BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

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

Rebuttal Testimony

of

Kandace Smith

on behalf of

Oklahoma Gas and Electric Company

May 17, 2024

QUALIFICATIONS, EXPERIENCE, AND PURPOSE

Q. **Would you please state your name and business address?**

A. My name is Kandace Smith. My business address is 321 North Harvey, Oklahoma City, Oklahoma, 73102.

Q. **By whom are you employed and in what capacity?**

A. I am employed by Oklahoma Gas and Electric Company ("OG&E" or "Company") as the Manager of Grid Modernization.

Q. **Please summarize your educational background and professional qualifications.**

A. I received a Bachelor of Science in Electrical Engineering from Oklahoma Christian University and a Master of Business Administration from Oklahoma Christian University. I have been employed by OG&E since 2003 and have held various positions within the organization including most recently Grid Innovation Manager and my current position, Manager Grid Modernization. Prior to the Grid Innovation Manager role, I served as a Product Innovation Manager, Manager of Business Relationship Management and Requirements, Manager of Energy Operations, Eastern Region Engineer, Senior Distribution Network Engineer, Distribution Planning Engineer, and Distribution Engineer.

Q. **Please describe your current role and responsibilities.**

A. My primary duties as Manager of Grid Modernization include reviewing opportunities presented by IIJA, developing grant applications for federal funding, and oversight of the compliance with the grants that are awarded. In this role previously, I led a cross-functional modeling and planning team to develop the Grid Modernization Plan in Arkansas and the Oklahoma Grid Enhancement Plan ("OGE Plan") in Oklahoma. This included developing and maintaining the multi-year plan and forecast as well as developing each year's Annual Investment Plan. My responsibilities also included creating and maintaining the cost-benefit optimization model and ensuring planned project cost and benefits are accurate.

While I was responsible for the modeling and planning of our grid enhancement plan, I also sat on the OGE Plan steering team and coordinated with the execution team to provide support and direction on scope, benefits, and costs as the plan moved into the design and execution phases.

Q. **Have you testified previously before this Commission?**

A. Yes. I have previously filed testimony on behalf of OG&E in Cause Nos. PUD 2021000164 and PUD 202000021. I have also filed testimony on behalf of the Company before the Arkansas Public Service Commission.

Q. **What is the purpose of your Rebuttal Testimony?**

A. The purpose of my Rebuttal Testimony is to support the inclusion in rate base of certain Grid Enhancement projects and respond to the recommendations of Public Utility Division ("PUD") witnesses Paul Alvarez and Dennis Stephens as well as Oklahoma Industrial Electric Consumers ("OIEC") witness Scott Norwood.

EXECUTIVE SUMMARY

Q. Please provide an executive summary of your Rebuttal Testimony.

A. OG&E cannot sufficiently serve customers without an adequate plan and investment strategy. It is not prudent to wait until the grid becomes unreliable to begin making improvements; a reactive, "wait and see" approach will not suffice. I am hopeful all parties desire for OG&E to have a reliable and resilient, yet affordable, system to deliver power to customers. Although many OG&E customers enjoy reliable service, improvements and updates to the grid are needed to correct current deficiencies, prevent outages, and modernize for the future.

Electricity plays an increasing role in our customers' lives. Increased work from home, virtual schooling, and electric vehicles are just a few examples of how the role of electricity is changing and expanding. Certain intervenors' preferences for waiting until there is a material degradation in reliability before taking action are unreasonable and contrary to the Company's role in delivering reliable and affordable power. OG&E's Grid

Enhancement Plan is beneficial and necessary to meet both the present and future energy needs of customers.

In this Rebuttal Testimony, I revisit the PUD's previous recommendations to find the 2020 and 2021 Grid Enhancement Projects prudent and the PUD's recognition of the "intuitive and undeniable"[1] benefits the projects yield for customers. The PUD has now appeared to discard the testimony of its 2021 rate case expert witness and completely reversed its previous position in this current case based upon the erroneous analysis of Mr. Stephens and Mr. Alvarez. As OG&E witness Brian Huckabay explains, some of the projects PUD recommends for disallowance in this case are the same projects they recommended as prudent in the 2021 rate case.[2]

I respond to witness Alvarez's claim that Grid Enhancement investments should be considered discretionary. Then I address his recommendations to disallow certain Grid Enhancement investments which are based on inaccurate and incomplete analysis including his claims of alleged lack of focus and diminishing returns. I share that the Grid Enhancement investments are providing significant benefits to OG&E's customers. I also address witness Alvarez and his lack of consideration for the 63% reliability improvement OG&E has experienced in its Arkansas jurisdiction due to Grid Enhancement efforts. Then, I discuss how witness Alvarez claims OG&E should only apply Grid Enhancement efforts to worst performing circuits based on a flawed view of the data. Finally, I address the concerns witness Alvarez has with OG&E's cost benefit model assumptions, including his misrepresentation of the analysis and his claim they have not been updated, even though he has been presented data on multiple occasions to show OG&E has monitored performance to determine the assumptions are appropriate.

In this testimony, I also respond to PUD witness Stephens' recommendation to disallow certain Grid Enhancement investments. This recommendation is based on inaccurate and incomplete analyses, including his claims of alleged lack of focus, and diminishing returns. I share that the Grid Enhancement investments are providing significant benefits to OG&E's customers, and I explain why investment decisions are not as simple as witness Stephens suggests with just two types of investments. Then, I address

[1] Cause No. PUD 202100164, Responsive Testimony of Kathy Champion, pg. 9 lns. 1-5.
[2] Rebuttal Testimony of Brian Huckabay, pg. 5-6.

his concerns with OG&E's cost benefit analysis where he claims OG&E has not validated its model. I present the results of our Arkansas circuits as well as positive early results of the Oklahoma 2020 Plan investments; all of which I previously provided to him in the last case (PUD 2021000164). Each of these results show the model results are as we would expect, and our assumptions are appropriate. Next, I discuss how witness Stephens' own cost benefit analysis provides $13.62 of benefits for every dollar in investment instead of the $0.44 he presents when updated with the correct data. I then address witness Stephens' concerns with specific programs and sub-programs which are based on a lack of understanding of the OG&E system and our Grid Enhancement Plan objectives. Lastly, I address his recommendation that the Commission spend additional dollars to develop independent evaluations of the Grid Enhancement Plan when at least four different evaluations have been performed and show the investments are beneficial to customers, including his own analysis when done correctly.

Finally, I address the testimony of OIEC witness Norwood by explaining how system reliability averages do not illustrate a complete picture of customer experience and detail how Grid Enhancement specifically targets lesser performing circuits to improve the customer experience for all. I also address Mr. Norwood's recommendation for disallowance of future Grid Enhancement projects.

PUD'S PREVIOUS RECOMMENDATIONS

Q. **Did PUD recommend the 2020 and 2021 grid enhancement projects be found prudent in OG&E's last rate case?**

A. Yes. PUD witness Champion stated at the time, "PUD recommends the Commission find the Grid Enhancement … projects prudent because PUD believes the Company has proven the need and benefits".[3] She also stated, it is "intuitive and undeniable" projects that improve customer reliability provide "real benefits to all customers through a reduction in unplanned outage events and in recovery time from those events".[4] As OG&E witness

[3] PUD 2021000164 - Responsive Testimony of Champion p. 7 lns. 3-4.
[4] PUD 2021000164 - Responsive Testimony of Champion p. 9 lns. 1-5.

Brian Huckabay explains, some of the projects PUD recommended for disallowance in this case are the same projects they recommended as prudent in the 2021 rate case.[5]

RESPONSE TO PUD WITNESS ALVAREZ

Q. **Please summarize your response to witness Alvarez's Responsive Testimony.**

A. I respond to the claims or recommendations witness Alvarez makes with regard to (1) discretionary investments, (2) disallowance of certain Grid Enhancement investments, (3) alleged lack of focus, (4) diminishing returns, (5) delivery of reliability expectations, (6) Grid Enhancement circuit selection, and (7) concerns with OG&E's cost benefit analysis as outlined below.

Discretionary Investments

Q. **Witness Alvarez states, "I believe capital spending in excess of that required for safe and reliable service to be discretionary."[6] Do you agree?**

A. No. Investment decisions are not this simple. Witness Alvarez goes on to say required spending is only for "safe and reliable service in the near term."[7] Focusing on only reliability in the near term is short-sighted. First, investments take time, and the grid is evolving at a faster pace than it has historically. We no longer have just a one-way power flow. Distributed energy resources such as solar, batteries, and electric vehicles continue to grow. These require OG&E to take action to prepare the grid to be more reliable, resilient, flexible, and efficient. Second, OG&E must consider all of the needed investments to ensure a reliable grid and balance those investments with affordability for our customers. This means, we must look to the future (not just the near-term) to ensure we are balancing investments across the years and not investing in an inconsistent manner that would have significant impacts on affordability.

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[5] Rebuttal Testimony of Brian Huckabay, pg. 5-6.
[6] Responsive Testimony of Alvarez p. 9 lns. 8-11.
[7] Responsive Testimony of Alvarez p. 10 ln. 16.

Disallowance of Certain Grid Enhancement Investments

Q. **Witness Alvarez states, "I recommend that the Commission disallow $90.7 million in Grid Enhancement capital costs from customer recovery."[8] Do you agree?**

A. No. Witness Alvarez says his recommendation is "due to lack of focus."[9] He recommends disallowance of circuits that are not on the 2020-2022 worst-performing circuit list.[10] I do not agree that these are appropriate reasons to find these Grid Enhancement investments not prudent.

Q. **Why do you not agree "lack of focus" is an appropriate reason for disallowance?**

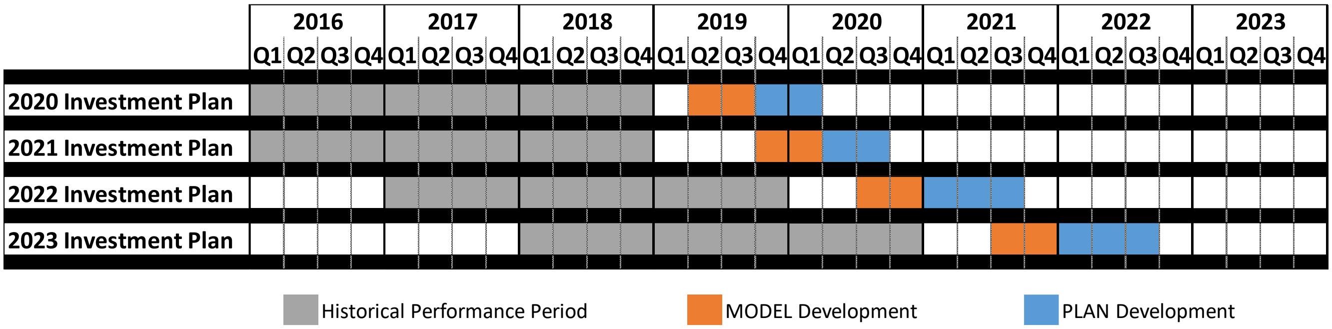
A. As I explain in the "Lack of Focus" section below, witness Alvarez suggests that because the Company has evaluated the Grid Enhancement investments on a circuit level and not by an individual investment type, the plan is not focused. This is simply not true. The Grid Enhancement plan is much more complex and requires a comprehensive review of costs and benefits, not the overly simplistic review witness Alvarez is suggesting.

Q. **Why do you not agree comparison with 2020-2022 worst performing circuits is an appropriate reason for disallowance?**

A. First of all, witness Alvarez continues to show information that is misleading. As shown in Figure 1 below, the 2020-2022 worst-performing circuits were not known at the time the investment plan development was initiated. The 2020 performance data was not even available until the 2023 investment plan was being developed. The 2021 and 2022 performance data were definitely not available at the time of plan development. Therefore, the comparison of Grid Enhancement circuits to 2020-2022 worst-performing circuits is not appropriate.

8 Responsive Testimony of Alvarez p. 37 lns. 8-10.
9 Responsive Testimony of Alvarez p. 37 lns. 10 .
10 Responsive Testimony of Alvarez p. 37 lns. 17-19.

Figure 1: Grid Enhancement Plan Development Timeline



Second, the worst performing circuit program and the Grid Enhancement Plan have different objectives with different selection criteria. The worst performing circuit program is targeting poor performing circuits with regard to reliability metrics (which measure sustained outages) excluding storms, whereas the Grid Enhancement Plan is reviewing performance from all events customers experience including blue-sky days, storms, sustained outages, and momentary outages. The Grid Enhancement investments are identified by evaluating the costs and benefits to determine which work will provide the most benefits for customers. These two programs should be viewed that way, as two distinct programs working towards their own goals and objectives that together improve reliability and resiliency for customers.

<u>Alleged Lack of Focus</u>

Q. **Witness Alvarez states there is "a distinct lack of focus in OG&E Grid Enhancement spending."[11] Do you agree?**

A. No. I do not agree. The Grid Enhancement Plan is focused with the intent to improve reliability, offer greater resilience, and increase flexibility while offering enhanced customer benefits and balancing affordability.

[11] Responsive Testimony of Alvarez p. 24 lns. 18-19.

Q. **How does witness Alvarez support his claim regarding OG&E's alleged "lack of focus?"**

A. Witness Alvarez says, "OG&E has not quantified the actual benefits delivered by various Grid Enhancement programs and subprograms. Without such an analysis, the Company cannot know which programs or subprograms deliver the greatest benefit."[12]

Q. **Do you agree with witness Alvarez that the Grid Enhancement investments should be evaluated on a program/sub-program level?**

A. No, I do not. As I explain below, the Grid Enhancement investments are complex and built upon each other and should be reviewed as a comprehensive program with program-wide costs and benefits. Also, in my Direct Testimony from the previous case, I present Exhibit KS-1,[13] which is a report EPRI produced to evaluate the Grid Enhancement plan. In this report EPRI concludes that the plan is in alignment with its objectives as well as with nationally established modernization efforts.

Q. **Why do you believe the Grid Enhancement projects should not be evaluated by each investment type (sub-program)?**

A. While I acknowledge there are different ways to design a grid enhancement program and perform an associated cost benefit analysis, I firmly believe the Company utilized a reasonable and sound approach. OG&E's evaluation on a circuit-by-circuit basis rather than by each investment type results in a more comprehensive approach that supports our goal of creating a step-change in reliability for each circuit enhanced. The paradigm of evaluating discrete costs and benefits on an investment type basis may not lead to investments that achieve the objectives of the Plan. A cost-benefit analysis on an individual investment type is most meaningful when investments have benefits and costs that are discrete and clearly attributable to the individual investments. The Grid Enhancement investment types often support multiple objectives and typically have joint benefits that will often increase as more capabilities and functions are added. For example, replacing aging infrastructure and adding automated switches to a circuit will provide a higher level

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12 Responsive Testimony of Alvarez p. 24 ln. 21 – p. 25 ln. 2.
13 PUD 2021000164 – Direct Testimony of Smith – Exhibit KS-1.

of reliability than if you just did one without the other. For these reasons, it is not reasonable to conduct a cost benefit analysis on an investment type basis for the Grid Enhancement Plan. In the previous case, witness DeStigter provided Exhibit KS-2,[14] which shows the complexity of analyzing the Grid Enhancement Plan on an investment type basis because there are so many interdependencies.

Q. **If OG&E did not evaluate costs and benefits at an individual investment type level, how can it be sure that the right projects are selected prior to being modeled at the circuit level?**

A. OG&E used investment criteria to evaluate each distinct work activity (investment type) for each specific circuit or substation prior to evaluating circuits and substations in the cost benefit model. Investment criteria are determined for each distinct work activity to ensure the work activity not only meets the guiding principles for each Annual Investment Plan but also yields the expected benefits. For example, on underground cable replacement, this work activity is only applied to circuits with a high volume of outages caused by cable failures. If there are minimal outages associated with underground cable, the work activity is not applied to the circuit. Using the investment criteria to select which distinct work activities (investment types) are applied to each circuit allows OG&E to optimize the investment on each circuit prior to ranking the circuits once they are analyzed by the cost benefit model and ensures the most beneficial projects are selected.

Diminishing Returns

Q. **Witness Alvarez presents his Figure 6 to show the law of diminishing return applied to grid reliability and resilience.[15] How do you respond?**

A. I cannot speak to the accuracy of the reliability benefit curve witness Alvarez is using in his Figure 6. However, the figure does show 24 graduations of investment, with 7 being in the white, “prudent” portion of the chart. This equates to about 29% (7 divided by 24) of investments within the curve as prudent. Given that the Grid Enhancement investments account for 267 of 1,280 circuits or around 21%, you could infer from the chart that the

[14] PUD 2021000164 - Direct Testimony of De Stigter p. 7 ln. 7.
[15] Responsive Testimony of Alvarez p. 33 ln. 10.

Grid Enhancement investments truly are prudent, even by Mr. Alvarez's overly simplistic logic.

Q. **What evidence does witness Alvarez provide to show he believes Grid Enhancement investments provide diminishing returns?**

A. Witness Alvarez first references two tranches of investments and asserts, "the more circuits on which OG&E spends Grid Enhancement capital, the smaller the reliability improvements"[16] which indicates to him that the law of diminishing returns is in action.[17] Next he says, "The benefit-cost analysis Mr. Stephens completed indicates that OG&E has already spent capital beyond the point of diminishing return."[18]

Q. **How do you respond to witness Alvarez's first reference to more circuits means smaller reliability improvements?**

A. First, OG&E's Grid Enhancement Plan is designed to develop Annual Investment Plans and select the circuits with the most benefit in each year. OG&E has never intended that the Grid Enhancement Plan will cover all circuits. The intention is to provide enhancements to the circuits that will best benefit our customers.

Second, witness Alvarez references two tranches of investments, with the first tranche of 128 circuits being responsible for 38.5% of SAIDI in 2018 and the second tranche of 139 circuits being responsible for 23.1% during that same year.[19] This is indicating that in total, 267 circuits (21% of circuits) were responsible for 61.6% of the SAIDI in 2018. This data demonstrates that OG&E is targeting the right circuits and is not within the diminishing return part of the investment curve.

Third, witness Alvarez is referencing 2018 as the sole year to compare reliability for improvement purposes. Best practices are to review multiple years of performance to determine reliability investment needs. Even witness Alvarez himself says "one should

16 Responsive Testimony of Alvarez p. 34 lns. 8-10.
17 Responsive Testimony of Alvarez p. 34 ln. 8.
18 Responsive Testimony of Alvarez p. 34 lns. 12-13.
19 Responsive Testimony of Alvarez p. 34 lns. 3-7.

not base a reliability improvement assumption on a single-year's results."[20] Yet, he did just that in this analysis.

Q. **How do you respond to witness Alvarez's second reference to witness Stephens' analysis showing Grid Enhancement investments are beyond the point of diminishing return?**

A. First, witness Stephens is evaluating only 11 of 54[21] circuits that were in-service in 2020. These circuits were already deemed prudent in the previous case (PUD 2021000164). As shown in Exhibit KS-3, all of these circuits have an in-service date prior to April 1, 2022, and therefore were included in OG&E's last general rate case. Second, his analysis is inaccurate and incomplete. As I explain in the "Witness Stephens' Cost Benefit Analysis" section of this testimony, the analysis includes "Cause Exclusions" outages which are **never** included in reliability reporting. Cause Exclusions include any issue that is not a result of the reliability of OG&E's system. These include factors like cancelled tickets, service-on upon arrival, customer-side equipment issues, and damage caused by the public.

Once those are removed, the analysis shows $13.62 in benefits for every $1 spent, instead of the inaccurate $0.44[22] in benefits witness Alvarez and Stephens present. I also explain that witness Stephens is using the incorrect historical performance period in his analysis and does not include any benefits for avoided momentary outages, avoided O&M expense, avoided capital, or avoided costs from storms. By fixing the errors in witness Stephens' analysis and not adding in the missing components, it can be concluded that the Grid Enhancement projects are providing significant value to customers.

20 Responsive Testimony of Alvarez p. 29 lns. 15-16.
21 Responsive Testimony of Stephens p. 10 lns. 10-11.
22 Responsive Testimony of Alvarez p. 22 lns. 18.-20

Delivery of Reliability Expectations

Q. **Witness Alvarez presents "OG&E's system average interruption duration with storms from 2018 – 2023"[23] and claims the 71.8-minute reduction in outage duration with storms included has not been delivered by investments in the 2020 and 2021 Grid Enhancement plan.[24] How do you respond?**

A. There are multiple flaws in how witness Alvarez presents the data and develops conclusions. First, witness Alvarez omits 2020 because he says it "enhances clarity."[25] I do not agree that omitting a full year's performance data provides any clarity to an analysis that determines if reliability was delivered.

Second, witness Alvarez does not show the full picture. The 3-year historical performance period of 2016 to 2018 for 2020 and 2021 Plan investments (as shown in Figure 1 above) should be compared to the 3-year performance period of 2021 to 2023 for 2020 Plan investments and 2022 to 2024 for 2021 Plan investments. Instead, witness Alvarez shows just 2018, 2019, 2021, 2022, and 2023.

Third, as discussed in response to witness Norwood and witness Stephens, OG&E used the performance data that was available at the time the annual investment plans were being developed.

Fourth, if you review the reliability improvement after project implementation, the results of the three-year performance period for the 2020 Plan circuits show the circuits have performed 45% better than the 3-year historical performance, which is a substantial improvement. When you review the data appropriately, it reveals that OG&E's Grid Enhancement investments are providing reliability improvements that benefit customers.

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23 Responsive Testimony of Alvarez p. 18 lns. 8-9.
24 Responsive Testimony of Alvarez p. 18 lns. 9-13.
25 Responsive Testimony of Alvarez p. 18 ln. 10.

Circuit Selection

Q. **Witness Alvarez states "Spending significant Grid Enhancement capital on circuits that are already above-average performers is no way to target such spending."[26] How do you respond?**

A. There are again flaws in the way witness Alvarez is viewing the data. witness Alvarez uses 2019 average interruption duration data to compare the 2020 circuits that were selected to the system-wide average.[27]

First, witness Alvarez is again using a single year's reliability performance to make a conclusion of whether an investment should have been made or not when he even acknowledges this should not be the case.[28]

Second, as shown in Figure 1 above, 2019 performance data was not known at the time the 2020 Plan investments were being developed.

Third, the Grid Enhancement Plan looks at the investments holistically across all events, storm, non-storm, sustained, and momentary interruptions. The investments are then evaluated across the benefits that are expected to be delivered in the 3-year performance period to determine the optimal investments for customers.

In conclusion, the data was not reviewed appropriately by witness Alvarez to come to the conclusion that the wrong circuits were selected when OG&E developed its 2020 Plan investments.

Q. **Witness Alvarez presents a different analysis showing the reliability improvements for the 2020 circuits and concludes that the investments did not provide desired benefits.[29] How do you respond?**

A. I find that witness Alvarez is again not looking at the data appropriately. This time, he uses a two-year historical performance period of 2019-2020. Again, neither of these years were available at the time the 2020 Plan was being developed. The appropriate historical performance period for the 2020 Plan investments should be 2016-2018. As presented to

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26 Responsive Testimony of Alvarez p. 31 lns. 1-3.
27 Responsive Testimony of Alvarez p. 30 ln. 16 – p. 31 ln. 1.
28 Responsive Testimony of Alvarez p. 29 lns. 15-16.
29 Responsive Testimony of Alvarez p. 32 lns. 1-12.

witness Stephens in the "OG&E's Cost Benefit Analysis" section of my testimony, the 2020 Plan investments have benefits that exceed the costs.

OG&E Cost Benefit Analysis

Q. **What issues does witness Alvarez have with OG&E's cost benefit analysis?**

A. Witness Alvarez makes the following claims about OG&E's cost benefit analysis: (1) the model has not been updated with actual results,[30] (2) minor storm restoration costs will fall 50% after Grid Enhancement seems to be a guess,[31] (3) 60% reliability improvement is based on a single year's work of results from Arkansas circuits,[32] and (4) $500 assumption for avoided truck rolls is still being used today.[33]

Q. **How do you respond to witness Alvarez's claim that the model has not been updated with actual results?**

A. The Grid Enhancement projects should be measured based on a three-year performance period after their implementation and compared to the three-year historical performance. OG&E has monitored the investments and identified early results that are in alignment with the planned benefits.

Q. **Witness Alvarez states that "OG&E's model assumes that minor storm restoration costs will fall 50% after Grid Enhancement."[34] How do you respond?**

A. This is not true. The "50% of Minor Storm savings" assumption is used to reduce the minor storm savings from reliability improvements by 50%. We used this assumption based on the vast experience within the Company to reduce the benefits provided during minor storms because some of the work is done during normal working hours by OG&E employees. This means we reduced the benefits to account for normal employee salaries that occur during minor storm events since we would not be expecting those costs to be avoided with the reliability improvements.

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30 Responsive Testimony of Alvarez p. 28 ln. 13-14.
31 Responsive Testimony of Alvarez p. 29 lns. 8-9.
32 Responsive Testimony of Alvarez p. 29 lns. 9-12.
33 Responsive Testimony of Alvarez p. 30 lns. 8-10.
34 Responsive Testimony of Alvarez p. 29 lns. 8-9.

Q. **Witness Alvarez states "OG&E's model assumes that service interruptions and service interruption durations will fall 60% after Grid Enhancement, that number seems to be based on a single year's worth of results from grid enhancement spending on 14 of the Company's Arkansas circuits in 2018."[35] How do you respond?**

A. The 60% reliability improvement assumption was initially derived from the first year of performance of the Arkansas circuits as witness Alvarez suggests. However, the performance of both Arkansas and Oklahoma circuits have been monitored to determine if an assumption update is needed. In my Rebuttal Testimony in PUD 202000021, I stated that the Arkansas Series I circuits experienced a 70% improvement from the historical 3-year average in 2019, and in 2020, through July, the circuits had performed 96% better.[36] Then in my Rebuttal Testimony in PUD 2021000164, I stated the Arkansas Series I circuits had performed 63% better than the performance period when measured for the 3-year post investment performance as well as Oklahoma 2020 Plan circuits performing 69% better in its first year of performance.[37] OG&E reviewed the available data at the time each annual investment plan was being developed and determined the 60% assumption is appropriate, therefore we kept the assumption constant.

Q. **Witness Alvarez states, "the same benefit assumption of $500 per truck roll avoided that the model employed in 2019 is still in use today,"[38] inferring that OG&E has not reviewed the data and updated the model. How do you respond?**

A. I do not have concerns with this estimate remaining consistent in the model. First, the average cost of a truck roll for distribution line work is $686 based on actual costs of projects in 2018. Given the rate of inflation, I am confident this number has likely increased, but we have chosen to keep the assumption constant. Increasing the number would actually increase the benefit of avoiding the truck roll costs to customers, so this does not support Mr. Alvarez's argument that Grid Enhancement projects fail to provide benefits in excess of costs.

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35 Responsive Testimony of Alvarez p. 29 lns. 8-12.
36 PUD 202000021 – Rebuttal Testimony of Smith p. 9 lns. 5-10.
37 PUD 2021000164 – Rebuttal Testimony of Smith p. 11 ln. 22 – p.12 ln. 2.
38 Responsive Testimony of Alvarez p. 30 lns. 8-10.

Other Matters

Q. **Witness Alvarez "encourages the Commission to consider commissioning an independent study of benefits delivered by OG&E Grid Enhancement spending to date before considering GEM rider expansion or extension."[39] Do you agree?**

A. I do not agree with witness Alvarez' statement. Multiple cost benefit evaluations have been performed to show the value in the Grid Enhancement Plan, and all of these evaluations, when done correctly, show the projects have more benefits than costs. I expand on these evaluations in response to witness Stephens in the "Independent Evaluation" section. For these reasons, I fail to understand why witness Alvarez would believe it would be in the best interests of customers for the Commission to spend money to complete yet another evaluation of the costs and benefits.

Q. **Witness Alvarez states, "The $164.9 million 2021 investment plan was anticipated to reduce O&M spending by $108.4 million over time."[40] Do you agree?**

A. No. Witness Alvarez incorrectly quotes the benefits from the 2021 Plan. He pulled these benefits from my Supplemental Direct Testimony in PUD 202000021. In my testimony, I stated, "The 2021 Plan is expected to provide an estimated $108.4 million in avoided cost of service benefits as well as $362.8 million in avoided economic harm benefits."[41] The $108.4 million in avoided costs of service benefits is composed of both avoided O&M spending as well as avoided Capital spending. It is not reduced O&M as witness Alvarez suggests.

<u>RESPONSE TO PUD WITNESS STEPHENS</u>

Q. **Please summarize your response to witness Stephens' Responsive Testimony.**

A. I respond to the claims or recommendations witness Stephens makes with regard to (1) disallowance of certain Grid Enhancement Investments, (2) reference to two types of investments, (3) concerns with OG&E's cost benefit analysis, (4) his cost benefit analysis,

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39 Responsive Testimony of Alvarez p. 37 lns. 3-5.
40 Responsive Testimony of Alvarez p. 15 ln. 4-5.
41 PUD 202000021 – Supplemental Direct Testimony of Smith p. 4 lns. 2-3.

(5) concerns with specific programs and sub-programs, and (6) recommendations for independent evaluations as outlined below.

Disallowance of Certain Grid Enhancement Investments

Q. **Witness Stephens says he endorses witness Alvarez's recommendation to disallow $90.7 million in Grid Enhancement capital spending from cost recovery.[42] Do you agree?**

A. No. I believe the Grid Enhancement investments are prudent. Witness Stephens' reasoning for disallowance is he believes the Grid Enhancement investments are discretionary. He then presents a cost benefit evaluation that shows a benefit of $0.44 for every $1 spent, which is seriously flawed. He also states that capital spending to enhance circuits not performing in the bottom 5% be disallowed.[43] The objective of the Grid Enhancement Plan is to make the grid more reliable, resilient, flexible, and efficient. Focusing on just the bottom 5% is not appropriate to maintain reliable service for our customers.

Two Types of Investment

Q. **Witness Stephens states "In my experience there are two types of investments that for-profit utilities make: 1) Those that utilities must make in the near-term to ensure that services are safe and reliable; and 2) those that utilities prefer to make but are not strictly necessary in the near-term for safe and reliable service."[44] Do you agree?**

A. No. Investment decisions are not this simple. Focusing on only reliability on Stephens' definition of the "near term" is short sighted. First, investments take time, and the grid is evolving at a faster pace than it has historically. We no longer have just a one-way power flow. Distributed energy resources such as solar, batteries, and electric vehicles continue to grow. These require OG&E to take action to prepare the grid to be more reliable, resilient, flexible, and efficient. Second, OG&E must consider all of the needed investments to ensure a reliable grid and balance those investments with affordability for our customers. This means, we must look to the future (not just the near-term) to ensure

[42] Responsive Testimony of Stephens p. 27 lns. 7-8.
[43] Responsive Testimony of Stephens p. 5 lns. 10-12.
[44] Responsive Testimony of Stephens p. 5 ln. 17 - p. 6 ln. 1.

we are balancing investments across the years and not investing in an inconsistent manner that would have significant impacts on affordability.

Q. What types of investments does witness Stephens suggest are in the required or must make category of investments?

A. Witness Stephens says there are four types of investments that are necessary (1) failed or damaged equipment, (2) connecting new customers, (3) load growth or capacity, and (4) administrative (example: customer billing).[45]

Q. Do you agree with witness Stephens on what investments are required?

A. No. Witness Stephens seems to be suggesting that OG&E only connect new customers and replace equipment as it fails. This is not good business practice. I do not believe that OG&E or its customers would want the Company to only replace things after they have failed. This would mean more outages for customers and a grid that underperforms. It is best practice to review the grid's performance and condition and evaluate what investments are necessary for the grid to perform reliably both now and in the future.

Q. What does witness Stephens say about the "prefer to make" category of investments?

A. He calls these investments discretionary[46] and says, "prudence should be awarded only in instances in which the investment is likely to deliver benefits to customers in excess of customers' costs."[47]

Q. What does witness Stephens present as his reasoning for Grid Enhancement investments being categorized as discretionary?

A. Witness Stephens gives three reasons: (1) customers are satisfied, (2) reliability is reasonable relative to peers, and (3) there are no assurances the Grid Enhancement circuits will weather storms better than other circuits. [48]

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45 Responsive Testimony of Stephens p. 6 lns. 6-10.
46 Responsive Testimony of Stephens p. 7 lns. 16-19.
47 Responsive Testimony of Stephens p. 6 lns. 17-18.
48 Responsive Testimony of Stephens p. 7 ln. 21 – p. 8 ln. 7.

Q. **Do you agree with witness Stephens' assessment that Grid Enhancement investments are discretionary?**

A. No. As I will discuss below, his three reasonings are short sighted because witness Stephens is only reviewing the data on a surface level. Surface level evaluation of customer satisfaction and grid performance will lead to inadequate conclusions that drive bad decisions. Best practices are to review the information and data in more detail.

Q. **Witness Stephens first reason Grid Enhancement investments are discretionary is because "customers are highly satisfied with existing reliability."[49] How do you respond?**

A. First, customer satisfaction should not be the driver for when and how OG&E invests in its system. Customer satisfaction is a lagging indicator of how customers feel at the time they are surveyed. Second, it is OG&E's responsibility to determine when the right time is to invest in the grid to ensure it is reliable both now and in the future. Third, OG&E does not want to be in a position where customers are unhappy and complaining about the reliability of the grid. Once that happens, OG&E has already dropped the ball in providing a reliable service. We simply cannot afford to wait for customers to complain before we invest in grid reliability. The Grid Enhancement Plan is part of OG&E's plan to address needed investments in the grid to ensure it is reliable for customers both now and in the future.

Q. **Is it sound policy for the Company to wait until customers are complaining about reliability before making improvements?**

A. No. Waiting for customers to be dissatisfied before investing in the grid is a reckless, reactive approach. It takes time to make significant grid improvements. Waiting for customers to complain before investing would signal that OG&E is not taking responsibility for the performance of the grid or potentially fulfilling its obligation to serve.

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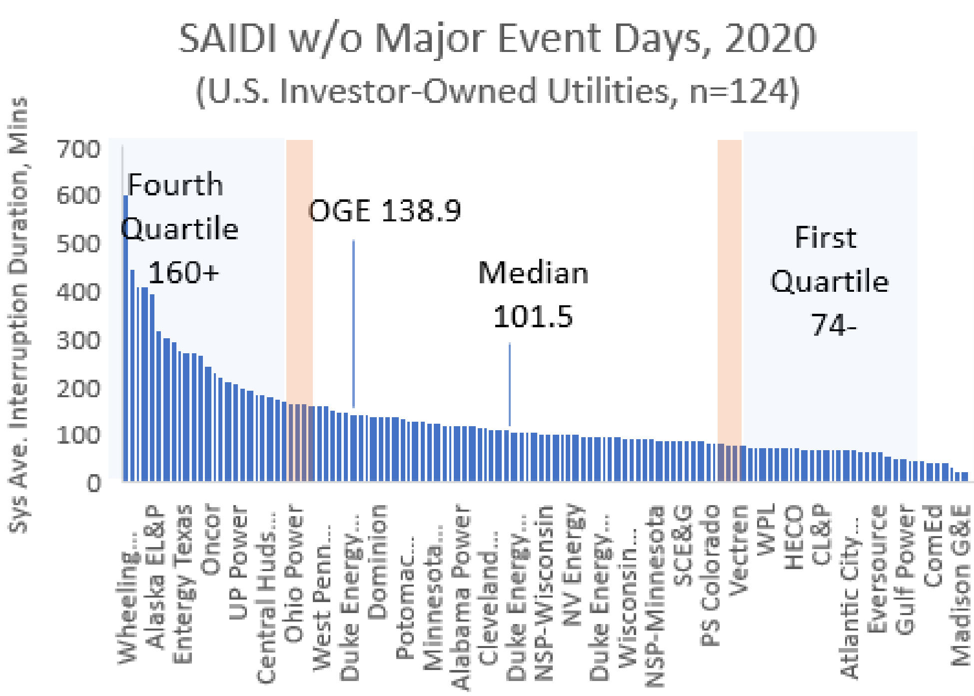
[49] Responsive Testimony of Stephens p. 7 ln. 21.

Q. **Witness Stephens second reason Grid Enhancement investments are discretionary is "OG&E reliability is reasonable relative to its peers."[50] Do you agree?**

A. No. Witness Stephens presents SAIDI without major event days in 2020 as Figure 1 in his Responsive Testimony[51] as his basis for his conclusion. There are a few flaws I see in how the data is presented and interpreted. First, he misrepresents the quartiles in the graph. I have included in Figure 2 below, an updated graph with the added orange shading to show the full first and fourth quartile. In this graph, OG&E is at the very bottom of the 3rd quartile. I do not believe being below average or in the bottom of the 3rd quartile in reliability should be considered reasonable relative to peers or an indicator that OG&E should not be investing in reliability on its system.

Figure 2: Stephens' 2020 SAIDI Analysis



Second, witness Stephens uses one year of data to define a need for reliability improvement. witness Stephens himself even says, "I always recommend a minimum of three years' reliability data pre-investment be compared to a minimum of three years'

50 Responsive Testimony of Stephens p. 8 ln. 1.
51 Responsive Testimony of Stephens p. 8 ln. 14-15.

reliability data post-investment."[52] I agree, good practice is to not use just a snapshot of one year when investing in reliability. Best practices review a series of data points over multiple years to determine how reliability is trending and if investments are needed. It is peculiar to me why witness Stephens would present only one year of data to determine there is no need for investment in reliability.

And third, witness Stephens combines both the Oklahoma and Arkansas jurisdictions for OG&E. These jurisdictions are reported separately to EIA, from which I must assume Mr. Stephens data was derived. Separating these two jurisdictions tells two distinct stories.

Q. **What are the two distinct stories you reference?**

A. First, Arkansas jurisdiction data shows an improvement in reliability indicating the Grid Enhancement investments in Arkansas have been beneficial. Our past Grid Enhancement investments started in Arkansas and now cover 83% of our Arkansas service area's circuits. These investments have helped OG&E's Arkansas jurisdiction improve SAIDI without major event days by 14% and SAIFI by 8% from 2019 to 2021 as shown in Exhibit KS-4.

Now, let's review the Oklahoma jurisdiction data trends before Grid Enhancement. As seen in Exhibit KS-4, OG&E's Oklahoma jurisdiction SAIDI without major event days is deteriorated by 9% and SAIFI by 15% from 2019 to 2021 as compared with industry improving by 3% and 2% respectively. This does not indicate to me that OG&E's Oklahoma reliability was reasonable relative to its peers. It tells me OG&E's reliability was deteriorating while the industry was improving.

Given the fact that OG&E's Arkansas reliability improved post Grid Enhancement work and the fact that OG&E's Oklahoma reliability was deteriorating before Grid Enhancement, I believe there is indication that reliability investments were required to ensure reliable service is provided to our customers in Oklahoma.

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[52] PUD 2021000164 - Responsive Testimony of Stephens p. 36 ln. 22 – p. 37 ln. 2.

Q. **Witness Stephens' third reason Grid Enhancement investments are discretionary is "there is no assurance that enhanced circuits will weather storms better."[53] Do you agree?**

A. No. OG&E has previously presented two specific examples of storms and the impacts the Grid Enhancements have made. One example was presented by OG&E witness Huckabay's Direct Testimony for this case where wind speeds exceeded 85 miles per hour. In this example, the Hennessey 23 circuit (which had been enhanced) had no poles required replacement and only two cross arms to be replaced whereas two other circuits in the area had more than 50 poles to be replaced due to wind damage.[54] Another example was presented in my Direct Testimony in the previous case where strong winds and tornados came through the Fort Smith area. The automation installed in the area through our Grid Enhancement efforts resulted in an estimated 20,000 customers in avoiding an outage.[55] These two examples show the impact Grid Enhancement investments can have when storms develop in our service area.

Q. **Can you provide a recent example of enhanced circuits weathering storms better than other circuits?**

A. Yes. On April 27, 2024, tornados and strong winds moved through our service area. Two (Honor Heights 21 and Jamesville 21) of the 11 circuits witness Stephens uses in his cost benefit analysis experienced winds up to 70 miles per hour. Both of these circuits, which were previously enhanced, weathered the storms with no pole failures. Another example is Cypress 21 and 22 both circuits experienced winds up to 75 miles per hour. Cypress 22, which was enhanced in the 2020 Grid Enhancement plan, weathered the storms with no pole failures, while Cypress 21, which had not been enhanced, experienced 34 failed poles as a result of the severe weather.

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53 Responsive Testimony of Stephens p. 8 ln. 5-7.

54 Direct Testimony of Huckabay p. 8 ln. 27 – p. 9 ln. 6.

55 PUD 2021000164 - Direct Testimony of Smith p. 13 lns. 16-26.

Q. **In summary, do you agree with witness Stephens that Grid Enhancement investments are discretionary?**

A. No. The Grid Enhancement investments are necessary to create a grid that is more reliable, resilient, flexible, and efficient. The three reasons witness Stephens' presents to suggest the investments are discretionary are based on a surface level evaluation that is flawed in its conclusions.

OG&E's Cost Benefit Analysis

Q. **Witness Stephens says OG&E's "model's outputs (benefits estimates) have not been validated against actual results of Grid Enhancement spending to date."[56] Do you agree?**

A. No. The Grid Enhancement projects should be measured based on a three-year performance period post implementation as compared to the three-year historical performance. While OG&E was not able to fully assess the Oklahoma Grid Enhancement projects prior to the initiation of the 2021 through 2023 plan development, we have monitored the investments and identified early results that are in alignment with the planned benefits.

Q. **What are the early results you have identified?**

A. OG&E has been able to measure the performance for its Arkansas Series I Grid Enhancement projects. As shown in Figure 3 below, these projects have performed 63% better than the three-year historical performance. Also, early indications for the 2020 Oklahoma Grid Enhancement circuits are they are performing as expected. This is shown in Figure 4 where in the first year, the 2020 circuits have performed 69% better than the three-year historical performance. These figures were both provided in my Rebuttal Testimony in the previous case.[57]

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56 Responsive Testimony of Stephens p. 9 lns. 20-21.
57 PUD 2021000164 - Rebuttal Testimony of Smith p. 12.

Figure 3: Arkansas Series I Performance

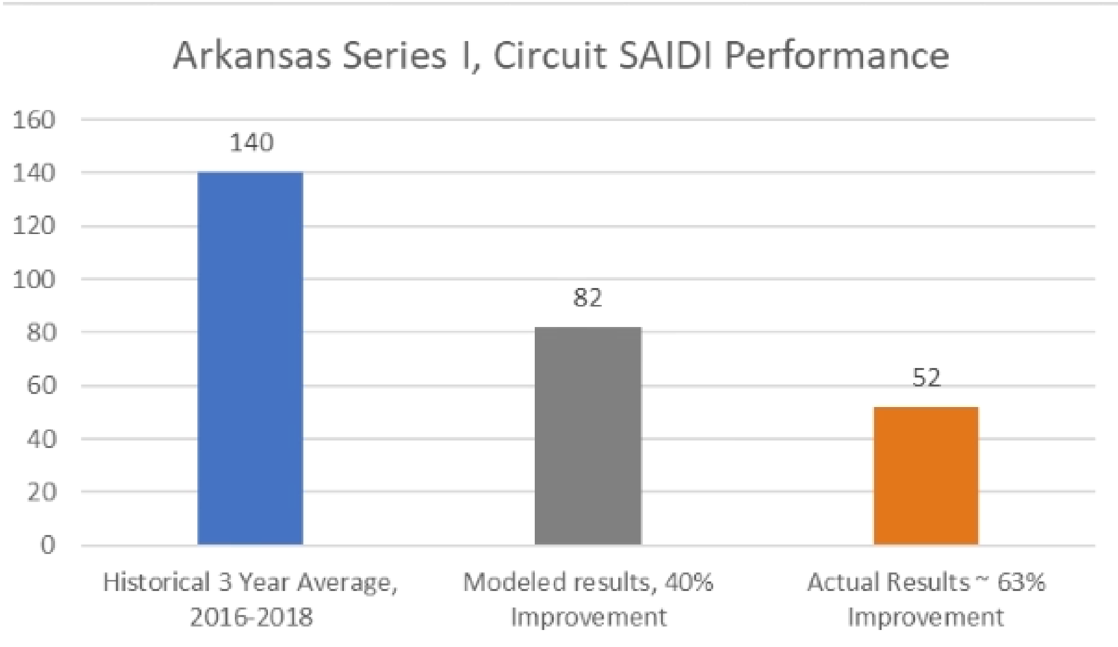
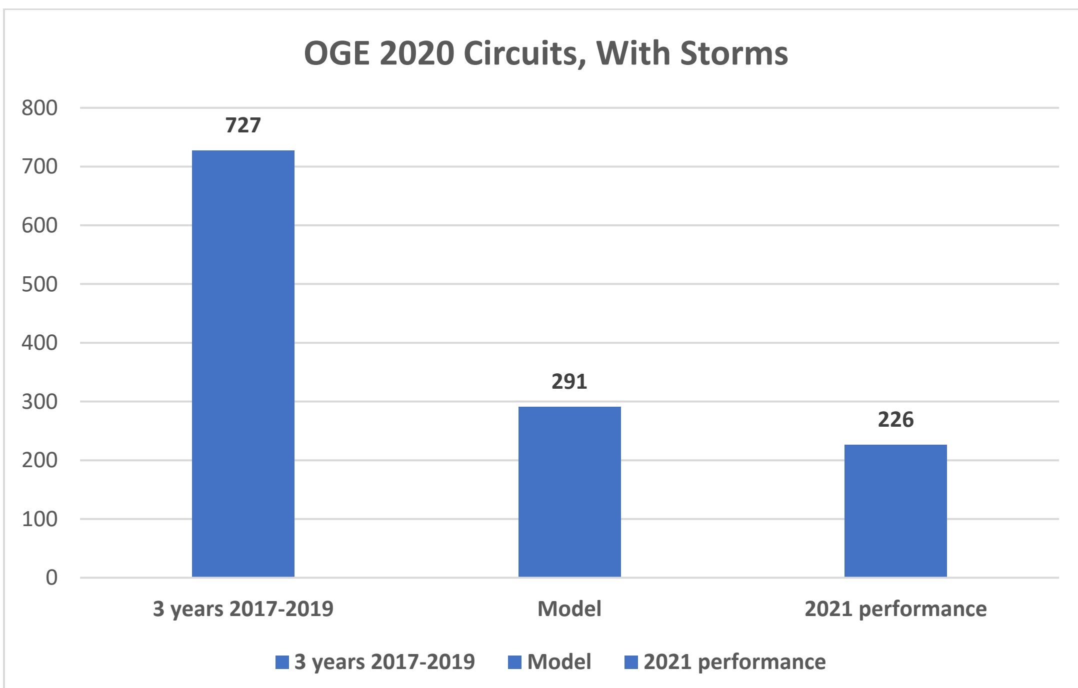


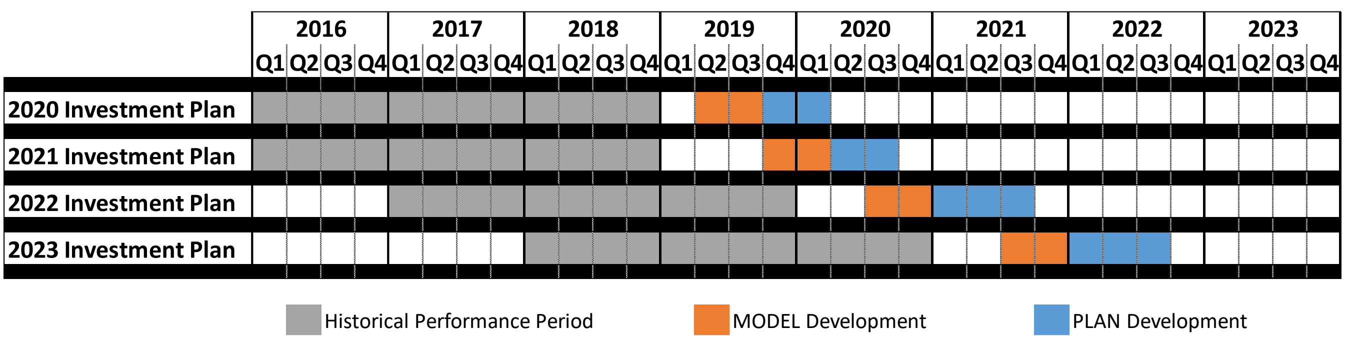
Figure 4: Oklahoma 2020 Circuits Performance



Q. **Witness Stephens states "three years have passed since OG&E applied Grid Enhancement to its first tranche of circuits in 2020, there is no excuse for OG&E's failure to validate the model."[58] How do you respond?**

A. This was not true at the time the plans were developed. As shown in Figure 5 below, all of the investment plans were developed before the three-year performance period (2021-2023) for the 2020 Plan investments had passed. In fact, the 2023 Plan was beginning model development in 2021 and issued in mid-2022. Therefore, the data provided above for Arkansas Series I (63% improvement) and early indications for Oklahoma Grid Enhancement 2020 circuits (69% improvement) is what was known at the time the plan was developed. Both of these show the projects are providing more benefits than the 60% reliability improvement assumptions that drive the model benefits outputs. Given this information, the decision was made to keep the model consistent.

Figure 5: Grid Enhancement Plan Development Timeline



Q. **Witness Stephens states "It is certainly possible that OGE has not validated its model because a new and improved version might not identify as many circuits for Grid Enhancement spending than the existing model does."[59] How do you respond?**

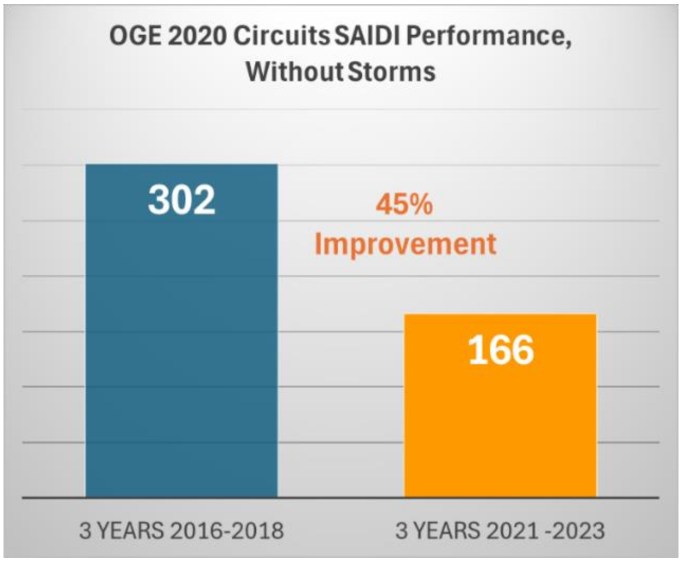
A. This is simply not true. To say we were not updating the model based on results is false, as discussed above. The Grid Enhancement Plan was not developed to cover our entire system or target a certain number of circuits. The Plan was developed with the idea of developing Annual Investment Plans that balance the costs with the benefits each year.

[58] Responsive Testimony of Stephens p. 10 lns. 1-2.
[59] Responsive Testimony of Stephens p. 10 lns. 2-4.

Q. **What are the results of the three-year performance period for the 2020 Plan circuits?**

A. As shown in Figure 6 below, the 2020 Oklahoma Grid Enhancement circuits have performed 45% better than the three-year historical performance.

Figure 6: 2020 Oklahoma Grid Enhancement Circuit Performance



Q. **Would the Grid Enhancement projects be beneficial if a 45% reliability improvement was used in the cost benefit evaluation?**

A. First, the prudence of the Grid Enhancement projects should be based on the information known at the time. However, if we went back and changed the benefits to the 45% improvement, each plan year is still beneficial to customers as shown in Table 1 below. These results show a minimum of 2.1 dollars in benefits for every dollar spent when you are using the lower reliability improvement numbers.

Table 1:Grid Enhancement Benefits at 45% Reliability Improvement

	Cost	Benefit (45%)	Benefit Ratio
2020 Plan	$81.4 million	$265.1 million	3.3
2021 Plan	$164.9 million	$351.4 million	2.1
2022 Plan	$189.0 million	$494.2 million	2.6
2023 Plan	$155.9 million	$1,842.7 million	11.8

Witness Stephens Cost Benefit Analysis

Q. **Witness Stephens states, "in my estimation the spending will deliver reliability benefits of just $0.44 for every $1 in Grid Enhancement spending."[60] Do you agree?**

A. No. First, witness Stephens is evaluating only 11 of 54[61] circuits that were in-service in 2020. These circuits were already deemed prudent in the previous case PUD 2021000164. Second, his analysis is inaccurate and incomplete.

Q. **How is witness Stephens' analysis inaccurate?**

A. Witness Stephens uses outages in both his "before" and "after" data that are never included in any reliability reporting with or without storms. These are characterized as "Cause Exclusions," which are events or service calls for things that turn out to not be caused by OG&E. None of these types of outages are expected to be impacted by the work on Grid Enhancement. They would also not be impacted by work performed in the Worst Performing Circuit program, which Mr. Alvarez says OG&E should focus on. If you remove these data points from witness Stephens' analysis and keep his same formulas and assumptions, the results show reliability benefits of $13.62 for every $1 in Grid Enhancement spending.

Q. **Are you saying that merely removing "Cause exclusion" from his analysis and keeping everything else the same shows that the 11 circuits he chose produce $13.62 of benefits for every dollar spent?**

A. Yes. Simply correcting his analysis shows an overwhelming benefit for the costs incurred.

Q. **How else is witness Stephens' analysis inaccurate?**

A. Witness Stephens is using a historical performance period of 2017 to 2019[62] for the 2020 Plan circuits. As shown in Figure 5 above, the 2020 Plan circuits should be using a historical period of 2016 to 2018.

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[60] Responsive Testimony of Stephens p. 10 lns. 11-13.
[61] Responsive Testimony of Stephens p. 10 lns. 10-11.
[62] Responsive Testimony of Alvarez p. 20 ln. 4.

Q. How is witness Stephens' analysis incomplete?

A. Witness Stephens only evaluates the benefits of the DOE's ICE calculator using sustained outage history. He does not include evaluation of avoided momentary outages, avoided O&M expense, avoided capital, or avoided costs from storms.

Specific Programs or Sub-Programs

Q. **Witness Stephens states, some Grid Enhancement programs and subprograms are not cost-effective ways to improve reliability.[63] Do you agree?**

A. No. The Grid Enhancement Plan was developed to create a step change in the way the circuits perform. As discussed in response to witness Alvarez, each investment type was evaluated to determine if it should be applied for each circuit. I will expand below on the inaccurate and incomplete assessments witness Stephens makes for each of the examples he provides showing cost-effectiveness.

Q. **What programs or subprograms does witness Stephens present as not cost-effective?**

A. Witness Stephens presents an analysis he developed during the last rate case (PUD 2021000164) as evidence that lateral automation is not cost-effective.[64]

Q. **Do you agree with witness Stephens' evaluation of lateral automation?**

A. No. I explain my reasoning in the "Lateral Automation" section below.

Q. **Does witness Stephens present other programs or subprograms as not cost-effective?**

A. No. However, he does conjecture about his theory as to why OG&E did not include conservation voltage reduction as part of the Grid Enhancement Plan. My response to his speculation is below in the "Conservation Voltage Reduction" section.

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63 Responsive Testimony of Stephens p. 12 lns. 4-5.
64 Responsive Testimony of Stephens p. 11 lns. 3-13.

Lateral Automation

Q. **First, what is meant by lateral automation?**

A. Lateral automation consists of replacing fuse stations with TripSavers. TripSavers are designed to help reduce the number of customers that experience either momentary (lights blinking) or sustained (power out for a period) outage. Lateral automation enables the Company to deploy a hybrid protection scheme which will combine aspects of both "Fuse Blowing" and "Fuse Saving" schemes. This hybrid approach will reduce both the number of momentary outages seen by customers, and long-term outages that require a truck roll.

Q. **What is the difference between a "Fuse Saving" and "Fuse Blowing" protection scheme?**

A. A "Fuse Saving" scheme uses automated switching to blink the entire circuit to try to clear temporary faults (i.e., tree limbs blowing against a line) instead of allowing the fuse to blow to clear the fault. The Fuse Saving scheme reduces the number of long-term outages that require truck rolls to fix but increases the number of momentary outages that customers see. The Fuse Saving scheme has traditionally been the preferred philosophy of OG&E.

A "Fuse Blowing" scheme allows the fuse to blow as the primary method of clearing both temporary and permanent (i.e., broken pole) faults. The Fuse Blowing scheme impacts fewer customers but would require more truck rolls and longer duration outages when temporary faults occur when compared to the fuse saving scheme.

Q. **What do you mean when you say OG&E is deploying a hybrid protection scheme?**

A. In general, the entire circuit will no longer blink to clear temporary lateral faults, which will prevent the momentary outage that all customers on the circuit would have had in the prior scheme. Instead, the TripSavers are able to reclose and will clear the temporary faults by only blinking the lateral that the temporary fault occurs on. The TripSavers will open up if the fault is permanent and unable to be cleared by the reclosing sequence. When the TripSaver opens up it will require a truck roll to fix the permanent fault, just like a blown fuse would. This new protection philosophy will greatly limit the number of temporary outages that customer's see while still minimizing the number of long-term outages to only what is necessary for a permanent fault. Another benefit, when restoring power after clearing the fault, the technician need only to reset the TripSaver and put it back into place. This ensures the correct fuse curves are always in place on the system.

Q. **Witness Stephens states, "I sincerely doubt there are anywhere near $72 million dollars' worth of laterals for which TripSavers are cost-effective on OG&E's distribution system."[65] Do you agree with this statement?**

A. No. First, witness Stephens' is missing the intent of lateral automation within the Grid Enhancement Plan. And second, witness Stephens' evaluation of the benefits is incomplete.

Q. **What is the intent of lateral automation within the Grid Enhancement Plan?**

A. The intent of lateral automation is to reduce the impact of temporary faults to all customers on the circuit. As stated above by deploying a hybrid protection scheme, we are able to reduce the momentary outages on the circuit to only the customers on the lateral behind the TripSaver. Witness Stephens even suggests "TripSavers can be effective in avoiding transitory faults, like when a tree branch only temporarily grazes a line."[66]

Q. **Witness Stephens says his evaluation of lateral automation from the previous rate case shows just $1.15 million in reliability benefits.[67] Do you agree with his evaluation?**

A. No. First, his evaluation from the last rate case resulted in $1.349[68] million in reliability benefits not the $1.15 million presented in this case. Second, witness Stephens' evaluation is incomplete.

Q. **Please explain how witness Stephens' evaluation of the benefits is incomplete.**

A. Witness Stephens' focuses only on permanent faults, ignores impacts to upstream customers, and only identifies a portion of Avoided Economic Harm benefits.

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65 Responsive Testimony of Stephens p. 12 lns. 4-5.
66 PUD 2021000164 - Responsive Testimony of Stephens p. 16 lns.13-15.
67 Responsive Testimony of Stephens p. 11 lns. 12-13.
68 PUD 2021000164 – Errata to Responsive Testimony of Stephens p. 19 ln.3.

Q. **Please expand on witness Stephens' focus only on permanent faults.**

A. Witness Stephens provides data request AG 32-10 (from PUD 2021000164) as the basis for his benefit analysis.[69] This data request specifically asked for the faults that were cleared by a TripSaver going to lockout, which only occurs with permanent faults. By utilizing the data request that included permanent fault data only, the analysis completely neglects the benefits seen from TripSavers for transient faults. As stated above, this analysis completely misses the main benefit of our hybrid protection scheme with TripSavers which is to reduce the number of momentary outages (caused by transient not permanent faults) seen by customers. OG&E does not believe that TripSavers will reduce the number of permanent faults that occur on laterals and has made no assertions of that kind.

Q. **What is the impact of focusing on only permanent faults?**

A. Witness Stephens states that "only 20-50 customers benefit from each lateral-level outage avoided,"[70] which he also uses for the basis of his benefit analysis. This statement is not true. All customers on the circuit (an average of 1,022 per circuit) will benefit from having TripSavers. When lateral-level outages occur, every customer on the circuit that is not on the faulted lateral will benefit from avoiding momentary outages that would have occurred under the prior fuse saving scheme.

Q. **Witness Stephens states, "I estimated a value of $11.33 for each customer avoiding a four-hour service interruption."[71] Do you agree with this statement?**

A. No. First, I am again confused as to why witness Stephens is valuing a four-hour service outage when he states TripSavers deliver no benefit for permanent faults.[72] Second, witness Stephens notes the cost to industrial customers is ignored because he assumed that TripSavers are not used for industrial customers.[73] This is not true. OG&E installs TripSavers for all types of customers, including industrial customers. Based on witness

69 PUD 2021000164 - Responsive Testimony of Stephens p. 17 lns. 14-16.
70 PUD 2021000164 - Responsive Testimony of Stephens p. 17 lns. 1-20.
71 PUD 2021000164 - Responsive Testimony of Stephens p. 18 lns 12-13.
72 PUD 2021000164 - Responsive Testimony of Stephens p. 17 lns. 6-7.
73 PUD 2021000164 - Response to Data Request OGE-AG 01-08.

Stephens' own analysis, if industrial customers were included, the $11.33 value would significantly increase to $709.26. And third, witness Stephens is ignoring the value of reducing the impact of momentary faults.

Q. **If you adjust witness Stephens' analysis for the updated and more appropriate value ($709.26) for avoided outages, what are the resulting benefits?**

A. The resulting benefits would be $84.4 million in present value benefits as compared to the $1.349 million[74] (or $1.15 million[75]) that witness Stephens presented. Keep in mind this is just for the avoided permanent outages that witness Stephens analyzed. It does not include any benefits associated with the avoided momentary outages which are the very reason for installing TripSavers in the first place. Momentary outages would represent an additional $84.7 million[76] in benefits, bringing the total Avoided Economic Harm benefits to $169.1 million.

Q. **Witness Stephens also says that fuses perform many of the same functions as TripSavers.[77] Do you agree?**

A. No. This statement is subjective and misleading. There are a few basic functions a fuse performs that can also be performed by a TripSaver, but there are many functions TripSavers perform that cannot be performed by fuses. Below are a few examples of the additional functionality offered by TripSavers.

- Reclosing – enables OG&E to move to a hybrid protection scheme to reduce the number of momentary outages experienced by customers.
- Hot Line Hold – safety feature which reduces the time to isolate and disables reclosing while crews are working on the line.
- Quicker Fault Clearing Times – reduces the equipment damage and voltage sag, as well as improving public safety.
- Multiple Fuse Curve Settings – increases circuit protection coordination which will limit the outage impacts to the least amount of customers.

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74 PUD 2021000164 – Errata to Response Testimony of Stephens p. 19 ln 3.
75 Response Testimony of Stephens p. 11 lns 12-13.
76 Using $144.04 average cost per momentary interruption.
77 Responsive Testimony of Stephens p. 11 lns 6-7.

- Reduced Lockout Curves – reduces the time for lateral lockout (meaning the lateral is de-energized) which will improve public safety and reduce equipment damage.

Conservation Voltage Reduction

Q. **Before you begin, please provide a brief explanation of Conservation Voltage Reduction ("CVR") and Integrated Volt VAR control ("IVVC").**

A. CVR is used to minimize end-use voltage within standard limits to reduce peak demand and possibly overall energy consumption. IVVC is used to operate transformer load tap changers, voltage regulators, and capacitors to control voltage and Volt-Ampere Reactive ("VAR") flow on the distribution system in specific ways to optimize voltage profiles. CVR can be run inside of an IVVC scheme to optimize for lower consumption.

Q. **Witness Stephens states CVR can be cost effective on 20 to 40% of most utilities' circuits.[78] How do you respond?**

A. As stated in my Rebuttal Testimony to witness Stephens in the previous case[79], the Company completed installation of the IVVC program as part of the Smart Grid Rider[80] and Demand Program Rider[81]. The programs invested in the optimization of 400 (46%) circuits across our service territory using CVR and IVVC practices. So, OG&E has already exceeded the recommendation of witness Stephens.

Q. **Why did OG&E choose to not continue deployment of the IVVC program within the Grid Enhancement Plan?**

A. When reviewing the potential for additional IVVC within the Grid Enhancement Plan, it was determined that the remaining circuits would provide diminished results. For this reason, additional IVVC was not included in the Plan. Witness Stephens suggests this is

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78 Responsive Testimony of Stephens p. 12 lns. 14-15.
79 PUD 2021000164 – Rebuttal Testimony of Smith p. 27.
80 Cause No. PUD201000029.
81 Cause No. PUD201200134.

true as well when he states, "I've found that CVR is generally cost-effective on between 20-40% of a utility's circuits."[82]

Q. **Witness Stephens states "conservation voltage reduction is conspicuous by its absence from the OGE grid modernization plans."[83] How do you respond?**

A. I disagree with witness Stephens' statement. As stated above, and in the prior cases in which Mr. Stephens participated, OG&E has already deployed IVVC on a significant number of its circuits.

Q. **If the Company was not intending to run IVVC for additional circuits, why did the Company install communications for capacitors and regulators as part of Grid Automaton?**

A. Installing communications for capacitors and regulators allows OG&E to have better control and visibility of its grid. The OG&E control center now has the ability to not only remotely monitor the status of the devices and circuits, but also operate the devices providing greater ability for voltage and VAR control. The ability to monitor these devices remotely will reduce the amount of time that OG&E personnel spend in the field inspecting and verifying proper settings and operation of these devices. Furthermore, the equipment we are installing to make capacitors and regulators remotely controllable will provide the added functionality that will be needed as the grid continues to evolve. As deployment of distributed energy resources ("DER") and electric vehicles ("EV") continues to grow, having better voltage and VAR control will be key in maintaining grid stability.

Q. **Witness Stephens even goes as far as saying his guess is the Company has no interest in pursuing programs that reduce Company earnings.[84] How do you respond?**

A. I disagree with witness Stephens' statement. CVR is not a focus of the Grid Enhancement Plan as discussed above. However, the Company is keenly aware of the need to balance necessary reliability and resilience investments with affordability. This is why we have pursued more than $430 million in federal funding through the Infrastructure Investment

[82] Responsive Testimony of Stephens p. 12 lines 14-15.
[83] Responsive Testimony of Stephens p. 12 lns. 9-10.
[84] Responsive Testimony of Stephens p. 13 lns. 3-5.

and Jobs Act programs. OG&E has been successful in securing $55 million in federal funding and is waiting to hear back on an additional $174 million in current applications. As explained in the Rebuttal Testimony of Kimber Shoop, OG&E also has some of the lowest electric rates in the nation, even after this Grid Enhancement investment is considered.

Independent Evaluation

Q. **Witness Stephens states, "[he] encourages the Commission to procure and oversee an independent evaluation of the benefits and costs of the Company's Grid Enhancement program."[85] How do you respond?**

A. I do not agree with witness Stephens' statement. Multiple cost benefit evaluations have been performed to show the value in the Grid Enhancement Plan, and all of these evaluations, when done correctly, show the projects have more benefits than costs. These evaluations have been completed by OG&E, 1898 & Co., and witness Stephens (with included corrections). All evaluations have shown significant benefits in excess of costs for OG&E's customers. For these reasons, I fail to understand why witness Stephens would believe it would be in the best interests of customers for the Commission to spend money to complete yet another evaluation of the costs and benefits.

Q. **Please summarize OG&E's evaluation of the costs and benefits.**

A. OG&E has provided a cost benefit analysis for the overall plan showing $1.9 billion[86] in benefit for $810 million[87] in investments, which results in a benefit ratio of 2.3, meaning for every dollar invested, there is 2.3 dollars in benefits to customers. Then, OG&E has provided the same analysis for each investment year as shown in the table below with benefit ratios of 2.8 and higher. All OG&E evaluations have shown positive benefit ratios.

85 Responsive Testimony of Stephens p. 29 lns. 2-4.
86 PUD 202000021 - Direct Testimony of Smith top of p. 6.
87 PUD 202000021 - Direct Testimony of Smith p. 6 ln. 7.

Table 2: Grid Enhancement Benefits

	Cost	Benefit	Benefit Ratio
2020 Plan	$81.4 million	$353.5 million	4.3
2021 Plan	$164.9 million	$468.5 million	2.8
2022 Plan	$189.0 million	$658.9 million	3.5
2023 Plan	$155.9 million	$2,456.9 million	15.8

Q. **Please summarize 1898 & Co.'s evaluation of the costs and benefits.**

A. In response to the settlement agreement approved by the Commission in PUD 202000021, OG&E hired 1898 & Co. for its 2021 general rate case to evaluate the estimated costs and benefits of the work identified in the Annual Scope of Work documents for both the 2020 and 2021 Plans. The results of the analysis performed by Mr. De Stigter and his team showed a benefit ratio of 3.1,[88] meaning for every dollar invested, there is 3.1 dollars in benefits to customers.

Q. **Did 1898 & Co. also perform the evaluation using a revenue requirement model?**

A. Yes. The results of the evaluation using a revenue requirement model performed by Mr. De Stigter and his team showed a benefit ratio of 2.6,[89] meaning for every dollar invested, there is 2.6 dollars in benefits to customers.

Q. **Did witness Stephens provide an evaluation of costs and benefits in this case?**

A. Yes. As discussed above, witness Stephens provided an evaluation showing a benefit ratio of 0.44.[90] However, when you update his analysis using the correct data, the benefit ratio is actually 13.62, meaning for every $1 invested, there is $13.62 dollars of benefits for OG&E's customers.

88 PUD 2021000164 - Direct Testimony of De Stigter p.8 lns. 2-4.
89 PUD 2021000164 - Direct Testimony of De Stigter p.42 Figure 1.
90 Responsive Testimony of Stephens p. 10 lns. 11-13.

RESPONSE TO OIEC WITNESS NORWOOD

Q. Please summarize your response to witness Norwood's Responsive Testimony.

A. I respond to the two claims or recommendations witness Norwood makes with regard to (1) minimal Grid Enhancement benefits and (2) disallowance of future Grid Enhancement projects as outlined below.

Grid Enhancement Benefits

Q. Witness Norwood uses average reliability measures to evaluate the Grid Enhancement projects benefits.[91] Do you agree with this approach?

A. No. It is erroneous that the Company and its customers should not be concerned with the current state of the distribution grid based just on certain system-wide average reliability metrics. This "no worries" approach is wrong and leads to a false sense of confidence about the future of distribution service. Consider your air conditioner in your vehicle or home for example. If you evaluated whether to repair your air conditioner based on the average air temperature in Oklahoma, which ranges from 62 to 58 degrees[92], you would decide not to fix it. However, almost no one who lives in Oklahoma would voluntarily decide to not have a working air conditioner during the hot and humid hours of an Oklahoma summer.

SAIDI and SAIFI are by definition "system averages" for the duration and frequency of outages. System-wide averages do not tell the complete story, particularly those that exclude storm events. OG&E cannot responsibly manage the distribution grid based only on an assessment of system "average" performance. It is important to understand the impact of the outage itself to a specific customer rather than only look at mere averages across the system. In essence, system averages do not paint the total picture of individual circuit performance or individual customer experience.

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91 Responsive Testimony of Norwood (Revenue Requirement Phase) p. 20 lns. 1-8

92 https://climate.ok.gov/index.php/site/page/climate_of_oklahoma

Q. **Please provide some examples.**

A. Looking exclusively at system averages like SAIDI and SAIFI to conclude that all is well on the grid is incomplete. While some circuits are performing admirably, others experience chronic outages. For example, Roman Nose 47 and Kellyville 24, which I will discuss in more detail below, have a three-year circuit SAIDI average of 1,263 and 1,446 minutes respectively and Customer Minutes of Interruptions (CMI) values of 297,173 minutes and 2,243,040 minutes, respectively. These numbers are extremely high and demand attention. Undue reliance on system averages leads to the erroneous conclusion that of all the distribution system performs equally well and within industry standards.

Witness Norwood, contending that future Grid Enhancement projects recovery should be disallowed because system SAIDI has not improved, is not looking close enough at the data and at the long-term consequences revealed in that data. To accurately assess the wisdom of the Grid Enhancement Plan, a deeper dive into the data is necessary. While it may be comforting to look at system averages at a snapshot in time, that is not the whole story.

Q. **Doesn't witness Norwood show SAIDI has improved in 2023?[93]**

A. Yes. Even though witness Norwood states "the average number and duration of outages on OG&E's system have actually increased since the GEP was implemented in 2020,"[94] he shows in his Table 4 that SAIDI improved by 32.5 minutes from 2022 to 2023.

Q. **Even if system average reliability metrics were not improving, as witness Norwood suggests, why would OG&E continue to pursue the Grid Enhancement Plan?**

A. OG&E developed the Grid Enhancement Plan based on the experience of customers, not just system averages. As I mentioned above, our customers do not have the luxury to exclude storms from their experience. To illustrate this point, I have set forth three example circuits addressed in our 2020 Investment Plan. These circuits are Roman Nose 47, Kellyville 24, and Woodward District 46. Shown in Table 3 below, is the three-year

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93 Responsive Testimony of Norwood (Revenue Requirement Phase) p. 20 ln. 8

94 Responsive Testimony of Norwood (Revenue Requirement Phase) p. 20 lns. 5-7

historical performance, the forecasted 60% improvement, and the actual 2021 experience for these three circuits.

Table 3: Examples of Circuit Improvement

Including Storms							
	Historical (2017-2019)		Forecasted		2021 Actuals		2021 Improvement Percent
Circuit Name	SAIDI	CMI	SAIDI	CMI	SAIDI	CMI	SAIDI
Roman Nose 47	1,263	297,173	505	118,869	160	35,467	87%
Kellyville 24	1,446	2,243,040	578	897,216	89	146,220	94%
Woodward dist 46	1,032	679,869	413	271,947	21	13,518	98%

Even though the system SAIDI is reasonable, according to witness Norwood, the customers on these circuits were nowhere near the average system performance. Even further, a certain residential customer on Kellyville 24, saw a duration of 56,423 minutes of outage in 2019 which means in total the customer was without power for approximately 39 days. Another example is a certain commercial customer on Roman Nose 47 which saw a duration of 80,054 minutes of outage (or in total approximately 55 days) in 2019.

As seen in these examples, the system wide average SAIDI does not tell the accurate story for customers like those on the Roman Nose 47, Kellyville 24, or Woodward District 46 circuits. These are examples of how hotspots of activity on the system are not represented well by the system averages. It is not acceptable for these customers to experience this volume of outage time just because other customers are experiencing less.

Q. **Witness Norwood states, "Very few OG&E customers would notice such a small improvement in reliability performance."[95] How do you respond?**

A. I disagree with Mr. Norwood because he is again focusing on system-wide average improvement and not individual circuit improvement or customer experience. The reliability improvement cannot simply be evaluated by percentage of minutes an average customer is out of power. As discussed above, you cannot and should not use system average reliability metrics alone to determine if improvements are needed on the distribution grid. The Grid Enhancement Plan is focused on improving the reliability of

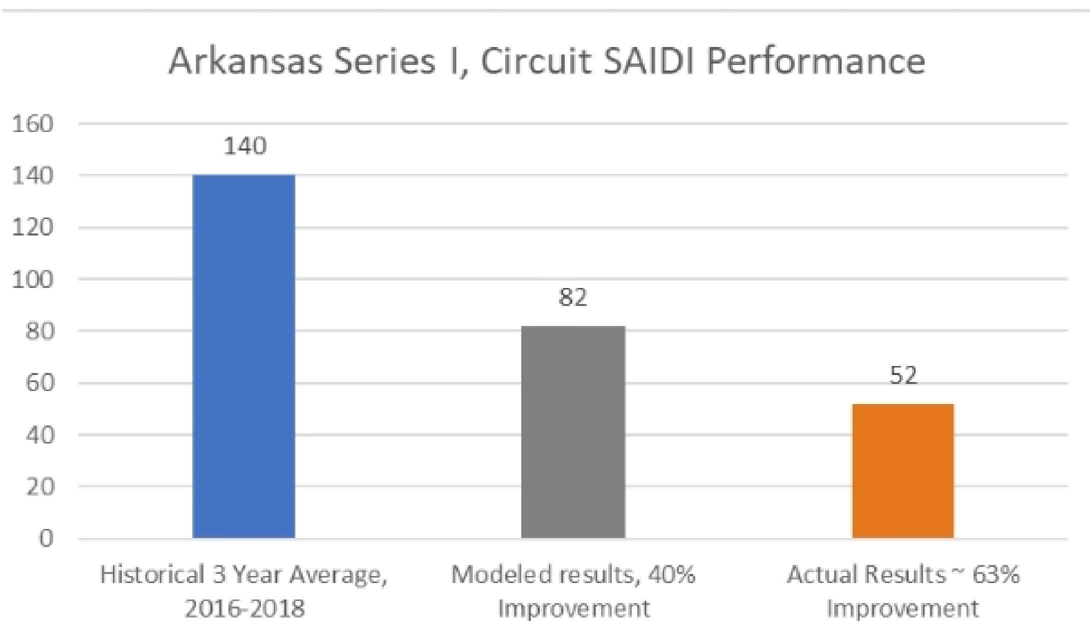
[95] Responsive Testimony of Norwood (Revenue Requirement Phase) p. 22 lns. 8-9.

each enhanced circuit which is estimated to improve reliability for those customers on average 60%.

Q. Witness Norwood states, "there has been no improvement to OG&E's system reliability … since the Company's $810 million investment in the GEP was initiated in 2020."[96] How do you respond?

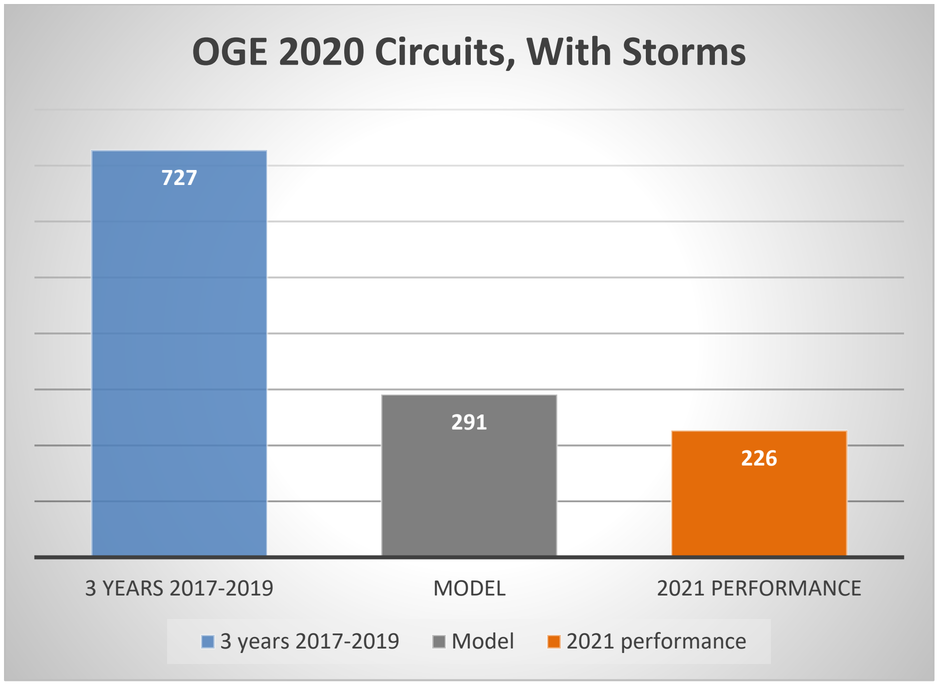
A. Early indications for the 2020 Oklahoma Grid Enhancement circuits are they are performing as expected. This is shown in Figure 8 where in the first year, the 2020 circuits have performed 69% better than the three-year historical performance. These figures were both provided in my Rebuttal Testimony in the previous case.[97] The Grid Enhancement projects should be measured based on a three-year performance period post implementation as compared to the three-year historical performance. OG&E has been able to measure this performance for its Arkansas Series I Grid Enhancement projects. As shown in Figure 7 below, these projects have performed 63% better than the three-year historical performance.

Figure 7: Arkansas Series I Performance



96 Responsive Testimony of Norwood (Revenue Requirement Phase) p. 20 lns. 3-5.
97 PUD 2021000164 - Rebuttal Testimony of Smith p. 12.

Figure 8: Oklahoma 2020 Circuits Performance



Disallowance of Future Grid Enhancement Projects

Q. **Witness Norwood recommends "the Commission disallow the recovery of any further investments on the GEP project that are placed in service after March 31, 2024."[98] How do you respond?**

A. I disagree with witness Norwood's recommendation. OG&E evaluated Grid Enhancement based on the experience of customers on enhanced circuits. He uses system-wide average reliability measures such as System Average Interruption Duration Index (SAIDI) and percentage of time served to show reliability on average for all customers as the benefits for the Grid Enhancement Plan. The Plan improves the reliability of each enhanced circuit with a goal to reduce the outages experienced by customers on these circuits.

[98] Responsive Testimony of Norwood (Revenue Requirement Phase) p. 22 lns. 17-19.

Conclusion

Q. **Do you have any concluding remarks?**

A. Yes. As my Rebuttal Testimony has shown, the recommendations witness Alvarez, Stephens, and Norwood with regard to Grid Enhancement investments are based on flawed information and should be rejected by the Commission. I request the Commission recognize the benefits of OG&E's Grid Enhancement investments and determine they are reasonable and prudent.

Q. **Does this conclude your Rebuttal Testimony?**

A. Yes.

Distribution Grid Modernization at Oklahoma Gas & Electric

Grid Modernization Across the Country

Grid modernization is happening

The distribution landscape is changing rapidly—introducing new opportunities along with increasing system complexity and uncertainty. This change is being driven by the need to accommodate and integrate distributed energy resources (DER), electric vehicles (EVs), changing customer expectations, changing load patterns, increased stakeholder engagement, and advanced technologies. Many utilities and states have launched grid modernization efforts to begin accommodating these changes and meet evolving customer needs. Grid modernization is a broad term, lacking a universally accepted definition; however, it generally refers to actions that make the electricity system more fully integrated—one that is highly flexible, reliable, resilient, accessible, responsive, and interactive.

In 2018 alone, at least forty-four states (Figure 1) have regulatory or legislative efforts underway to modernize the distribution grid.[1] Some states, like California and New York, are several years into comprehensive modernization efforts and are actively integrating smart grid technologies, defining new planning and analytical methods, defining and deploying new technologies to operate the grid, and developing processes to fully integrate DER. In other states, like Minnesota, the grid modernization efforts to date have focused more on future methods and tools for distribution planning. Ohio also recently completed an initial roadmap for grid modernization through a stakeholder process called Power Forward. In Illinois and Michigan, state commissions have initiated more comprehensive modernization efforts and asked utilities to lay out their plans for grid modernization over the next five years so that stakeholder input can be solicited.

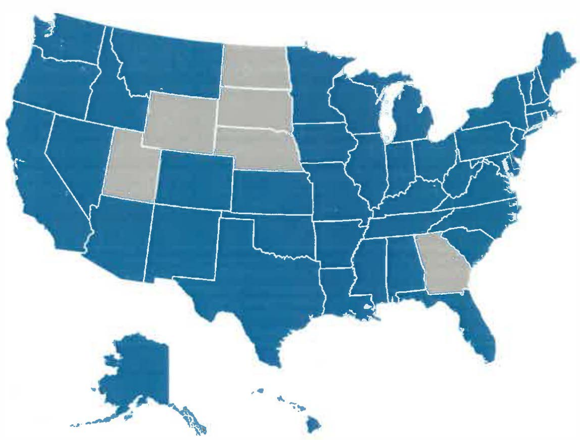


Figure 1. States with Regulatory or Legislative Efforts Related to Distribution Modernization

1 North Carolina Clean Energy Technology Center, The 50 States of Grid Modernization: 2018 Review and Q4 2018 Quarterly Report, February 2019. https://nccleantech.ncsu.edu/wp-content/uploads/2019/02/Q42018-GridMod-Exec-Final2.pdf

Across the forty-four states, there are a range of activities and focus areas that include:

- *Distribution Planning/Integrated Planning* – Regulators in many states are considering distribution system planning rules and requirements. A key analytical component of state activities is non-wires alternative (NWA) assessments. Establishing an approach to evaluate NWAs alongside traditional solutions is central to the consideration of DER in the planning process.[2] To do this effectively, new processes, methods, and tools are being defined. Determining hosting capacity[3] is another analytical component of state efforts. Hosting capacity has been utilized across the industry to communicate the amount of DER that can be accommodated. States are in various stages of utilizing hosting capacity resulting in a range of requirements and needs.
- *Smart Grid Deployments* – Investments in smart distribution technology are continuing to increase. Utilities are using distribution automation (DA) to increase reliability by reducing the number and duration of outages for an event. Because of this, utility DA investments are expected to increase by four times between 2014 and 2024.[4] Similarly, utilities are also investing in applications, like distribution management systems (DMS) that enable increased visibility, controllability, and better management of the distribution system and its devices. Across the U.S., over half of customer meters (78 million) are advanced metering infrastructure (AMI) and this is anticipated to rise to over 80% in the next five years.[5] Each utility's infrastructure and topology are unique resulting in many deployment strategies. To date, AMI is being used to capture customer consumption primarily, but is also capable of collecting other data useful for operations like voltage, temperature, current, etc.[6]
- *Grid Modernization Investigations* – States are at several different stages of grid modernization investigations. Some have concluded studies and are at or near publishing final reports with findings and recommended next steps. Several utilities are requesting special ratemaking treatment for grid modernization investments.
- *Value of Energy Storage and Policy Options* – Several states have completed studies focused on energy storage, including policy options to encourage storage development and energy storage roadmaps. Some are also examining rules to create clear interconnection requirements for energy storage systems.
- *Regulators Considering Rules for Access to Customer Usage Data* – Rules governing access to customer energy usage data are coming under consideration in several states, especially as AMI is more fully deployed. Commissions are requiring utilities to file data privacy tariffs and opening proceedings on data access.

Industry Efforts

Grid modernization activities have also led to several industry efforts to support further understanding, demonstration, and deployments of new technologies.

DOE DSPx

The U.S. Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability, at the request of and with guidance from several state commissions, began working with state regulators, the utility industry, and others to develop a foundational definition and understanding of a modern distribution grid. More specifically, the effort aimed to determine the functional requirements for a modern grid that would enable higher reliability and resilience while also enabling integration and utilization of DER. Called the "Next-Generation Distribution System Platform (DSPx) Project," the objective was to develop a consistent understanding of the requirements to inform investments in grid modernization.[7]

The DSPx project results can be a useful tool to help understand and organize the interrelationship of technology investments needed in a modernized distribution system. In that regard, over twenty-four state regulatory commissions and utilities have

2 Guidance on DER as Non-Wires Alternatives (NWAs): Technical and Economic Considerations for Assessing NWA Projects. EPRI, Palo Alto, CA: 2018. 3002013327.
3 Impact Factors, Methods, and Considerations for Calculating and Applying Hosting Capacity. EPRI, Palo Alto, CA: 2018. 3002011009.
4 Smart Grid System Report: 2018 Report to Congress. US Department of Energy. November 2018.
5 Wood Mackenzie Power and Renewables DataHub
6 Voices of Experience: Leveraging AMI Networks and Data. Office of Electricity US Department of Energy. March 2019.
7 Modern Distribution Grid, Customer and State Policy Driven Functionality, Volume I, U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability, March 2017. https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

leveraged the Modern Distribution Grid reports[8] to inform regulatory proceedings. DOE produced a four-volume set of reports including:

- Volume I – maps grid modernization functionality to state policy objectives;
- Volume II – assesses the readiness of advanced grid technology to enable the functionality and objectives identified in Volume I;
- Volume III – provides decision criteria and considerations related to developing a grid modernization strategy and implementation roadmap; and
- Volume IV – provides a multi-step framework to support development of grid modernization strategy and investment plans including a comprehensive cost-effectiveness framework.

The reports also describe the importance and interrelationships of sequencing investments to yield the greatest near- and long-term value and interoperability of utility systems while preserving the flexibility to adapt to an evolving customer and technology landscape. This DSPx framework provides a recognized industry reference for aligning and communicating utility grid modernization plans.

Core Components and Capabilities of Modernization

As part of DOE's DSPx efforts, the concept of the distribution system as a platform was developed. The platform concept describes how core infrastructure and advanced technology investments can build on each other to achieve primary outcomes of improved safety, reliability, and cost while also preparing for a more complex future with a dynamic and integrated electric grid. It depicts a "building block" relationship between the core components, which form the foundation of the platform, and future applications that are dependent on and enabled by the core. This "building block" concept is useful for describing overall relationships between the various components of distribution grid modernization.

Considering DOE's Modern Grid Initiative, EPRI's Grid Modernization research, and the research of others, the core components of the distribution system can be condensed and categorized into the following foundational areas,[9] illustrated in Figure 2.

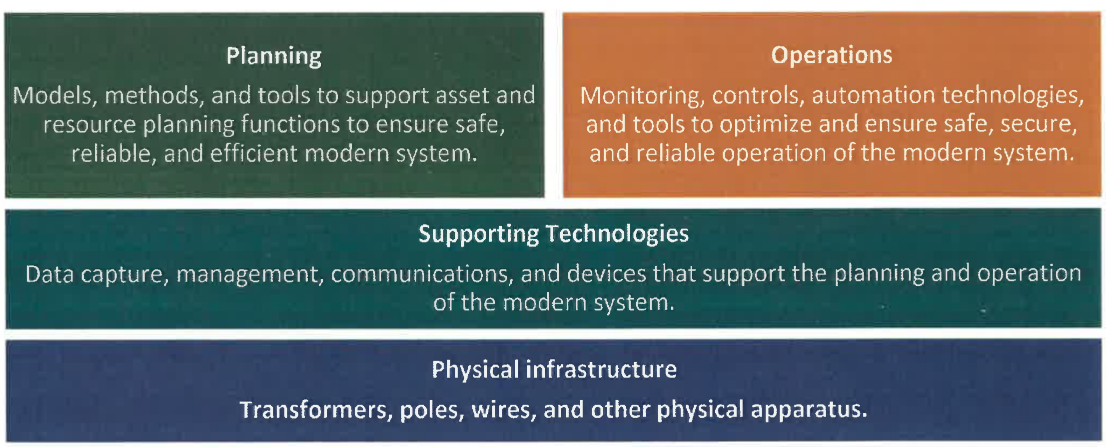


Figure 2. Foundational Areas of Grid Modernization

The concept is further based on the assumption that foundational components that form the core physical platform are unchanging—they must exist even if only to provide traditional electric service. Wires and transformers comprise part of the core platform, for example, but other components such as operational communications and sensing and measurement, are

8 Based on various state commission requests and utility feedback and filings.

9 Modern Distribution Grid, Decision Guide, Volume III, U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability, June 2017. https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

also considered as core in a modern grid. These core components typically provide immediate system benefits, while also supporting other functional capabilities (applications) that may be added in the future.

Core components

Physical infrastructure – The physical infrastructure of the grid which is comprised of transformers, poles, wires, and other physical apparatus.

Supporting Technologies – The operational communications, sensing and measurement, and information systems and devices that are integral to be able to perform both planning and operational functions within grid modernization.

- Operational communications – includes the integration of multiple physical operational communication technologies and networks, like wide area networks, field area networks, neighborhood area networks, and communications network management systems.
- Sensing and measurement – includes devices for data collection and communications necessary to perform key functions, such as grid visibility, grid state determination, asset health, and includes AMI.
- Information systems – includes the systems that provide a digital representation of the distribution system to be used across planning and operations including the network model, geographic information system (GIS), supervisory control and data acquisition (SCADA), outage management (OMS), and PI. Also includes various forms of field data; and inputs from meter data management, asset management, and workforce management systems.

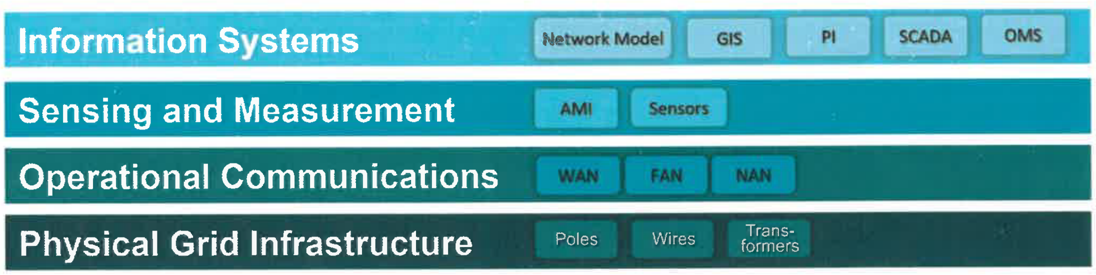


Figure 3. Core Components of Supporting Technologies and Physical Infrastructure

Operations Technologies – Leverages the supporting technologies to transform historical and real-time grid data into actionable insights for improving operational reliability and efficiencies. This includes the monitoring, coordination, and operation of distribution system components – the ability to adjust to changing loads and failure conditions in real time and typically without intervention. Technologies that make up this component are automated field devices like reclosers, switches, and capacitors; SCADA; advanced protection; and operational systems like DMS, OMS, DA, and meter data management systems.

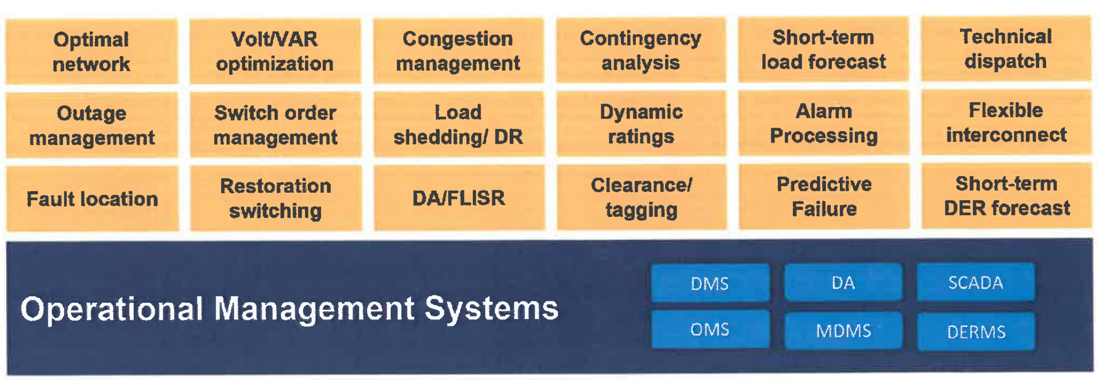


Figure 4. Core Components of Operations Technologies

Planning Technologies – Leverages supporting technologies to analyze and inform investments to meet future needs. This includes planning models, methods, tools and analytical capabilities needed for the traditional planning studies being conducted today and more advanced analytics needed for emerging technologies and processes in the future. Capabilities that make up this component are the tools and systems to perform planning studies like power flow tools to investigate voltage, capacity, reliability, energy implications, DER/load forecasting tools, quasi-static time series simulation, and tools to analyze impacts to reliability.

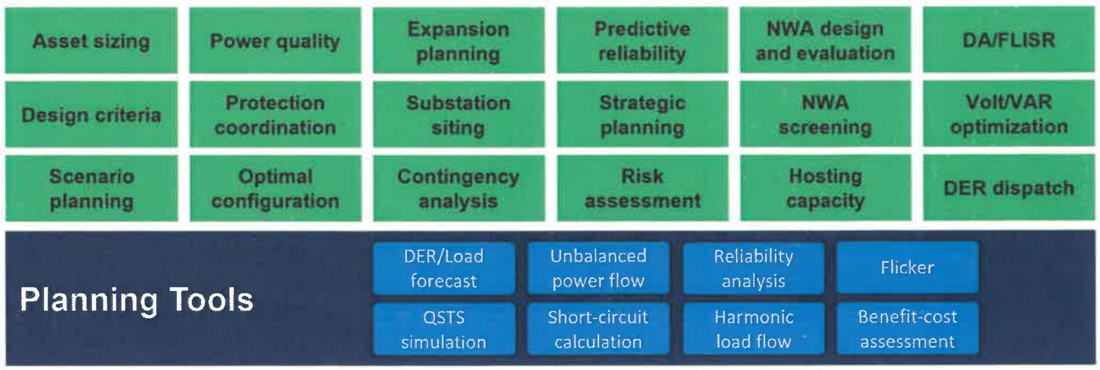


Figure 5. Core Components of Planning Technologies

Applications that utilize the core components

Applications are complementary modules that are built on top of the core components (see Figures 4 and 5 above) and are modernized incrementally over time as needs dictate. An example application might be fault location, isolation, and service restoration (FLISR), which is a common application many utilities are deploying to improve system reliability. However, FLISR operation requires the prerequisite sensing, communication, automation, and controls within the core components for full functionality.

Another example operational application might be a distributed energy resource management system (DERMS) which may become necessary as DER penetrations increase, and utilities consider integrating them into utility operations. While the DERMS may manage DER on individual feeders and provide localized stability and control, it integrates into the DMS—the core operational system that manages the entire distribution grid with a unified view. A DMS with an integrated DERMS will likely become the distribution utility's next key software platform.

Applications on the planning side might be analytics needed for emerging technologies (e.g., DA, smart inverters, AMI, distributed var control) and emerging processes (advanced hosting capacity analysis, NWAs). NWA assessments will require leveraging the quasi-static time series (QSTS) capabilities of power flow tools to look across more time frames than has been done in the past. Planning tools with QSTS capabilities, will be a required capability in the future.

Together the supporting systems along with planning and operational tools and systems enable many of the near and long-term applications that will be required for operating a modern distribution system.

Establishing a Grid Modernization Plan

There are many factors that come into play when developing a grid modernization plan. These investments are significant and can't happen all at once. They must be well defined and sequenced as building blocks for future capabilities. In most cases, these investments span several years and require complex engineering and close coordination with physical infrastructure upgrades. Therefore, it is important to establish a comprehensive plan that can be utilized as a guide or roadmap for future investments.

Aligning Capabilities and Objectives

A first step is to identify: 1) specific objectives and desired outcomes from modernization efforts and 2) the timing and pace of needed changes. Objectives define a specific set of desired outcomes. They also provide the foundation to inform subsequent decisions around the system characteristics that must change in order to achieve the stated outcomes and the related timing requirements. Timing considerations establish an important constraint that informs the overall planning process and what can be accomplished. The DSPx project established a list of general grid modernization objective categories to help inform development of specific objectives for states or utilities.

Table 1. Objective Categories for Grid Modernization

Affordability	**Operational Excellence**
Safety	**Enable DER Integration**
Customer Enablement	**Reliability and Resilience**
System Efficiency	**Enable Technology Innovation**
Cyber-Physical security	**DER Utilization**
Reduce Carbon Emissions	**Enable Electrification**

The next step in the process is to identify the capabilities needed to execute a specific course of action to accomplish the objectives within a defined grid modernization scope. Capabilities subsequently inform the functions, processes, workforce requirements, and enabling tools or technologies that will be needed over the time horizon of the modernization plan. The concept of objectives driving new capabilities and informing new or enhanced functions is illustrated in Table 2 .

Table 2. Aligning Objectives and Capabilities

Objective	Capability	Function	Technology
Ensure Reliability	Situational Awareness	Sensing and Measurement	OMS
DER Utilization	Situational Awareness	DER Operational Control	DERMS

With these concepts in mind, modernization plans can then identify a range of capabilities needed to achieve each objective as well as the functions and technologies needed to support it. The starting point of modernization planning is the current state which then establishes the context for any changes or additions required across the planning horizon. A grid modernization plan then describes a logical progression and timing of new or enhanced capabilities needed to achieve the desired objectives. As noted, there is no generic starting point applicable to all jurisdictions or utilities, so clarity on the objectives, corresponding functionality, and the desired timing is critical. The overall objective, then, of modernization planning is to identify the simplest path to achieve the desired outcomes, while also delivering customer value. Figure 6 illustrates this process showing line of sight from identified objectives to selected technologies and the overall modernization plan. The line of sight facilitates identification of interdependencies.

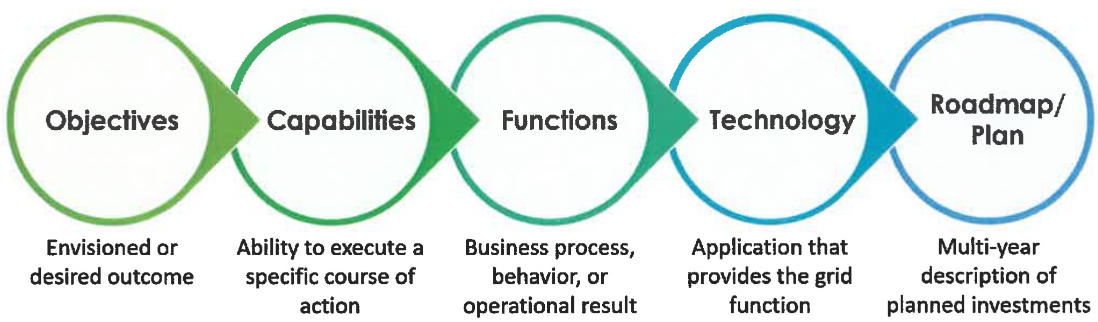


Figure 6. Structure for Grid Modernization Plan Development

Considerations on Drivers, Progression and Timing

Determining progression and timing is a key component of plan development. Each utility has a unique starting point based on existing capabilities and system design. This starting point will be impacted by historical investments and planned activities. Additionally, each utilities' end point varies depending on their unique set of drivers and requirements. Understanding the starting and ending point is critical to laying out a no regrets progression. In establishing the sequence and timing of investments, there are several important considerations:

Each distribution system has a unique starting point, set of drivers and objectives, and policy considerations.

1. What is the relative commercial maturity of technologies under consideration?
2. Are there any specific in-service dates critical to support stated objectives?
3. How does new technology integrate with legacy systems—both the underlying physical grid infrastructure and operational systems?
4. Are the communications, information, operational, and cyber security systems in place, where and as needed?
5. To what extent is DER adoption driving modernization decisions?
6. To what extent do policy or regulatory drivers influence the investment plan?

The DSPx reports describe a three-stage evolution of existing distribution grids to a more modern integrated grid with high DER adoption and market operations. This is shown in Figure 7. The first stage is grid modernization, where the focus is on enhancing reliability, resiliency, and operational efficiencies while addressing aging infrastructure replacement and advanced grid technologies. The second and third stages typically involve policy objectives toward higher levels of DER integration and utilization. Stage 1: Grid Modernization can be a long process as moderate to high levels of DER adoption have thus far tended to be more localized than wide spread.

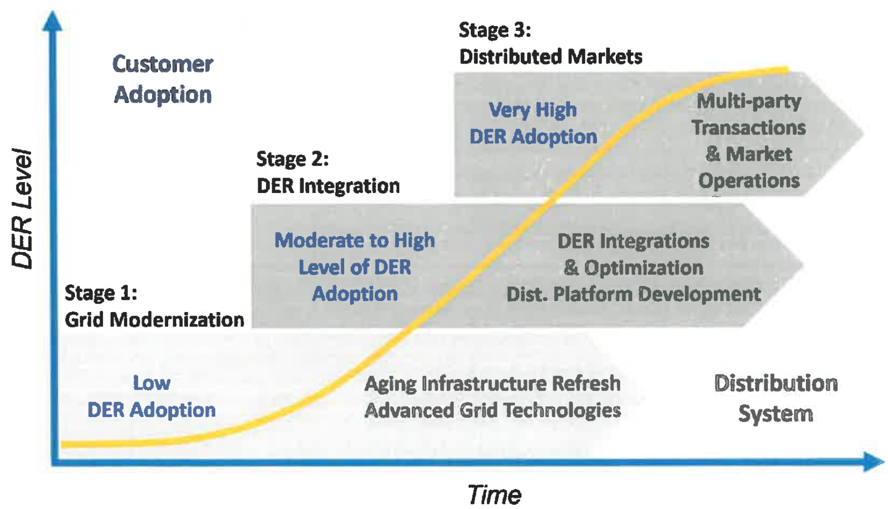


Figure 7. Distribution System Evolution[10]

In fact, when looking across national grid modernization efforts, most distribution systems in the U.S. are currently at Stage 1, meaning that utilities are focusing on advancing core physical grid infrastructure to provide the necessary foundation that enables future capabilities. As a point of reference, New York and California are five years into policy-driven efforts aimed at higher levels of DER integration, yet still have low to moderate levels of DER, are still progressing through Stage 1, and are continuing to modernize the core components of their grids. Very few states are actively working toward Stage 3: Distributed Markets – New York's Reforming the Energy Vision (REV) initiative being one example. Therefore, a key question becomes, "Where do you start and how quickly do you progress?" Specific technology choices, the timing and pace of deployment, and their interdependencies, are typically driven by customer needs and preferences, policy objectives, and technology maturity. Recognizing these timing and pace considerations, a deliberate, incremental implementation approach is useful to help guide modernization decisions through each of the stages.

10 Modern Distribution Grid, Decision Guide, Volume III, U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability, June 2017. https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

A deliberate, incremental approach to implementation is useful to guide modernization decisions through each of the stages.

Managing flexibility and risk through implementation is also important. Starting with mature technologies, less complex implementations, and capability gaps that are more manageable to overcome would be appropriate. In the early stages, one would start with mature solutions. For example, it would be common to focus on a refresh of physical infrastructure and supporting systems while establishing data, model and tool requirements that are in alignment with the planning horizon. Similarly, a DMS is a relatively mature and common technology that can enable a host of decision support capabilities to monitor, control, and optimize the distribution system. Successful implementation is highly dependent upon the accuracy of the data sources, so an early phase activity is to ensure that all electrical network assets and their respective locations are accurately represented.

These activities are particularly important because they establish a foundation for future capabilities to support the transition necessary for a more modern grid leveraging advanced applications. It is important to note that progression through the stages is realized through multiple steps as each technology matures from concept or early investigation to commercial adoption. This process helps ensure that full scale deployment aligns with technology readiness and need, thereby helping to meet least cost objectives, manage risk and reduce uncertainty throughout the modernization process.

Applying the concepts described, modernization plans are more likely to achieve "no regrets" outcomes, while at the same time managing cost and risk, providing customer value, and also providing the foundation to evolve grid capabilities as the need arises.

Oklahoma Gas & Electric's Grid Modernization Plan

Drivers and Objectives

Oklahoma Gas & Electric (OG&E)'s Grid Modernization Plan focuses on investments in distribution and transmission infrastructure while at the same time developing a vision, roadmap, and portfolio of investments for the future grid requirements. The drivers for grid modernization in Oklahoma and Arkansas are generally aligned with those across the country. Most notable are the growing desire from customers for a more resilient and reliable grid to respond to events like windstorms and severe weather as well as the need to modernize aging infrastructure. While DER penetration is still relatively small across the service territory, there is a growing expectation to connect more solar. Additionally, EVs are expected to be on the rise causing new challenges for both planners and operators. In 2018, the Arkansas Public Utilities Commission issued an order on DER facilitating a series of educational stakeholder sessions on topics like DER interconnection, data (customer data sharing and hosting capacity), system planning and third party aggregation.

With this as a backdrop, objectives establish the basis for modernization and a line of site for OG&E to achieve future goals. To that end, OG&E has established six future grid objectives based on achieving improved reliability, flexibility and efficiency across the OG&E system. Summarized in Table 3, OG&E uses each of these objectives as a lever that can be measured individually and contribute collectively to the overall goals.

OG&E is also in the process of developing methods to measure its success for each lever in their grid modernization plan. Of particular note, OG&E has focused on how its grid modernization investments not only improve system performance but also provide customer benefit. With each lever, OG&E has sought to quantify tangible customer value by way of reducing the number of outages, minimizing down time, and increasing customer choice. One example of this can be seen in distribution automation investments. OG&E is tracking the reduction in the number of customer outages and outage duration resulting from its DA investments, a component of the improved reliability lever.

Table 3. Future Grid Drivers and Objectives Defined by OG&E

Drivers of Change	Future Grid Objectives
Customers / regulator expectations: Increased expectations regarding services, power quality, cost, communication, control, and personalization.	Additional Affordability
Grid reliability and resilience: Growing demands for a more resilient and reliable grid (cyber and physical)	Improved Reliability
Customer / 3rd Party participation: Growing supply and demand side opportunities for customers and other 3rd parties to participate in electricity markets (e.g. DERs, EVs)	Greater Resilience
IT / OT convergence and cyber: IT / OT convergence increasing the threat of cyber attacks	Enhanced Flexibility
Integrating DERs: DERs operating in a system that was designed to accommodate a one-way flow of electricity	Increased Efficiency
Changing generation mix: Changing mix of electric generation types and characteristics (distributed and clean energy)	Expanded Customer Engagement
Aging electricity infrastructure	

OG&E Plans for Oklahoma and Arkansas

Drivers and objectives subsequently inform the OG&E grid modernization plan across a range of activities in both Arkansas and Oklahoma. The initial implementation of OG&E's modernization strategy was focused on the portion of their service territory in Arkansas. While geographically small, by comparison to its service area in Oklahoma, the Arkansas rollout enabled OG&E to target investments in grid resilience, distribution automation, and substation automation and to make initial assessment of impacts on their objectives of improving reliability, streamlining grid operations and reducing costs. The first phase of these investments wrapped up in early 2019 and the lessons learned and value realized informed the grid modernization plan for Oklahoma. A summary of lessons learned from the Arkansas deployment include:

- Continuous improvement of the planning model – improved visibility to specific benefits from each type of investment and impact on objectives. Improved prioritization processes to identify greatest value circuits
- Included storm benefit in analysis – customers experienced far fewer interruptions during storms and this was captured in the SAIDI calculations. Also, changed the DOE ICE calculator benefit
- Customer focused evaluation – began to evaluate customer impact by looking at all interruptions, not just SAIDI
- Project composition – more focused deployment specific to each circuit and not a one size solution

The Oklahoma plan is more comprehensive and represents a larger investment by OG&E across both the distribution and transmission systems. Like Arkansas, investments span grid resilience and system automation, but also include upgrades to technology platforms and applications and communication systems. Table 4 provides further details into the planned investments, categorized into five areas. This represents a five to six-year plan for the types of investments that will be needed to help achieve their overarching objectives.

OG&E's modernization strategy is designed so that investments are prioritized every year based on up-to-date information about existing system conditions, emerging technology, customer trends, and future requirements. By implementing their plan in this way, OG&E is managing the inherent uncertainty and risk of grid modernization decisions. As distribution planners assess investment needs, there may be uncertainty in DER adoption and load forecasts, the availability and performance of grid technologies, technology maturity and obsolescence, and the operating performance of the existing distribution system. The annual prioritization process is intended to help minimize these risks and identify "no-regrets" investment strategies.

Table 4. Planned Grid Modernization Investments by Category

Category	Investments
Grid Resiliency	• Storm reinforcement – distribution line reliability, river crossing reinforcement • Conductor upgrades – UG cable and OH conductor replacement, network upgrades • Equipment upgrades – transformer load management, lightning outage reduction program, substation breaker replacement, substation transformer replacement, wood pole substations, transmission attachments • Capacity reinforcement – mobile substations, generator, and storage, 4kV conversions • Animal protection
Distribution Automation	• Smart field devices – add communications to capacitors and regulators and smart sensors • Automated circuit tie lines • Automated lateral lines – smart lateral fuses • Remote fault location – fault location SCADA inputs and smart fault indicators • SCADA for automating throw over cubicles
Substation Automation	• Modern protection relays • Substation automation – SCADA, smart meters, remote equipment monitoring • Workforce optimization
Communication Systems	• Wide area network – freewave network, microwave and wimax • Mesh network • Fiber for transmission and distribution
Technology Platforms and Applications	• GIS application – DER assets in GIS, Secondary Model • Grid operations application – Advanced DMS applications • Workforce optimization platform – digital field services management, add smart devices, digital workforce optimization • Grid planning application – DER/ load forecasting, power flow, etc. • Operational analytics platform – LiDAR change management and weather forecast integration • Design tool – Substation, SP&C • DER management platform – DERMS and DER interconnection management and visualization

How OG&E Aligns with Industry Efforts

General Observations about OG&E's Plan

Comparing the OG&E plan with industry efforts provides a good benchmark for evaluating both the components and the timing and pace of its grid modernization plan. The starting point is the current state of the OG&E system. This section will look at the capabilities enabled by the planned investments from the context of how these align with and support stated objectives.

Current State and Drivers

The current state assessment of OG&E's distribution grid is based on materials reviewed and interviews with OG&E staff. The assessment looks at several aspects of the OG&E system, including equipment and technology maturity, deployment level, operational readiness, and data readiness. Like many other electric utilities, OG&E is currently at Stage 1 of the *Distribution System Evolution* meaning that investments are focused on advancing the foundational physical grid infrastructure while also providing the necessary foundation to enable future capabilities. A key driver for OG&E is a desire to improve overall system reliability and resilience due to aging infrastructure and storms. Industry experience has demonstrated that modernization objectives cannot be achieved on the existing aging infrastructure; therefore, a coordinated deployment of new grid technology with physical grid infrastructure upgrades will be needed. Progression to Stage 2 would occur after addressing physical infrastructure issues, maturing foundational advanced grid capabilities, and based on DER integration drivers and the level of customer DER adoption.

Aligning Capabilities with Objectives

As noted previously, an essential step in the modernization planning process is to identify new business capabilities and/or enhancements to existing capabilities, and the subsequent functions and technologies, needed to accomplish the stated objectives. There are many factors that come into play when determining the capabilities needed and the progression, timing and dependencies of grid modernization investments. Investments will span over several years and require complex engineering and close coordination with other physical infrastructure upgrades. While no two utilities have the same grid modernization starting point, nor have the same set of objectives, industry trends have developed and are helpful in establishing a line of sight between OG&E's overarching objectives and the capabilities and technologies needed to begin closing any gaps. The following summarizes important capabilities (functions and technologies) that might be expected across the core functional areas—Planning, Operations, Supporting Technology, and Physical Grid Infrastructure—considering OG&E's modernization objectives and current state. These form the basis for evaluating OG&E's plan in the context of whether the capability exists currently, does not exist but is included in the plan, or is not included in the plan.

Planning Capabilities

Table 5. OG&E Alignment with Planning Capabilities

OG&E	Planning Capabilities
Part of plan	Generation, Transmission, and Distribution planning functions are integrated to enable optimization from a more holistic, system view and with consideration for DER.
Part of plan	A system model includes all electrical network assets and DER including their respective locations.
Not in plan	Tools and processes to efficiently assess future scenarios and design objectives including active system designs, contingency analysis, flexibility requirements, reliability, different DER adoption trends, and dispatchable loads.
Not in plan	Tools and methods that screen for viability, automate design, and holistically evaluate non-wire alternative solutions against traditional planning alternatives across multiple planning horizons.
Exists today and part of plan	Tools and methods to optimize and prioritize a range of planning project based on system and customer value.
Not in plan	DER adoption and output (temporal behavior) are forecasted at the feeder level for areas with high expected levels of future adoption or DER output, for example vehicle fleet electrification and fast charging stations.
Part of plan	Tools and methods that efficiently assess DER hosting capacity for the entire service area and for different types of DER; hosting capacity tools are fully integrated with the distribution planning process.
Part of plan	DER interconnection process includes automation for non-technical DER application management while streamlining technical components of the review process through screening criteria.
Not in plan	DER interconnection requirements includes latest industry standards (IEEE Std. 1547-2018) to enable functionality from "smart" inverter-based systems.

Comparing OG&E Planning Investment Plan with Industry

From a future planning perspective, OG&E has a good starting point for building out the data and models needed for the expected planning studies. OG&E is also working across their Generation, Transmission, and Distribution planning organizations to identify the processes needed to align resource plans, including consideration for DER. Forecasting DER adoption and production is not a significant problem with only 700 solar sites system-wide; however, this capability will be needed at some point. The system is fully modeled in GIS, and customers are currently mapped to the appropriate transformer and line segment. OG&E is further exploring the need to add secondary models to their GIS for future applications. This could be beneficial for some analytics but is not currently required. A gap in the system model is existing DER. Part of the plan is to add these DER to the model as well as separate production meters for future installations which will support visibility requirements.

To gain experience with more advanced analytical methods, OG&E has investigated the use of NWA assessments for two large, new substation projects. Similarly, in order to better understand DER integration on their system, the plan includes new capabilities to perform DER hosting capacity analytics. While hosting capacity analysis and maps are not currently required in Arkansas or Oklahoma, OG&E is proactively seeking hands on experience on their system recognizing this capability will be an important tool for future planning and interconnection activities.

In anticipation of increases in DER interconnection requests, OG&E has worked to formalize their interconnection guidelines and processes internally to have more consistent review and more transparency into approach. In the future, monitoring and aligning of screens with other industry standards may be required (like FERC SGIP) as DER developers seek more consistent approaches from state-to-state. As part of their grid modernization plans, OG&E plans to implement an interconnection management system to help streamline that process and integrate into existing systems to make DER interconnections visible.

Operations Capabilities

Table 6. OG&E Alignment with Operations Capabilities

OG&E	Operations Capabilities
Exists today and part of plan	Operational data management systems (OMS, DMS, EMS, SCADA, GIS) and customer information systems are fully integrated into one platform providing all users with one "as-operated" view of system performance, real-time situational awareness, and control.
Part of plan	An accurate model of grid connectivity and GIS enables advanced applications including representation and visibility of DER location and operation.
Exists today and part of plan	Monitoring, coordination, and operation of distribution system components is enabled system-wide through automated, intelligent devices (reclosers, switches, and capacitors, AMI, SCADA, DMS state estimation, and advanced protection) to optimize system performance through applications like integrated volt-var control (IVVC).
Exists today and part of plan	SCADA and AMI are integrated with the DMS to operationalize data from grid devices and DER and enable advanced analytics, such as edge-of-the-grid monitoring, parsing out customer load vs. generation, and identify customer issues.
Part of plan	Automated fault location, isolation, sectionalizing and restoration system is enabled on all feeders and lines devices, accounts for DER and is model-based.
Part of plan	Distribution operator can monitor and manage DER in concert with distribution devices.
Part of plan	Distribution system can automatically/remotely change configuration and settings based on a range of scenarios including weather, changing load, operating conditions, DER operation, and cyber events. This includes changes to protection schemes.
Not in plan	Advancements in ability to assess system vulnerability to threats from cyber, weather, and physical attacks and whether/how improvements can be characterized/measured.
Exists today	Outage notifications are integrated with operations, providing impacted customers with more accurate ETRs.

Comparing OG&E Operations Investment Plan with Industry

OG&E has a DMS, the foundational operating and decision support system, and is on track for being fully integrated with other data management systems. For example, OG&E is actively working to further build out their OMS and DMS capabilities to integrate with day-to-day operations. The usefulness of the DMS is highly dependent upon the accuracy of the data sources, and OG&E is undertaking the effort to ensure that all electrical network assets and DER are accurately represented along with their respective locations. AMI is not currently integrated into the DMS, but it is part of their planned activities. AMI is currently integrated with their OMS for receiving outage notifications.

Investments in circuit and substation automation intended to improve system reliability and flexibility are a significant component of the plan. Key elements include automated switches on storm priority circuits and load areas with the highest capacity constraints to add flexibility to the distribution system; smart lateral fuses on worst performing circuits to reduce the number of customers interrupted on the circuit; replacing electromechanical relays with digital relays; and installing SCADA to enable substation automation. Each of these has an expected impact to SAIDI. OG&E does not currently have SCADA for the network protectors. Adding SCADA capabilities as part of the modernization efforts would provide visibility into the network's operation. It would also build network experience that will be needed as workforce knowledge is lost.

OG&E is making targeted investments in proven, advanced applications to derive immediate value (improved reliability and operational efficiency) from the DMS. FLISR and IVVC are two such applications. These applications are reliant on the coordinated expansion of telecommunication and distribution automation programs that enable SCADA and optimize substation/circuit switching. OG&E is looking to expand the use of these application to have automated FLISR running and to better incorporate new data streams, like AMI, into the IVVC control. Integration of weather forecast data into operational systems are also included to help better plan for and respond to storms.

Although DER penetration levels are still quite small, OG&E has factored in a future need for a DERMS to manage DER. While not an immediate investment in the plan, OG&E will be able to monitor how DERMS technology deployments mature, to better ensure seamless integration with the DMS in the future.

Supporting Technology Capabilities

Table 7. OG&E Alignment with Supporting Technology Capabilities

OG&E	Supporting Technology Capabilities
Part of plan	Telecommunications infrastructure is robust (both bandwidth and latency) and supports near real-time data flow from large volumes of devices.
Part of plan	Telecommunications infrastructure serves as the platform for remote operations, including utilization of the data capabilities, remote programming and adjustment of field equipment.
Part of plan	Integration of GIS and different telecom network elements (WAN, FAN) into more unified network management framework.
Part of plan	Operational data management practice ensures that data is collected and integrated for analysis purposes and shared to all interested users, secured by appropriate roles, on request.
Exists today	Ability to transform historical and real-time grid data into actionable insights for improving operational reliability and efficiencies.
Part of plan	Work management system data is incorporated in the Outage Management System (OMS) to more accurately determine fault location, ETR's, and to more efficiently route crews.
Part of plan	Data analytics methods to proactively analyze data for all aspects of utility operations, improving situational awareness and continuous improvement for the daily business tasks.
Not in plan	Cyber security is built into operational processes, systems, and devices.

Comparing OG&E Supporting Technology Investment Plan with Industry

A priority for OG&E is extending and upgrading its wide area and mesh networks throughout the system. The WAN upgrade serves the dual purpose of enabling communication to the distribution automation as well as the bandwidth to handle increased amounts of data. The mesh network upgrade is in response to telecommunication providers retiring 3G technology, which is currently used as a backhaul for the AMI collection points and SCADA protective devices. Targeted replacements and upgrades to the mesh network will establish communications through 4G/5G networks as the 2G/3G networks are phased out, thus enabling meter reading and operational analytics.

OG&E is also keenly focused on the impacts these new systems and requirements will have on the future workforce. To that end OG&E is working on building "digital field services" applications to enable improved efficiency in the field workforce. Potential use cases include: process adherence, job safety tailboard, job hazards awareness, and mobile document access. The application would also support automated work ticket generation and dispatch for selected tasks.

OG&E is also looking at what new skillsets will be required in the future operator and planner as well as the increased role of analytics in operations. The modernization plan includes investments in internal tools that will help manage the new processes and technologies like replacing RTUs in a more streamlined and automated way.

The system is fully modeled in GIS, and customers are currently mapped to the appropriate transformer and line segment. OG&E is further exploring the need to add secondary models to their GIS for future applications.

Physical Grid Infrastructure – Asset Management

Table 8. OG&E Alignment with Physical Infrastructure Capabilities

OG&E	Physical Infrastructure/Asset Management Capabilities
Exists today	Improve fundamental understanding of asset aging and failure.
Exists today and part of plan	Establish the data management and analytics foundation, assigning risk factors to each asset class based on multiple indicators and cost of asset failure.
Exists today and part of plan	Analytics, algorithms, and machine learning are utilized to identify asset issues, end of life prediction, and to identify targeted maintenance.
Not in plan	Inspections are scheduled based on asset health scores, which takes in information from all available online sources and industry-wide performance data.
Part of plan	Inspections utilize advanced technologies and become more automated based on online monitors, sensors, UAVs, and image processing.
Exists today	Maintenance informed by proactive approaches (time and condition) and metrics to assist in tracking effectiveness.
Part of plan	Designs are refined for reliability and resilience considerations through historical failure analyses and advanced data analytics.

Comparing OG&E Physical Grid Infrastructure Investment Plan with Industry

Investments in the foundational grid infrastructure—the physical components—are planned over the next 5-6 years to not only address aging infrastructure issues but also to upgrade core grid capabilities needed for modernization. Inspection and assessment programs are in place to identify worst-performing circuits and equipment based on reliability and resilience metrics. The resultant investments will replace obsolete overhead conductor, unjacketed underground cable, as well as transformers and circuit breakers with a high risk of failure due to condition or age. Storm resilience is a major concern for OG&E and consequently plans are to inspect 50 circuits annually that have the highest storm risk and upgrade facilities with deigns to improve storm resilience.

OG&E is currently using infrared inspections on substation assets to identify "hot spots" indicative of degradation or failure. There is a desire to make these inspections more proactive and mobile, particularly for transformers and lightning arrestors.

Additional plans are to install remote monitoring equipment (dissolved gas analysis) at large substation transformers with the highest risk of failure. This will provide more visibility and allow for preventive maintenance prior to an equipment failure. Permanent monitoring will allow OG&E to establish longer term trending and migrate to more predictive maintenance practices. OG&E is also exploring bringing in additional information from their AMI system to inform asset analytics decisions like predicting failures.

Overall thoughts and observations

Overall, OG&E is currently in the early stages of grid modernization with a primary focus on a refresh of its aging physical infrastructure while at the same time modernizing key grid technologies, operational and communications systems, and planning tools and processes. The modernization plan is in alignment with its stated drivers and objectives as well as with modernization efforts that have been established nationally. At the same time, there may be opportunities to enhance the plan. The following provides some additional observations for consideration as OG&E implements its plan over the next 5 years.

Keep an eye on DER: Distributed resources are a major driver for grid modernization efforts nationwide. In Oklahoma, however, DER adoption is very low. This gives OG&E time to pursue a more deliberate, incremental approach to evaluating and implementing the tools and process that will be needed. Considerations include:

- DER interconnection – OG&E has a formal process, but it is manual and screening is tailored to the OGE grid characteristics. Many jurisdictions are adopting the provisions in IEEE Std 1547 and evolving to more streamlined and automated interconnection processes.
- DER forecasting – Accurately including DER into utility load forecasts can lead to a more precise understanding of their

impact – both costs and benefits. While current forecasts are typically a top-down allocation of system-wide adoption, future planning studies will need to be informed by more locational forecasts based on customer adoption.

- Electrification – OG&E envisions EV having more of a near-term impact over other DER, fueled in part by the Oklahoma Electric Vehicle Charging Grant Program. The Program could yield a ramp up in residential and public fast charging installations. Evaluation of residential charging, particularly smart charging capabilities, will require more advanced analytics to assess potential impacts. Similarly, fast charging presents additional forecasting and analytical challenges requiring the application of novel tools and techniques.
- DERMS – While not an immediate priority in the plan, a DERMS may become a needed extension to the DMS as DER become more prevalent. By monitoring DERMS technology now as it matures and learning from utility pilots, OG&E will be in a good position to apply lessons learned and ensure a more successful deployment when they need it.

Develop planning analytic capabilities: The complexity of distribution planning is changing. The core responsibilities of planning and designing the system to ensure reliability and service standards are met will remain. Moving into the future, however, tools and methods for power system analysis will become more complex and engineers will be faced with new technical challenges. Considerations include:

- Reliability planning – While OG&E has some asset reliability statistics, a more rigorous process of integrating assets with reliability planning could prove useful. Including reliability as a decision metric when evaluating and prioritizing future projects should directly benefit system reliability metrics as well as support capitalization of these efforts
- Non-Wires Alternatives – Assessing NWAs alongside wires as a planning solution is becoming a high-priority in many jurisdictions. OG&E has begun piloting NWA assessments for large, new substation projects and have an initial basis for NWA screening based on size of the unit in rural vs urban areas. Before NWA analysis becomes a requirement, as it has in some states, it would be beneficial to build the models and test the analytical methods needed to formalize into a routine practice that can be automated if needed.
- Hosting capacity – Hosting capacity is a mature planning method and is being actively applied across the U.S. for load and DER integration analytics. Although not yet required in Oklahoma or Arkansas, OG&E has protectively planned to begin assessing hosting capacity tools. A logical progression would be to begin by evaluating hosting capacity for a few circuits and then move to a more comprehensive system-wide analysis over time while also incorporating hosting capacity analysis into routine planning and interconnection studies.
- Scenario planning – OG&E expects that planners will need to be able to evaluate and design for a range of future scenarios, system configurations, and technology options. While some of these studies can be performed by planners today, more efficient and automated assessment processes will be needed in the future. Example study types might include: QSTS simulations for NWA, energy storage, and electric vehicles; more robust analysis to fully consider a complex set of potential future states and system designs; and evaluating adaptive protection and feeder configuration technology. Formal planning metrics and criteria may also be needed to ensure system plans provide the desired flexibility to consider all potential system designs and scenarios.

Fully leverage operational capabilities: OG&E has already made many of the preliminary investments in operational tools and applications, but there is opportunity to more fully leverage these as part of the grid modernization efforts. Considerations include:

- FLISR – OG&E has the capability for operating an automated FLISR scheme but are not currently using it. Turning this capability on and automating FLISR operation across the system could further improve reliability statistics and improve operator efficiency. Alongside this, adding a metric to the FLISR application to measure its impact could further inform reliability statistics.
- IVVC – Currently, OG&E is running IVVC on only a subset of the system. Full utilization of IVVC on all feeders with inclusion of additional system information from SCADA and AMI will further improve its application.
- AMI – AMI has many potential uses beyond revenue metering, including grid and customer outage information, equipment health, and grid management. However, to realize these benefits, AMI must first be integrated into the operational

data management systems. OG&E is utilizing some of these today, like outage information, but should consider fully integrating AMI with its DMS and ensure AMI meters that are being replaced have capability to provide data with the granularity and time synchronization for the intended use case.

Develop processes and tools to enable data analytics for asset management: Data and analytics are becoming ever more important to inform daily business tasks, long-term investment decision, and continuous improvement. In some cases, utilities are creating a practice around data analytics comprised of data scientists that interface with all areas of utility operations. OG&E also envisions data-supported decision-making which may lead to a stronger analytics focus in the future. They have already created a business intelligence/analytics team to support this. Considerations include:

- Asset analytics – Distribution assets are distributed over a wide geographic area, are near or past the expected service life, and typically have no health monitoring due to the asset's low cost. However, industry efforts are underway to collect failure data and develop the analytical tools and models required to support more predictive decision-making for distribution assets. Beyond participating in these industry efforts, several opportunities for OG&E include: utilize existing data/oscillography from AMI and other smart grid devices where use cases have proven success for asset diagnostics; install monitoring on high-value or problem-area assets; expand infrared inspection practice; explore emerging analytical methods, like overhead asset imaging and artificial intelligence.

Focus on workforce is critical: Advancements in operations and planning will also require a closer look at workforce needs. As the distribution system becomes more complex through the deployment of grid modernization technologies and integration of DER, the roles of distribution engineers and operators will evolve. In addition to an increase in the technical challenges, there will be a greater need to process and analyze large sets of data. Utilities across the country are beginning to rethink job functions and define the new skillsets that will be needed in the future in order to evolve the workforce. At the same time, it is important to identify gaps in workforce training that will be required to utilize the new planning and operational tools. As OG&E continues to modernize its grid, it is particularly critical to ensure that the workforce is enabled to fully leverage the new capabilities.

Cyber security: As grid modernization infrastructure is implemented with increasing connectivity and information flow internally and with others externally, this also increases the attack surface for any potential adversary. Recognizing this, modernization strategies should address the need to enhance and extend cyber defenses and evolve into a proactive deterrence rather than the traditional reactive defense.

Telecommunications: The industry is experiencing rapid growth and need for connectivity in the field both for operational needs as well as security. With this need comes the requirement for higher bandwidth. Commercial cellular providers and private LTE networks are insufficient and cannot effectively and economically meet the needs for all use cases. To meet the future bandwidth needs, fiber will be required, and the industry is working to install and make this investment over time as projects present the opportunity.

Technology maturity: Considering technology maturity in relation to OG&E's adoption strategy is a key consideration with respect to selection and timing. All the grid investments included in the OG&E plan are well within the mature, adoption phase. OG&E is planning to evaluate several new technologies on a small scale to ensure system compatibility and to evaluate costs and benefits before executing them system-wide. Examples are energy storage demonstration for capacity reinforcement and hosting capacity applications.

Industry collaboration: There is substantial industry activity around grid modernization, spanning research, demonstration, and application. Engagement in these various distribution grid research efforts – EPRI, DOE, National Labs, peer working groups – can help OG&E stay abreast of the latest technology trends and changes, leverage national efforts and lessons learned, seek alignment with other utilities leading to more informed "no regrets" decisions.

Further Reading

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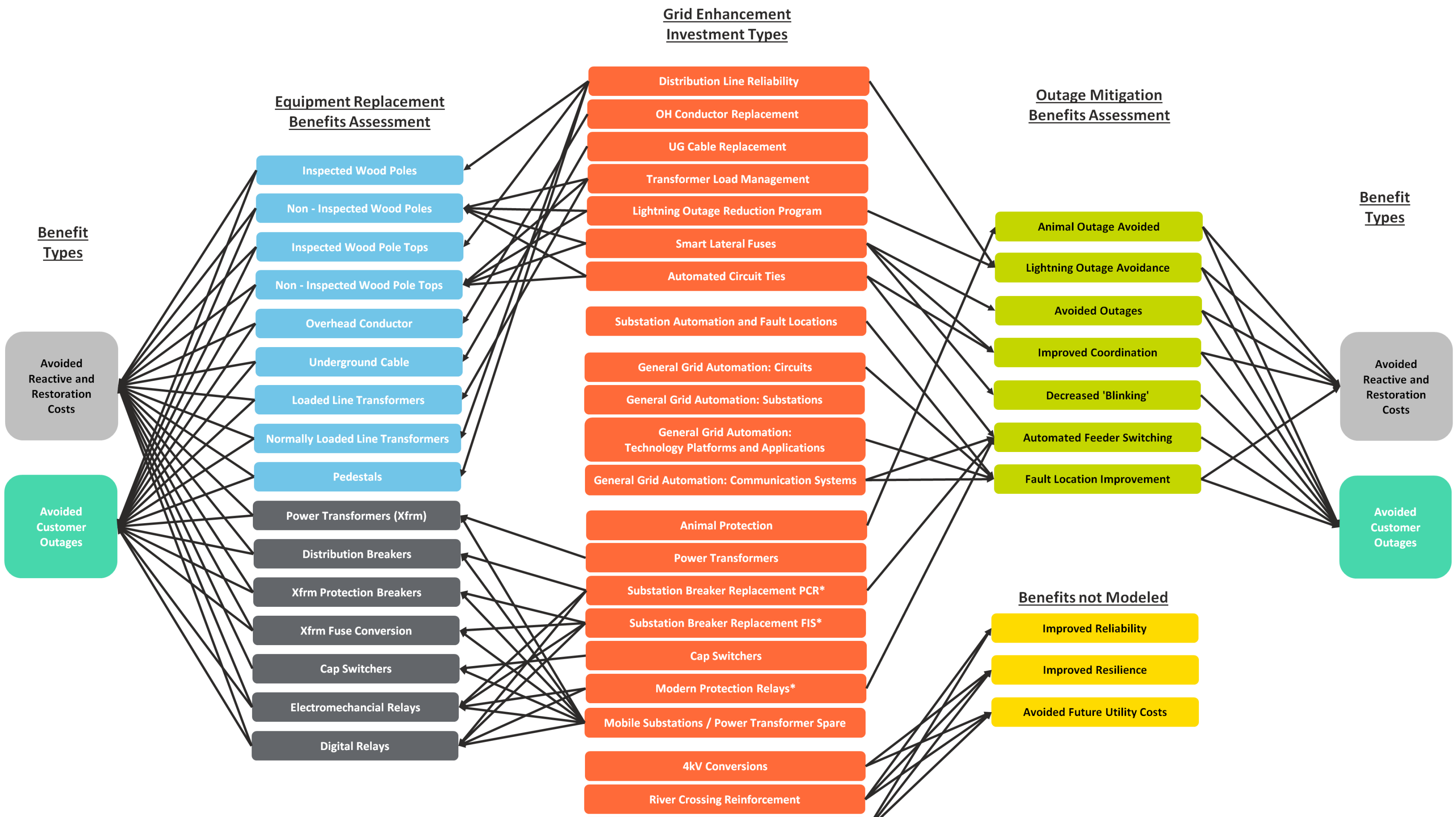
Rebuttal Exhibit KS-2

Investments and Benefits Mapping Diagram



*Includes the addition of new equipment. Those benefits were not modeled

Rebuttal Exhibit KS-3

WBS element	Name	Cost as of 12/31/2020	Program	Category	Type	Circuit/Substation	Project ID	PLIS Period
K:01303-0210.1	DLN-OK GRID MOD ANTIOCH 49 4 KV	230,054.12	OGE Plan 2020	Distribution Line	Grid Resiliency	Antioch 49	762049	12/31/2020
K:01303-0107.1	DLN- AUTO OK GRID MOD ARDMORE 26	439,427.18	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Ardmore 26	510526	12/31/2020
K:01303-0107.4	DLN-OGM DLI OH ARDMORE 26-AUC	266,785.70	OGE Plan 2020	Distribution Line	Grid Resiliency	Ardmore 26	510526	9/30/2020
K:01303-0045.1	DLN- AUTO OK GRID MOD BEGGS 24	194,401.78	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Beggs 24	321824	12/31/2020
K:01303-0045.4	DLN-OGM DLI OH LINE BEGGS 24-AUC	247,292.35	OGE Plan 2020	Distribution Line	Grid Resiliency	Beggs 24	321824	12/31/2020
K:01303-0045.2	DLN- AUTO OK GRID MOD BEGGS 29	532,751.38	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Beggs 29	321829	12/31/2020
K:01303-0045.6	DLN-OGM DLI OH LINE BEGGS 29-AUC	194,019.52	OGE Plan 2020	Distribution Line	Grid Resiliency	Beggs 29	321829	11/30/2020
K:01303-0021.1	DLN- AUTO OK GRID MOD BOWDEN 23	403,350.99	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Bowden 23	321323	12/31/2020
K:01303-0021.4	DLN-OGM DLI OH LINE BOWDEN 23-AUC	163,612.11	OGE Plan 2020	Distribution Line	Grid Resiliency	Bowden 23	321323	9/30/2020
K:01303-0021.2	DLN- AUTO OK GRID MOD BOWDEN 29	1,074,417.95	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Bowden 29	321329	12/31/2020
K:01303-0021.6	DLN-OGM DLI OH LINE BOWDEN 29-AUC	885,685.90	OGE Plan 2020	Distribution Line	Grid Resiliency	Bowden 29	321329	9/30/2020
K:01303-0025.1	DLN- AUTO OK GRID MOD CHECOTAH 21	437,236.60	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Checotah 21	331221	10/31/2020
K:01303-0025.4	DLN-OGM DLI OH LINE CHECOTAH 21-AUC	730,137.38	OGE Plan 2020	Distribution Line	Grid Resiliency	Checotah 21	331221	9/30/2020
K:01303-0025.2	DLN- AUTO OK GRID MOD CHECOTAH 22	685,706.15	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Checotah 22	331222	12/31/2020
K:01303-0025.6	DLN-OGM DLI OH LINE CHECOTAH 22-AUC	630,746.35	OGE Plan 2020	Distribution Line	Grid Resiliency	Checotah 22	331222	9/30/2020
K:01303-0111.1	DLN- AUTO OK GRID MOD CYPRESS 22	463,768.97	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Cypress 22	720822	12/31/2020
K:01303-0035.1	DLN- AUTO OK GRID MOD DEWEY 41	472,677.44	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Dewey 41	461141	12/31/2020
K:01303-0035.4	DLN-OGM DLI OH LINE DEWEY 41-AUC	165,915.25	OGE Plan 2020	Distribution Line	Grid Resiliency	Dewey 41	461141	9/30/2020
K:01303-0006.1	DLN-OK GRID MOD DRAPER LAKE 34	1,892,343.59	OK 2019	Distribution Line	Distribution Circuit Automation/Grid Resilie	Draper Lake 34	862134	9/30/2020
K:01303-0006.2	DLN-OK GRID MOD DRAPER LAKE 71	2,355,281.30	OK 2019	Distribution Line	Distribution Circuit Automation/Grid Resilie	Draper Lake 71	862171	10/31/2020
K:01303-0006.3	DLN-OK GRID MOD DRAPER LAKE 73	481,206.34	OK 2019	Distribution Line	Distribution Circuit Automation/Grid Resilie	Draper Lake 73	862173	11/30/2019
K:01303-0212.1	DLN-OK GRID MOD DRUMRIGHT 44 4KV	91,590.09	OGE Plan 2020	Distribution Line	Grid Resiliency	Drumright 44	760544	12/31/2020
K:01303-0069.1	DLN- AUTO OK GRID MOD EIGHTY FOURTH 31	453,701.06	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Eighty Fourth ST 31	833731	12/31/2020
K:01303-0008.1	DLN-OK GRID MOD EL RENO 21	233,958.35	OK 2019	Distribution Line	Distribution Circuit Automation/Grid Resilie	El Reno 21	890521	8/31/2020
K:01303-0008.2	DLN-OK GRID MOD EL RENO 22	251,052.44	OK 2019	Distribution Line	Distribution Circuit Automation/Grid Resilie	El Reno 22	890522	6/30/2020
K:01303-0057.1	DLN- AUTO OK GRID MOD FIXICO 22	579,180.85	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Fixico 22	730622	12/31/2020
K:01303-0057.4	DLN-OGM DLI OH LINE FIXICO 22-AUC	253,845.82	OGE Plan 2020	Distribution Line	Grid Resiliency	Fixico 22	730622	12/31/2020
K:01303-0057.2	DLN- AUTO OK GRID MOD FIXICO 24	685,644.22	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Fixico 24	730624	12/31/2020
K:01303-0057.6	DLN-OGM DLI OH LINE FIXICO 24-AUC	221,363.14	OGE Plan 2020	Distribution Line	Grid Resiliency	Fixico 24	730624	10/31/2020
K:01303-0105.1	DLN- AUTO OK GRID MOD GREEN PASTURES 21	371,525.43	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Green Pastures 21	845821	12/31/2020
K:01303-0105.4	DLN-OGM DLI OH GREEN PASTURES 21-AUC	514,742.21	OGE Plan 2020	Distribution Line	Grid Resiliency	Green Pastures 21	845821	12/31/2020
K:01303-0043.1	DLN- AUTO OK Grid Mod Hancock 22	293,467.07	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Hancock 22	312822	10/31/2020
K:01303-0043.4	DLN-OGM DLI OH LINE HANCOCK 22-AUC	194,665.29	OGE Plan 2020	Distribution Line	Grid Resiliency	Hancock 22	312822	9/30/2020
K:01303-0043.2	DLN- AUTO OK GRID MOD HANCOCK 24	473,056.55	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Hancock 24	312824	11/30/2020
K:01303-0043.6	DLN-OGM DLI OH LINE HANCOCK 24-AUC	267,399.51	OGE Plan 2020	Distribution Line	Grid Resiliency	Hancock 24	312824	9/30/2020
K:01303-0017.1	DLN- AUTO OK GRID MOD HEALDTON 21	1,105,959.78	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Healdton 21	530521	12/31/2020
K:01303-0017.4	DLN-OGM DLI OH LINE HEALDTON 21-AUC	1,476,718.64	OGE Plan 2020	Distribution Line	Grid Resiliency	Healdton 21	530521	9/30/2020
K:01303-0053.1	DLN- AUTO OK GRID MOD HONOR HEIGHTS 21	569,241.22	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Honor Heights 21	310921	11/30/2020
K:01303-0053.4	DLN-OGM DLI OH LINE HONOR HEIGHTS 21-AUC	449,686.36	OGE Plan 2020	Distribution Line	Grid Resiliency	Honor Heights 21	310921	10/31/2020
K:01303-0109.1	DLN- AUTO OK GRID MOD HOWE 22	311,597.47	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Howe 22	350722	12/31/2020
K:01303-0109.4	DLN-OGM DLI OH HOWE 22-AUC	133,571.96	OGE Plan 2020	Distribution Line	Grid Resiliency	Howe 22	350722	12/31/2020
K:01303-0027.1	DLN- AUTO OK GM ILLINOIS RIVER 21	160,731.34	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Illinois River 21	331321	9/30/2020
K:01303-0027.4	DLN-OGM DLI OH LINE ILLINOIS RIVR 21-AUC	513,853.06	OGE Plan 2020	Distribution Line	Grid Resiliency	Illinois River 21	331321	9/30/2020
K:01303-0073.1	DLN- AUTO OK GRID MOD INGLEWOOD 22	567,013.19	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Inglewood 22	743022	12/31/2020
K:01303-0019.1	DLN- AUTO OK GRID MOD JAMESVILLE 21	648,916.58	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Jamesville 21	332621	11/30/2020
K:01303-0019.4	DLN-OGM DLI OH LINE JAMESVILLE 21-AUC	683,152.16	OGE Plan 2020	Distribution Line	Grid Resiliency	Jamesville 21	332621	9/30/2020
K:01303-0019.2	DLN- AUTO OK GRID MOD JAMESVILLE 41	307,468.86	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Jamesville 41	332641	12/31/2020
K:01303-0019.6	DLN-OGM DLI OH LINE JAMESVILLE 41-AUC	401,331.43	OGE Plan 2020	Distribution Line	Grid Resiliency	Jamesville 41	332641	9/30/2020
K:01303-0049.1	DLN- AUTO OK GRID MOD JENSEN RD 69	125,003.20	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Jensen Rd 69	892169	12/31/2020
K:01303-0049.4	DLN-OGM DLI OH LINE JENSEN RD 69-AUC	295,424.20	OGE Plan 2020	Distribution Line	Grid Resiliency	Jensen Rd 69	892169	9/30/2020
K:01303-0063.1	DLN- AUTO OK GRID MOD KELLYVILLE 24	1,083,197.36	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Kellyville 24	322024	12/31/2020
K:01303-0063.4	DLN-OGM DLI OH LINE KELLYVILLE 24-AUC	725,035.96	OGE Plan 2020	Distribution Line	Grid Resiliency	Kellyville 24	322024	11/30/2020
K:01303-0067.1	DLN- AUTO OK GRID MOD LITTLE RIVER 21	660,100.40	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Little River 21	730721	12/31/2020
K:01303-0067.4	DLN-OGM DLI OH LITTLE RIVER 21-AUC	240,961.77	OGE Plan 2020	Distribution Line	Grid Resiliency	Little River 21	730721	12/31/2020
K:01303-0029.1	DLN- AUTO OK GRID MOD LONE STAR 22	639,302.99	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Lone Star 22	321422	11/30/2020
K:01303-0029.4	DLN-OGM DLI OH LINE LONE STAR 22-AUC	499,180.20	OGE Plan 2020	Distribution Line	Grid Resiliency	Lone Star 22	321422	9/30/2020
K:01303-0214.1	DLN-OK GRID MOD MAUD TAP 21 4 KV	124,179.99	OGE Plan 2020	Distribution Line	Grid Resiliency	Maud Tap 21	741021	12/31/2020
K:01303-0051.1	DLN- AUTO OK GRID MOD MAY AVE 21	358,892.89	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	May Ave 21	822021	12/31/2020
K:01303-0051.4	DLN-OGM DLI OH LINE MAY AVE 21-AUC	443,942.74	OGE Plan 2020	Distribution Line	Grid Resiliency	May Ave 21	822021	12/31/2020
K:01303-0051.2	DLN- AUTO OK GRID MOD MAY AVE 22	538,923.93	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	May Ave 22	822022	12/31/2020
K:01303-0051.6	DLN-OGM DLI OH LINE MAY AVE 22-AUC	453,205.13	OGE Plan 2020	Distribution Line	Grid Resiliency	May Ave 22	822022	12/31/2020

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K:01303-0051.3	DLN- AUTO OK GRID MOD MAY AVE 24	419,134.72	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	May Ave 24	822024	12/31/2020
K:01303-0031.1	DLN- AUTO OK GRID MOD MERIDIAN 22	478,183.02	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Meridian 22	822122	12/31/2020
K:01303-0031.4	DLN-OGM OH LINE MERIDIAN 22-AUC	1,078,336.32	OGE Plan 2020	Distribution Line	Grid Resiliency	Meridian 22	822122	10/31/2020
K:01303-0031.2	DLN- AUTO OK GRID MOD MERIDIAN 23	257,820.69	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Meridian 23	822123	11/30/2020
K:01303-0031.6	DLN-OGM DLI OH LINE MERIDIAN 23=AUC	1,085,619.70	OGE Plan 2020	Distribution Line	Grid Resiliency	Meridian 23	822123	12/31/2020
K:01303-0031.3	DLN- AUTO OK GRID MOD MERIDIAN 29	428,740.24	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Meridian 29	822129	11/30/2020
K:01303-0031.8	DLN-OGM DLI OH LINE MERIDIAN 29-AUC	636,827.00	OGE Plan 2020	Distribution Line	Grid Resiliency	Meridian 29	822129	9/30/2020
K:01303-0093.1	DLN- AUTO OK GRID MOD NEWMAN AVE 41	1,047,196.31	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Newman Ave 41	461641	12/31/2020
K:01303-0093.4	DLN-OGM DLI OH LINE NEWMAN AVE 41-AUC	717,607.35	OGE Plan 2020	Distribution Line	Grid Resiliency	Newman Ave 41	461641	12/31/2020
K:01303-0071.1	DLN- AUTO OK GRID MOD RIVERSIDE 24	502,930.67	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Riverside 24	311024	10/31/2020
K:01303-0071.4	DLN-OGM DLI OH LINE RIVERSIDE 24-AUC	287,676.08	OGE Plan 2020	Distribution Line	Grid Resiliency	Riverside 24	311024	10/31/2020
K:01303-0047.1	DLN- AUTO OK GRID MOD ROMAN NOSE 47	420,455.44	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Roman Nose 47	890847	12/31/2020
K:01303-0047.4	DLN-OGM DLI OH LINE ROMAN NOSE 47-AUC	118,890.49	OGE Plan 2020	Distribution Line	Grid Resiliency	Roman Nose 47	890847	9/30/2020
K:01303-0216.1	DLN-OK GRID MOD SOUHTARD 47 4KV CONV.	35,095.72	OGE Plan 2020	Distribution Line	Grid Resiliency	Southard 47	890647	12/31/2020
K:01303-0099.1	DLN- AUTO OK GRID MOD STONEWALL 24	521,138.96	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Stonewall 24	847424	12/31/2020
K:01303-0099.4	DLN-OGM DLI OH LINE STONEWALL 24-AUC	686,739.98	OGE Plan 2020	Distribution Line	Grid Resiliency	Stonewall 24	847424	12/31/2020
K:01303-0023.1	DLN- AUTO OK GRID MOD TENNYSON 22	701,575.35	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Tennyson 22	311422	12/31/2020
K:01303-0023.4	DLN-OGM DLI OH LINE TENNYSON 22-AUC	325,093.60	OGE Plan 2020	Distribution Line	Grid Resiliency	Tennyson 22	311422	9/30/2020
K:01303-0023.5	DLN-OGM UG RP TENNYSON 22-AUC	302,270.70	OGE Plan 2020	Distribution Line	Grid Resiliency	Tennyson 22	311422	9/30/2020
K:01303-0023.2	DLN- AUTO OK GRID MOD TENNYSON 23	547,561.09	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Tennyson 23	311423	12/31/2020
K:01303-0023.6	DLN-OGM DLI OH LINE TENNYSON 23-AUC	327,487.30	OGE Plan 2020	Distribution Line	Grid Resiliency	Tennyson 23	311423	9/30/2020
K:01303-0023.3	DLN- AUTO OK GRID MOD TENNYSON 24	428,752.01	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Tennyson 24	311424	10/31/2020
K:01303-0023.8	DLN-OGM DLI OH LINE TENNYSON 24-AUC	649,881.99	OGE Plan 2020	Distribution Line	Grid Resiliency	Tennyson 24	311424	9/30/2020
K:01303-0055.1	DLN- AUTO OK GRID MOD TIBBEN RD 24	610,701.53	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Tibbens Road 24	320824	12/31/2020
K:01303-0220.1	DLN-OGM WARICK 41 4KV CONV.	35,722.33	OGE Plan 2020	Distribution Line	Grid Resiliency	Warwick 41	711941	12/31/2020
K:01303-0033.1	DLN- AUTO OK GRID MOD WESTERN 23	597,938.23	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Western Ave 23	836123	12/31/2020
K:01303-0033.4	DLN-OGM DLI OH LINE WESTERN 23-AUC	980,514.59	OGE Plan 2020	Distribution Line	Grid Resiliency	Western Ave 23	836123	10/31/2020
K:01303-0033.2	DLN- AUTO OK GRID MOD WESTERN 24	396,507.84	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Western Ave 24	836124	12/31/2020
K:01303-0033.6	DLN-OGM DLI OH LINE WESTERN 24-AUC	380,295.25	OGE Plan 2020	Distribution Line	Grid Resiliency	Western Ave 24	836124	9/30/2020
K:01303-0033.3	DLN- AUTO OK GRID MOD WESTERN 25	388,128.87	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Western Ave 25	836125	12/31/2020
K:01303-0033.8	DLN-OGM DLI OH LINE WESTERN25-AUC	235,395.68	OGE Plan 2020	Distribution Line	Grid Resiliency	Western Ave 25	836125	9/30/2020
K:01303-0101.1	DLN- AUTO OK GRID MOD WOODWARD DIST 46	438,854.53	OGE Plan 2020	Distribution Line	Distribution Circuit Automation	Woodward District 46	460846	12/31/2020
K:01303-0101.4	DLN-OGM DLI OH WOODWARD 46-AUC	93,583.18	OGE Plan 2020	Distribution Line	Grid Resiliency	Woodward District 46	460846	9/30/2020

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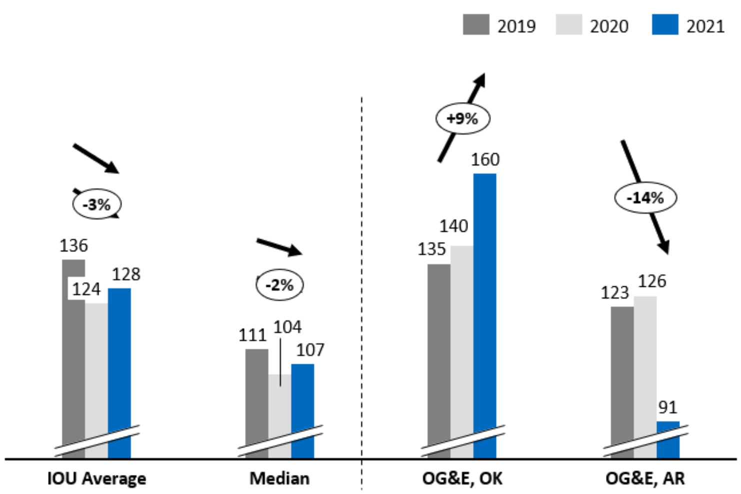
US Investor-Owned Utility Reliability: OG&E Performance

US Investor-Owned Utility Average Interruption Duration[1], (N=175)
2019-2021 historical, Minutes of Outage (SAIDI without MED) and CAGRs



US Investor-Owned Utility Average Interruption Frequency[2], (N=175)
2019-2021 historical, Number of Outage Events (SAIFI without MED) and CAGRs