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

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CORPORATION COMMISSION
OF OKLAHOMA

Rebuttal Testimony

of

Kandace Smith

on behalf of

Oklahoma Gas and Electric Company

September 14, 2020

I. Introduction

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. **Are you the same Kandace Smith that previously filed direct testimony in this proceeding?**

A. Yes.

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

A. The purpose of my Rebuttal Testimony is to respond to intervenors critiques of the Oklahoma Grid Enhancement Plan ("OGE Plan" or "Plan") and its underlying analysis.

Specifically, I will support our cost benefit analysis by explaining why it is reasonable to exclude certain revenue requirement components, as we were utilizing a project optimization model not intended to calculate customer rate impacts. I will also show that evaluating our plan on a circuit-by-circuit basis rather than project-by-project results in a more comprehensive approach supportive of our goal to create a step-change in the way we plan the system.

I will defend our reliability performance projections against intervenor criticism by reiterating our assumptions are based on *actual* Arkansas Grid Enhancement results. I also remind intervenors who criticize those projections for lack of variability that we performed a sensitivity analysis on the 2020 projects and detail the results below.

I respond to the intervenors who claim we should ignore the full impact of outages on customers despite the availability of the Department of Energy's (DOE) Interruption Cost Estimate (ICE) calculator to capture these impacts. In this section, I also address requests to alter our ICE analysis and show that by using the same assumptions as were used in the avoid cost of service analysis, as recommended by PUD, <u>the Plan benefits increase to $3.8 billion, an increase of $2.4 billion in customer benefit for the Plan.</u>

Finally, I discuss how our project selection criteria favored longer-term solutions as opposed to shorter-term answers such a tree-trimming that will continue to occur in parallel with the Plan.

II. Background on OGE Plan

Q. Please summarize the OGE Plan.

A. The OGE Plan is a five-year asset deployment plan is focused on upgrading aging physical infrastructure while also modernizing key grid technologies. To develop the Plan, the Company prioritized projects based upon a cost benefit analysis, which results in an Annual Investment Plan and detailed Scope of Work for each year of the Plan. These documents serve as a guide to the projects and types of work to be completed to allow for the most benefit to customers, over the life of the 5-year Plan. Ultimately, the Plan will result in a modernized grid that is more reliable, resilient, flexible, and efficient, while at the same time maintaining affordability and enhancing service for customers.

Q. Is the Plan focused solely on selecting projects for the purpose of improving system reliability as measured by average reliability indices as suggested by many of the intervenors?

A. No. It is focused on modernizing and optimizing the grid through the six objectives outlined in Witness Gladhill's Direct Testimony. While improved reliability and greater resilience are two of the objectives, they are not the sole focus of project selection within the Plan. Even when reviewing improved reliability and greater resilience, the Plan is not focused on improving system average reliability indices. However, the Plan does select projects based on reliability and resiliency improvements of each specific circuit. The Plan is intended to cause a step change in the reliability of each modernized circuit resulting in a significantly improved customer experience.

Q. Is the Plan designed to include flexibility over the next 5 years?

A. Yes. The Plan is designed so that as the market trends evolve, technology emerges, and system characteristics change, the optimization criteria, guiding principles, and investment criteria for project selection will continue to evolve and accommodate necessary changes through the Annual Invest Plan process. In the early years, OG&E is making foundational investments that are broad-scale and touch entire circuits. As the Plan progresses, and as technology emerges that allows for cost effective solutions to specific areas and locations, the Company will transition to a more granular approach with targeted investments to specific areas, instead of circuits, and potentially to precise locations.

Q. **How were the projects selected in the 2020 and 2021 Annual Investment Plans?**

A. The projects in the 2020 and 2021 Annual Investment Plans were selected through the following methodology. First, each distinct work activity within the list of potential investments was reviewed to determine if it fit within the guiding principles for the year and the associated technology was mature enough to gain the desired value for each activity.

Second, investment criteria were developed for each distinct work activity that was selected for the Annual Investment Plan. As part of the investment criteria, it was determined that all line and substation distinct work activities would be limited to only include work on the top 250 circuits and their associated substations when ranked by criticality and condition. Criticality was determined using a mix of total circuit load and customers per mile. Condition analysis included asset age, interruption counts (momentary and sustained), SAIDI (system average interruption duration index), and CAIDI (customer average interruption duration index). The criticality component factors in how many customers/load will be affected by outages. The condition component factors in circuit health by evaluating both existing reliability and aging infrastructure on each circuit.

Third, the net present value (including limited economic harm benefits derived from the DOE's ICE calculator) of each project was used as the optimization criteria to select which circuits and substations were included in the Annual Investment Plan.

III. Cost Benefit Analysis and Plan Composition

Q. **Do certain responsive witnesses challenge the Plan with regard to the cost benefit analysis and project selection?**

A. Yes. As I will more fully discuss below, intervenors challenged our cost benefit analysis and project selection by criticizing our decisions to:

(a) exclude certain revenue requirement components from an optimization model not intended to calculate customer impacts,

(b) evaluate our plan on a comprehensive circuit by circuit basis rather than project by project;

(c) assume performance projections based on actual Arkansas Grid Enhancement results;

(d) consider the economic and societal impacts imposed on customers during an outage and calculate a corresponding value through a DOE developed model; and,

(e) exclude short-term answers in favor of long-term solutions.

Q. **Do you agree with those criticisms?**

A. No, I do not. While I acknowledge there are different ways to design a grid enhancement program and perform an associated cost benefit analysis, I firmly believe we utilized a reasonable and sound approach. Our Plan was developed by experienced engineers who performed exhaustive research and study of our system to determine how to best solve for its needs now and in the future.

Q. **Before addressing the intervenors' concerns, please provide a simple explanation for how the cost-benefit analysis works.**

A. The cost benefit analysis compares the costs of the various projects to the avoided cost of service and avoided economic harm benefits. The avoided cost of service benefits are based on a 60% reliability improvement and the three-year historical average number of incidents per circuit along with the following system-wide assumptions: average cost of an operations and maintenance truck roll, average cost of a capital work order, average operations and maintenance storm cost, and average capital storm cost. The avoided economic harm benefits are derived by leveraging the DOE's ICE calculator.

A. Net Present Value Performed for Project Optimization

Q. **Please describe why the cost benefit analysis was performed and how the Net Present Value (NPV) calculation is used.**

A. The cost benefit analysis was developed to evaluate the costs and benefits associated with each Annual Investment Plan as well as the overall benefits of the five-year plan. The NPV calculation in the cost benefit model was developed for optimization of the work to ensure we are investing in the most beneficial locations. It is intended to help optimize the locations in which we should enhance the grid first and the volume of investments for each location. The benefits in the NPV calculation are reduced for optimization purposes. This in no way means the Company is discounting the benefits for each project. The benefits are only limited to optimize projects with a higher value given to the cost of service benefits as compared to the economic harm benefits. The Company recognizes all these benefits and uses them to justify each project.

Q. **Witness Betchan testifies the Company's NPV calculation lacks all the inputs considered in a full revenue requirement analysis.[1] Was a full revenue requirement included in the cost benefit analysis?[2]**

A. No. OG&E used a cashflow NPV in the cost benefit analysis. It was not developed to determine the customer rate impact of each project. Instead, it was developed to compare circuits and substations so that work could be optimized to ensure we are investing in locations with the most benefit to customers first. While the NPV calculation is a cash flow analysis and not a revenue requirement impact, it does include the following: total capital investment, avoided operations and maintenance expense, avoided capital investment, interest expense, income tax, depreciation expense, ad valorem tax expense, and deferred

[1] Responsive Testimony of Betchan p. 24-28.

[2] Responsive testimony of Bohrmann p. 17.

tax benefit. OG&E calculated a customer impact through the revenue requirement model shared in the Direct Testimony of Witness Rowlett.

B. Comprehensive Circuit-by-Circuit Evaluation

Q. **Witness Betchan was also critical of OG&E for not evaluating each project on a technology-by-technology basis through the cost benefit analysis. Please explain why OG&E did not perform its analysis in this manner.**

A. The paradigm of evaluating discrete costs and benefits on a project-by-project or technology-by-technology basis may not lead to investments that achieve the objectives of the Plan. A cost-benefit analysis on an individual project or technology is most meaningful when investments have benefits and costs that are discrete and clearly attributable to the individual investment. 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 of reliability than if you just did one without other. For these reasons, it is not reasonable to conduct a cost benefit analysis on a technology by technology basis for the Grid Enhancement Plan.

Q. **If OG&E did not evaluate work at a project 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 for each specific circuit or substation prior to evaluating circuits and substations in the cost benefit model. Investment criteria is determined for each distinct work activity (or technology) 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. Another example is transformer load management (TLM). TLM is only applied to transformers with greater than 60 hours of overloading a year. In another example, it was determined that costs for adding communications to capacitors was running higher than expected, so this distinct work activity was removed from the 2021 Annual–Investment Plan. Using the investment criteria to select which distinct work activities (or technology) 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.

Q. **In your experience, is the overall granularity of the cost benefit analysis reasonable at the circuit-by-circuit level?**

A. Yes, the granularity of the analysis is reasonable. The Grid Enhancement Plan is intended to cause a step change in the reliability of each circuit within the plan. In order to create this step change, we needed to change our "typical" reliability and asset management planning practices which evaluate programs individually and translate that into evaluating which programs need to be applied to which specific circuits or substations.

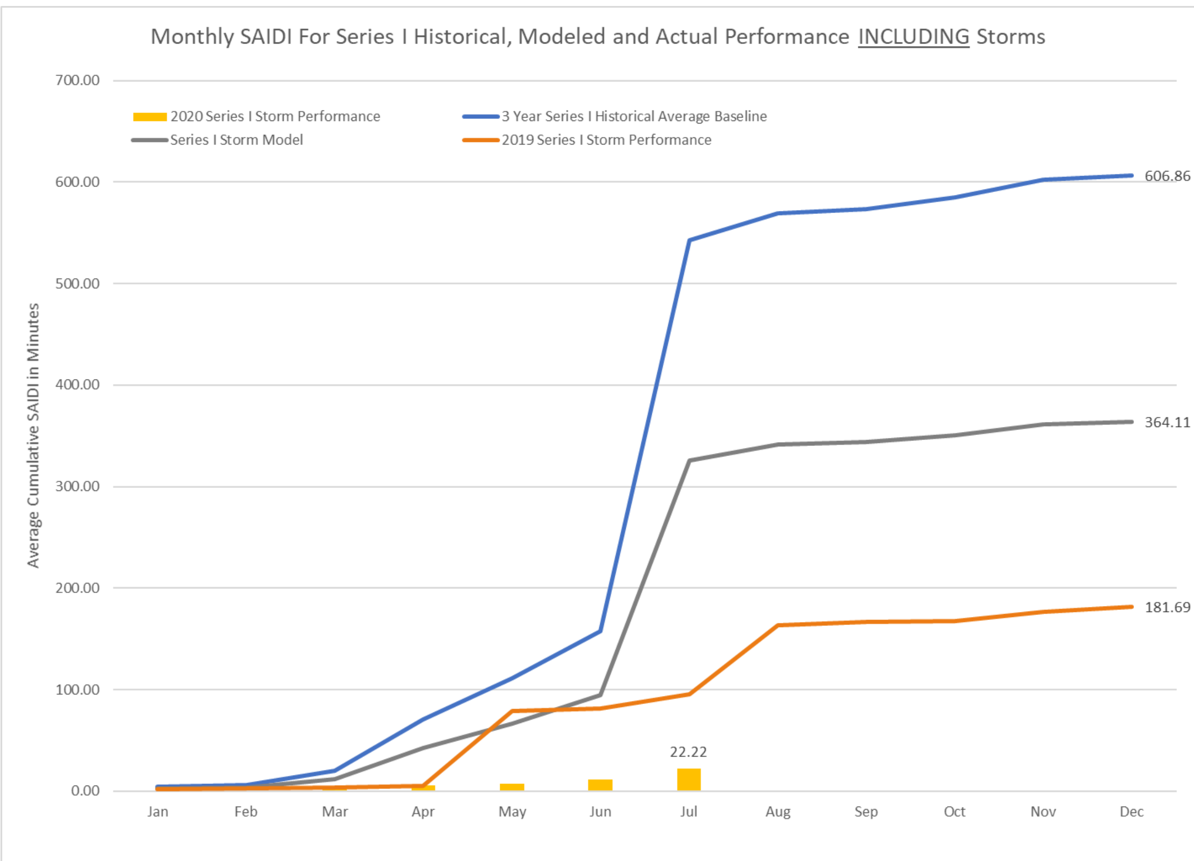
"Typical" reliability and asset management planning practices look at a series of programs to maintain "status quo" reliability levels. For example, the underground cable replacement program targets the worst of the worst pieces of underground cable to replace. Which means there may be pieces of conductor on several different circuits. Another program for example, the transformer load management program targets the worst of the worst overloaded distribution transformers to replace. Which again means transformers will be replaced one at a time across the service territory without consideration of location. These investments are usually not coordinated together because the intent is to maintain reliability levels and replace assets just before failure.

The Plan, however, looks at each circuit and substation and reviews all of the investment opportunities that have been identified for each year and determines the optimal set of investments for each circuit and substation through the investment criteria developed for each distinct work activity. Planning the investments in this manner has proven to provide a "step change" in the reliability of each circuit delivering a much-improved customer experience.

C. Reliability Projects Based on Actual Experience

Q. Certain responsive parties challenged the 60% reliability improvement assumption claiming it is too high. Is the 60% reliability improvement assumption reasonable?[3]

A. Yes, a 60% reliability improvement assumption is reasonable. Arkansas Series 1 circuits experienced a 70% improvement from the historical 3-year average in 2019 and in 2020 (year to date) has experienced 96% improvement from the historical 3-year average as shown in the chart below. Based on these *actual* experiences, the 60% reliability improvement assumption is reasonable. Witness Givens also states that PUD believes that OG&E's 60% reduction estimate may be reasonable.[4]



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[3] Responsive Testimonies of Alverez p. 6 and 8; Betchan p.18; Alexander p. 12.

[4] Responsive Testimony of Givens p. 14, lns. 14-18.

Q. **Some of the same parties criticized your analysis for not considering any variability in the reliability projection. Has a sensitivity analysis been performed on the 60% improvement assumption?[5]**

A. Yes, in response to data request AG 7-16, the Company provided NPV results for each substation/circuit(s) project in the 2020 Investment Plan run at 60%, 55%, 50%, 40%, and 30% improvements. At both 60% and 55% improvement levels, all 30 (100%) of the projects are positive NPV. At 50% improvement levels, 28 (93%) of the projects are positive NPV. At 40% improvement levels, 27 (90%) of the projects are at positive NPV levels. And at 30% improvement levels, 23 (77%) of the projects are at positive NPV levels.

Q. **Witness Alvarez states only 52% of outage minutes resulted from equipment deterioration and it is impossible for a 60% improvement to be secured.[6] Do you agree with his assessment?**

A. No. Aging infrastructure is only one component of the Grid Enhancement Plan. The Grid Enhancement Plan is also adding automation to the circuits that are being modernized. When you combine the benefits of automation and the fact that over half of the outage duration is equipment deterioration, as Witness Alvarez points out, it is very possible to achieve a 60% improvement.

Q. **Witness Alvarez also suggests that after the upgrades, SAIDI only improved 24% relative to historical averages with storms for Arkansas Series 1 circuits.[7] Is he correct?**

A. No. Witness Alvarez manipulated the data by removing the year 2016 because it was a high storm year. Not only is this misleading, it also is not an accurate view of a 3-year historical average. The actual 3-year historical average for those circuits is 636 minutes of SAIDI. The 2019 performance of those circuits was 190.5 minutes of SAIDI resulting in a 70% improvement over the 3-year historical average.

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[5] Responsive Testimony of Betchan p. 14.

[6] Responsive Testimony of Alverez p. 8, ln. 17 – p. 9, ln. 5.

[7] *Id*. P. 8, lns. 5-10.

Q. **Witness Alexander suggests that OG&E double counted storm improvements by using an 88% improvement instead of 60%.[8] Do you agree?**

A. No, we did not double count storm improvements, although it is correct that 88% was utilized in the storm benefit analysis. To develop the storm benefit, we reduce the possible storm related costs for any particular circuit by the percent improvement of customer minutes of interruption ("CMI"). To get the percent improvement of CMI, we first reduced the storm related outages by applying a 60% improvement. Then, we applied a normalization factor to the remaining storm related CMI per outage. The normalization factor was developed using the results from our System Hardening Program where rates of pole failures during storms was reviewed for both system hardened circuits and non-system hardened circuits. The normalization factor is 2.23, meaning non-system hardened circuits have 2.23 times more pole failures than system-hardened circuits during storms. When you apply this normalization factor to the CMI per outage during a storm and multiply by the 60% improvement in number of outages, there is an 88% improvement to CMI during storms.

D. Full Valuation of Avoided Outages on Customers

Q. **Certain parties such as OIEC and AARP challenge OG&E's consideration of avoided economic harm benefits. They claim they should not be considered if they are not directly reflected on customers' electric bills.[9] Do you agree with this assertion?**

A. Absolutely not. It is irresponsible to ignore the total effect of outages on our customers. Although outage costs on the utility's side of the meter are easier to calculate, that doesn't excuse ignoring the costs imposed on customers on their side of the meter. Moreover, the avoided economic harm benefits associated with the Plan are derived using a reputable model developed by the Department of Energy--a model it has been using as part of its mission to support modernization of the electric system. It begs the question as to why intervenors are so quick to disregard a model supported and developed by the DOE.

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[8] Responsive Testimony of Alexander p. 14.

[9] Responsive Testimonies of Alverez p. 10, ln. 3 – p. 12, ln. 11; and Norwood p. 17, lns. 7-14.

The objective of the Plan is to minimize the total costs of electricity service by balancing the cost of investments in reliability (utility costs) against the costs that customers experience as a result of unreliability associated with the investment. Excluding the value avoiding customer interruption costs (avoided economic harm) in valuing the benefits of the Plan makes for a most incomplete equation.

Q. **AARP witness Alvarez also alleges that the benefits to residential customers are disproportionate with costs. Are economic harm benefits different for residential, commercial, and industrial customers?**

A. While all customers on modernized circuits, regardless of service class, will receive the same reliability benefits, some classes may monetize the benefits differently. As explained below, it is very difficult to monetize the residential benefits, but it is known that residential customers are impacted when outages occur. Commercial and industrial customers are able to monetize the reliability improvements through avoided waste, production loss, sales loss, etc. Therefore, the DOE ICE calculator can produce more estimated economic harm benefits for those customers.

Q. **What does the DOE ICE calculator account for in economic harm benefits for residential customers?**

A. Residential benefits are derived primarily on surveys related to short duration (few hours or less) outages, which most of these losses are intangible and extremely difficult to cost out for these customers. They do not account for longer duration outages where a residential customer may lose contents of fridge and freezer, therefore these costs are not captured in the DOE ICE calculator. The societal costs of outages, like those that may occur for customers working or learning from home during COVID, are very difficult to capture, and therefore, very underestimated. Further, individual customer costs do not include downstream costs such as those that occur when a customer is unable to get products and services.

Q. **Like the Company, Witness Bohrmann suggests that economic harm benefits should be considered as part of the Company's cost-effectiveness analysis; however, he recommends a different method in calculating the benefits. Please explain.**

A. In the Company's analysis, economic harm benefits were calculated using the DOE ICE calculator for all of Oklahoma assuming all circuits were modernized. Then, the benefits were allocated to each circuit based upon the ratio of three-year average number of incidents for the circuit compared to the system. Mr. Bohrmann testifies that the benefits should instead be allocated on a circuit by circuity basis.

Q. **Why did OG&E use an allocation method for economic harm benefits instead of running each circuit through the DOE model as recommended by Witness Bohrmann?[10]**

A. The DOE model currently does not accept any interface inputs such as an API. An API is an interface that allows access to data between systems or applications. This would have allowed OG&E to load all the circuit data, send it to the DOE model and get the results for all the circuits. Since the model does not accept this type of interface, OG&E attempted with two different methods to automatically run each circuit through the DOE model using robot technology and computer automation. Each of those methods aborted multiple times and crashed the DOE model site. After each attempt, OG&E personnel contacted the DOE to restart their services so that access to the model could be regained. At this point, it was decided to run the model for all of Oklahoma and allocate the benefits to each circuit.

Q. **Aside from the technical issues, is the Company's allocation method for economic harm benefits reasonable?**

A. Yes, the method of allocation for economic harm benefits is reasonable for the following reasons. First, OG&E utilized conservative assumptions for the ICE calculator benefits since these benefits are on the customer side of the meter. The total Oklahoma ICE calculator was only run for 40% improvement and 20-year NPV to be conservative on the customer benefit. Second, less than 20% of the total expected $1.4 billion economic harm

[10] Responsive Testimony of Bohrmann p. 21-23.

benefits is required to offset the forecasted spend of $810.2 million when you consider the estimated $500 million of avoided cost of service benefits. Third, only a small portion of the ICE calculator benefit is expected to be utilized when evaluating circuits within each annual investment plan. For example, the 2020 Investment Plan utilized 0% of the economic harm benefits and the 2021 Investment Plan utilized 10% of the economic harm benefits.

Q. **Witness Givens questions certain assumptions used in the economic harm benefits. More specifically, he questions what the total economic harm benefits would be with assumptions of 60% improvement and 30 years?[11]**

A. If the economic harm benefit assumptions were updated to 60% improvement and 30 years, the total economic harm benefits for the Grid Enhancement Plan would be $2.6 billion. The update would result in an increase of $1.2 billion in customer benefit for the Plan.

Q. **Witness Givens points out that the economic harm benefits were not run with the same assumptions as the cost of service benefits. What would the total economic harm (ICE calculator) benefits be for the Grid Enhancement Plan if run with the same assumptions as the Cost of Service Benefits?[12]**

A. To update the economic harm (ICE calculator) benefit assumptions to match the assumptions in the cost benefit model, the following assumptions would need to be updated: (1) 60% improvement, (2) 30 year duration of benefits, (3) 2.5% reliability inflation without the projects, and (4) 2% degradation of reliability improvement after 10 years. The update would result in a total economic harm benefit for the Grid Enhancement Plan of $3.8 billion. The update would result in an increase of $2.4 billion in customer benefit for the Plan.

[11] Responsive Testimony of Givens p. 16, lns. 4-8.

[12] *Ibid.*

E. Project Selection Based on Long-Term Solutions.

Q. **Witnesses Bohrmann and Alvarez challenge the Plan's composition of projects suggesting the Plan's objectives can be achieved with varying combinations of capital and O&M expenses. Is this correct?**

A. While it is true some of the Grid Enhancement objectives could potentially be met with varying combinations of capital and O&M expenses, O&M expense options such as tree trimming provide only short-term benefits and need re-occurring investment to sustain the benefit. The Grid Enhancement Plan is focused on providing improved experiences for customers over 30 years. Therefore, it is focused specifically on capital investments, not short-term solutions.

Q. **Why was additional tree trimming not included in the Grid Enhancement Plan?**

A. Additional tree trimming was not included because it is only aids in improving reliability in the short-term. Tree trimming must be completed regularly to maintain the improved reliability levels. In order to sustain the reliability benefits provided by additional tree trimming, the Company must increase its cycle trimming (as discussed below).

Q. **Will tree trimming be conducted in parallel with the Grid Enhancement Plan?**

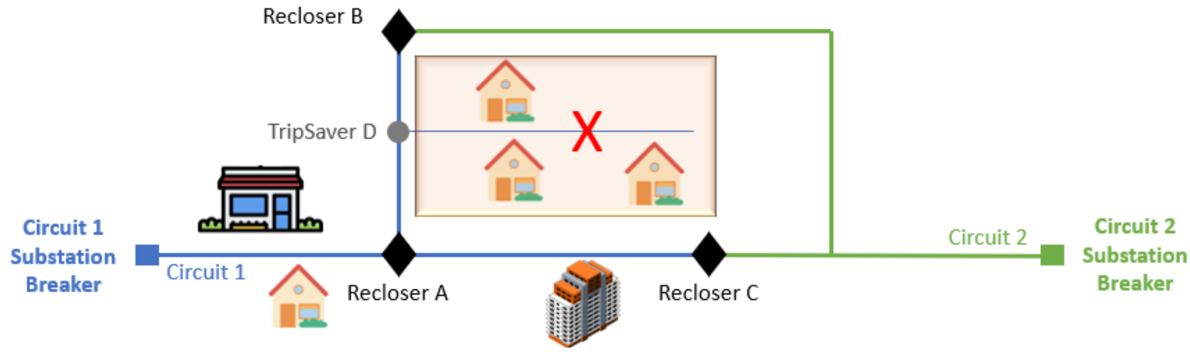
A. Yes. Cycle trimming established as normal course of business will continue to be conducted in parallel with the Grid Enhancement Plan.

Q. **Does the Grid Enhancement Plan address tree related outages that cannot be addressed with tree trimming alone?**

A. Yes, the Grid Enhancement Plan addresses tree related outages through the grid automation work activities. See the figures below for an example circuit.

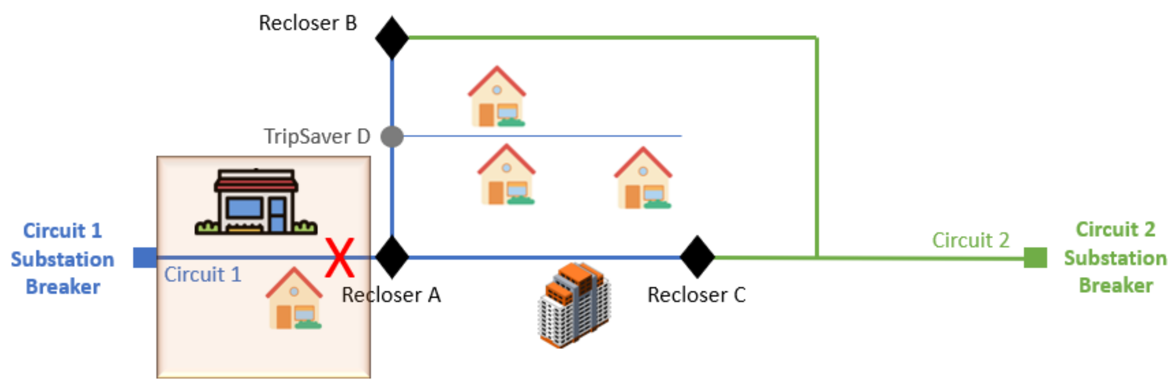
Example 1: If a tree limb were to fall on the line to the right of TripSaver D (represented by the red X in the figure below), the TripSaver would open and reclose to clear the line fault caused by the falling tree limb. If the limb fell off the line, all power would be restored automatically. If the limb did not fall off the line, the TripSaver would open and crews would be routed to the area for restoration. Only the customers in the shadow box would be affected.

Figure 1



Example 2: If a tree limb were to fall on the line between Circuit 1 Substation Breaker and Recloser A (represented by the red X in the figure below), the Circuit Breaker would open and reclose to clear the line fault caused by the falling limb. If the limb fell off the line, all power would be restored automatically. If the limb did not fall off the line, the Recloser A would open and Recloser C downstream would close allowing power to be restored to majority of the customers on the circuit. While all customers on the circuit will see a brief outage, the longer duration outage would be limited to only the customers in the shadow box below.

Figure 2



These two automation examples show how automated restoration can limit the exposure to tree related outages and improve the outage times.

IV. Other Issues

Q. **Witness Alvarez also faults OG&E for not including CVR (conservation voltage reduction) in the Grid Enhancement Plan. Did OG&E consider CVR to be included in its Grid Enhancement Plan?[13]**

A. Yes. The Company runs voltage optimization on 400 feeders across our service territory. The voltage optimization is run through an integrated volt var control (IVVC) program. OG&E invested in these 400 circuits to run IVVC in both our Smart Grid and Energy Efficiency Programs. When reviewed, it was determined that the remaining circuits would provide diminished results. For this reason, additional IVVC was not included in the Grid Enhancement Plan.

Q. **Do you agree with Witness Alvarez that spending is ill-defined because OG&E has yet to determine how it will upgrade its communications network?[14]**

A. No. The communications network investment was appropriately defined for the planning stage at the time. Since the filing of direct testimony, additional planning work is now complete that provides increased certainty. Additionally, as detailed in the data requests referenced by Witness Alverez, the available solution options were known. Therefore, the information was available at the time to generate a high-level estimate of the investment. In the time since initial testimony was filed, a strategic assessment was completed, analyzing the existing communication systems, industry trends, and available solutions to narrow the range of solution options to be considered. That work was performed in consultation with the Networks, Integration, and Automation department at Burns & McDonnell, a reputable firm in the industry.

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[13] Responsive Testimony of Alverez p. 19, lns. 1-14.

[14] *Id.* p. 23, lns. 8-16

Q. **Do you agree with Witness Alvarez's example showing that $167.5 million allocated to distribution line reliability (from the list of potential investments) is based on a single assumption that will be adequate for 250 circuits?[15]**

A. No. When combining the 2020 and 2021 Annual Investment Plans, 122 circuits have been selected for the distribution line reliability work activity with an estimated cost of $81 million. This is an average cost of $660,000 per circuit. In the list of potential investments, it was estimated for the 5-year plan that this work activity would be completed on 250 circuits for $167.5 million. This would be an average of $670,000 per circuit. Based on this data, the spending forecast is on track for the distribution line reliability work activity and the estimated spend is within an acceptable tolerance for forecasting accuracy.

Q. **Before concluding, please discuss whether intervenors were afforded an opportunity to review the cost-benefit analysis model?**

A. Yes, however, it was not without issue. The cost benefit model was developed in the SAS VA tool which is not available for use without a license. Consequently, we were initially unable to provide direct access to the model other than through a virtual demonstration and through a workpaper provided with my direct testimony which included a summary of the model. In recognition the intervenors needed more direct access, I created an example calculation in response to AG 7-11. I further provided details of the projected plan benefits in response to AG 3-4 that could be used along with the spreadsheet provided in AG 7-11 to reproduce what was developed in the cost benefit model itself. The combination of these documents enabled intervenors to recreate the model, despite the access issues created early on by the SAS VA license.

V. <u>Conclusion</u>

Q. **Do you have any final remarks before concluding your testimony?**

A. Yes. I respectively recommend the Commission consider the reasonableness underlying the development of our five-year and recognize it was designed to yield tremendous benefits to our customers as we ready our grid for the future.

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[15] *Ibid.*

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

A. Yes.