Replace S4 meters and AD meters in distribution substations	[redacted]	107 S4 Meters 214 AD Meters	$ 2,290,000	Yes	All on selected substatsions	Eliminating 1 truck roll per month for each Substation
23	Grid Automation	Substation	Substation Automation	Substation Equipment Monitoring	Install remote monitoring equipment at substations (e.g. - transformers)	[redacted]	50 Substations	$ 2,000,000	No	n/a	n/a
24	Technology Platforms and Applications	Technology Platforms and Applications	Workforce Optimization	Sub Ops Workforce Optimization	Configure work force management system to optimize substation operations work	[redacted]	120 mobile data units (MDUs) Configure CADS	$ 3,600,000	No	n/a	n/a
25	Communication Systems	Communication Systems	Wide Area Network	Freewave Network Upgrade	Replace freewave towers and remotes	[redacted]	52 Towers 2,606 Remotes	$ 6,772,000	No	n/a	n/a
26	Communication Systems	Communication Systems	Wide Area Network	Microwave and Wimax Upgrade	Replace Wimax telecom backhaul infrastructure and Upgrade Microwave backhaul infrastructure	[redacted]	85 wimax towers 100 microwave towers	$ 55,500,000	No	n/a	n/a
27	Communication Systems	Communication Systems	Mesh Network	Mesh Network Upgrade	Replace access points (APs) and relays on the mesh network	[redacted]	421 APs 2,235 Relays	$ 18,737,500	No	n/a	n/a

Oklahoma Grid Enhancement 5 Year Plan

List of Potential Investments

ID	Category	System	Investment	Specific Investment	Description	Assumptions	Estimated Volume of Work	Estimated Capital Cost	Include in 2020	2020 Investment Criteria	Additional Benefits to Include in Model
28	Technology Platforms and Applications	Technology Platforms and Applications	DER Management Application	DERMS	Add DERMS application to our ADMS Platform for the real-time monitoring, management and optimal dispatch of distributed energy resources including renewable generation, energy storage, electric vehicles, backup generators, and demand response	[redacted]	Add DERMS Application	$ 7,000,000	No	n/a	n/a
29	Technology Platforms and Applications	Technology Platforms and Applications	DER Management Platform	DER Interconnection Management	Invest in platform to manage DER interconnection process and integrate into existing systems to make DER interconnections visible	[redacted]	Interconnection Platform	$ 600,000	Yes	Invest due to increasing DER	n/a
30	Technology Platforms and Applications	Technology Platforms and Applications	Grid Planning Application	Advanced Planning Tools	Purchase planning applications to enable DER integration, forecasting, and power flow analysis	[redacted]	Integration Capacity Analysis (ICA) EPRI Drive Application Python Script Application Python Run Application Reliability Analysis	$ 67,250	Yes	Invest now to begin understanding impacts of DER	n/a
31	Technology Platforms and Applications	Technology Platforms and Applications	Expand GIS Nework Model	DER Assets in GIS	Add DER assets in GIS platform to enable visablity and connectivity throughout operations platforms and applications	[redacted]	Add existing DER Assets	$ 1,000,000	No	n/a	n/a
32	Technology Platforms and Applications	Technology Platforms and Applications	GIS Application	GIS Secondary Network Model	The GIS Secondary model will support real time power quality management for individual customers by allowing integration of secondary measurements into the electric model.	[redacted]	Model the secondary network where necessary	$ 2,000,000	No	n/a	n/a
33	Technology Platforms and Applications	Technology Platforms and Applications	Grid Operations Application	Advanced DMS Apps	Add the following applications to the ADMS … Epilog Pro, Compass (Real-time model to field), OSI Landscape	[redacted]	Epilog Pro Compass OSI Landscape	$ 10,000,000	No	n/a	n/a
34	Technology Platforms and Applications	Technology Platforms and Applications	Workforce Optimization Platform	Digital Field Services Management	Implement Digital Field Services Management (DFSM) - Work Load Leveling, Ticket Prioritization, Route Optimization	[redacted]	Work Load Leveling Ticket Prioritization Route Optimization	$ 10,000,000	No	n/a	n/a
35	Technology Platforms and Applications	Technology Platforms and Applications	Operational Analytics Platform	LiDAR - Change Management	Implement Criteria Based Vegetation Management	[redacted]	Data acquisition - 7,500 sq miles Implement Targeted Veg Mgmt	$ 4,500,000	No	n/a	n/a
36	Technology Platforms and Applications	Technology Platforms and Applications	Operational Analytics Platform	Weather Forecast Integration	Integrate weather forecast data into operational systems to better plan for and respond to storms	[redacted]	Integration of Weather Forecast Data	$ 4,000,000	No	n/a	n/a

Oklahoma Grid Enhancement 5 Year Plan

List of Potential Investments

ID	Category	System	Investment	Specific Investment	Description	Assumptions	Estimated Volume of Work	Estimated Capital Cost	Include in 2020	2020 Investment Criteria	Additional Benefits to Include in Model
37	Grid Resiliency	Distribution Line	Capacity Reinforcement	4 kV Conversions	4 kV Conversions	Redacted	8 circuits remaining	$ 760,000	Yes	All remaining 4kV lines	n/a
38	Grid Resiliency	Substation	Equipment Upgrades	Wood Pole Substation Replacement	Wood Pole Substations	Redacted	15 substations	$ 42,000,000	No	n/a	n/a
39	Grid Resiliency	Distribution Line	Equipment Upgrades	Transmission Attachment Upgrades	Complete structural loading study for Distribution Underbuild Attachments	Redacted	50 miles of line	$ 12,500,000	No	n/a	n/a
40	Grid Resiliency	Distribution Line	Storm Reinforcement	River Crossing Reinforcement	Review and provide Proactive Washout Protection for river crossings	Redacted	20 crossings	$ 4,000,000	No	n/a	n/a
41	Grid Automation	Distribution Line	Smart Field Devices	Remaining Subs without SCADA	Solution to Remaining Substations without SCADA	Redacted	50 Substations	$ 2,950,000	No	n/a	n/a
42	Technology Platforms and Applications	Technology Platforms and Applications	Design Platform	SP&C / Substation Design	SP&C and Substation Design Tool	Redacted	Purchase and integrate design tool	$ 10,000,000	No	n/a	n/a
43	Technology Platforms and Applications	Technology Platforms and Applications	Workforce Optimization	Add Smart Devices to CADS Dispatch	Add regulators, reclosers, and ATOs to CADS so that maintenace tickets can be dispatched efficiently	Redacted	Add smart devices to dispatch system	$ 50,000	No	n/a	n/a
44	Technology Platforms and Applications	Technology Platforms and Applications	Workforce Optimization	Digital Workforce Optimization	Automate workflow processes for field and office personel	Redacted	75 use cases	$ 14,250,000	No	n/a	n/a
45	Grid Automation	Distribution Line	Distribution Automation	SCADA for ATOs	Add SCADA to existing ATOs	Redacted	80 ATOs	$ 800,000	No	n/a	n/a
46	Grid Resiliency	Distribution Line	Equipment Upgrades	Oil Filled Stepdown Replacement	Replace oil filled stepdown stations with padmounted transformers	Redacted	20 stepdowns	$ 2,500,000	No	n/a	n/a
47	Technology Platforms and Applications	Technology Platforms and Applications	Grid Operations Application	Advanced EMS Apps	EMS Upgrade - New Apps, Modules (Transient Analysis, Stability Analysis, GEO Map, Switch Order Mgmt, Operator Log, Historian, Security Profiler)	Redacted	Upgrade Add new apps	$ 6,000,000	Yes	Upgrade and implement new application	n/a
48	Technology Platforms and Applications	Technology Platforms and Applications	Field Data Application	Syncrophaser Data in TCC	Make Syncrophaser Data to Operators	Redacted	Bring data into operating system for existing devices	$ 1,500,000	No	n/a	n/a
								$ 810,794,250			

Attorney General
Data Request AG-3
Cause No. PUD 202000021

3-8 Please refer to the direct testimony of Zachary Gladhill, page 18, lines 27 through 30. Please provide all workpapers supporting the referenced calculation. Please provide the workpapers in Excel-compatible format with all formulas fully functional and intact. Where necessary, please provide workpapers that show the inputs to the DOE ICE model with clear notes showing how values were used as inputs and how the ICE model was used.

Response*: The Company used the DOE ICE calculator to develop total potential Oklahoma ICE savings. Please see attachment AG 3-8_Att, for the inputs used for determining that assumption. Please see Witness Smith Workpaper Oklahoma Cost Benefit Model Summary for how the Company applied the total potential Oklahoma ICE savings to calculate Avoided Economic Harm benefits for each project. The cost benefit model is within the SAS VA tool, the information provided is a summarization of the calculations in the model.

Response provided by:	Kandace Smith
Response provided on:	March 17, 2020
Contact & Phone No:	Jill Butson 405-553-3285

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Sector	# of Customers	Total Benefit (2015$)	Benefit per Customer (2015$)	Year	Without Improvement (Baseline)	With Improvement	Total Benefit
Residential	690730	42,448,953.08	61.46	2019	382,118,565.68	229,200,832.41	152,917,733.28
Small C&I	101232	1,041,203,910.99	10,285.32	2020	389,760,937.00	233,892,504.08	155,868,432.92
Medium and Large C&I	13906	832,279,017.53	59,850.35	2021	397,556,155.74	238,570,354.16	158,985,801.58
All	**805868**	**1,915,931,881.60**	**2,377.48**	2022	405,507,278.85	243,341,761.24	162,165,517.61
				2023	413,617,424.43	248,208,596.47	165,408,827.96
				2024	421,889,772.92	253,172,768.40	168,717,004.52
				2025	430,327,568.38	258,236,223.76	172,091,344.61
				2026	438,934,119.74	263,400,948.24	175,533,171.51
				2027	447,712,802.14	268,668,967.20	179,043,834.94
				2028	456,667,058.18	274,042,346.55	182,624,711.63
				2029	465,800,399.34	279,523,193.48	186,277,205.87
				2030	475,116,407.33	285,113,657.35	190,002,749.98
				2031	484,618,735.48	290,815,930.49	193,802,804.98
				2032	494,311,110.19	296,632,249.10	197,678,861.08
				2033	504,197,332.39	302,564,894.09	201,632,438.31
				2034	514,281,279.04	308,616,191.97	205,665,087.07
				2035	524,566,904.62	314,788,515.81	209,778,388.81
				2036	535,058,242.71	321,084,286.12	213,973,956.59
				2037	545,759,407.57	327,505,971.85	218,253,435.72
				2038	556,674,595.72	334,056,091.28	222,618,504.44

Attorney General
Data Request AG-3 Supplemental Response
Cause No. PUD 202000021

3-4 Please refer to the direct testimony of Zachary Gladhill, page 17, Table 2. Please provide all workpapers supporting the referenced calculation. Please provide the workpapers in Excel-compatible format with all formulas fully functional and intact.

Supplemental Response*: Please see supplemental attachment AG 3-4_Att_Supplement, for a detailed explanation of how the plan benefits were derived.

Response provided by: Kandace Smith
Response provided on: July 09, 2020
Contact & Phone No: Jill Butson 405-553-3285

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

NPV	***$501,072,020***						
Inflation	2.50%						
Degredation	2%						
WACC	7.55%						
Total Tax Rate for ADIT	25.57%						
Book Life	55						
Ad Valorem Tax Rate	0.705%						
Cost of Debt	2.482%						
Total Investment Cost	$ CELL B15						
		2020	2021	2022	2023	2024	2025
Avoided Cost of Service Benefits	Annual	$ -	$ 39,753,140	$ 40,746,969	$ 41,765,643	$ 42,809,784	$ 43,880,029
Avoided O&M	$ 12,758,822	$ -	$ 13,077,793	$ 13,404,738	$ 13,739,856	$ 14,083,352	$ 14,435,436
Avoided CAP	$ 26,024,729	$ -	$ 26,675,348	$ 27,342,231	$ 28,025,787	$ 28,726,432	$ 29,444,592
Cash Flow							
Net Income	CELL B16	$ -	$ 9,733,971	$ 9,977,320	$ 10,226,753	$ 10,482,422	$ 10,744,483
Avoided CAP		$ -	$ 26,675,348	$ 27,342,231	$ 28,025,787	$ 28,726,432	$ 29,444,592
Depreciation		$ -	$ -	$ -	$ -	$ -	$ -
Interest Expense		$ -	$ -	$ -	$ -	$ -	$ -
Deferred Tax Benefit		$ -	$ -	$ -	$ -	$ -	$ -
Net Cash from Operations		***$ -***	***$ 36,409,319***	***$ 37,319,552***	***$ 38,252,540***	***$ 39,208,854***	***$ 40,189,075***
Total CapEx		$ -	$ -	$ -	$ -	$ -	$ -
Net Cash from Investing Activities		***$ -***	***$ 36,409,319***	***$ 37,319,552***	***$ 38,252,540***	***$ 39,208,854***	***$ 40,189,075***
Net Plant							
Plant in Service		$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation		$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Deferred Tax for Rate Base		$ -	$ -	$ -	$ -	$ -	$ -
Net Rate Base		***$ -***	***$ -***	***$ -***	***$ -***	***$ -***	***$ -***
Expenses							
Avoided O&M		$ -	$ (13,077,793)	$ (13,404,738)	$ (13,739,856)	$ (14,083,352)	$ (14,435,436)
Depreciation Expense		$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorem Expense		$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses		***$ -***	***$ (13,077,793)***	***$ (13,404,738)***	***$ (13,739,856)***	***$ (14,083,352)***	***$ (14,435,436)***
Tax Depreciation			$ -	$ -	$ -	$ -	$ -
20-Year MACRS Tax Schedule			3.750%	7.219%	6.677%	6.177%	5.713%
Interest Expense		$ -	$ -	$ -	$ -	$ -	$ -
Income Tax		$ -	$ 3,343,822	$ 3,427,417	$ 3,513,103	$ 3,600,930	$ 3,690,953
Net Income After Taxes		***$ -***	***$ 9,733,971***	***$ 9,977,320***	***$ 10,226,753***	***$ 10,482,422***	***$ 10,744,483***

2026	2027	2028	2029	2030	2031	2032	2033	2034
$ 44,977,029	**$ 46,101,455**	**$ 47,253,992**	**$ 48,435,341**	**$ 49,646,225**	**$ 49,869,633**	**$ 50,094,046**	**$ 50,319,469**	**$ 50,545,907**
$ 14,796,322	$ 15,166,230	$ 15,545,386	$ 15,934,021	$ 16,332,371	$ 16,405,867	$ 16,479,693	$ 16,553,852	$ 16,628,344
$ 30,180,707	$ 30,935,225	$ 31,708,606	$ 32,501,321	$ 33,313,854	$ 33,463,766	$ 33,614,353	$ 33,765,618	$ 33,917,563
$ 11,013,095	$ 11,288,422	$ 11,570,633	$ 11,859,899	$ 12,156,396	$ 12,211,100	$ 12,266,050	$ 12,321,247	$ 12,376,693
$ 30,180,707	$ 30,935,225	$ 31,708,606	$ 32,501,321	$ 33,313,854	$ 33,463,766	$ 33,614,353	$ 33,765,618	$ 33,917,563
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 41,193,802	*$ 42,223,647*	*$ 43,279,238*	*$ 44,361,219*	*$ 45,470,250*	*$ 45,674,866*	*$ 45,880,403*	*$ 46,086,865*	*$ 46,294,256*
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 41,193,802	*$ 42,223,647*	*$ 43,279,238*	*$ 44,361,219*	*$ 45,470,250*	*$ 45,674,866*	*$ 45,880,403*	*$ 46,086,865*	*$ 46,294,256*
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
$ (14,796,322)	$ (15,166,230)	$ (15,545,386)	$ (15,934,021)	$ (16,332,371)	$ (16,405,867)	$ (16,479,693)	$ (16,553,852)	$ (16,628,344)
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (14,796,322)	*$ (15,166,230)*	*$ (15,545,386)*	*$ (15,934,021)*	*$ (16,332,371)*	*$ (16,405,867)*	*$ (16,479,693)*	*$ (16,553,852)*	*$ (16,628,344)*
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 3,783,227	$ 3,877,808	$ 3,974,753	$ 4,074,122	$ 4,175,975	$ 4,194,767	$ 4,213,643	$ 4,232,605	$ 4,251,651
$ 11,013,095	*$ 11,288,422*	*$ 11,570,633*	*$ 11,859,899*	*$ 12,156,396*	*$ 12,211,100*	*$ 12,266,050*	*$ 12,321,247*	*$ 12,376,693*

2035	2036	2037	2038	2039	2040	2041	2042	2043
$ 50,773,364	**$ 51,001,844**	**$ 51,231,352**	**$ 51,461,893**	**$ 51,693,472**	**$ 51,926,092**	**$ 52,159,760**	**$ 52,394,479**	**$ 52,630,254**
$ 16,703,172	$ 16,778,336	$ 16,853,838	$ 16,929,681	$ 17,005,864	$ 17,082,391	$ 17,159,261	$ 17,236,478	$ 17,314,042
$ 34,070,192	$ 34,223,508	$ 34,377,514	$ 34,532,212	$ 34,687,607	$ 34,843,702	$ 35,000,498	$ 35,158,000	$ 35,316,211
$ 12,432,388	$ 12,488,334	$ 12,544,531	$ 12,600,981	$ 12,657,686	$ 12,714,645	$ 12,771,861	$ 12,829,335	$ 12,887,067
$ 34,070,192	$ 34,223,508	$ 34,377,514	$ 34,532,212	$ 34,687,607	$ 34,843,702	$ 35,000,498	$ 35,158,000	$ 35,316,211
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 46,502,580	*$ 46,711,841*	*$ 46,922,045*	*$ 47,133,194*	*$ 47,345,293*	*$ 47,558,347*	*$ 47,772,360*	*$ 47,987,335*	*$ 48,203,278*
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 46,502,580	*$ 46,711,841*	*$ 46,922,045*	*$ 47,133,194*	*$ 47,345,293*	*$ 47,558,347*	*$ 47,772,360*	*$ 47,987,335*	*$ 48,203,278*
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
$ (16,703,172)	$ (16,778,336)	$ (16,853,838)	$ (16,929,681)	$ (17,005,864)	$ (17,082,391)	$ (17,159,261)	$ (17,236,478)	$ (17,314,042)
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (16,703,172)	*$ (16,778,336)*	*$ (16,853,838)*	*$ (16,929,681)*	*$ (17,005,864)*	*$ (17,082,391)*	*$ (17,159,261)*	*$ (17,236,478)*	*$ (17,314,042)*
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	2.231%	0.000%	0.000%
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 4,270,784	$ 4,290,002	$ 4,309,307	$ 4,328,699	$ 4,348,178	$ 4,367,745	$ 4,387,400	$ 4,407,143	$ 4,426,976
$ 12,432,388	*$ 12,488,334*	*$ 12,544,531*	*$ 12,600,981*	*$ 12,657,686*	*$ 12,714,645*	*$ 12,771,861*	*$ 12,829,335*	*$ 12,887,067*

2044	2045	2046	2047	2048	2049
$ 52,867,090	**$ 53,104,992**	**$ 53,343,964**	**$ 53,584,012**	**$ 53,825,140**	**$ 54,067,353**
$ 17,391,955	$ 17,470,219	$ 17,548,835	$ 17,627,805	$ 17,707,130	$ 17,786,812
$ 35,475,134	$ 35,634,773	$ 35,795,129	$ 35,956,207	$ 36,118,010	$ 36,280,541
$ 12,945,059	$ 13,003,311	$ 13,061,826	$ 13,120,604	$ 13,179,647	$ 13,238,956
$ 35,475,134	$ 35,634,773	$ 35,795,129	$ 35,956,207	$ 36,118,010	$ 36,280,541
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ 48,420,193	*$ 48,638,084*	*$ 48,856,955*	*$ 49,076,812*	*$ 49,297,657*	*$ 49,519,497*
$ -	$ -	$ -	$ -	$ -	$ -
$ 48,420,193	*$ 48,638,084*	*$ 48,856,955*	*$ 49,076,812*	*$ 49,297,657*	*$ 49,519,497*
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
$ (17,391,955)	$ (17,470,219)	$ (17,548,835)	$ (17,627,805)	$ (17,707,130)	$ (17,786,812)
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ (17,391,955)	*$ (17,470,219)*	*$ (17,548,835)*	*$ (17,627,805)*	*$ (17,707,130)*	*$ (17,786,812)*
$ -	$ -	$ -	$ -	$ -	$ -
0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
$ -	$ -	$ -	$ -	$ -	$ -
$ 4,446,897	$ 4,466,908	$ 4,487,009	$ 4,507,201	$ 4,527,483	$ 4,547,857
$ 12,945,059	*$ 13,003,311*	*$ 13,061,826*	*$ 13,120,604*	*$ 13,179,647*	*$ 13,238,956*

Attorney General
Data Request AG-8
Cause No. PUD 202000021

8-6 Please refer to the direct testimony of Gwin Cash, direct exhibit GC-1. Does the proposed Grid Enhancement Mechanism tariff impose a maximum value for the revenue requirement that OGE may collect under the tariff?

Response*: No, as proposed the Grid Enhancement Mechanism tariff does not provide a maximum value for the revenue requirement. However, recovery is limited only to those expenditures as authorized in this cause, and, as is stated in the "REPORTING REQUIREMENTS" section of the tariff, quarterly reporting of completed in-service Grid Enhancement expenditures will be provided by the Company to the PUD.

Response provided by: Gwin Cash
Response provided on: April 14, 2020
Contact & Phone No: Jill Butson 405-553-3285

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Attorney General of Oklahoma
Data Request AG-6
Cause No. PUD 202000021

6-1 Please refer to the direct testimony of Donald R. Rowlett, page 8, line 31 through page 9, line 3. Please describe alternative cost recovery mechanisms OGE identified and considered. Please provide a detailed explanation for why OGE selected the cost recovery mechanism it has requested in this proceeding.

Response*: OG&E sought a balancing of interests between diminished regulatory lag and customer interests. The proposed mechanism protects customer interests by only allowing recovery of costs on plant that is used and useful and an ultimate determination of prudence in OG&E's next general rate case.

Response provided by: Donald Rowlett
Response provided on: March 27, 2020
Contact & Phone No: Jill Butson 405-553-3285

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Attorney General
Data Request AG-7
Cause No. PUD 202000021

7-6 Please refer to the Company's response to OIEC-OGE-1-6. Has OGE performed any evaluation of its residential customers' and general service customers' ability or willingness to pay for 7% and 7.5% increases in bills by 2025? If so, please provide a narrative description of OGE's evaluation. If not, please explain why no evaluation has been performed.

Response*: While no specific evaluation of "ability" or "willingness" has been performed, OG&E believes the value of enhancing the grid to provide continued reliable electric service is an appropriate cost that its customers would benefit from.

Response provided by: Jason Thenmadathil
Response provided on: April 13, 2020
Contact & Phone No: Jill Butson 405-553-3285

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

AFFIDAVIT OF PAUL J. ALVAREZ
CAUSE NO. PUD 2020-21

County of Douglass)
) ss
State of Colorado)

I, Paul J. Alvarez, state under penalty of perjury under the laws of Colorado, that the foregoing Responsive Testimony filed on behalf of AARP in Cause No. PUD 2020-21 on August 25, 2020, is true and correct to the best of my knowledge and belief.

Paul J. Alvarez

Subscribed and sworn to before me this 24TH day of August 2020.

My Commission Expires: 06/06/2024

Notary Public: Brad Cook

BRAD COOK
NOTARY PUBLIC - STATE OF COLORADO
NOTARY ID 20124033594
MY COMMISSION EXPIRES JUN 6, 2024