BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	CAUSE NO. PUD 202100164
AUTHORIZING APPLICANT TO MODIFY ITS	)	
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

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CORPORATION COMMISSION
OF OKLAHOMA

Direct Testimony

of

Kandace Smith

on behalf of

Oklahoma Gas and Electric Company

December 30, 2021

Q. **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 leading 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 includes developing and maintaining the multi-year plan and forecast as well as developing each year's Annual Investment Plan. My responsibilities also include creating and maintaining the cost-benefit optimization model and ensuring planned project cost and benefits are accurate. While I am responsible for the modeling and planning of our grid enhancement plan, I also sit on the OGE Plan steering team and coordinate with the execution team to provide support and direction on scope, benefits, and costs as the plan moves 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 No. 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 testimony?**

A. The purpose of my testimony is to present the Grid Enhancement projects completed to date and requested for inclusion in base rates. In doing so, I will first provide a brief background of the Grid Enhancement Mechanism (GEM) and the OGE Plan. Then, I will describe how the projects completed to date, were chosen, are necessary, beneficial to customers, prudently incurred and reasonable.

I will describe additional investments that have been identified to address severe storms such as that experienced in October 2020. After the October 2020 ice storm, OG&E identified a series of projects to further harden its system and make its grid more resilient to weather related storms. While these "Weather Hardening" projects are separate from those originally included in the OGE Plan, I explain how they are complimentary in nature and should also be included in the Grid Enhancement Mechanism ("GEM") going forward.

Finally, per the terms of the settlement in Cause No. PUD 202000021, Order No. 715188, I will address the cost benefit analysis performed to prioritize projects and inform our decision to move forward with the OGE plan. I will also introduce the work of 1898 & Co., the engineering firm OG&E retained to perform a cost benefit analysis ("CBA") on a project by project basis, using a revenue requirement model, and showing results without the use of the Department of Energy's longstanding Interruption Cost Estimate Calculator ("ICE" or "ICE model").

Q. **What is OG&E seeking in this case with regard to Grid Enhancement?**

A. OG&E is seeking four outcomes related to Grid Enhancement. First, OG&E is requesting that the Commission make a finding of prudence related to the completed Grid

Enhancement projects including both projects in the GEM and those that were excluded from the GEM. Second, OG&E is requesting that the current GEM be extended through end of 2024. Third, OG&E seeks to expand the GEM to include Weather Hardening projects.

The Grid Enhancement Mechanism

Q. **What is the approved Grid Enhancement Mechanism ("GEM")?**

A. In Cause No. PUD 202000021, the Commission authorized the GEM. The GEM is a cost recovery mechanism only and does not address the prudency of the Grid Enhancement projects. All prudence determinations regarding the Grid Enhancement projects, currently in service, are being addressed in this base rate case. All cost recovery through the GEM is subject to true-up and refund if the Commission determines that a project was not prudently undertaken.

Q. **What were the limitations for the approved Grid Enhancement Mechanism?**

A. The GEM approved in Cause No. PUD 202000021, is limited to investments in Grid Automation, Communication Systems, and Technology Platforms that have been placed in service in 2020 and 2021. Cost recovery is capped at $7,000,000 annually.

Q. **Was there an approved list of projects for the Grid Enhancement Mechanism?**

A. Yes. A list of the Grid Enhancement Mechanism investments for 2020 and 2021 was submitted to the stipulating parties for review. After review, some projects were removed from the list based on agreements between OG&E and the parties.

Q. **How does the Grid Enhancement Mechanism work?**

A. The GEM cost recovery request is filed quarterly. This includes submitting reports for the projects placed in service along with the associated revenue requirements and billing factors to the stipulating parties by the 15^{th} day of the month following quarter end. All parties have 30 days to object to any project or calculation. The cost recovery does not begin until the Public Utility Division ("PUD") has reviewed the reports and approved the updated billing factors.

Q. **Are there customers excluded from cost recovery through the Grid Enhancement Mechanism?**

A. Yes. Customers that qualify for LIHEAP and Senior Citizen discounts are exempt from the GEM. Also, Power and Light and Large Power and Light Service Level 1 and 2 customers are exempt from cost recovery.

<u>OG&E Grid Enhancement Plan</u>

Q. **Please generally describe the OGE Plan introduced in Cause No. PUD 202000021.**

A. The OGE Plan is a five-year asset deployment plan designed with the objective of making our grid more reliable, resilient, flexible, and efficient, while focusing on affordability and improving customer experiences. The plan is focused on upgrading aging physical infrastructure while also modernizing key grid technologies, operational platforms, and communications systems, as well as planning tools and processes. It is comprised of strategic, data-driven, investments that will modernize and optimize our system while providing benefits to customers for years to come. It is focused on the upgrade and replacement of aging and poor performing equipment, hardware, and other assets to improve reliability, resilience, and safety. It also involves the installation of new technology, equipment, and communication systems that will create an efficient, automated grid with improved visibility and control of the system.

Q. **What are the four categories of investments?**

A. The four categories of investments are grid resiliency, grid automation, communications systems, and technology platforms and applications.

- *<u>Grid Resiliency</u>* investments build the foundation for the circuits and substations which supports the Grid Automation capabilities. These investments are focused on proactive replacement of deteriorated, poor performing, and outdated assets. This work improves the durability of a distribution line or substation, increasing its ability to sustain extreme conditions and reducing the probability of a customer experiencing an outage. This means for example, avoiding outages associated with deteriorated infrastructure such as poles. If a pole has weakened, it might perform fine under "normal" conditions, but under "storm" conditions with higher windspeeds, the pole will likely fail causing an outage to customers on the circuit. In some cases, it may also cause collateral damage to existing poles that are in good condition resulting in extended outage durations. Other Grid Resiliency investments help with the quick recovery and survivability of the grid.

- *Grid Automation* investments reduce customer outages on the distribution system by quickly isolating an outage so that it minimizes the impact to customers. Grid Automation is focused on installation of technology at key locations to provide data and information, as well as more remote and automated control. The data and information about how power is being delivered enables us to better monitor the status of the system and respond to the events more efficiently. Remote and automated control enables us to automatically isolate the problems and minimize the impact to our customers. For example, if a pole were to fail on a circuit with automated switches, the circuit can be remotely switched to isolate the outage to a smaller subset of customers, resulting in a reduced customer impact.

- *Communication Systems* investments are the foundation for devices such as digital meters, automated switches, capacitors, regulators, relays, and substation SCADA to communicate back to the OG&E control center and data centers. The Communication Systems also provide a connection between office locations, for example, between control centers and backup control centers. Without an efficient and optimal communication system, the benefits associated with Grid Resiliency and Grid Automation will be diminished.

- *Technology Platforms and Applications* investments are the link between the data in the field and acting on that data. For example, when a fault causes an outage in the field, data will come into the distribution management system (DMS) to identify where the location of the fault occurred, and then the system will recommend automated switching to be executed. These systems allow for efficient use of the data provided by the Grid Resiliency and Grid Automation work activities. Without the Technology Platforms and Applications, the benefits associated with the Grid Resiliency and Grid Automation will be diminished.

Q. **Why are these investments necessary?**

A. OG&E's grid infrastructure is aging which is driving a decrease in customer reliability as well as increased outages during extreme weather events. The development of technologies such as distributed energy resources, electric vehicles, sensors, software, and automated equipment provide an opportunity to modernize the grid while investing in replacement of aging infrastructure, providing a more flexible grid that can automatically respond to changing conditions. The grid enhancement investments will increase resiliency and modernize the grid resulting in fewer outages, shorter outage durations, quicker response, and grid flexibility. This is critical to meet the rising expectation that power is always on and available.

Q. **What do you mean by rising expectations that power is always on and available?**

A. In past decades when the grid was being built, customers used the electric grid to power their lights, heating, and air conditioning. Today, the electric grid is used to provide life-sustaining and life enhancing products and services. It enabled the work from home model during the pandemic, which allowed our State to continue functioning. It powers our communication systems (mobile phones, TVs, radios, internet, and computers), our healthcare systems (breathing machines, powered wheelchairs, oxygen, and dialysis), and our economy through electronic processes (indoor heating and irrigation). These are just a few examples of the electric-enabled technologies that energize the lives of our customers. Today customers expect their power to be ready and available when they need to use it, and their tolerance for interruptions is very low. These customer expectations are the very reason it is necessary for OG&E to make the grid enhancement investments.

Q. Please elaborate on OG&E's aging infrastructure.

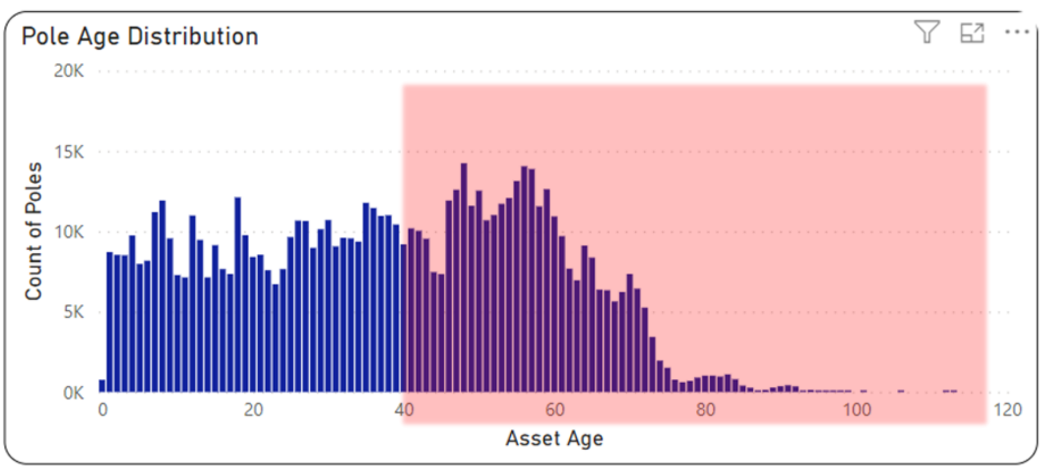
A. The grid infrastructure is aging and at risk of failure. A close look at our assets demonstrates that many assets have outlived their useful life and are at higher risk of failure. The expected useful life of a distribution pole is around 40 years of age. As shown in Table 1 below, 47% of our distribution poles are beyond their useful life, and 23% of our power transformers are beyond their useful life.

Table 1: OG&E Distribution Asset Life

	Life Expectancy (LE)	Avg Age	# Units > LE	% Units > LE
Wood Distribution Poles	40 years	38.6	341k	47%
Power Transformers	50 years	31	197	23%
Breakers	35 years	16	305	11%

The distribution of poles by age, shown in Figure 1 below, shows many poles are much older than life expectancy which puts them at greater risk for decay and potential failure.

Figure 1: Distribution of Poles by Age



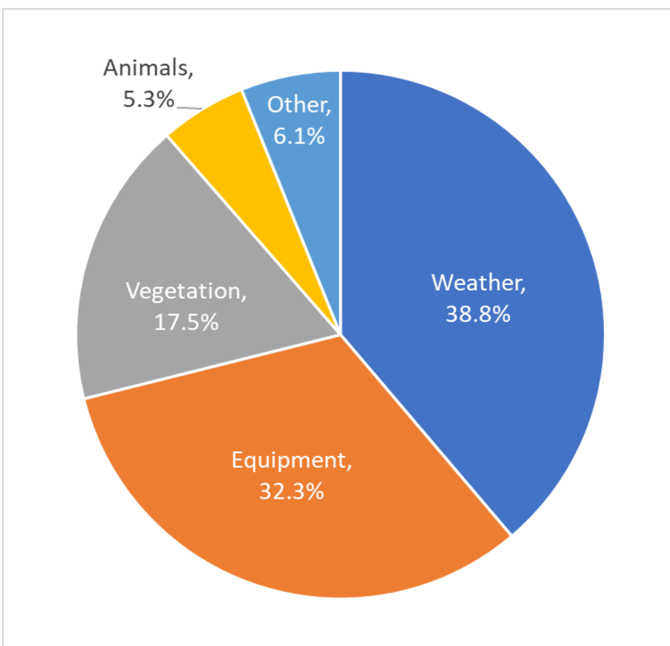
Q. Is OG&E the only utility with aging infrastructure?

A. No. Aging infrastructure is a challenge for utilities across the nation. According to the American Society of Civil Engineers, "[m]ost electric transmission and distribution lines were constructed in the 1950s and 1960s with a 50-year life expectancy".[1] This means that electric infrastructure across the U.S has reached or surpassed life expectancies.

Q. Why is aging infrastructure an issue?

A. Aging infrastructure (such as poles, transformers, breakers, conductor, etc.) contributes to lower reliability for OG&E customers. In fact, equipment is one of the largest factors for the frequency and duration of OG&E outages, second only to weather. Equipment failures and weather are not only the most frequent cause of customer outages, but also drive most customer minutes interrupted. Simply put, equipment and weather are the main factors in how often customers experience outages and the amount of time customers are without power. The combination of equipment-related and weather-related outages (it should be noted that older equipment is more susceptible to failure during weather events) make up over 70 percent of customer minutes interrupted as shown in Figure 2 below.

Figure 2: OG&E Outages by Cause



[1] ASCE, 2017 Infrastructure Report Card

Q. How is aging infrastructure driving a decrease in customer reliability?

A. The age of much of OG&E's existing equipment means that parts of the system are increasingly subject to momentary and sustained outages. As can be seen from Figure 2, aging equipment failure is the second leading cause of outages on the OG&E system.

Q. How is aging infrastructure driving increased outages during extreme weather events?

A. Severe weather is a major driver for customer outages. Weather events are worsening in both frequency and severity[2] and with our customers' greater reliance on the grid, outages can be even more disruptive than in years past. According to the Federal Emergency Management Agency, Oklahoma is the third-most disaster-prone state in the nation.[3] Since 1950, an average of 53 tornadoes have been observed annually within Oklahoma's borders.[4] A significant portion of the state's precipitation during transition seasons is associated with severe thunderstorm systems. On average, thunderstorms occur between 45 days and 55 days per year across the state of Oklahoma.[5] The state is noted for severe thunderstorms that produce the most tornadoes (per unit area) of any place in the world.[6] Despite the grid facing increasing threats of weather, there is an expectation that the grid performance be more resilient to keep going in almost any circumstance. As was recently stated by Oklahoma Secretary of Energy and Environment Ken Wagner "We want our citizens to be able to expect they can have power or heat, regardless of what type of man-made or weather-related disaster has happened."[7] This means that the grid must be strengthened not only to better withstand outages altogether, but to also mitigate the effect

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[2] US DOE, Grid Modernization Multi-Year Program Plan, November 2015, p. 83, 85. Available online at: https://www.energy.gov/sites/prod/files/2016/01/f28/Grid%20Modernization%20Multi-Year%20Program%20Plan.pdf.

[3] https://www.moving.com/tips/which-states-are-most-prone-to-natural-disasters/

[4] Oklahoma Climatology Survey, Climate of Oklahoma, Accessed on 2/17/20, Available online at: https://climate.ok.gov/index.php/site/page/climate_of_oklahoma

[5] Ibid.

[6] Oklahoma Historical Society, Climate, Accessed on 2/17/20, Available online at: https://www.okhistory.org/publications/enc/entry.php?entry=CL015

[7] Money, Jack. Oklahoma Hires Vendor to Help it Update its Energy Assurance Plan, The Oklahoman, February 7, 2020. Available online at: https://oklahoman.com/article/5654311/oklahoma-hires-vendor-to-help-it-update-its-energy-assurance-plan.

of them by creating a more resilient grid. It must be noted that much of the grid in service today was not built to withstand the extreme conditions we are designing our grid for today.

Q. **Are these challenges unique to OG&E?**

A. No. Numerous efforts to modernize infrastructure are underway across the country. According to the North Carolina Clean Energy Technology Center, in Q1 2021, at least forty-seven states had efforts underway related to modernizing the grid.[8] These efforts and the need for them have been recognized at a national level by entities such as the Department of Energy's Office of Electricity Delivery and Energy Reliability and the National Association of Regulatory Utility Commissioners ("NARUC") Board of Directors. These efforts have led to a series of leading industry practices that have been codified by industry groups such as the Department of Energy and Electric Power Research Institute ("EPRI"). Based on our research, including EPRI's report, "*Modernization Playbook: Distribution Grid Modernization at Oklahoma Gas & Electric*", we believe our objectives are in alignment with other grid modernization activity taking place nationally. Please see Direct Exhibit KS-1 for EPRI's *Grid Modernization Playbook: Distribution Grid Modernization at Oklahoma Gas & Electric.*

<u>Grid Enhancement Benefits</u>

Q. **Are OG&E's efforts to modernize the grid beneficial to customers?**

A. Yes. A safer, more reliable, and resilient modernized grid that balances affordability is beneficial to customers. Not only will customers have better quality of service, the grid will be much safer resulting in fewer public safety hazards when aging equipment fails and falls to the ground. The customers will also experience a much more flexible grid that can respond to changing conditions from weather, distributed energy resources, or electric vehicle charging. The investments also have a positive impact on our economy by bringing in workers and jobs while the Plan is being implemented, as well as attracting new businesses through better reliability.

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[8] https://nccleantech.ncsu.edu/2021/04/28/the-50-states-of-grid-modernization-q1-2021-grid-modernization-sees-busiest-quarter-yet-driven-by-state-legislative-activity/

Q. **Are there both quantitative and qualitative benefits associated with the OGE Plan?**

A. Yes. OG&E identified both the qualitative and quantitative benefits in Cause No. PUD 202000021. The quantitative benefits are estimated based on projected improvements that will occur from the OGE Plan through a reduction in both the number and duration of multiple types of outages. OG&E also identified a series of qualitative benefits, which are difficult to quantify, but are real and significant in terms of their impact on our customers, our members, and the state. Take the impact of increased safety for example—a safer and more reliable grid cannot be emphasized enough and must be considered in determining the value of the Plan.

Q. **Please summarize the quantifiable benefits that will be created for customers through the five-year plan.**

A. As shown in Table 2 below, the Plan is estimated to produce $1.9 billion of benefits for customers over a 30-year period. That means that our current estimate for every $1 spent on the Plan will produce over $2.14 in quantifiable customer benefits.

Table 2: Estimated Quantifiable Benefits for the Plan

Category	Amount
Avoided Cost of Service	$500,000,000
Avoided Economic Harm	$1,400,000,000
Total Avoided Future Costs to Customers	***$1,900,000,000***

Q. **Please summarize the qualitative benefits associated with the Plan.**

A. The qualitative benefits associated with OG&E's Plan include improved: (1) safety; (2) security; (3) flexibility; (4) customer experience; and (5) economic impact.

- *Safety* will be improved by reducing exposure to potentially hazardous conditions with a more resilient grid and adding visibility to the system, so the control center and line crews understand what is happening on the grid in near-real time.
- *Security* will be improved through better threat monitoring and increased situational awareness. Increased visibility will allow for large amounts of data to be analyzed in a way that permits threats to be identified sooner and increased grid automation

allows the threat to be isolated more quickly. The communicating nature of automated devices also allows OG&E to have more "eyes and ears" on the ground gathering intelligence and increasing cyber security.

- *Flexibility* will allow the grid to respond to changing conditions quicker by remotely or automatically switching load and proactively changing system characteristics.
- *Customer Experience* improves through better quality of service with fewer outages and outages with shorter durations. There will also be future customer engagement opportunities such as an improved means of communication and more granular visibility to usage patterns.
- *Economic Impact* is improved through increased reliability. Reliability is critical to both existing and prospective businesses considering locating in Oklahoma. The economy is also improved through the impact of nearly 1,000 contract workers brought in to execute on the Plan.

Q. **Can you share an example of how the Grid Enhancement Plan can benefit customers?**

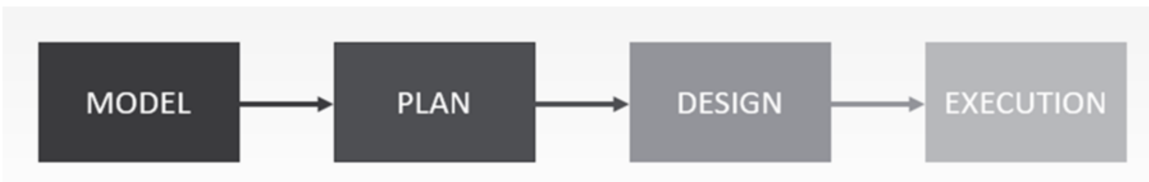
A. Yes. On May 3, 2021, the Fort Smith area experienced a major storm with strong winds and tornados. 27,000 (35%) customers in the Fort Smith area were affected. Prior to the storm, OG&E had completed both series 1 and 2 grid modernization efforts in Arkansas. The newly installed automation isolated and restored power where possible, preventing several circuits from a circuit wide sustained outage. This resulted in saving an estimated 20,000 customers from experiencing a sustained outage. The replacement of deteriorated and aging equipment in the grid modernization program also reduced the amount of pole damage and wire down. It is estimated, had the grid modernization investments not occurred, OG&E would have needed 50% more resources and the restoration process would have extended 1 to 1.5 days.

Project Selection

Q. **Please explain the grid enhancement process at a high-level.**

A. There are four main stages of the grid enhancement process: MODEL, PLAN, DESIGN, and EXECUTION. Each stage builds upon itself as shown in Figure 3 below. The process starts with the MODEL stage where we use average number of devices per circuit or substation to select potential projects for the investment year. Next, we move to the PLAN stage where we review the unique characteristics of each circuit and substation to identify the specific number of devices required (based on a set of criteria) for each project. Next in the DESIGN stage, there is a field engineering survey and detailed design that provides the exact location and condition for each device (identifying additional information like asset, soil, or tree conditions). Last, in the EXECUTION stage, the work is performed to enhance each identified circuit or substation.

Figure 3: High-Level Grid Enhancement Process



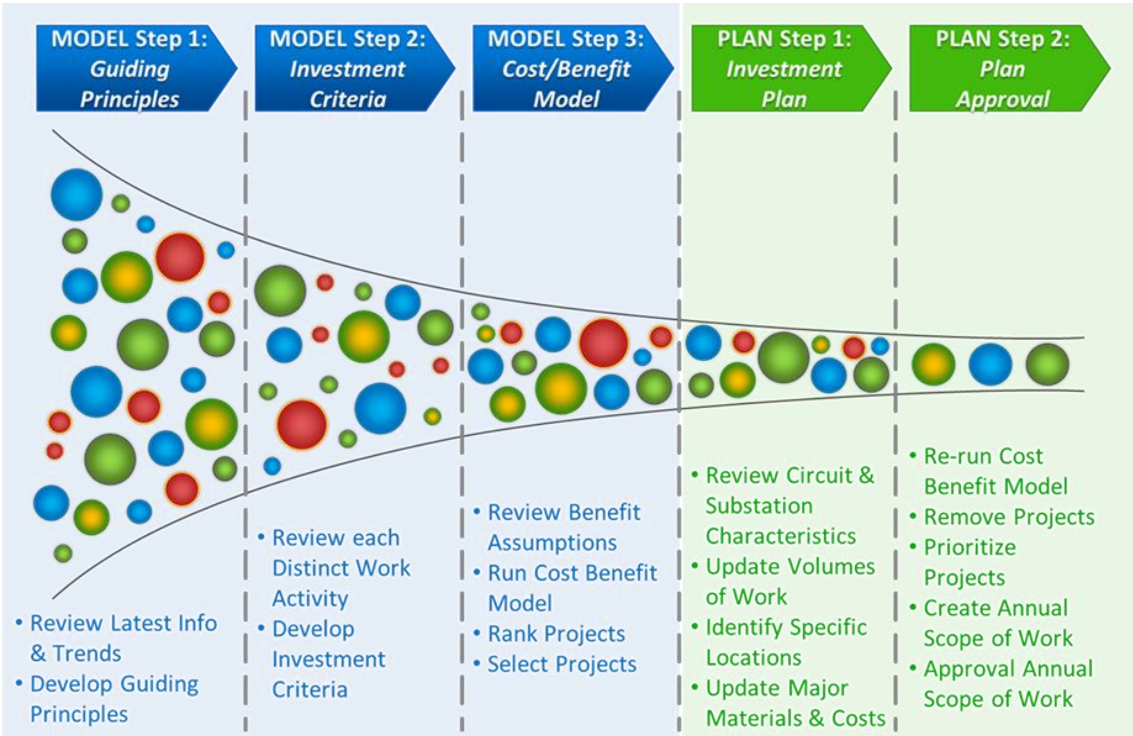
Q. **At what stage in the grid enhancement process are projects selected?**

A. Project selection occurs at the end of the PLAN stage.

Q. **How are the projects selected between the MODEL and PLAN stages?**

A. In Figure 4 below, the blue section represents the MODEL stage with three main steps and the green section represents the PLAN stage with two main steps. At a high level, you can think of the process as a side-ways funnel. With each step, circuits and substations are filtered from the potential investment list until we reach the end of the PLAN stage where final project selection occurs.

Figure 4: MODEL and PLAN Steps



Q. **What are the steps of the MODEL stage?**

A. There are three steps in the MODEL stage. The first step is to develop the guiding principles. In the second step, we develop the investment criteria for each distinct work activity. The investment criteria are used to determine when each work activity will be applied to a circuit or substation. For example, the underground cable replacement work activity was only applied when a circuit that had a history of outages caused by underground cable failures. The investment criteria are used to determine the optimal mix of activity types for each circuit or substation. In the third and final step of the MODEL stage, we run the cost/benefit model and select the potential projects for that year's annual investment plan.

Q. **What are the steps of the PLAN stage?**

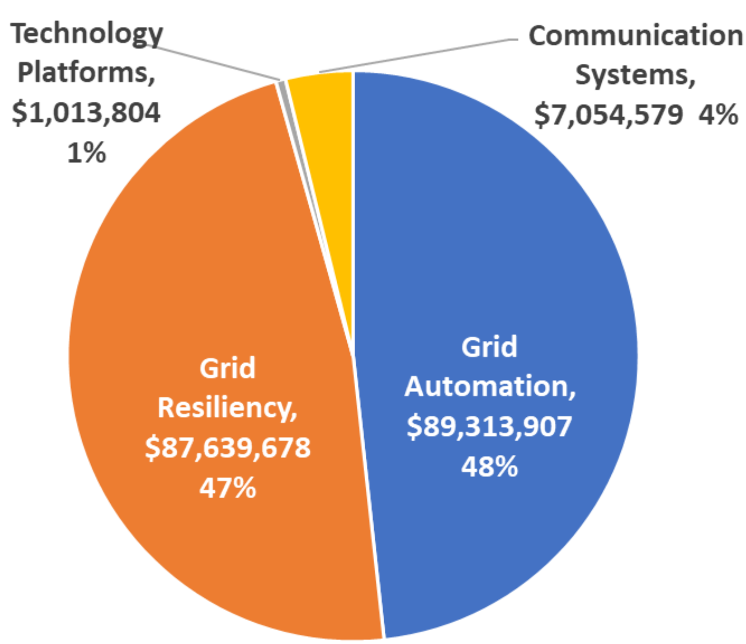
A. There are two steps in the PLAN stage. The first step is to develop the investment plan including volumes of work, work locations, major materials, project costs based on the unique characteristics of each of each circuit or substation. Then in the second step, plan approval, the cost benefit model is re-run, projects are selected and prioritized, and the annual scope of work is created and approved.

Completed Projects Requested for Recovery

Q. **Please describe the Grid Enhancement investments from the 2020 and 2021 Annual Investment Plans that have been completed through September 2021.**

A. The scope of the projects include 53 substation, 123 distribution circuits, 4 mobile substations, 4kV conversions, 4 technology applications, and 3 communication systems platforms. The total grid enhancement investment through end of September 2021 is approximately $185.0 million which is distributed amongst the categories of investment as shown in Figure 5 below. $97.4 million (Grid Automation, Communications Systems and Technology Platforms) was eligible for recovery through the GEM, while $87.6 million (Grid Resiliency) was not. The GEM's third quarter report which shows the detailed list of plant in-service projects is attached as Direct Exhibit KS-2. A report detailing the list of plant in-service projects that were not eligible for GEM recovery is attached as Direct Exhibit KS-3.

Figure 5: Grid Enhancement Investment by Category



Q. As of September 30, 2021, are all the 2020 and 2021 projects complete?

A. No, however the projects are on track to be completed by March 31, 2022.

Q. What are the estimated quantifiable benefits associated with the 2020 and 2021 Plans?

A. According to OG&E's analysis presented in Cause No. PUD 202000021, the 2020 and 2021 Plans are expected to provide over $800 million in benefits over a 30-year period. Beginning in 2022, customers can expect to see approximately 27.6 minutes of storm excluded SAIDI reduction across the state, a reduction of approximately 35,600,000 customer minutes of interruption during storms, and an overall SAIDI improvement of 71.8 minutes when comparing to the historical three-year averages. The two plan years combined are also expected to yield approximately 5,200 avoided hours of work and 32,100 minutes of reduced isolation time.

Q. Were the grid enhancement investments made in 2020 and 2021 prudently incurred?

A. Yes. The Company believes that OG&E's decision to implement the 2020 and 2021 Grid Enhancement investments was prudent based on the balance of costs to expected benefits customers will receive. As stated above, customers will see a significant improvement to SAIDI (27.6 minutes) as well as reduced customer impact during storms (35,600,000 customer minutes of interruption). The projects are expected to provide a significant number of quantifiable benefits as well as qualitative benefits such as improvements in safety, security, flexibility, customer experience, and economic impact.

Q. Were the grid enhancement investments made in 2020 and 2021 reasonable?

A. Yes. OG&E believes that Grid Enhancement investments discussed above are reasonable. OG&E leveraged a mixture of internal resources, negotiated contracts, and competitive bids to execute these projects at a reasonable cost to customers.

Extension of the Grid Enhancement Mechanism

Q. Is OG&E requesting extension of the GEM?

A. Yes. OG&E asks that the GEM be extended through end of 2024.

Q. **Is OG&E also requesting to expand the GEM?**

A. Yes. OG&E is requesting to recover the approved categories of investment (Grid Automation, Technology and Communications) for each of the remaining annual investment plan years without the limitation of the existing annual revenue requirement cap. OG&E also requests that the GEM be expanded to include the Weather Hardening projects discussed below. The redline and clean versions of the GEM tariff are attached as Direct Exhibit KS- 4.

Q. **What is the remaining forecasted investment for the Grid Enhancement projects to be included in the GEM?**

A. Although OG&E intends to continue working the Grid Enhancement Plan as comprehensive Annual Investment Plans, the Grid Resiliency investments will not be included in the Grid Enhancement Mechanism. The investment categories included in the mechanism are Grid Automation, Technology Platforms and Applications, and Communication Systems. As shown in Table 3 below, the remaining forecasted investment for 2022 through 2024 is approximately $320.2 million. OG&E requests to include these projects in the GEM.

Table 3: Remaining Forecasted Investment for Grid Enhancement Plan
(in millions of dollars)

Category	2022	2023	2024
Grid Automation	$55.7	$65.0	$64.9
Communication Systems	$39.4	$20.0	$20.0
Technology Platforms and Applications	$7.4	$20.3	$20.3
Total	***$102.5***	***$105.3***	***$105.2***

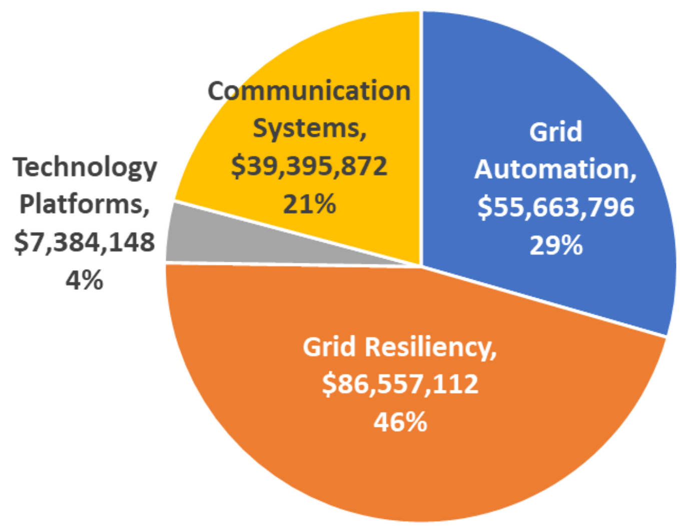
Q. **Has the 2022 Annual Investment Plan been developed?**

A. Yes. The 2022 Annual Investment Plan has been developed. Please see Direct Exhibit KS-5 for the Annual Investment Plan and Confidential Direct Exhibit KS-6 for the detailed Annual Scope of Work.

Q. **Please describe the 2022 Annual Investment Plan.**

A. The estimated cost for the 2022 Annual Investment Plan is approximately $189.0 million and is expected to be distributed amongst the categories of investment as shown in Figure 6 below. The planned scope includes 30 substations, 82 circuits, as well as 4 technology platforms and applications projects, and continued investment in modernizing the communication systems.

Figure 6: 2022 Annual Investment Plan by Category



Q. **What are the estimated quantifiable benefits associated with the 2022 Plan?**

A. The 2022 Plan is expected to provide an estimated $163.7 million in avoided cost of service benefits as well as $205.9 million in avoided economic harm benefits. It is also expected to yield an estimated 11.3 minutes of storm excluded SAIDI reduction, while reducing approximately 42,900,000 customer minutes of interruption during storms. The Plan is also expected to result in the reduction of approximately 2,300 work hours and reduced isolation time of 11,400 hours.

<u>Weather Hardening</u>

Q. **Does OG&E also seek to expand the GEM to include any additional investments?**

A. Yes. After the October 2020 ice storm, OG&E identified five Weather Hardening categories of non-routine, targeted upgrades to infrastructure.

The categories of investment are listed below.

1. Additional system strength and resilience upgrades
2. Convert certain overhead highway crossings to underground
3. Replace secondary exposed wire with covered cable
4. Convert overhead primary wire to underground
5. Convert overhead service wire to underground

Q. **Please elaborate on what is meant by "additional system strength and resilience".**

A. The additional system strength and resilience category is focused on strengthening areas that have historically had heavier ice accumulation. In these areas, the ice loading is exceeding our system design which is causing areas of cascading failures. This means in these areas the poles will typically fail in domino fashion leaving entire pole lines to be replaced and extending outage times by two to four days depending on the extent of damage. The expectation for this work would be to add additional anchors and guys as well as reduce span lengths in key areas. Giving the system additional strength to withstand the heavier ice accumulation will reduce the impact of ice and windstorms in the future. This is not routine replacement of infrastructure, but a targeted upgrade to bolster system strength, necessitated by the severe weather in Oklahoma.

Q. **Please elaborate on what is meant by convert overhead highway crossings to underground.**

A. The convert overhead highway crossings to underground category is focused on replacing overhead lines crossing heavily traveled highways with underground to allow travel and commerce to remain uninterrupted during storms where icing and winds can cause the lines to fall on the roadways.

Q. **Please elaborate on what is meant by replace secondary exposed wire with covered cable.**

A. The replace secondary exposed wire with covered cable category is focused on replacing secondary conductors that typically run in backyards where trees are with a stronger covered conductor. When trees fall during ice and windstorms into the exposed wire, it typically breaks and interrupts power for extended periods of time which can extend overall storm restoration by up to three additional days depending on the extent of damage. By replacing this wire with covered cable, the lines will be strengthened and many of the secondary related outages can be avoided in future storms. Additionally, covered cable is resistant to animal and vegetation intrusion as well as slapping of the exposed conductors, this will improve reliability on blue sky days as well.

Q. **Please elaborate on what is meant by convert overhead primary wire to underground.**

A. The convert overhead primary wire to underground category is focused on converting areas where there is one block or less of primary overhead lines that could be served by a single transformer at the end of the block and extending underground secondary conductor. This work would remove the overhead lines from the backyards which could reduce storm impacts by three to five days depending on the extent of damage.

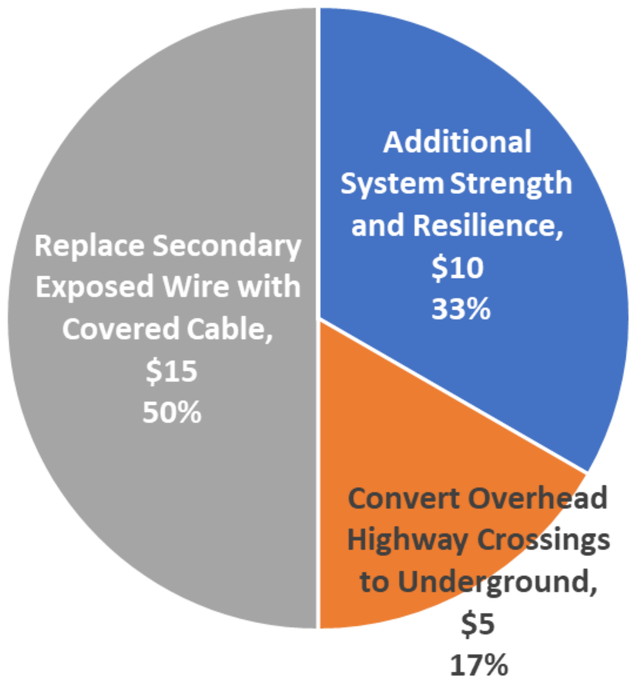
Q. **Please elaborate on what is meant by convert overhead service wire to underground.**

A. The convert overhead service wire to underground category is focused on converting overhead service lines to underground cable in conduit with a system that can connect to the existing meter panel and forgo the need for a customer to hire an electrician. This work would remove the overhead service lines from customers backyards which could reduce overall storm impacts by up to three days depending on the extent of the damage.

Q. **How will OG&E implement Weather Hardening projects in 2022?**

A. OG&E will begin the Weather Hardening work in 2022 by investing in the following three categories: additional system strength and resilience, convert overhead highway crossings to underground, and replace secondary exposed wire with covered cable. The estimated investment for 2022 is approximately $30 million and is broken down by category as shown in Figure 7 below.

Figure 7: 2022 Weather Hardening Investments by Category
(in millions of dollars)



Q. **What is the estimated forecast for investing in Weather Hardening projects going forward?**

A. The forecasted invest from 2022 through 2024 in Weather Hardening projects is $240 million and is broken down by year as shown in Table 4 below.

Table 4: Weather Hardening Investment Forecast
(in millions of dollars)

	2022	2023	2024
Weather Hardening	*$30*	*$100*	*$110*

<u>Compliance with Stipulation</u>

Q. **What additional requirements were agreed to in the Grid Enhancement Mechanism joint stipulation?**

A. The following additional requirements were agreed to in the joint stipulation.

1. OG&E agreed to initiate an ongoing public stakeholder process regarding grid modernization, with the first meeting occurring within 90 days of the issuance of a Final Order in the cause.
2. OG&E agreed to present all support for the prudency of any Grid Enhancement investments, recovered as part of the Mechanism and/or requested for recovery in the rate case including any cost benefit analysis relied upon by the Company to make investment decisions.
3. OG&E agreed to also include a cost benefit analysis for each investment or project and such additional analysis shall exclude avoided economic harm benefits and calculate costs based on the revenue requirement expected to be paid by customers.

Q. **Did OG&E host stakeholder meetings for Grid Enhancement?**

A. Yes. OG&E hosted a stakeholder meeting on February 2, 2021, had multiple informal discussions with stakeholders around the approved list of Grid Enhancement Mechanism Investments, and plans to hold another formal stakeholder meeting in first quarter of 2022. OG&E has also increased communications with customers regarding the Grid Enhancement investments. Some examples of the communications are social media posts, customer email, update in September video newsletter (currents), flyers handed out at the OK state fair and during fan donations, radio communications, Grid Enhancement specific door hangers, and updates to the Grid Enhancement page on oge.com including a video and a map.

Q. **Did OG&E provide support for the prudency of Grid Enhancement investments?**

A. Yes, as outlined above, OG&E has provided support for prudency of the Grid Enhancement investments.

Q. **What were the results of the cost benefit analysis the Company relied upon to make investment decisions for the 2020 and 2021 Annual Plans?**

A. The estimated costs for the 2020 and 2021 Annual Investment Plans were approximately \$246.2 million. The benefits associated with those plans were approximately \$817.0 million. This results in an estimated \$3.18 of customer benefits for every dollar spent on the 2020 and 2021 Plans. For the results of the cost benefit analysis and example model calculations, please see my workpapers.

Q. **How has OG&E complied with providing the additional elements within the cost benefit analysis as described in #3 above?**

A. While OG&E does not agree this is the best approach for evaluating costs and benefits, we have complied with the stipulation. To perform the additional elements within the cost benefit analysis, we hired 1898 & Co. which is a service mark of Burns & McDonnell Engineering Company, Inc. 1898 & Co. to provide a look back at the projects in the 2020 and 2021 Plans and perform the cost benefit analysis with the elements requested in the stipulation. For details and results of the analysis performed, see the Direct Testimony of Jason De Stigter. Included in 1898 & Co.'s analysis are the following elements:

- Analysis for each investment type or project
- Calculation of costs based on the revenue requirement expected to be paid by customers
- Exclusion of avoided economic harm benefits

Q. **Why do you believe the grid enhancement projects should not be evaluated by each investment type?**

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 supportive of our goal to create a step-change 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. 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. In Figure 5 of Witness De Stigter's testimony, he has provided a visual that shows the complexity of analyzing the Grid Enhancement Plan on a project by project 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 is 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.

Q. **Why do you believe the grid enhancement projects should be evaluated with the inclusion of economic harm benefits?**

A. It is unreasonable to ignore the total effect of outages on our customers. The economic impact of outages on customers must be factored into the analysis. The avoided economic harm benefits associated with the Grid Enhancement Plan are derived using a reputable model developed by the Department of Energy (“DOE”). The objective of the cost benefit evaluation is to minimize the total costs of electricity service by balancing the cost of investments against the costs that customers experience (on both sides of the meter) when an outage occurs. Excluding the value of avoided economic harm benefits in valuing the plan is an incomplete picture of the full impact of outages on customers.

Q. **Why do you believe it is reasonable to evaluate projects using a cashflow model instead of a full revenue requirement model?**

A. The cost benefit model is intended to be used to optimize the selection of projects and is not intended to calculate customer rate impacts. 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 tax benefit.

Q. **What was the basis for 1898 & Co.'s cost benefit analysis?**

A. 1898 & Co. evaluated the estimated costs and benefits based to the work identified in the Annual Scope of Work documents for both the 2020 and 2021 Plans.

Q. **What were the results of 1898 & Co.'s cost benefit analysis?**

A. To review the summarized results of 1898 & Co.'s cost benefit analysis, see Figure 14 (Circuits & Substations Business Case Results) and Figure 16 (Grid Enhancement Business Case Summary) from Witness De Stigter Testimony. Witness De Stigter represents the business case with a 3.1 cost benefit ratio, meaning for every dollar invested, there is 3.1 dollars in benefits to customers. For details about the assessment on a project by project basis, please see Witness De Stigter Direct Exhibit JDD-1.

Q. **Did 1898 & Co. perform the cost benefit analysis using a revenue requirement model?**

A. Yes. To review the summarized results of 1898 & Co. cost benefit analysis using a revenue requirement model, see Figure 17 (Grid Enhancement Business Case Summary - Revenue Requirement) from Witness De Stigter Testimony. Witness De Stigter represents the revenue requirement business case with a 2.6 cost benefit ratio, meaning for every dollar invested, there is 2.6 dollars in benefits to customers. For details about the assessment on a revenue requirement basis, please see Witness De Stigter Direct Exhibit JDD-1.

Q. **Did 1898 & Co.'s analysis address the exclusion of economic harm benefits?**

A. Yes. Witness De Stigter performs his analysis to allow for the easy exclusion of the economic harm benefits.

Conclusion

Q. **What are your recommendations to the Commission?**

A. I recommend that the Commission find the 2020 and 2021 Grid Enhancement investments prudent and allow for these investments to be included in base rates. I also recommend the Commission approve the extension of the Grid Enhancement Mechanism and include the following changes as requested by OG&E:

1. Expand the GEM to include the 2022, 2023 and 2024 projects associated with each year's annual investment plan;
2. Expand the GEM categories to include Weather Hardening, and

Q. **Does this conclude your testimony?**

A. Yes.

Direct Exhibit KS-1

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.

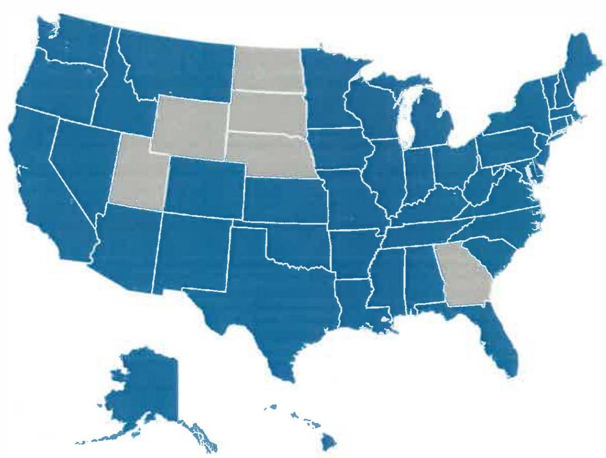


Figure 1. States with Regulatory or Legislative Efforts Related to Distribution Modernization

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.

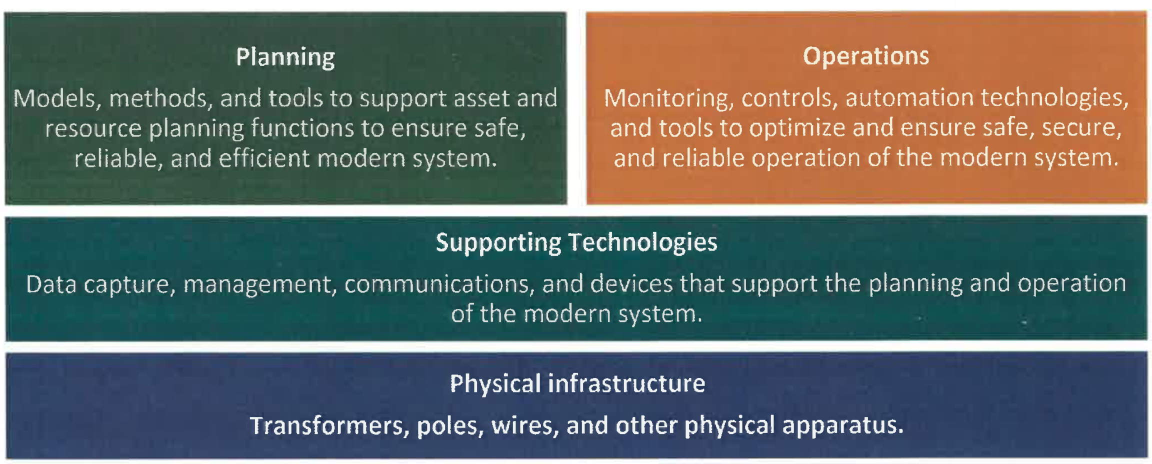


Figure 2. Foundational Areas of Grid Modernization

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.

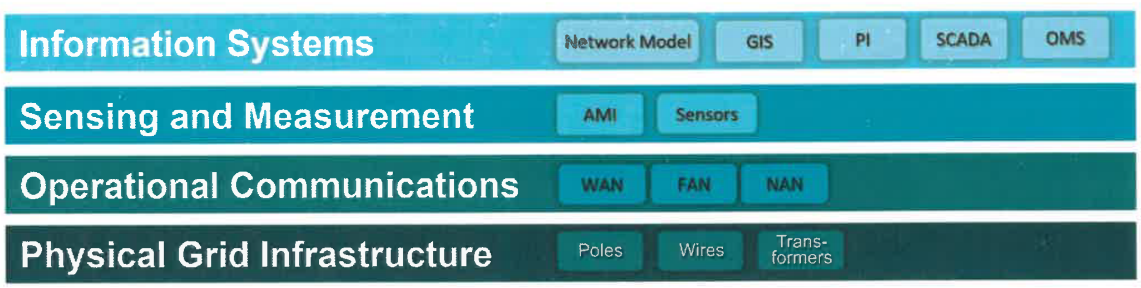


Figure 3. Core Components of Supporting Technologies and Physical Infrastructure

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.

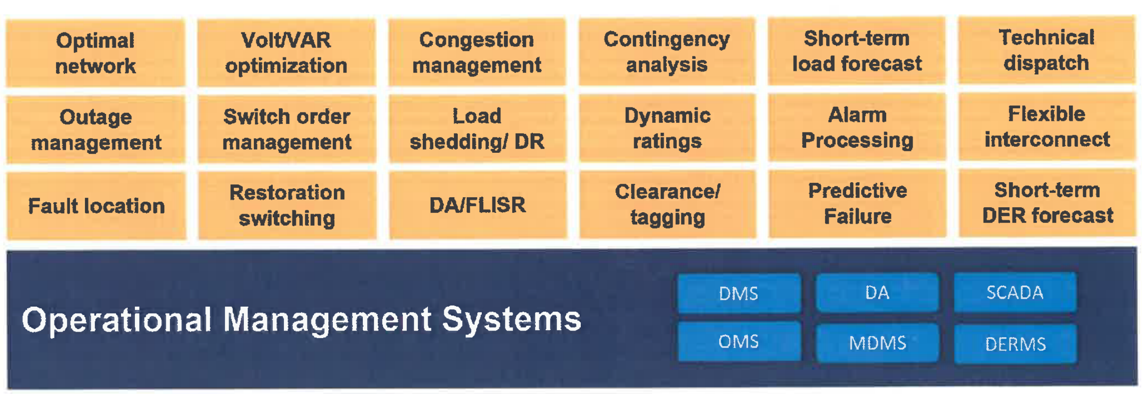


Figure 4. Core Components of Operations Technologies

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.

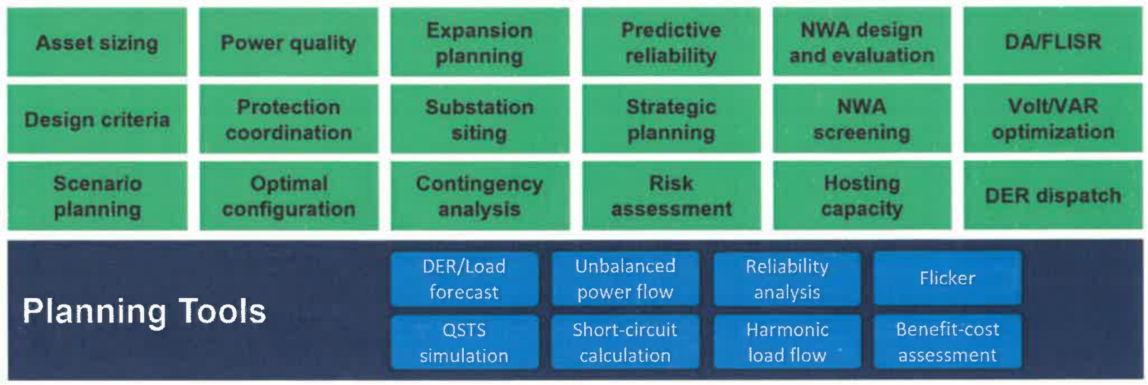


Figure 5. Core Components of Planning Technologies

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.

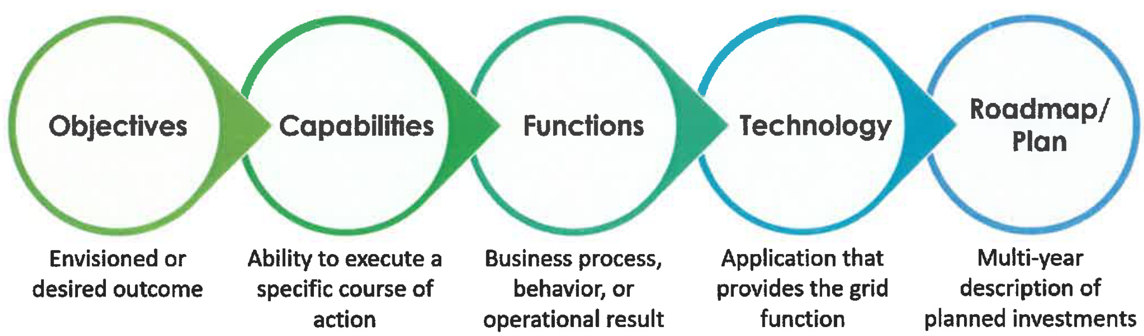


Figure 6. Structure for Grid Modernization Plan Development

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.

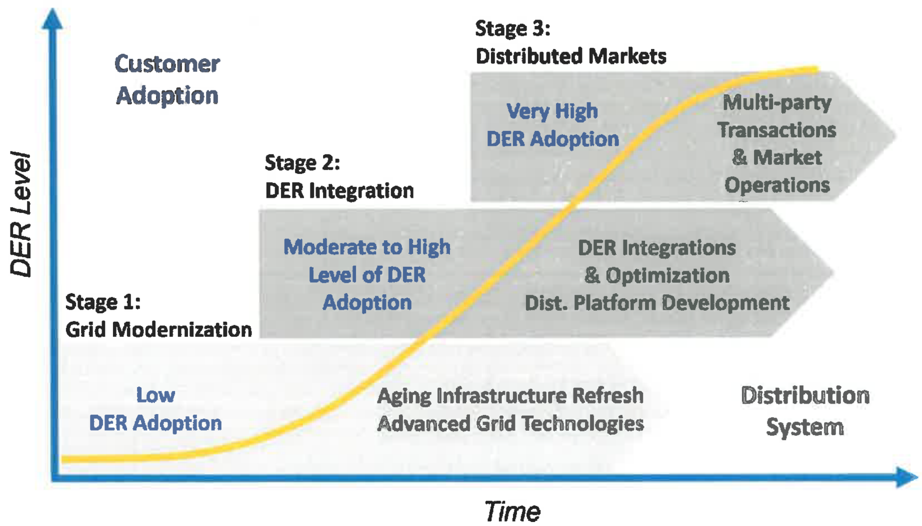


Figure 7. Distribution System Evolution[10]

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
Customers / regulator expectations: Increased expectations regarding services, power quality, cost, communication, control, and personalization.
Grid reliability and resilience: Growing demands for a more resilient and reliable grid (cyber and physical)
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)
IT / OT convergence and cyber: IT / OT convergence increasing the threat of cyber attacks
Integrating DERs: DERs operating in a system that was designed to accommodate a one-way flow of electricity
Changing generation mix: Changing mix of electric generation types and characteristics (distributed and clean energy)
Aging electricity infrastructure

Future Grid Objectives
Additional Affordability
Improved Reliability
Greater Resilience
Enhanced Flexibility
Increased Efficiency
Expanded Customer Engagement

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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OG&E Distribution Grid Automation Projects
Project List and Summary
September 30, 2021

Project Category Summary

Last Updated: 10/06/2021

Category	Category Description	Total Cost	November	December	January	February	March	April	May	June	July	August	September
GACS	Grid Automation Communication Systems	$ 7,054,579.06	$ -	$ -	$ -	$ 148.08	$ 6,554,513.69	$ 1,249.67	$ 1,768.83	$ 1,472.06	$ 756.78	$ (1,290.79)	$ 495,960.74
GADL	Grid Automation Distribution Lines	$ 62,606,644.65	$ 5,557,021.96	$ 18,369,425.72	$ 104,141.29	$ (209,939.75)	$ 10,330,765.18	$ 8,804,724.80	$ 5,641,483.42	$ 10,743,098.78	$ (223,468.54)	$ 1,220,231.68	$ 2,269,160.11
GADS	Grid Automation Distribution Substations	$ 26,707,262.55	$ 3,884,828.08	$ 837,003.65	$ 1,258,891.50	$ 430,382.97	$ 2,357,057.94	$ 536,542.04	$ 742,753.96	$ 7,334,030.88	$ 193,491.08	$ 632,550.37	$ 8,499,730.08
GATP	Grid Automation Technology Platforms	$ 1,013,804.44	$ 40,675.00	$ -	$ -	$ -	$ -	$ -	$ 594,090.46	$ 361,357.53	$ 888.92	$ 16,762.23	$ 30.30
	Total	**$ 97,382,290.70**	**$ 9,482,525.04**	**$ 19,206,429.37**	**$ 1,363,032.79**	**$ 220,591.30**	**$ 19,242,336.81**	**$ 9,342,516.51**	**$ 6,980,096.67**	**$ 18,439,959.25**	**$ (28,331.76)**	**$ 1,868,253.49**	**$ 11,264,881.23**

Project List

No.	Category	Project Description	Total Cost	November	December	January	February	March	April	May	June	July	August	September
1	GADS	Healdton Substation Automation	$ 296,848.25	$ 305,261.40	$ 31,128.56	$ (45,978.12)	$ -	$ 94.42	$ 6,275.98	$ -	$ -	$ -	$ -	$ 66.01
2	GADS	Jamesville Substation Automation	$ 276,756.20	$ -	$ 248,896.17	$ 14,169.49	$ -	$ -	$ 12,347.16	$ (272.00)	$ -	$ 1,251.09	$ 364.29	$ -
3	GADS	Beggs Substation Automation	$ 140,055.81	$ -	$ 137,475.80	$ 430.76	$ -	$ 308.94	$ 782.48	$ -	$ 1,057.83	$ -	$ -	$ -
4	GADS	Roman Nose Substation Automation	$ 10,001.25	$ -	$ 62,599.65	$ (51,063.82)	$ (1,642.66)	$ 57.17	$ 50.91	$ -	$ -	$ -	$ -	$ -
5	GADS	May Ave Substation Automation	$ 435,918.47	$ -	$ 435,875.09	$ (229.05)	$ 126.85	$ -	$ -	$ 137.03	$ -	$ 8.55	$ -	$ -
6	GADS	Fixico Substation Automation	$ 4,182.95	$ -	$ 4,182.95	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	GADS	Newman Substation Automation	$ 75,718.13	$ 252,226.69	$ (177,677.46)	$ 13.07	$ 116.18	$ (94.47)	$ 343.31	$ -	$ (0.07)	$ -	$ 683.37	$ 107.51
8	GADS	Woodward District Substation Automation	$ 4,253.91	$ -	$ 23,619.50	$ (19,991.61)	$ 31.58	$ 14.82	$ 301.63	$ 92.28	$ -	$ 166.22	$ 11.14	$ 8.35
9	GADS	Mobile Substation Automation	$ 3,312,415.15	$ 3,300,303.06	$ (47,051.94)	$ 38,482.11	$ 2,128.10	$ 932.13	$ 11,904.82	$ -	$ 1,304.70	$ -	$ 3,482.26	$ 929.91
10	GADS	Tennyson Substation Automation	$ 222,020.14	$ -	$ -	$ 214,976.71	$ 3,941.47	$ 1,028.84	$ 613.39	$ 35.87	$ -	$ 985.37	$ 438.49	$ -
11	GADS	Kellyville Substation Automation	$ 220,208.02	$ -	$ -	$ 275,320.52	$ (46,268.75)	$ (9,579.94)	$ 16,098.45	$ 12,253.51	$ (12,910.00)	$ (20,111.31)	$ 5,405.54	$ -
12	GADS	Eighty Fourth St Substation Automation	$ 306,543.12	$ -	$ -	$ 341,181.68	$ (48,051.80)	$ 14,932.96	$ (2,121.14)	$ 564.72	$ -	$ 36.70	$ -	$ -
13	GADS	Ardmore Substation Automation	$ 109,827.11	$ -	$ -	$ 112,136.48	$ (14,216.50)	$ 5,464.12	$ (1,233.55)	$ 376.55	$ 21,779.16	$ (14,479.15)	$ -	$ -
14	GADS	Honor Heights Substation Automation	$ 232,476.52	$ -	$ -	$ -	$ 206,576.69	$ 6,154.56	$ 13,556.07	$ 5,629.85	$ 172.24	$ 386.79	$ 578.09	$ (577.77)
15	GADS	Lone Star Substation Automation	$ 171,332.87	$ -	$ -	$ -	$ 168,381.85	$ 1,327.07	$ 120.71	$ -	$ 139.39	$ 1,363.85	$ -	$ -
16	GADS	Tibbens Road Substation Automation	$ 92,522.34	$ -	$ -	$ -	$ 44,723.37	$ 41,871.12	$ 4,513.20	$ -	$ -	$ 1,414.65	$ -	$ -
17	GADS	Jensen Road Substation Automation	$ 297,481.22	$ -	$ -	$ -	$ -	$ 289,087.12	$ (31,508.33)	$ 6,485.46	$ 32,603.44	$ 663.30	$ -	$ 150.23
18	GADS	Cypress Substation Automation	$ 24,056.65	$ -	$ -	$ -	$ -	$ 26,360.50	$ (2,303.85)	$ -	$ -	$ -	$ -	$ -
19	GADS	Green Pastures Substation Automation	$ 507,474.92	$ -	$ -	$ -	$ -	$ 540,766.70	$ (117,505.87)	$ (415.58)	$ 78,381.25	$ 4,928.35	$ 1,062.70	$ 257.37
20	GADS	Illinois River Substation Automation	$ 472,255.85	$ -	$ -	$ -	$ -	$ 238,095.10	$ 62,531.21	$ (10,308.24)	$ 179,109.20	$ 2,118.13	$ 710.45	$ -
21	GADS	Howe Substation Automation	$ 193,725.51	$ -	$ -	$ -	$ -	$ 161,717.30	$ 4,674.12	$ 1,928.65	$ 30,779.80	$ (9,073.89)	$ 3,699.53	$ -
22	GADS	Western Ave Substation Automation	$ 632,070.15	$ -	$ -	$ -	$ -	$ 688,442.26	$ (64,083.30)	$ 1,559.34	$ 5,796.06	$ 355.79	$ -	$ -
23	GADS	Bowden Substation Automation	$ 486,411.67	$ -	$ -	$ -	$ -	$ -	$ 428,991.93	$ 3,173.06	$ 42,512.72	$ (7,121.64)	$ 1,330.26	$ 17,525.34
24	GADS	Little River Substation Automation	$ 408,265.16	$ -	$ -	$ -	$ -	$ -	$ -	$ 367,043.59	$ 38,543.54	$ 2,640.88	$ 37.15	$ -
25	GADS	Checotah Substation Automation	$ 638,072.56	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 665,313.99	$ (39,260.73)	$ 11,200.81	$ 818.49
26	GADS	Meridian Substation Automation	$ 354,789.52	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 401,998.20	$ (55,116.98)	$ 7,908.30	$ -
27	GADS	Dewey Substation Automation	$ 599,814.50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 592,963.86	$ 6,850.64	$ -	$ -
28	GADS	Hancock Substation Automation	$ 659,850.41	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 697,115.59	$ (39,853.61)	$ 2,588.43	$ -
29	GADS	Riverside Substation Automation	$ 980,175.86	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 903,421.05	$ 67,862.48	$ (23,912.70)	$ 32,805.03
30	GADS	Stonewall Substation Automation	$ 524,248.04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 524,248.04
31	GADL	Healdton 21 Circuit Feeder Automation	$ 214,106.09	$ -	$ 214,106.09	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	GADL	Healdton 21 Circuit Lateral Automation	$ 823,295.19	$ -	$ 891,853.69	$ (76,924.05)	$ -	$ 885.98	$ 3,841.39	$ 2,024.99	$ 1,543.94	$ 69.25	$ -	$ -
33	GADL	Jamesville 21 Circuit Feeder Automation	$ 102,295.33	$ 100,444.45	$ -	$ -	$ -	$ -	$ 1,850.88	$ -	$ -	$ -	$ -	$ -
34	GADL	Jamesville 21 Circuit Lateral Automation	$ 530,278.81	$ 556,315.54	$ (7,843.41)	$ (25,936.36)	$ 2,765.99	$ 193.62	$ -	$ -	$ 4,783.43	$ -	$ -	$ -
35	GADL	Jamesville 41 Circuit Feeder Automation	$ 206,089.66	$ -	$ 204,684.20	$ -	$ -	$ -	$ 1,405.46	$ -	$ -	$ -	$ -	$ -
36	GADL	Jamesville 41 Circuit Lateral Automation	$ 105,550.65	$ -	$ 102,784.66	$ -	$ 2,765.99	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	GADL	Bowden 23 Circuit Feeder Automation	$ 114,307.04	$ -	$ 114,307.04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38	GADL	Bowden 23 Circuit Lateral Automation	$ 289,043.95	$ -	$ 289,043.95	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	GADL	Bowden 29 Circuit Feeder Automation	$ 321,135.70	$ -	$ 353,794.49	$ -	$ -	$ -	$ -	$ -	$ -	$ (32,658.79)	$ -	$ -
40	GADL	Bowden 29 Circuit Lateral Automation	$ 676,514.52	$ -	$ 720,623.46	$ (5,982.82)	$ (55,185.27)	$ 2,319.72	$ 11,270.73	$ 2,201.14	$ 1,267.56	$ -	$ -	$ -
41	GADL	Tennyson 22 Circuit Feeder Automation	$ 242,455.92	$ -	$ 373,091.07	$ -	$ -	$ -	$ -	$ -	$ -	$ (130,635.15)	$ -	$ -
42	GADL	Tennyson 22 Circuit Lateral Automation	$ 328,656.52	$ -	$ 328,484.28	$ 172.24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	GADL	Tennyson 23 Circuit Feeder Automation	$ 187,608.46	$ -	$ 187,608.46	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	GADL	Tennyson 23 Circuit Lateral Automation	$ 360,512.87	$ -	$ 359,952.63	$ 476.50	$ -	$ -	$ -	$ -	$ -	$ -	$ 83.74	$ -
45	GADL	Tennyson 24 Circuit Feeder Automation	$ 64,626.18	$ 66,234.62	$ (1,608.44)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	GADL	Tennyson 24 Circuit Lateral Automation	$ 364,260.76	$ 361,952.96	$ 2,172.87	$ 134.93	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	GADL	Checotah 21 Circuit Feeder Automation	$ 71,077.03	$ 66,960.21	$ 4,116.82	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	GADL	Checotah 21 Circuit Lateral Automation	$ 367,050.38	$ 361,819.74	$ 4,339.83	$ -	$ -	$ -	$ 890.81	$ -	$ -	$ -	$ -	$ -

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Project List

No.	Category	Project Description	Total Cost	November	December	January	February	March	April	May	June	July	August	September
49	GADL	Checotah 22 Circuit Feeder Automation	$ 237,815.46	$ -	$ 237,815.46	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	GADL	Checotah 22 Circuit Lateral Automation	$ 409,371.39	$ -	$ 447,890.69	$ 476.50	$ (41,994.19)	$ -	$ 2,741.67	$ 69.21	$ 187.51	$ -	$ -	$ -
51	GADL	Illinois River 21 Circuit Lateral Automation	$ 163,068.37	$ 160,601.82	$ 129.52	$ 1,376.98	$ -	$ -	$ 960.05	$ -	$ -	$ -	$ -	$ -
52	GADL	Lone Star 22 Circuit Feeder Automation	$ 198,162.12	$ 305,007.03	$ (49.47)	$ (10,873.58)	$ (10,953.26)	$ (35,651.56)	$ (49,317.04)	$ -	$ -	$ -	$ -	$ -
53	GADL	Lone Star 22 Circuit Lateral Automation	$ 302,566.49	$ 333,140.74	$ 1,204.69	$ (983.20)	$ (30,795.74)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	GADL	Meridian 22 Circuit Feeder Automation	$ 206,086.60	$ -	$ 235,749.83	$ -	$ 2,995.56	$ -	$ -	$ -	$ -	$ (32,658.79)	$ -	$ -
55	GADL	Meridian 22 Circuit Lateral Automation	$ 242,141.81	$ -	$ 242,433.19	$ -	$ -	$ -	$ -	$ (291.38)	$ -	$ -	$ -	$ -
56	GADL	Meridian 23 Circuit Feeder Automation	$ 102,975.65	$ 102,975.65	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	GADL	Meridian 23 Circuit Lateral Automation	$ 154,845.04	$ 154,203.63	$ 641.41	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	GADL	Meridian 29 Circuit Feeder Automation	$ 159,364.79	$ 165,183.11	$ (5,818.32)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59	GADL	Meridian 29 Circuit Lateral Automation	$ 269,375.45	$ 280,644.69	$ (11,269.24)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	GADL	Western Ave 23 Circuit Feeder Automation	$ 366,493.04	$ -	$ 330,149.60	$ -	$ -	$ -	$ (10,390.66)	$ -	$ -	$ -	$ (80,770.15)	$ 127,504.25
61	GADL	Western Ave 23 Circuit Lateral Automation	$ 246,640.74	$ -	$ 267,788.63	$ (21,147.89)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	GADL	Western Ave 24 Circuit Feeder Automation	$ 219,720.38	$ -	$ 219,720.38	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	GADL	Western Ave 24 Circuit Lateral Automation	$ 165,589.01	$ -	$ 176,787.46	$ -	$ (11,198.45)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	GADL	Western Ave 25 Circuit Feeder Automation	$ 160,365.36	$ -	$ 160,365.36	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65	GADL	Western Ave 25 Circuit Lateral Automation	$ 227,763.51	$ -	$ 227,763.51	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	GADL	Dewey 41 Circuit Feeder Automation	$ 115,780.56	$ -	$ 115,780.56	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	GADL	Dewey 41 Circuit Lateral Automation	$ 276,542.05	$ -	$ 356,896.88	$ 198.56	$ (80,490.18)	$ (2,615.36)	$ 2,552.15	$ -	$ -	$ -	$ -	$ -
68	GADL	Hancock 22 Circuit Feeder Automation	$ 127,576.23	$ 122,283.45	$ 5,255.29	$ 37.49	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
69	GADL	Hancock 22 Circuit Lateral Automation	$ 165,928.33	$ 165,184.29	$ 744.04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	GADL	Hancock 24 Circuit Feeder Automation	$ 170,796.65	$ 206,679.38	$ (36,363.55)	$ 39.99	$ 440.83	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	GADL	Hancock 24 Circuit Lateral Automation	$ 302,740.72	$ 301,887.34	$ 853.38	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	GADL	Beggs 24 Circuit Feeder Automation	$ 74,296.60	$ -	$ 78,167.24	$ 15,848.06	$ (15,830.73)	$ 9,737.97	$ (13,625.94)	$ -	$ -	$ -	$ -	$ -
73	GADL	Beggs 24 Circuit Lateral Automation	$ 70,021.39	$ -	$ 116,234.54	$ (564.30)	$ (4,225.85)	$ -	$ -	$ 69.21	$ (41,492.21)	$ -	$ -	$ -
74	GADL	Beggs 29 Circuit Feeder Automation	$ 133,582.36	$ -	$ 146,136.46	$ -	$ -	$ -	$ -	$ (12,554.10)	$ -	$ -	$ -	$ -
75	GADL	Beggs 29 Circuit Lateral Automation	$ 391,067.57	$ -	$ 386,614.92	$ 264.73	$ 2,343.46	$ (6,583.24)	$ 3,314.60	$ 5,113.10	$ -	$ -	$ -	$ -
76	GADL	Roman Nose 47 Circuit Feeder Automation	$ 249,923.81	$ -	$ 382,733.21	$ -	$ -	$ -	$ -	$ 2,993.06	$ -	$ (135,911.60)	$ -	$ 109.14
77	GADL	Roman Nose 47 Circuit Lateral Automation	$ 172,454.23	$ -	$ 37,722.23	$ -	$ 456.56	$ -	$ 69.25	$ 133,317.60	$ 888.59	$ -	$ -	$ -
78	GADL	Jensen Rd 69 Circuit Feeder Automation	$ 53,722.80	$ -	$ 53,512.32	$ -	$ -	$ -	$ -	$ 210.48	$ -	$ -	$ -	$ -
79	GADL	Jensen Rd 69 Circuit Lateral Automation	$ 116,441.31	$ -	$ 71,490.88	$ -	$ -	$ -	$ -	$ 44,950.43	$ -	$ -	$ -	$ -
80	GADL	May Ave 21 Circuit Feeder Automation	$ 111,113.45	$ -	$ 119,372.95	$ (3,462.82)	$ -	$ -	$ (4,796.68)	$ -	$ -	$ -	$ -	$ -
81	GADL	May Ave 21 Circuit Lateral Automation	$ 199,209.13	$ -	$ 239,519.94	$ -	$ (45,096.37)	$ 30,418.70	$ (25,633.14)	$ -	$ -	$ -	$ -	$ -
82	GADL	May Ave 22 Circuit Feeder Automation	$ 321,689.30	$ -	$ 275,693.90	$ -	$ -	$ -	$ -	$ -	$ -	$ (13,074.65)	$ (102,083.26)	$ 161,153.31
83	GADL	May Ave 22 Circuit Lateral Automation	$ 260,662.07	$ -	$ 263,230.03	$ 231.65	$ (2,799.61)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84	GADL	May Ave 24 Circuit Feeder Automation	$ 198,523.28	$ -	$ 199,249.91	$ -	$ -	$ -	$ -	$ -	$ -	$ (726.63)	$ -	$ -
85	GADL	May Ave 24 Circuit Lateral Automation	$ 179,210.51	$ -	$ 219,884.81	$ -	$ 312.91	$ -	$ 69.25	$ -	$ (41,056.46)	$ -	$ -	$ -
86	GADL	Honor Heights 21 Circuit Feeder Automation	$ 145,295.80	$ 144,486.76	$ -	$ 809.04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87	GADL	Honor Heights 21 Circuit Lateral Automation	$ 436,944.16	$ 418,925.55	$ 5,828.91	$ 2,116.78	$ 5,287.23	$ -	$ 2,832.41	$ 257.85	$ -	$ -	$ 1,695.43	$ -
88	GADL	Tibben Rd 24 Circuit Feeder Automation	$ 207,170.54	$ -	$ 235,730.25	$ 128.38	$ (12,383.03)	$ 14,082.53	$ (30,387.59)	$ -	$ -	$ -	$ -	$ -
89	GADL	Tibben Rd 24 Circuit Lateral Automation	$ 334,307.96	$ -	$ 374,971.28	$ 5,177.81	$ 12,056.66	$ -	$ (57,897.79)	$ -	$ -	$ -	$ -	$ -
90	GADL	Fixico 22 Circuit Feeder Automation	$ 221,340.04	$ -	$ 221,809.47	$ -	$ (469.43)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	GADL	Fixico 22 Circuit Lateral Automation	$ 330,087.90	$ -	$ 357,371.38	$ -	$ -	$ (29,804.98)	$ 2,452.29	$ 69.21	$ -	$ -	$ -	$ -
92	GADL	Fixico 24 Circuit Feeder Automation	$ 137,618.67	$ -	$ 173,618.08	$ (23,518.42)	$ -	$ -	$ (571.09)	$ (11,909.90)	$ -	$ -	$ -	$ -
93	GADL	Fixico 24 Circuit Lateral Automation	$ 441,943.02	$ -	$ 512,026.14	$ (8,083.93)	$ (14,031.68)	$ 69.23	$ (8,786.50)	$ (39,250.24)	$ -	$ -	$ -	$ -
94	GADL	Kellyville 24 Circuit Feeder Automation	$ 315,392.32	$ -	$ 321,574.66	$ -	$ (6,182.34)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95	GADL	Kellyville 24 Circuit Lateral Automation	$ 676,502.99	$ -	$ 761,622.70	$ (38,615.16)	$ (124,718.22)	$ 102,781.10	$ (96,111.00)	$ 71,474.38	$ 69.19	$ -	$ -	$ -
96	GADL	Little River 21 Circuit Feeder Automation	$ 101,291.77	$ -	$ 101,291.77	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
97	GADL	Little River 21 Circuit Lateral Automation	$ 360,390.89	$ -	$ 558,808.63	$ (84,497.39)	$ (15.34)	$ 8,648.74	$ 960.05	$ 10,155.06	$ (133,668.86)	$ -	$ -	$ -
98	GADL	Eighty Fourth 31 Circuit Feeder Automation	$ 145,267.20	$ -	$ 188,744.96	$ (5,520.61)	$ (42,412.97)	$ 42,457.00	$ (38,001.18)	$ -	$ -	$ -	$ -	$ -
99	GADL	Eighty Fourth 31 Circuit Lateral Automation	$ 255,555.99	$ -	$ 264,956.10	$ -	$ (5,106.45)	$ -	$ (4,293.66)	$ -	$ -	$ -	$ -	$ -
100	GADL	Riverside 24 Circuit Feeder Automation	$ 203,775.40	$ 333,795.90	$ -	$ 614.65	$ -	$ -	$ -	$ -	$ -	$ (130,635.15)	$ -	$ -
101	GADL	Riverside 24 Circuit Lateral Automation	$ 172,260.41	$ 169,134.77	$ -	$ -	$ 249.08	$ -	$ 484.85	$ -	$ 2,391.71	$ -	$ -	$ -
102	GADL	Inglewood 22 Circuit Feeder Automation	$ 146,070.70	$ -	$ 146,070.70	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
103	GADL	Inglewood 22 Circuit Lateral Automation	$ 347,035.99	$ -	$ 420,942.49	$ (75,420.21)	$ 851.91	$ 471.87	$ 189.93	$ -	$ -	$ -	$ -	$ -
104	GADL	Newman Ave 41 Circuit Feeder Automation	$ 228,372.98	$ -	$ 339,013.68	$ -	$ -	$ -	$ -	$ -	$ -	$ (101,933.70)	$ (8,707.00)	$ -
105	GADL	Newman Ave 41 Circuit Lateral Automation	$ 624,577.44	$ -	$ 708,182.63	$ 364.03	$ (1,851.28)	$ (83,990.53)	$ 1,872.59	$ -	$ -	$ -	$ -	$ -
106	GADL	Stonewall 24 Circuit Feeder Automation	$ 155,368.75	$ -	$ 163,747.00	$ -	$ (8,598.55)	$ 220.30	$ -	$ -	$ -	$ -	$ -	$ -
107	GADL	Stonewall 24 Circuit Lateral Automation	$ 321,443.22	$ -	$ 357,391.96	$ (35,948.74)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
108	GADL	Woodward Dist 46 Circuit Feeder Automation	$ 105,192.33	$ -	$ 105,192.33	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
109	GADL	Woodward Dist 46 Circuit Lateral Automation	$ 347,343.26	$ -	$ 333,662.20	$ 12,407.46	$ 1,273.60	$ -	$ -	$ -	$ -	$ -	$ -	$ -
110	GADL	Green Pastures 21 Circuit Feeder Automation	$ 160,893.07	$ -	$ 160,672.77	$ -	$ -	$ 220.30	$ -	$ -	$ -	$ -	$ -	$ -
111	GADL	Green Pastures 21 Circuit Lateral Automation	$ 210,592.67	$ -	$ 210,852.66	$ (696.92)	$ 436.93	$ -	$ -	$ -	$ -	$ -	$ -	$ -
112	GADL	Ardmore 26 Circuit Feeder Automation	$ 224,082.27	$ -	$ 224,210.30	$ -	$ (348.33)	$ 220.30	$ -	$ -	$ -	$ -	$ -	$ -

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Project List

No.	Category	Project Description	Total Cost	November	December	January	February	March	April	May	June	July	August	September
113	GADL	Ardmore 26 Circuit Lateral Automation	$ 215,216.88	$ -	$ 215,216.88	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
114	GADL	Howe 22 Circuit Feeder Automation	$ 166,993.42	$ -	$ 166,480.99	$ (84.47)	$ -	$ -	$ 596.90	$ -	$ -	$ -	$ -	$ -
115	GADL	Howe 22 Circuit Lateral Automation	$ 148,978.30	$ -	$ 145,116.48	$ -	$ -	$ -	$ 3,792.61	$ 69.21	$ -	$ -	$ -	$ -
116	GADL	Cypress 22 Circuit Feeder Automation	$ 135,309.62	$ -	$ 135,096.36	$ -	$ (194.25)	$ -	$ 407.51	$ -	$ -	$ -	$ -	$ -
117	GADL	Cypress 22 Circuit Lateral Automation	$ 241,839.54	$ -	$ 328,672.61	$ (87,900.16)	$ -	$ -	$ 928.70	$ 138.39	$ -	$ -	$ -	$ -
118	GATP	OK GRID MOD CYME SECURITY	$ 40,675.00	$ 40,675.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
119	GATP	DER Interconnection	$ 653,146.59	$ -	$ -	$ -	$ -	$ -	$ -	$ 594,090.46	$ 41,374.68	$ 888.92	$ 16,762.23	$ 30.30
120	GADS	Lone Grove Substation Automation	$ 47,512.63	$ -	$ -	$ -	$ -	$ 46,202.86	$ (1,024.00)	$ -	$ 1,393.04	$ -	$ -	$ 940.73
121	GADS	WR Airport Substation Automation	$ 45,552.40	$ -	$ -	$ -	$ -	$ 70,039.00	$ (26,980.46)	$ 33,135.53	$ 2,007.78	$ (26,208.90)	$ (6,440.55)	$ -
122	GADS	Lakeside Substation Automation	$ 48,333.72	$ -	$ -	$ -	$ -	$ 48,459.75	$ (237.66)	$ -	$ -	$ -	$ -	$ 111.63
123	GADS	Otter Substation Automation	$ 818.09	$ -	$ -	$ -	$ -	$ -	$ 285.26	$ 1,536.71	$ (1,003.88)	$ -	$ -	$ -
124	GADS	Sulphur Substation Automation	$ 7,126.34	$ -	$ -	$ -	$ -	$ -	$ 5,947.15	$ -	$ -	$ 691.98	$ -	$ 487.21
125	GADS	Lightning Creek Substation Automation	$ 20,676.28	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,155.46	$ 1,452.85	$ 67.97	$ -	$ -
126	GADS	Bellcow Substation Automation	$ 90,337.15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,972.76	$ (2,009.73)	$ 1,658.11	$ (283.99)
127	GADS	Morrison Tap Substation Automation	$ 214,994.93	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 205,958.72	$ (5,334.64)	$ 15,678.85	$ (1,308.00)
128	GADS	Warwick Substation Automation	$ 1,121.38	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,121.38	$ -	$ -	$ -
129	GADS	Mobile Substation 2019	$ 3,010,990.88	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,007,779.85	$ -	$ 1,168.84	$ 2,042.19
130	GADS	Dale Substation Automation	$ 68,688.61	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 63,671.42	$ 13,084.41	$ (8,067.22)
131	GADS	Key West Substation Automation	$ 283,346.46	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 296,816.33	$ (13,469.87)
132	GADS	Jumper Creek Substation Automation	$ 74,764.34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 73,264.33	$ 1,500.01
133	GADS	Prairie Point Substation Automation	$ 32,485.29	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,966.05	$ 12,519.24
134	GADS	Inglewood Substation Automation	$ 391,253.16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 391,253.16
135	GADS	Vian Substation Automation	$ 257,305.27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 257,305.27
136	GADS	Pearson Substation Automation	$ 111,668.14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 111,668.14
137	GADS	Letha Substation Automation	$ 155,441.85	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 155,441.85
138	GADS	Reno Substation Automation	$ 163,279.85	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 163,279.85
139	GADS	South Ada Substation Automation	$ 23,493.27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,493.27
140	GADS	Fairmont Substation Automation	$ 111,318.92	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 111,318.92
141	GADS	Boyd Substation	$ 302,299.63	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 302,299.63
142	GADS	Mobile Substation 2018	$ 3,104,956.84	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,104,956.84
143	GADS	Mobile Substation 2020	$ 3,102,867.74	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,102,867.74
144	GADL	Otter 41 Circuit Feeder Automation	$ 281,502.84	$ -	$ -	$ -	$ -	$ 271,895.55	$ 10,960.65	$ (2,007.84)	$ 654.48	$ -	$ -	$ -
145	GADL	Otter 41 Circuit Lateral Automation	$ 413,380.15	$ -	$ -	$ -	$ -	$ 409,478.12	$ 1,700.61	$ (125.53)	$ 2,326.95	$ -	$ -	$ -
146	GADL	Midway 31 Circuit Feeder Automation	$ 173,054.23	$ -	$ -	$ -	$ -	$ 205,448.75	$ (31,031.49)	$ (3.80)	$ (1,359.23)	$ -	$ -	$ -
147	GADL	Midway 31 Circuit Lateral Automation	$ 424,999.37	$ -	$ -	$ -	$ -	$ 464,838.82	$ (7,727.31)	$ (95.68)	$ (32,016.46)	$ -	$ -	$ -
148	GADL	Wilshire 22 Circuit Feeder Automation	$ 187,534.73	$ -	$ -	$ -	$ -	$ 191,636.51	$ (5,387.52)	$ 1.95	$ 1,283.79	$ -	$ -	$ -
149	GADL	Wilshire 22 Circuit Lateral Automation	$ 213,483.47	$ -	$ -	$ -	$ -	$ 206,498.50	$ 5,387.52	$ 46.55	$ 1,550.90	$ -	$ -	$ -
150	GADL	Wilshire 23 Circuit Feeder Automation	$ 244,845.92	$ -	$ -	$ -	$ -	$ 251,128.07	$ (4,898.18)	$ (2,193.50)	$ 809.53	$ -	$ -	$ -
151	GADL	Wilshire 23 Circuit Lateral Automation	$ 177,640.50	$ -	$ -	$ -	$ -	$ 169,313.12	$ 4,273.99	$ 2,077.00	$ 1,976.39	$ -	$ -	$ -
152	GADL	Bellcow 50 Circuit Feeder Automation	$ 105,380.32	$ -	$ -	$ -	$ -	$ 103,624.35	$ 1,866.91	$ (110.94)	$ -	$ -	$ -	$ -
153	GADL	Bellcow 50 Circuit Lateral Automation	$ 205,578.92	$ -	$ -	$ -	$ -	$ 209,204.91	$ (4,840.62)	$ 1,214.63	$ -	$ -	$ -	$ -
154	GADL	Bixby 22 Circuit Feeder Automation	$ 186,871.27	$ -	$ -	$ -	$ -	$ 190,632.86	$ (4,187.93)	$ 833.49	$ (194.66)	$ (125.65)	$ (60.60)	$ (26.24)
155	GADL	Bixby 22 Circuit Lateral Automation	$ 240,127.17	$ -	$ -	$ -	$ -	$ 233,333.27	$ 6,725.99	$ 3,047.70	$ (4,775.54)	$ 1,080.85	$ 487.92	$ 226.98
156	GADL	Bixby 29 Circuit Feeder Automation	$ 147,384.99	$ -	$ -	$ -	$ -	$ 152,973.48	$ (8,124.36)	$ 1,059.09	$ 1,226.29	$ -	$ -	$ 250.49
157	GADL	Bixby 29 Circuit Lateral Automation	$ 356,930.11	$ -	$ -	$ -	$ -	$ 351,099.50	$ 1,475.63	$ 3,099.62	$ 1,290.49	$ -	$ -	$ (35.13)
158	GADL	Sulphur 23 Circuit Feeder Automation	$ 142,753.85	$ -	$ -	$ -	$ -	$ 151,983.98	$ (211.48)	$ 1,009.97	$ (317.61)	$ 1,622.62	$ (11,333.63)	$ -
159	GADL	Sulphur 23 Circuit Lateral Automation	$ 183,622.05	$ -	$ -	$ -	$ -	$ 193,109.10	$ 735.98	$ 1,251.36	$ 2,094.77	$ (301.81)	$ (13,267.35)	$ -
160	GADL	Sulphur 29 Circuit Feeder Automation	$ 54,001.86	$ -	$ -	$ -	$ -	$ 54,192.40	$ 2,272.92	$ (113.98)	$ 1,125.68	$ (10.37)	$ (3,464.79)	$ -
161	GADL	Sulphur 29 Circuit Lateral Automation	$ 204,828.32	$ -	$ -	$ -	$ -	$ 238,623.51	$ (13,480.59)	$ 1,549.14	$ 793.30	$ 142.14	$ (22,799.18)	$ -
162	GADL	Belle Isle Sta 28 Circuit Feeder Automation	$ 68,375.84	$ -	$ -	$ -	$ -	$ 78,410.69	$ 33,566.09	$ (43,872.09)	$ 271.15	$ -	$ -	$ -
163	GADL	Belle Isle Sta 28 Circuit Lateral Automation	$ 346,862.15	$ -	$ -	$ -	$ -	$ 423,217.07	$ (663.45)	$ (75,711.78)	$ 20.31	$ -	$ -	$ -
164	GADL	Wewoka 21 Circuit Feeder Automation	$ 170,756.21	$ -	$ -	$ -	$ -	$ 192,894.29	$ 405.94	$ (105.88)	$ 585.77	$ (23,023.91)	$ -	$ -
165	GADL	Wewoka 21 Circuit Lateral Automation	$ 459,413.37	$ -	$ -	$ -	$ -	$ 481,425.86	$ 2,745.24	$ 4,880.48	$ 4,186.00	$ (33,824.21)	$ -	$ -
166	GADL	Wewoka 24 Circuit Feeder Automation	$ 201,267.82	$ -	$ -	$ -	$ -	$ 233,504.53	$ (19,698.74)	$ (991.71)	$ (11,547.36)	$ 857.05	$ (855.95)	$ -
167	GADL	Wewoka 24 Circuit Lateral Automation	$ 317,364.63	$ -	$ -	$ -	$ -	$ 364,361.79	$ (4,828.95)	$ 671.31	$ (42,868.91)	$ 24,013.30	$ (23,983.91)	$ -
168	GADL	Lone Oak 71 Circuit Feeder Automation	$ 117,365.68	$ -	$ -	$ -	$ -	$ 110,262.61	$ 3,587.45	$ 1,222.32	$ 714.20	$ 1,369.22	$ 209.88	$ -
169	GADL	SW 5th ST 23 Circuit Feeder Automation	$ 139,659.72	$ -	$ -	$ -	$ -	$ 146,122.40	$ (6,438.23)	$ (249.53)	$ 553.81	$ (305.24)	$ -	$ (23.49)
170	GADL	SW 5th ST 23 Circuit Lateral Automation	$ 275,937.46	$ -	$ -	$ -	$ -	$ 314,342.55	$ (14,508.47)	$ (7,614.81)	$ (40.01)	$ (16,466.03)	$ -	$ 224.23
171	GADL	Tennessee 26 Circuit Feeder Automation	$ 156,993.63	$ -	$ -	$ -	$ -	$ 211,035.98	$ 1,654.07	$ -	$ (12,025.60)	$ (22.09)	$ (42,679.23)	$ (969.50)
172	GADL	Tennessee 26 Circuit Lateral Automation	$ 165,294.06	$ -	$ -	$ -	$ -	$ 92,313.61	$ 2,548.52	$ -	$ 80,632.62	$ 160.59	$ (10,284.01)	$ (77.27)
173	GADL	Fixico 29 Circuit Feeder Automation	$ 150,917.62	$ -	$ -	$ -	$ -	$ 154,385.35	$ 3,368.28	$ 77.73	$ (2,874.33)	$ (4,012.34)	$ (27.07)	$ -
174	GADL	Fixico 29 Circuit Lateral Automation	$ 247,551.56	$ -	$ -	$ -	$ -	$ 260,081.48	$ (1,064.04)	$ 1,119.62	$ (4,727.86)	$ (8,093.32)	$ 235.68	$ -
175	GADL	Maysville 21 Circuit Lateral Automation	$ 110,203.86	$ -	$ -	$ -	$ -	$ 159,630.37	$ (9,356.85)	$ (13,183.28)	$ 1,110.74	$ (27,997.12)	$ -	$ -
176	GADL	Maysville 22 Circuit Lateral Automation	$ 155,471.87	$ -	$ -	$ -	$ -	$ 185,734.78	$ (23,396.12)	$ (6,866.79)	$ -	$ -	$ -	$ -

Project List

No.	Category	Project Description	Total Cost	November	December	January	February	March	April	May	June	July	August	September
177	GADL	Letha 21 Circuit Feeder Automation	$ 96,863.48	$ -	$ -	$ -	$ -	$ 93,661.15	$ 2,002.36	$ 759.87	$ 440.10	$ -	$ -	$ -
178	GADL	Letha 21 Circuit Lateral Automation	$ 183,843.44	$ -	$ -	$ -	$ -	$ 199,039.99	$ 1,887.02	$ (12,751.23)	$ (4,332.34)	$ -	$ -	$ -
179	GADL	Lightning Creek 31 Circuit Feeder Automation	$ 143,395.31	$ -	$ -	$ -	$ -	$ 122,578.49	$ 25,742.84	$ (100.60)	$ 2,149.24	$ -	$ (6,974.66)	$ -
180	GADL	Lightning Creek 31 Circuit Lateral Automation	$ 286,906.84	$ -	$ -	$ -	$ -	$ 316,085.51	$ 4,142.72	$ (18,942.65)	$ (7,527.69)	$ -	$ (6,851.05)	$ -
181	GADL	NE 10TH ST 26 Circuit Feeder Automation	$ 184,696.61	$ -	$ -	$ -	$ -	$ 188,748.57	$ (5,337.43)	$ (667.43)	$ 1,952.90	$ -	$ -	$ -
182	GADL	NE 10TH ST 26 Circuit Lateral Automation	$ 232,642.82	$ -	$ -	$ -	$ -	$ 263,739.92	$ (19,321.99)	$ (11,479.85)	$ (295.26)	$ -	$ -	$ -
183	GADL	Eighty Fourth St 29 Circuit Feeder Automation	$ 171,013.64	$ -	$ -	$ -	$ -	$ 155,149.72	$ (2,254.22)	$ 5,519.37	$ 12,755.78	$ (220.08)	$ (162.71)	$ 225.78
184	GADL	Eighty Fourth St 29 Circuit Lateral Automation	$ 189,484.34	$ -	$ -	$ -	$ -	$ 202,524.87	$ 3,717.06	$ (11,176.87)	$ (8,788.12)	$ 1,791.71	$ 1,336.21	$ 79.48
185	GADL	Meridian 28 Circuit Feeder Automation	$ 140,948.59	$ -	$ -	$ -	$ -	$ 159,279.67	$ 4,429.52	$ (4,575.34)	$ 1,959.16	$ (20,144.42)	$ -	$ -
186	GADL	Meridian 28 Circuit Lateral Automation	$ 301,966.49	$ -	$ -	$ -	$ -	$ 353,879.76	$ 2,972.79	$ (9,608.39)	$ (341.30)	$ (44,936.37)	$ -	$ -
187	GADL	Tishomingo 21 Circuit Lateral Automation	$ 240,546.57	$ -	$ -	$ -	$ -	$ 273,300.76	$ (6,788.99)	$ 11,291.36	$ 992.14	$ (32,670.13)	$ (5,578.57)	$ -
188	GADL	Bellcow 21 Circuit Feeder Automation	$ 193,215.35	$ -	$ -	$ -	$ -	$ -	$ 192,937.12	$ (480.48)	$ (1,592.87)	$ 2,105.23	$ -	$ 246.35
189	GADL	Bellcow 21 Circuit Lateral Automation	$ 413,479.06	$ -	$ -	$ -	$ -	$ -	$ 433,068.59	$ 5,666.17	$ (25,233.60)	$ 4.29	$ -	$ (26.39)
190	GADL	Bristow 21 Circuit Feeder Automation	$ 195,077.16	$ -	$ -	$ -	$ -	$ -	$ 193,498.70	$ 1,849.14	$ (419.04)	$ -	$ (96.20)	$ 244.56
191	GADL	Bristow 21 Circuit Lateral Automation	$ 496,919.90	$ -	$ -	$ -	$ -	$ -	$ 490,503.55	$ (287.54)	$ 5,471.05	$ -	$ 1,269.70	$ (36.86)
192	GADL	Dale 29 Circuit Feeder Automation	$ 41,828.81	$ -	$ -	$ -	$ -	$ -	$ 45,142.05	$ (2,517.23)	$ (729.43)	$ (28.36)	$ (38.22)	$ -
193	GADL	Dale 29 Circuit Lateral Automation	$ 258,094.30	$ -	$ -	$ -	$ -	$ -	$ 393,626.97	$ (106,180.35)	$ (31,782.94)	$ 1,052.44	$ 1,378.18	$ -
194	GADL	Davis 21 Circuit Feeder Automation	$ 115,886.07	$ -	$ -	$ -	$ -	$ -	$ 118,281.53	$ 929.86	$ (293.06)	$ (4,379.69)	$ 1,351.19	$ (3.76)
195	GADL	Davis 21 Circuit Lateral Automation	$ 290,627.44	$ -	$ -	$ -	$ -	$ -	$ 319,992.95	$ (6,383.81)	$ (24,557.95)	$ (95,259.27)	$ 97,126.84	$ (291.32)
196	GADL	Jumper Creek 25 Circuit Feeder Automation	$ 97,890.58	$ -	$ -	$ -	$ -	$ -	$ 98,882.75	$ 367.24	$ (1,224.16)	$ (135.25)	$ -	$ -
197	GADL	Jumper Creek 25 Circuit Lateral Automation	$ 362,701.01	$ -	$ -	$ -	$ -	$ -	$ 382,891.33	$ 704.64	$ (23,022.19)	$ 2,127.23	$ -	$ -
198	GADL	Jumper Creek 27 Circuit Feeder Automation	$ 58,712.53	$ -	$ -	$ -	$ -	$ -	$ 50,248.02	$ 5,421.16	$ 3,043.35	$ -	$ -	$ -
199	GADL	Jumper Creek 27 Circuit Lateral Automation	$ 376,577.22	$ -	$ -	$ -	$ -	$ -	$ 383,303.25	$ (7,015.75)	$ 289.72	$ -	$ -	$ -
200	GADL	Key West 46 Circuit Feeder Automation	$ 119,873.92	$ -	$ -	$ -	$ -	$ -	$ 119,742.10	$ 1,521.73	$ (881.54)	$ 3.26	$ (511.63)	$ -
201	GADL	Key West 46 Circuit Lateral Automation	$ 261,535.37	$ -	$ -	$ -	$ -	$ -	$ 281,553.94	$ (463.22)	$ (25,431.12)	$ 108.47	$ 5,767.30	$ -
202	GADL	Key West 47 Circuit Feeder Automation	$ 128,070.18	$ -	$ -	$ -	$ -	$ -	$ 135,707.94	$ (759.01)	$ (8,862.02)	$ 1,983.27	$ -	$ -
203	GADL	Key West 47 Circuit Lateral Automation	$ 217,926.06	$ -	$ -	$ -	$ -	$ -	$ 227,333.72	$ (36.46)	$ (9,075.30)	$ (295.90)	$ -	$ -
204	GADL	Meridian 24 Circuit Feeder Automation	$ 111,105.52	$ -	$ -	$ -	$ -	$ -	$ 112,755.65	$ 13,622.34	$ (15,248.34)	$ -	$ 0.54	$ (24.67)
205	GADL	Meridian 24 Circuit Lateral Automation	$ 311,427.12	$ -	$ -	$ -	$ -	$ -	$ 455,487.92	$ (142,345.62)	$ (1,224.35)	$ -	$ 19.42	$ (510.25)
206	GADL	Oak Grove 21 Circuit Feeder Automation	$ 170,860.23	$ -	$ -	$ -	$ -	$ -	$ 172,924.67	$ 127.26	$ (2,067.30)	$ (39.57)	$ (44.82)	$ (40.01)
207	GADL	Oak Grove 21 Circuit Lateral Automation	$ 320,050.88	$ -	$ -	$ -	$ -	$ -	$ 396,756.66	$ (29,392.08)	$ (48,683.49)	$ 434.86	$ 493.47	$ 441.46
208	GADL	Pearson 21 Circuit Feeder Automation	$ 95,257.17	$ -	$ -	$ -	$ -	$ -	$ 98,056.59	$ 1,156.13	$ (385.26)	$ (4,433.14)	$ 862.85	$ -
209	GADL	Pearson 21 Circuit Lateral Automation	$ 540,395.33	$ -	$ -	$ -	$ -	$ -	$ 578,817.64	$ (456.98)	$ (15,553.65)	$ (23,093.40)	$ 681.72	$ -
210	GADL	Pennsylvania 36 Circuit Feeder Automation	$ 152,660.83	$ -	$ -	$ -	$ -	$ -	$ 206,370.24	$ (13,140.75)	$ (788.54)	$ (39,780.12)	$ -	$ -
211	GADL	Pennsylvania 36 Circuit Lateral Automation	$ 133,555.33	$ -	$ -	$ -	$ -	$ -	$ 166,333.12	$ (20,436.55)	$ (5,765.70)	$ (6,575.54)	$ -	$ -
212	GADL	Southgate 24 Circuit Feeder Automation	$ 109,291.16	$ -	$ -	$ -	$ -	$ -	$ 113,993.69	$ 324.08	$ (5,564.03)	$ -	$ (16.01)	$ 553.43
213	GADL	Southgate 24 Circuit Lateral Automation	$ 187,442.56	$ -	$ -	$ -	$ -	$ -	$ 213,961.74	$ (12,382.19)	$ (14,430.51)	$ -	$ 145.00	$ 148.52
214	GADL	Thirty Eighth ST 23 Circuit Feeder Automation	$ 192,002.83	$ -	$ -	$ -	$ -	$ -	$ 213,833.31	$ 16,856.38	$ (39,027.30)	$ -	$ -	$ 340.44
215	GADL	Thirty Eighth ST 23 Circuit Lateral Automation	$ 265,924.64	$ -	$ -	$ -	$ -	$ -	$ 274,113.26	$ (4,407.00)	$ (3,754.08)	$ -	$ -	$ (27.54)
216	GADL	Thirty Eighth ST 25 Circuit Feeder Automation	$ 142,633.97	$ -	$ -	$ -	$ -	$ -	$ 160,893.54	$ (488.77)	$ (17,770.80)	$ -	$ -	$ -
217	GADL	Thirty Eighth ST 25 Circuit Lateral Automation	$ 390,779.19	$ -	$ -	$ -	$ -	$ -	$ 461,455.27	$ (20,999.54)	$ (49,676.54)	$ -	$ -	$ -
218	GADL	Vian 22 Circuit Feeder Automation	$ 60,137.34	$ -	$ -	$ -	$ -	$ -	$ 63,159.04	$ (2,908.34)	$ (113.36)	$ -	$ -	$ -
219	GADL	Vian 22 Circuit Lateral Automation	$ 145,538.41	$ -	$ -	$ -	$ -	$ -	$ 151,805.96	$ (7,677.84)	$ 1,410.29	$ -	$ -	$ -
220	GADL	Wells 49 Circuit Feeder Automation	$ 153,805.54	$ -	$ -	$ -	$ -	$ -	$ 156,740.02	$ (1,901.38)	$ (669.34)	$ (363.76)	$ -	$ -
221	GADL	Wells 49 Circuit Lateral Automation	$ 273,952.11	$ -	$ -	$ -	$ -	$ -	$ 285,874.42	$ (9,247.43)	$ (6,230.68)	$ 3,555.80	$ -	$ -
222	GADL	SW 5th ST 64 Circuit Feeder Automation	$ 232,776.86	$ -	$ -	$ -	$ -	$ -	$ -	$ 242,073.24	$ (10,141.39)	$ -	$ 883.41	$ (38.40)
223	GADL	SW 5th ST 64 Circuit Lateral Automation	$ 97,394.87	$ -	$ -	$ -	$ -	$ -	$ -	$ 93,925.42	$ 3,333.79	$ -	$ (68.27)	$ 203.93
224	GADL	Morrison Tap 22 Circuit Feeder Automation	$ 125,827.27	$ -	$ -	$ -	$ -	$ -	$ -	$ 120,962.83	$ 4,928.19	$ -	$ -	$ (63.75)
225	GADL	Morrison Tap 22 Circuit Lateral Automation	$ 105,941.27	$ -	$ -	$ -	$ -	$ -	$ -	$ 105,701.38	$ (225.31)	$ -	$ -	$ 465.20
226	GADL	Cushing Tap 49 Circuit Feeder Automation	$ 103,538.95	$ -	$ -	$ -	$ -	$ -	$ -	$ 102,735.18	$ 853.23	$ -	$ -	$ (49.46)
227	GADL	Cushing Tap 49 Circuit Lateral Automation	$ 198,692.08	$ -	$ -	$ -	$ -	$ -	$ -	$ 198,162.98	$ 41.00	$ -	$ -	$ 488.10
228	GADL	Vanoss 22 Circuit Feeder Automation	$ 102,982.80	$ -	$ -	$ -	$ -	$ -	$ -	$ 102,514.84	$ 498.98	$ -	$ -	$ (31.02)
229	GADL	Vanoss 22 Circuit Lateral Automation	$ 383,801.19	$ -	$ -	$ -	$ -	$ -	$ -	$ 408,068.40	$ (24,809.36)	$ -	$ -	$ 542.15
230	GADL	Midway 63 Circuit Feeder Automation	$ 206,079.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 214,543.79	$ 53.38	$ (8,518.03)	$ -	$ -
231	GADL	Midway 63 Circuit Lateral Automation	$ 344,175.86	$ -	$ -	$ -	$ -	$ -	$ -	$ 341,153.83	$ 1,735.08	$ 1,286.95	$ -	$ -
232	GADL	Inglewood 21 Circuit Feeder Automation	$ 223,568.52	$ -	$ -	$ -	$ -	$ -	$ -	$ 221,442.38	$ 2,159.51	$ -	$ -	$ (33.37)
233	GADL	Inglewood 21 Circuit Lateral Automation	$ 222,881.58	$ -	$ -	$ -	$ -	$ -	$ -	$ 222,583.32	$ 64.15	$ -	$ -	$ 234.11
234	GADL	Lakeside 22 Circuit Feeder Automation	$ 106,763.43	$ -	$ -	$ -	$ -	$ -	$ -	$ 105,623.03	$ 1,227.67	$ (87.27)	$ -	$ -
235	GADL	Lakeside 22 Circuit Lateral Automation	$ 144,155.12	$ -	$ -	$ -	$ -	$ -	$ -	$ 143,591.72	$ 2,404.90	$ (1,841.50)	$ -	$ -
236	GADL	Jensen Rd 63 Circuit Feeder Automation	$ 160,538.16	$ -	$ -	$ -	$ -	$ -	$ -	$ 204,484.99	$ (43,946.83)	$ -	$ -	$ -
237	GADL	Jensen Rd 63 Circuit Lateral Automation	$ 213,123.60	$ -	$ -	$ -	$ -	$ -	$ -	$ 246,804.90	$ (33,681.30)	$ -	$ -	$ -
238	GADL	Mcloud 22 Circuit Feeder Automation	$ 133,641.96	$ -	$ -	$ -	$ -	$ -	$ -	$ 133,013.75	$ 179.75	$ 448.46	$ -	$ -
239	GADL	Mcloud 22 Circuit Lateral Automation	$ 201,877.31	$ -	$ -	$ -	$ -	$ -	$ -	$ 201,332.75	$ 610.87	$ (66.31)	$ -	$ -
240	GADL	Rush Creek 22 Circuit Feeder Automation	$ 198,240.28	$ -	$ -	$ -	$ -	$ -	$ -	$ 218,977.95	$ (15,249.08)	$ (1,114.41)	$ (4,374.18)	$ -

Project List

No.	Category	Project Description	Total Cost	November	December	January	February	March	April	May	June	July	August	September
241	GADL	Rush Creek 22 Circuit Lateral Automation	$ 283,169.17	$ -	$ -	$ -	$ -	$ -	$ -	$ 298,212.76	$ (1,777.16)	$ (9,243.89)	$ (4,022.54)	$ -
242	GADL	Lone Grove 22 Circuit Feeder Automation	$ 45,663.96	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,863.53	$ 3,136.51	$ (336.08)	$ -	$ -
243	GADL	Lone Grove 22 Circuit Lateral Automation	$ 220,299.10	$ -	$ -	$ -	$ -	$ -	$ -	$ 236,636.82	$ 338.52	$ (16,676.24)	$ -	$ -
244	GADL	Lone Grove 23 Circuit Feeder Automation	$ 122,347.05	$ -	$ -	$ -	$ -	$ -	$ -	$ 118,613.09	$ 2,397.19	$ 1,336.77	$ -	$ -
245	GADL	Lone Grove 23 Circuit Lateral Automation	$ 284,975.86	$ -	$ -	$ -	$ -	$ -	$ -	$ 281,826.91	$ 2,397.30	$ 751.65	$ -	$ -
246	GADL	Ardmore 24 Circuit Lateral Automation	$ 312,897.05	$ -	$ -	$ -	$ -	$ -	$ -	$ 393,316.68	$ (85,462.07)	$ 2,997.01	$ 1,202.85	$ 842.58
247	GADL	Tennessee 31 Circuit Feeder Automation	$ 196,041.03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 201,485.48	$ (5,444.45)	$ -	$ -
248	GADL	Tennessee 31 Circuit Lateral Automation	$ 103,735.44	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 107,544.06	$ (3,808.62)	$ -	$ -
249	GADL	Tennessee 35 Circuit Feeder Automation	$ 195,372.59	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 196,734.58	$ -	$ 605.01	$ (1,967.00)
250	GADL	Tennessee 35 Circuit Lateral Automation	$ 157,268.16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 162,492.74	$ -	$ (66.22)	$ (5,158.36)
251	GADL	Inglewood 23 Circuit Feeder Automation	$ 187,961.34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 185,077.32	$ 2,884.02	$ -	$ -
252	GADL	Inglewood 23 Circuit Lateral Automation	$ 543,099.32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 547,511.10	$ (4,411.78)	$ -	$ -
253	GADL	WR Airport 21 Circuit Feeder Automation	$ 115,338.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 115,508.16	$ (530.50)	$ 360.96	$ -
254	GADL	WR Airport 21 Circuit Lateral Automation	$ 71,525.79	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 71,592.17	$ (29.95)	$ (36.43)	$ -
255	GADL	Reno 31 Circuit Feeder Automation	$ 95,454.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 95,531.31	$ -	$ (77.31)	$ -
256	GADL	Reno 31 Circuit Lateral Automation	$ 305,203.26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 303,952.45	$ -	$ 1,250.81	$ -
257	GADL	Russett 21 Circuit Feeder Automation	$ 105,062.36	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 105,201.23	$ (138.87)	$ -	$ -
258	GADL	Russett 21 Circuit Lateral Automation	$ 237,832.10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 236,095.95	$ 1,736.15	$ -	$ -
259	GADL	Rosedale Tap 24 Circuit Feeder Automation	$ 62,912.16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 64,665.42	$ (9.40)	$ (985.00)	$ (758.86)
260	GADL	Rosedale Tap 24 Circuit Lateral Automation	$ 257,913.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 294,907.70	$ 193.85	$ (2,446.89)	$ (34,741.54)
261	GADL	Heavener 22 Circuit Feeder Automation	$ 108,166.63	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 108,390.36	$ (36.72)	$ (187.01)	$ -
262	GADL	Heavener 22 Circuit Lateral Automation	$ 309,443.07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 305,948.87	$ 569.01	$ 2,925.19	$ -
263	GADL	Mission Hill 24 Circuit Feeder Automation	$ 190,568.38	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 189,358.52	$ -	$ 1,228.83	$ (18.97)
264	GADL	Mission Hill 24 Circuit Lateral Automation	$ 395,094.40	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 397,187.58	$ -	$ (2,312.89)	$ 219.71
265	GADL	Fixico 46 Circuit Lateral Automation	$ 159,842.60	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 174,143.53	$ -	$ (14,300.93)	$ -
266	GADL	Remington 21 Circuit Feeder Automation	$ 93,404.80	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92,199.13	$ (47.07)	$ 1,252.74	$ -
267	GADL	Remington 21 Circuit Lateral Automation	$ 275,515.08	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 279,006.05	$ 675.72	$ (4,166.69)	$ -
268	GADL	Davis 22 Circuit Feeder Automation	$ 59,737.42	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 58,808.14	$ 1,035.28	$ -	$ (106.00)
269	GADL	Davis 22 Circuit Lateral Automation	$ 274,172.87	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 306,333.18	$ (26,666.50)	$ -	$ (5,493.81)
270	GADL	South Ada 24 Circuit Feeder Automation	$ 108,282.17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 105,836.44	$ 2,445.73	$ -	$ -
271	GADL	South Ada 24 Circuit Lateral Automation	$ 132,076.72	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 132,322.70	$ (245.98)	$ -	$ -
272	GADL	South Ada 29 Circuit Feeder Automation	$ 193,164.24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 204,582.99	$ (1,015.58)	$ (9,507.07)	$ (896.10)
273	GADL	South Ada 29 Circuit Lateral Automation	$ 189,396.76	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 276,999.47	$ (72,261.27)	$ 561.89	$ (15,903.33)
274	GADL	Belle Isle Sta 22 Circuit Feeder Automation	$ 177,418.50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 178,668.24	$ 1,781.44	$ (3,031.18)	$ -
275	GADL	Belle Isle Sta 22 Circuit Lateral Automation	$ 174,798.46	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 176,211.70	$ 985.07	$ (2,398.31)	$ -
276	GADL	Belle Isle Sta 26 Circuit Feeder Automation	$ 202,928.72	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 228,905.32	$ 1,136.26	$ (26,024.24)	$ (1,088.62)
277	GADL	Belle Isle Sta 26 Circuit Lateral Automation	$ 425,065.72	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 433,551.90	$ 251.94	$ (8,629.93)	$ (108.19)
278	GADL	Warwick 41 Circuit Feeder Automation	$ 119,388.50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 115,318.97	$ 19,420.56	$ (15,351.03)	$ -
279	GADL	Warwick 41 Circuit Lateral Automation	$ 530,118.52	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 555,546.81	$ (25,096.62)	$ (331.67)	$ -
280	GADL	Fairmont 29 Circuit Feeder Automation	$ 191,968.88	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 190,087.32	$ 1,881.56	$ -	$ -
281	GADL	Fairmont 29 Circuit Lateral Automation	$ 433,782.93	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 434,090.19	$ (307.26)	$ -	$ -
282	GADL	Western Ave 27 Circuit Feeder Automation	$ 184,111.87	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 175,533.64	$ 3,146.56	$ (39,387.29)	$ 44,818.96
283	GADL	Western Ave 27 Circuit Lateral Automation	$ 285,832.74	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 294,415.17	$ 577.21	$ (112,517.18)	$ 103,357.54
284	GADL	Western Ave 28 Circuit Feeder Automation	$ 142,975.20	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 143,299.72	$ (2,213.02)	$ 1,888.50	$ -
285	GADL	Western Ave 28 Circuit Lateral Automation	$ 225,490.39	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 206,512.57	$ 18,923.80	$ 54.02	$ -
286	GADL	Western Ave 21 Circuit Feeder Automation	$ 236,482.04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 220,373.79	$ 15,546.81	$ (7,034.62)	$ 7,596.06
287	GADL	Western Ave 21 Circuit Lateral Automation	$ 253,673.93	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 258,949.33	$ (5,296.06)	$ 413.39	$ (392.73)
288	GADL	Lone Oak 64 Circuit Feeder Automation	$ 224,059.86	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 222,313.46	$ 899.46	$ 846.94	$ -
289	GADL	Lone Oak 64 Circuit Lateral Automation	$ 193,713.13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 186,664.13	$ 6,899.96	$ 149.04	$ -
290	GADL	Prairie Point 21 Circuit Lateral Automation	$ 245,808.82	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 239,783.28	$ -	$ -	$ 6,025.54
291	GADL	Boyd 23 Circuit Feeder Automation	$ 257,919.29	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 309,303.40	$ 10,850.30	$ 1,752.41	$ (63,986.82)
292	GADL	Boyd 23 Circuit Lateral Automation	$ 156,512.25	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 161,130.42	$ 3,444.87	$ 45.73	$ (8,108.77)
293	GADL	SW 5th ST 64 Circuit Capacitor Automation	$ 48,139.17	$ -	$ -	$ -	$ -	$ -	$ 43,842.85	$ 627.97	$ 1,665.84	$ 1,086.82	$ 554.93	$ 360.76
294	GADL	Bellcow 21 Circuit Capacitor Automation	$ 149,904.59	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 165,899.35	$ (16,919.79)	$ 443.97	$ 481.06
295	GADL	Wells 49 Circuit Capacitor Automation	$ 19,047.39	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,175.20	$ 1,003.83	$ (170.79)	$ 39.15
296	GADL	Bristow 21 Circuit Capacitor Automation	$ 93,070.24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92,486.84	$ 583.40	$ -	$ -
297	GADL	Wewoka 21 Circuit Capacitor Automation	$ 103,814.63	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 101,923.51	$ 966.09	$ 443.97	$ 481.06
298	GADL	Heavener 22 Circuit Capacitor Automation	$ 83,631.42	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 82,628.85	$ 798.01	$ 204.56	$ -
299	GADL	Cushing Tap 49 Circuit Capacitor Automation	$ 20,455.15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,683.53	$ 1,328.37	$ 5,068.06	$ 375.19
300	GADL	Midway 63 Circuit Capacitor Automation	$ 16,021.47	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,049.06	$ (3,027.59)	$ -
301	GADL	Bixby 22 Circuit Capacitor Automation	$ 58,458.18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 57,266.95	$ 1,191.23	$ -
302	GADL	Sulphur 29 Circuit Capacitor Automation	$ 68,571.11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 66,310.63	$ 1,718.52	$ 541.96
303	GADL	Mcloud 22 Circuit Capacitor Automation	$ 65,848.97	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 74,393.56	$ (9,602.83)	$ 1,058.24
304	GADL	Fixico 29 Circuit Capacitor Automation	$ 48,764.47	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 48,470.78	$ 609.73	$ (316.04)

Project List

No.	Category	Project Description	Total Cost	November	December	January	February	March	April	May	June	July	August	September
305	GADL	Russett 21 Circuit Capacitor Automation	$ 63,958.30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 51,889.96	$ -	$ 12,068.34
306	GADL	Vian 22 Circuit Capacitor Automation	$ 18,186.02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,268.60	$ (82.58)	$ -
307	GADL	Maysville 21 Circuit Capacitor Automation	$ 31,113.10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,343.88	$ 1,769.22	$ -
308	GADL	Maysville 22 Circuit Capacitor Automation	$ 37,344.13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,668.48	$ (5,324.35)	$ -
309	GADL	Dale 29 Circuit Capacitor Automation	$ 24,746.22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,273.29	$ (2,527.07)	$ -
310	GADL	Rosedale Tap 24 Circuit Capacitor Automation	$ 29,593.60	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,942.53	$ 651.07	$ -
311	GADL	Letha 21 Circuit Capacitor Automation	$ 47,126.02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 55,848.18	$ (8,839.57)	$ 117.41
312	GADL	Jensen Rd 63 Circuit Capacitor Automation	$ 29,403.06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,403.06	$ -	$ -
313	GADL	Sulphur 23 Circuit Capacitor Automation	$ 72,161.32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 70,896.77	$ 1,264.55
314	GADL	Key West 46 Circuit Capacitor Automation	$ 96,674.90	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 96,161.73	$ 513.17
315	GADL	Fairmont 29 Circuit Capacitor Automation	$ 92,761.45	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,524.80	$ 2,236.65
316	GADL	Pearson 21 Circuit Capacitor Automation	$ 82,669.48	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 150,621.19	$ (67,951.71)
317	GADL	WR Airport 21 Circuit Capacitor Automation	$ 29,618.42	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,715.15	$ 903.27
318	GADL	Mission Hill 24 Circuit Capacitor Automation	$ 79,532.80	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 105,912.50	$ (26,379.70)
319	GADL	Remington 21 Circuit Capacitor Automation	$ 64,361.58	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 64,258.41	$ 103.17
320	GADL	Davis 22 Circuit Capacitor Automation	$ 50,823.30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 40,429.54	$ 10,393.76
321	GADL	Otter 41 Circuit Capacitor Automation	$ 76,581.05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 76,581.05
322	GADL	Bellcow 50 Circuit Capacitor Automation	$ 37,554.22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,554.22
323	GADL	Bixby 29 Circuit Capacitor Automation	$ 171,944.57	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 171,944.57
324	GADL	Warwick 41 Circuit Capacitor Automation	$ 105,616.10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 105,616.10
325	GADL	Wewoka 24 Circuit Capacitor Automation	$ 100,682.90	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 100,682.90
326	GADL	Key West 47 Circuit Capacitor Automation	$ 70,793.18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 70,793.18
327	GADL	Lone Grove 22 Circuit Capacitor Automation	$ 33,608.26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 33,608.26
328	GADL	Lone Oak 64 Circuit Capacitor Automation	$ 18,913.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,913.12
329	GADL	Fixico 46 Circuit Capacitor Automation	$ 54,053.88	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 54,053.88
330	GADL	Thirty Eighth ST 23 Circuit Capacitor Automation	$ 93,986.97	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 93,986.97
331	GADL	Jumper Creek 25 Circuit Capacitor Automation	$ 90,336.15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,336.15
332	GADL	Jumper Creek 27 Circuit Capacitor Automation	$ 57,255.84	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 57,255.84
333	GADL	Prairie Point 21 Circuit Capacitor Automation	$ 57,276.61	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 57,276.61
334	GADL	Oak Grove 21 Circuit Capacitor Automation	$ 123,999.24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 123,999.24
335	GADL	Davis 21 Circuit Capacitor Automation	$ 74,897.53	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 74,897.53
336	GADL	Rush Creek 22 Circuit Capacitor Automation	$ 116,278.32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 116,278.32
337	GADL	Vanoss 22 Circuit Capacitor Automation	$ 63,218.97	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 63,218.97
338	GADL	Tishomingo 21 Circuit Capacitor Automation	$ 87,974.99	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 87,974.99
339	GADL	Bixby 29 Circuit Regulator Automation	$ 11,877.26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,877.26	$ -	$ -	$ -
340	GADL	Wells 49 Circuit Regulator Automation	$ 17,628.01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,084.92	$ 1,543.09	$ -	$ -
341	GADL	Key West 46 Circuit Regulator Automation	$ 12,206.78	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,029.72	$ 3,698.08	$ -	$ 478.98
342	GADL	Lone Grove 22 Circuit Regulator Automation	$ 13,584.91	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,137.04	$ 1,528.39	$ 919.48	$ -
343	GADL	Fixico 29 Circuit Regulator Automation	$ 4,354.55	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,448.17	$ 1,528.39	$ -	$ 377.99
344	GADL	Jumper Creek 25 Circuit Regulator Automation	$ 11,737.84	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,076.82	$ 2,735.99	$ 443.97	$ 481.06
345	GADL	Jumper Creek 27 Circuit Regulator Automation	$ 25,131.80	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,591.14	$ 3,504.67	$ 554.93	$ 481.06
346	GADL	Maysville 22 Circuit Regulator Automation	$ 18,579.36	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,169.66	$ 2,373.71	$ 554.93	$ 481.06
347	GADL	Pearson 21 Circuit Regulator Automation	$ 17,757.74	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,572.40	$ 2,963.37	$ 221.97	$ -
348	GADL	Dale 29 Circuit Regulator Automation	$ 109,865.82	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 108,878.88	$ 1,140.01	$ (153.07)	$ -
349	GADL	Rosedale Tap 24 Circuit Regulator Automation	$ 6,338.50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,810.11	$ 1,528.39	$ -	$ -
350	GADL	Letha 21 Circuit Regulator Automation	$ 10,813.23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,937.18	$ 1,876.05	$ -	$ -
351	GADL	Russett 21 Circuit Regulator Automation	$ 49,112.33	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 52,608.19	$ (3,495.86)	$ -
352	GADL	Otter 41 Circuit Regulator Automation	$ 118,902.47	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 116,764.65	$ 2,137.82
353	GADL	Sulphur 29 Circuit Regulator Automation	$ 32,070.36	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 31,209.80	$ 860.56
354	GADL	Wewoka 21 Circuit Regulator Automation	$ 59,962.89	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 58,773.65	$ 1,189.24
355	GADL	Fairmont 29 Circuit Regulator Automation	$ 103,011.98	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 108,641.03	$ (5,629.05)
356	GADL	Davis 21 Circuit Regulator Automation	$ 26,193.50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 26,193.50	$ -
357	GADL	Davis 22 Circuit Regulator Automation	$ 33,257.86	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 26,647.21	$ 6,610.65
358	GADL	Vanoss 22 Circuit Regulator Automation	$ 28,717.09	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,395.46	$ (1,678.37)
359	GADL	Warwick 41 Circuit Regulator Automation	$ 91,161.91	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 91,161.91
360	GADL	Tishomingo Substation Removal	$ 782,097.77	$ -	$ -	$ -	$ -	$ -	$ -	$ 172,389.05	$ 33,265.46	$ (166,449.09)	$ 384,873.66	$ 358,018.69
361	GACS	Palo Alto Ent License Agrmnt Refresh-SW	$ 7,693,750.76	$ -	$ -	$ -	$ -	$ 7,693,750.76	$ -	$ -	$ -	$ -	$ -	$ -
361.1	GACS	PALO ALTO NETWORKS ENTERPRISE LICENSE (Remove per STAFF 5/2021)	$ (1,140,070.00)					$ (1,140,070.00)						
362	GATP	Tarigma Ied Licenses	$ 288,088.34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 288,088.34	$ -	$ -	$ -
363	GATP	Dsb-Elt Software -- Fme	$ 31,894.51	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 31,894.51	$ -	$ -	$ -
364	GACS	Multiplatform NCM/NMS-SW	$ 178,911.56	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 178,911.56
365	GACS	Comp_FAN Equip, Infrastructure, Config	$ 315,469.13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 315,469.13
366	GADS	Substation Removal Costs	$ 2,346,857.12	$ 27,036.93	$ 117,955.33	$ 379,443.28	$ 114,536.59	$ 185,375.61	$ 214,202.42	$ 300,642.17	$ 344,266.43	$ 256,597.50	$ 201,765.89	$ 205,034.97

Project List

No.	Category	Project Description	Total Cost	November	December	January	February	March	April	May	June	July	August	September
367	GADL	Circuit Automation Removal Costs	$ 5,658,674.76	$ 679,160.33	$ 425,005.02	$ 569,426.54	$ 272,705.06	$ 491,956.92	$ 972,539.75	$ 783,371.36	$ 727,118.86	$ 333,603.48	$ 276,365.89	$ 127,421.55
368	GACS	Communication Systems Removal Costs	$ 6,517.61	$ -	$ -	$ -	$ 148.08	$ 832.93	$ 1,249.67	$ 1,768.83	$ 1,472.06	$ 756.78	$ (1,290.79)	$ 1,580.05
		Total	**$ 97,382,290.70**	**$ 9,482,525.04**	**$ 19,206,429.37**	**$ 1,363,032.79**	**$ 220,591.30**	**$ 19,242,336.81**	**$ 9,342,516.51**	**$ 6,980,096.67**	**$ 18,439,959.25**	**$ (28,331.76)**	**$ 1,868,253.49**	**$ 11,264,881.23**

Grid Enhancement Non-Mechanism Reporting

OGE Plan 2020 & 2021 (excludes OK 2019)
Actuals through 10/31/2021
Updated: 11/24/2021

Category Description	Total Cost	2020	January	February	March	April	May	June	July	August	September	October
Distribution Line Resiliency	$ 50,410,335.50	$ 19,475,135.60	$ 1,314,611.28	$ 4,007,711.79	$ 1,433,657.13	$ 844,373.07	$ 2,314,272.96	$ 5,350,201.37	$ 2,462,877.79	$ 5,578,488.32	$ 3,854,684.82	$ 3,774,321.37
Distribution Substation Resiliency	$ 12,849,961.61	$ 2,235,528.55	$ 676,075.63	$ 551,123.12	$ 1,340,938.01	$ 893,995.84	$ 158,470.21	$ 2,886,878.12	$ 288,249.34	$ 1,341,828.00	$ 2,246,650.61	$ 230,224.18
Transmission Substation	$ 2,198,942.77	$ 199,941.50	$ 555,638.75	$ (12,383.09)	$ 160,931.05	$ 192,103.43	$ 6,482.92	$ 597,031.88	$ (259.26)	$ 8,182.79	$ 516,757.80	$ (25,485.00)
Distribution Removal	$ 19,601,442.27	$ 7,529,580.97	$ 745,675.47	$ 1,067,523.19	$ 544,364.55	$ 1,182,727.23	$ 1,449,126.13	$ 1,319,102.88	$ 861,219.13	$ 1,954,061.95	$ 1,508,844.35	$ 1,439,216.42
Substation Removal	$ 2,578,995.90	$ 1,030,610.12	$ 110,322.01	$ 122,770.46	$ 125,918.24	$ 151,701.85	$ 126,089.45	$ 115,139.29	$ 118,308.44	$ 234,298.92	$ 253,594.24	$ 190,242.88
Total	**$ 87,639,678.05**	**$ 30,470,796.74**	**$ 3,402,323.14**	**$ 5,736,745.47**	**$ 3,605,808.98**	**$ 3,264,901.42**	**$ 4,054,441.67**	**$ 10,268,353.54**	**$ 3,730,395.44**	**$ 9,116,859.98**	**$ 8,380,531.82**	**$ 5,608,519.85**

							2021	2021	2021	2021	2021	2021	2021	2021	2021	2021
WBS element	**Name**	**Category**	**Type**	**Project**	**Total**	**2020**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**
K:01503-4353.00/5	OGE PLAN 2021 DSB RES INSTALL-OTTER SUB	Substation	DSB GR	Otter	24,222.86	-	-	-	-	24,688.93	(466.07)	-	-	-	-	-
K:01503-4353.41/5	DLN GR OH OTTER 41 - AUC	Distribution	GR OH	Otter 41	303,113.56	-	302,052.88	174.97	-	1,055.03	(169.32)	-	-	-	-	-
K:01503-8522.31/5	DLN GR OH MIDWAY 31 - AUC	Distribution	GR OH	Midway 31	952,799.03	-	-	-	-	-	-	951,595.09	5,889.55	44.03	(4,970.04)	240.40
K:01503-8522.63/5	DLN GR OH MIDWAY 63 - AUC	Distribution	GR OH	Midway 63	544,902.32	-	-	-	-	-	-	545,081.54	3,888.46	1,043.51	(5,111.19)	-
K:01503-8347.22/5	DLN GR OH WILLSHIRE 22 - AUC	Distribution	GR OH	Wilshire 22	407,260.71	-	-	-	-	587,726.95	-	505.99	1,462.98	(175,451.94)	(6,983.27)	-
K:01503-8347.23/5	DLN GR OH WILLSHIRE 23 - AUC	Distribution	GR OH	Wilshire 23	959,554.06	-	-	-	-	-	-	630,171.92	175,326.08	102,029.33	41,679.27	10,347.46
K:01503-5804.00/5	OGE PLAN 2021 DSB RES INSTALL-SOUTH ADA	Substation	DSB GR	South Ada	135,113.09	-	-	-	-	-	-	-	-	-	127,100.66	8,012.43
K:01503-7104.00/5	OGE PLAN 2021 DSB RES INSTALL-BELL COW	Substation	DSB GR	Bellcow	318,829.62	-	-	-	-	-	-	290,120.74	-	490.51	28,218.37	-
K:01503-7104.21/5	DLN GR OH BELLCOW 21 - AUC	Distribution	GR OH	Bellcow 21	1,398,905.26	-	-	-	-	-	-	-	-	1,584,020.86	(185,388.83)	273.23
K:01503-7104.50/5	DLN GR OH BELLCOW 50 - AUC	Distribution	GR OH	Bellcow 50	1,411,316.11	-	-	-	-	-	-	-	-	-	1,420,140.88	(8,824.77)
K:01503-3209.22/5	DLN GR OH BIXBY 22 - AUC	Distribution	GR OH	Bixby 22	116,733.08	-	-	-	-	116,097.34	(183.99)	819.73	-	-	-	-
K:01503-3209.29/5	DLN GR OH BIXBY 29 - AUC	Distribution	GR OH	Bixby 29	445,332.51	-	-	-	-	383,231.59	-	11,778.06	73,151.62	(23,014.92)	186.16	-
K:01503-5705.00/5	OGE PLAN 2021 DSB RES INSTALL-SULPHUR	Substation	DSB GR	Sulphur	188,124.30	-	-	-	-	185,688.40	587.40	179.28	-	-	1,669.22	-
K:01503-5705.23/5	DLN GR OH SULPHUR 23 - AUC	Distribution	GR OH	Sulphur 23	494,990.78	-	-	-	-	-	-	695,879.83	1,293.17	(202,182.22)	-	-
K:01503-5705.29/5	DLN GR OH SULPHUR 29 - AUC	Distribution	GR OH	Sulphur 29	676,670.30	-	-	-	-	-	-	-	-	-	958,624.27	(281,953.97)
K:01503-8312.28/5	DLN GR OH BELLE ISLE 28 - AUC	Distribution	GR OH	Belle Isle 28	694,120.88	-	-	-	-	-	-	-	-	-	685,504.12	8,616.76
K:01503-7706.21/5	DLN GR OH BRISTOW 21 - AUC	Distribution	GR OH	Bristow 21	876,140.37	-	-	-	-	-	-	-	-	-	-	876,140.37
K:01503-7119.00/5	OGE PLAN 2021 DSB RES INSTALL WARWICK	Substation	DSB GR	Warwick	54,064.44	-	-	-	-	-	-	51,003.17	2,821.10	240.17	-	-
K:01503-7505.21/5	DLN GR OH WEWOKA 21 - AUC	Distribution	GR OH	Wewoka 21	722,537.13	-	-	-	-	-	-	718,786.25	9,657.65	(4,999.59)	(1,300.33)	393.15
K:01503-7505.24/6	DLN GR UG WEWOKA 24 - AUC	Distribution	GR UG	Wewoka 24	237,302.21	-	-	-	-	-	-	-	-	-	-	237,302.21
K:01503-7118.00/5	OGE PLAN 2021 DSB RES INSTALL KEY WEST	Substation	DSB GR	Key West	455,346.82	-	-	-	-	-	-	-	-	453,791.25	12,194.33	(10,638.76)
K:01503-7118.46/5	DLN GR OH KEY WEST 46 - AUC	Distribution	GR OH	Key West 46	34,824.33	-	-	-	-	-	58,345.58	(23,521.25)	-	-	-	-
K:01503-7118.47/5	DLN GR OH KEY WEST 47 - AUC	Distribution	GR OH	Key West 47	918,196.67	-	-	-	-	-	-	-	-	-	-	918,196.67
K:01503-5125.00/5	OGE PLAN 2021 DSB RES INSTALL LONE GROV	Substation	DSB GR	Lone Grove	96,970.78	-	-	-	100,159.78	(4,019.26)	830.26	-	-	-	-	-
K:01503-5125.22/5	DLN GR OH LONE GROVE 22 - AUC	Distribution	GR OH	Lone Grove 22	1,074,020.40	-	-	-	-	-	-	-	-	-	983,694.89	90,325.51
K:01503-5125.23/5	DLN GR OH LONE GROVE 23	Distribution	GR OH	Lone Grove 23	565,229.09	-	-	-	-	-	-	-	-	-	-	565,229.09
K:01503-4158.00/5	OGE PLAN 2021 DSB RES INSTALL FAIRMONT	Substation	DSB GR	Fairmont	299,549.22	-	-	-	-	-	-	-	-	-	294,418.25	5,130.97
K:01503-4158.29/5	DLN GR OH FAIRMONT 29 - AUC	Distribution	GR OH	Fairmont 29	511,848.85	-	-	-	-	-	-	329,458.31	230,258.50	(28,551.57)	(19,316.39)	-
K:01503-8248.64/5	DLN GR OH SW 5TH ST 64 - AUC	Distribution	GR OH	SW 5th ST 64	893,369.44	-	-	-	-	-	-	-	-	-	-	893,369.44
K:01503-8248.23/5	DLN GR OH SW 5TH ST 23 - AUC	Distribution	GR OH	SW 5th ST 23	603,489.68	-	-	-	-	-	-	691,837.39	133,082.02	(129,104.00)	-	(92,325.73)
K:01503-8336.26/5	DLN GR OH TENNESSEE 26 - AUC	Distribution	GR OH	Tennessee 26	368,145.25	-	-	-	-	-	-	567,424.39	(29,315.85)	20,450.40	(191,024.24)	610.55
K:01503-8336.31/5	DLN GR OH TENNESSEE 31 - AUC	Distribution	GR OH	Tennessee 31	202,580.55	-	-	-	-	232,863.74	1,798.66	(35,840.20)	3,758.35	-	-	-
K:01503-8336.35/5	DLN GR OH TENNESSEE 35 - AUC	Distribution	GR OH	Tennessee 35	276,610.26	-	-	-	-	-	-	262,455.67	5,905.03	-	8,249.56	-
K:01503-7430.00/3	OGE PLAN 2021 TSB AUTO INSTALL INGLEWOOD	Substation	TSB Auto	Inglewood	332,213.50	-	-	-	-	-	-	-	-	-	349,996.06	(17,782.56)
K:01503-7430.00/5	OGE PLAN 2021 DSB RES INSTALL INGLEWOOD	Substation	DSB GR	Inglewood	546,198.81	-	-	-	-	-	-	-	-	-	474,215.71	71,983.10
K:01503-7430.00/7	OGE PLAN 2021 TSB RES INSTALL INGLEWOOD	Substation	TSB GR	Inglewood	155,009.11	-	-	-	-	-	-	-	-	-	162,711.55	(7,702.44)
K:01503-7306.29/5	DLN GR OH FIXICO 29 - AUC	Distribution	GR OH	Fixico 29	221,215.37	-	-	-	-	-	276,345.57	(55,469.51)	144.34	-	194.97	-
K:01503-7306.46/5	DLN GR OH FIXICO 46 - AUC	Distribution	GR OH	Fixico 46	151,907.22	-	-	-	-	-	93,591.14	(30,418.60)	(745.07)	(4.85)	58,538.11	30,946.49
K:01503-8322.23/5	DLN GR OH THIRTY EIGHTH STREET 23 - AUC	Distribution	GR OH	Thirty Eight ST 23	1,699,408.02	-	-	-	-	-	-	-	-	2,556,905.99	(5,850.93)	(851,647.04)
K:01503-8322.25/5	DLN GR OH THIRTY EIGHTH STREET 25 - AUC	Distribution	GR OH	Thirty Eight ST 25	481,373.12	-	-	-	-	-	-	-	576,004.91	-	(94,631.79)	-
K:01503-7312.00/5	OGE PLAN 2021 DSB RES INSTL JUMPER CRK	Substation	DSB GR	Jumper Creek	722,626.04	-	-	-	-	-	-	-	-	725,542.47	(2,917.20)	0.77
K:01503-3327.00/5	OGE PLAN 2021 DSB RES INSTALL VIAN SUB	Substation	DSB GR	Vian	249,443.18	-	-	-	-	-	-	-	-	-	205,506.64	43,936.54
K:01503-7611.00/5	OGE PLAN 2021 DSB RES INSTALL MORRISON	Substation	DSB GR	Morrison Tap	258,752.00	-	-	-	-	-	-	286,533.89	(30,944.36)	2,492.67	669.80	-
K:01503-7611.22/5	DLN GR OH MORRISON TAP 22 - AUC	Distribution	GR OH	Morrison Tap 22	338,702.88	-	-	-	-	-	-	296,584.87	34,123.01	6,830.78	(314.80)	1,479.02
K:01503-5611.21/5	DLN GR OH MAYSVILLE 21 - AUC	Distribution	GR OH	Maysville 21	591,179.23	-	-	-	-	-	-	-	876,397.08	(39,128.44)	(249,080.97)	2,991.56
K:01503-7412.00/5	OGE PLAN 2021 DSB RES INSTALL PEARSON	Substation	DSB GR	Pearson	60,933.48	-	-	-	-	-	-	-	-	-	62,255.02	(1,321.54)
K:01503-5620.00/5	OGE PLAN 2021 DSB RES INSTL PRAIRIE PNT	Substation	DSB GR	Prairie Point	138,034.79	-	-	-	-	-	-	-	-	144,814.93	(20,450.28)	13,670.14
K:01503-7411.00/5	OGE PLAN 2021 DSB RES INSTALL DALE	Substation	DSB GR	Dale	250,804.35	-	-	-	-	-	-	-	262,524.88	(16,775.18)	4,126.67	927.98
K:01503-7411.29/5	DLN GR OH DALE 29 - AUC	Distribution	GR OH	Dale 29	298,969.41	-	-	-	-	-	-	-	-	381,097.94	(82,128.53)	-
K:01503-5607.24/5	DLN GR OH ROSEDALE TAP 24 - AUC	Distribution	GR OH	Rosedale Tap 24	1,897,366.99	-	-	-	-	-	-	-	-	1,866,571.36	32,196.35	(1,400.72)
K:01503-8133.00/5	OGE PLAN 2021 DSB RES INSTALL WRWA	Substation	DSB GR	WRWA	13,102.30	-	-	-	-	13,102.30	-	-	-	-	-	-
K:01503-8133.21/5	DLN GR OH WRWA 21 - AUC	Distribution	GR OH	WRWA 21	28,271.61	-	-	-	-	-	-	-	-	22,989.94	4,101.47	1,180.20
K:01503-7321.00/5	OGE PLAN 2021 DSB RES INSTL LETHA	Substation	DSB GR	Letha	230,453.94	-	-	-	-	-	-	-	-	-	211,519.96	18,933.98
K:01503-7321.21/5	DLN GR OH LETHA 21 - AUC	Distribution	GR OH	Letha 21	506,277.88	-	-	-	-	-	-	-	-	-	505,822.88	455.00
K:01503-7606.49/5	DLN GR OH CUSHING TAP 49 - AUC	Distribution	GR OH	Cushing Tap 49	35,136.48	-	-	-	-	24,408.05	3,410.93	797.24	6,520.26	-	-	-
K:01503-8706.00/5	OGE PLAN 2021 DSB RES INSTALL BOYD	Substation	DSB GR	Boyd	274,555.22	-	-	-	-	-	-	-	-	-	238,566.41	35,988.81
K:01503-8706.23/5	DLN GR OH - BOYD 23 - AUC	Distribution	GR OH	Boyd 23	279,282.89	-	-	-	-	-	-	-	-	-	-	279,282.89
K:01503-8620.00/5	OGE PLAN 2021 DSB RES INSTL LIGHT CRK	Substation	DSB GR	Lightning Creek	40,725.82	-	-	-	-	-	40,725.82	-	-	-	-	-
K:01503-8542.00/5	OGE PLAN 2021 DSB RES INSTALL RENO	Substation	DSB GR	Reno	286,530.42	-	-	-	-	-	-	-	-	-	293,439.85	(6,909.43)
K:01503-8365.00/5	OGE PLAN 2021 DSB RES INSTL LAKESIDE	Substation	DSB GR	Lakeside	20,352.95	-	-	-	-	19,656.05	106.00	27.76	563.14	-	-	-
K:01503-8365.22/5	DLN GR OH LAKE SIDE 22 - AUC	Distribution	GR OH	Lakeside 22	627,158.57	-	-	-	-	-	-	-	-	-	-	627,158.57
K:01503-5708.21/5	DLN GR OH DAVIS 21 - AUC	Distribution	GR OH	Davis 21	511,569.35	-	-	-	-	-	-	-	-	-	-	511,569.35
K:01503-8221.24/5	DLN GR OH - MERIDIAN 24 - AUC	Distribution	GR OH	Meridian 24	341,130.71	-	-	-	-	-	-	-	439,651.13	(98,712.10)	191.68	-
Multiple	K:01503 Distribution Removal	Distribution		Distribution Rmvl	9,750,287.04	311,273.44	342,822.56	408,336.50	539,914.50	670,570.65	588,257.34	1,196,887.19	888,310.64	1,848,112.92	1,507,832.01	1,447,969.29
Multiple	K:01503 Substation Removal	Substation		Substation Rmvl	995,990.06	23,324.94	15,080.57	12,200.36	17,514.15	41,957.83	79,141.93	72,790.28	112,683.78	208,792.26	233,151.48	179,352.48
K:01303-0004	DLN-LAYDOWN YARD-WORK ORDER - 8961605	Distribution	GR OH	Laydown Yard	336,305.94	-	-	-	-	-	-	327,783.55	-	-	-	8,522.39
K:01303-0017.4	DLN-OGM DLI OH LINE HEALDTON 21-AUC	Distribution	GR OH	Healdton 21	1,472,328.98	1,476,718.64	520.75	323.46	-	(5,187.38)	-	(46.49)	-	-	-	-
K:01303-0019.4	DLN-OGM DLI OH LINE JAMESVILLE 21-AUC	Distribution	GR OH	Jamesville 21	673,096.68	683,152.16	-	-	-	(932.67)	-	-	-	-	-	(9,122.81)
K:01303-0019.6	DLN-OGM DLI OH LINE JAMESVILLE 41-AUC	Distribution	GR OH	Jamesville 41	394,645.75	401,331.43	-	-	-	-	-	-	-	-	-	(6,685.68)
K:01303-0021.4	DLN-OGM DLI OH LINE BOWDEN 23-AUC	Distribution	GR OH	Bowden 23	163,723.84	163,612.11	-	111.73	-	-	-	-	-	-	-	-
K:01303-0021.6	DLN-OGM DLI OH LINE BOWDEN 29-AUC	Distribution	GR OH	Bowden 29	878,662.70	885,685.90	(5,768.26)	-	-	-	-	(1,254.94)	-	-	-	-
K:01303-0023.4	DLN-OGM DLI OH LINE TENNYSON 22-AUC	Distribution	GR OH	Tennyson 22	325,360.22	325,093.60	23.70	242.92	-	-	-	-	-	-	-	-
K:01303-0023.5	DLN-OGM UG RP TENNYSON 22-AUC	Distribution	GR UG	Tennyson 22	302,639.40	302,270.70	368.70	-	-	-	-	-	-	-	-	-
K:01303-0023.6	DLN-OGM DLI OH LINE TENNYSON 23-AUC	Distribution	GR OH	Tennyson 23	327,649.70	327,487.30	-	162.40	-	-	-	-	-	-	-	-
K:01303-0023.8	DLN-OGM DLI OH LINE TENNYSON 24-AUC	Distribution	GR OH	Tennyson 24	650,426.86	649,881.99	-	162.40	-	150.76	-	-	-	231.71	-	-
K:01303-0025.4	DLN-OGM DLI OH LINE CHECOTAH 21-AUC	Distribution	GR OH	Checotah 21	729,100.37	730,137.38	-	242.92	-	-	-	-	-	(1,279.93)	-	-
K:01303-0025.6	DLN-OGM DLI OH LINE CHECOTAH 22-AUC	Distribution	GR OH	Checotah 22	608,615.84	630,746.35	-	3,008.91	-	-	-	-	(2,854.40)	(21,584.39)	(700.63)	-
K:01303-0027.4	DLN-OGM DLI OH LINE ILLINOIS RIVR 21-AUC	Distribution	GR OH	Illinois River 21	509,813.61	513,853.06	-	(3,042.93)	-	-	(996.52)	-	-	-	-	-
K:01303-0029.4	DLN-OGM DLI OH LINE LONE STAR 22-AUC	Distribution	GR OH	Lone Star 22	496,801.57	499,180.20	-	-	-	(1,845.14)	-	(533.49)	-	-	-	-

Direct Exhibit KS-3

K:01303-0031.4	DLN-OGM OH LINE MERIDIAN 22-AUC	Distribution	GR OH	Meridian 22	1,078,336.32	1,078,336.32	-	-	-	-	-	-	-	-	-	-
K:01303-0031.6	DLN-OGM DLI OH LINE MERIDIAN 23=AUC	Distribution	GR OH	Meridian 23	790,035.32	1,085,619.70	(296,641.01)	-	1,056.63	-	-	-	-	-	-	-
K:01303-0031.8	DLN-OGM DLI OH LINE MERIDIAN 29-AUC	Distribution	GR OH	Meridian 29	637,087.74	636,827.00	-	260.74	-	-	-	-	-	-	-	-
K:01303-0033.4	DLN-OGM DLI OH LINE WESTERN 23-AUC	Distribution	GR OH	Western Ave 23	598,655.65	980,514.59	-	2,598.83	-	(2,199.78)	(167,100.78)	(215,157.21)	-	-	-	-
K:01303-0033.6	DLN-OGM DLI OH LINE WESTERN 24-AUC	Distribution	GR OH	Western Ave 24	381,747.12	380,295.25	-	1,032.50	-	-	-	-	-	146.14	-	273.23
K:01303-0033.8	DLN-OGM DLI OH LINE WESTERN25-AUC	Distribution	GR OH	Western Ave 25	235,395.68	235,395.68	-	-	-	-	-	-	-	-	-	-
K:01303-0035.4	DLN-OGM DLI OH LINE DEWEY 41-AUC	Distribution	GR OH	Dewey 41	165,675.21	165,915.25	-	162.40	-	-	-	-	-	(402.44)	-	-
K:01303-0043.4	DLN-OGM DLI OH LINE HANCOCK 22-AUC	Distribution	GR OH	Hancock 22	195,001.96	194,665.29	-	-	490.42	(153.75)	-	-	-	-	-	-
K:01303-0043.6	DLN-OGM DLI OH LINE HANCOCK 24-AUC	Distribution	GR OH	Hancock 24	266,455.06	267,399.51	-	-	-	-	-	-	-	-	-	(944.45)
K:01303-0045.4	DLN-OGM DLI OH LINE BEGGS 24-AUC	Distribution	GR OH	Beggs 24	227,484.61	247,292.35	(18,793.05)	(481.20)	-	-	-	(533.49)	-	-	-	-
K:01303-0045.6	DLN-OGM DLI OH LINE BEGGS 29-AUC	Distribution	GR OH	Beggs 29	183,312.37	194,019.52	-	4,190.37	1,394.29	(16,419.18)	1,196.13	(1,068.76)	-	-	-	-
K:01303-0047.4	DLN-OGM DLI OH LINE ROMAN NOSE 47-AUC	Distribution	GR OH	Roman Nose 47	119,052.89	118,890.49	-	162.40	-	-	-	-	-	-	-	-
K:01303-0049.4	DLN-OGM DLI OH LINE JENSEN RD 69-AUC	Distribution	GR OH	Jensen Rd 69	295,667.12	295,424.20	-	242.92	-	-	-	-	-	-	-	-
K:01303-0051.4	DLN-OGM DLI OH LINE MAY AVE 21-AUC	Distribution	GR OH	May Ave 21	441,737.65	443,942.74	233,869.95	(2,047.06)	-	-	-	-	-	(234,304.49)	276.51	-
K:01303-0051.6	DLN-OGM DLI OH LINE MAY AVE 22-AUC	Distribution	GR OH	May Ave 22	543,993.68	453,205.13	314,141.07	10,367.17	-	-	(149,323.45)	(84,396.24)	-	-	-	-
K:01303-0051.8	DLN-OGM DLI OH LINE MAY AVE 24-AUC	Distribution	GR OH	May Ave 24	1,126,687.61	-	-	-	1,424,268.98	(2,432.74)	(297,093.17)	-	-	740.18	1,204.36	-
K:01303-0053.4	DLN-OGM DLI OH LINE HONOR HEIGHTS 21-AUC	Distribution	GR OH	Honor Heights 21	428,942.25	449,686.36	1,050.01	54,417.68	2,212.63	(602.72)	-	-	(77,818.44)	(3.27)	-	-
K:01303-0055.4	DLN-OGM DLI OH LINE TIBBEN RD 24-AUC	Distribution	GR OH	Tibben Rd 24	373,280.63	-	433,258.07	(59,972.61)	-	(1.56)	-	-	-	(3.27)	-	-
K:01303-0057.4	DLN-OGM DLI OH LINE FIXICO 22-AUC	Distribution	GR OH	Fixico 22	254,210.54	253,845.82	-	242.92	-	-	-	-	-	121.80	-	-
K:01303-0057.6	DLN-OGM DLI OH LINE FIXICO 24-AUC	Distribution	GR OH	Fixico 24	222,115.92	221,363.14	(2,474.81)	1,914.98	284.62	318.51	273.66	-	-	-	-	435.82
K:01303-0063.4	DLN-OGM DLI OH LINE KELLYVILLE 24-AUC	Distribution	GR OH	Kellyville 24	705,882.79	725,035.96	4,820.50	628.87	-	-	-	-	-	-	-	(24,602.54)
K:01303-0067.4	DLN-OGM DLI OH LITTLE RIVER 21-AUC	Distribution	GR OH	Little River 21	188,292.55	240,961.77	(52,889.52)	-	220.30	-	-	-	-	-	-	-
K:01303-0069.4	DLN-OGM DLI OH EIGHTY FOURTH 31-AUC	Distribution	GR OH	Eighty Fourth 31	1,479,055.19	-	-	1,988,550.31	-	(478,826.02)	(29,044.07)	(1,625.03)	-	-	-	-
K:01303-0071.4	DLN-OGM DLI OH LINE RIVERSIDE 24-AUC	Distribution	GR OH	Riverside 24	275,696.13	287,676.08	1,190.38	524.31	-	-	-	-	-	-	-	(13,694.64)
K:01303-0073.4	DLN-OGM DLI OH LINE INGLEWOOD 22-AUC	Distribution	GR OH	Inglewood 22	1,818,642.61	-	-	2,304,679.35	3,190.73	13,216.98	(352,114.75)	(150,329.70)	-	-	-	-
K:01303-0093.4	DLN-OGM DLI OH LINE NEWMAN AVE 41-AUC	Distribution	GR OH	Newman Ave 41	554,858.05	717,607.35	(144,072.54)	(1,019.47)	149.48	-	18.02	(6,782.23)	(11,589.05)	(519.15)	881.28	184.36
K:01303-0099.4	DLN-OGM DLI OH LINE STONEWALL 24-AUC	Distribution	GR OH	Stonewall 24	843,438.29	686,739.98	245,665.15	(86,558.98)	-	(2,407.86)	-	-	-	-	-	-
K:01303-0101.4	DLN-OGM DLI OH WOODWARD 46-AUC	Distribution	GR OH	Woodward Dist 46	94,948.01	93,583.18	168.75	330.98	168.75	168.80	-	-	527.55	-	-	-
K:01303-0105.4	DLN-OGM DLI OH GREEN PASTURES 21-AUC	Distribution	GR OH	Green Pastures 21	622,437.61	514,742.21	307,982.35	(201,795.55)	-	(3,587.62)	(1,257.41)	7,108.73	(755.10)	-	-	-
K:01303-0107.4	DLN-OGM DLI OH ARDMORE 26-AUC	Distribution	GR OH	Ardmore 26	267,006.00	266,785.70	-	-	220.30	-	-	-	-	-	-	-
K:01303-0109.4	DLN-OGM DLI OH HOWE 22-AUC	Distribution	GR OH	Howe 22	131,597.35	133,571.96	(2,108.31)	133.70	-	-	-	-	-	-	-	-
K:01303-0111.4	DLN-OK GRID MOD CYPRESS 22-AUC	Distribution	GR OH	Cypress 22	2,799,111.61	-	-	-	-	-	2,876,576.73	(80,890.05)	8,914.01	(5,489.08)	-	-
K:01303-0210.1	DLN-OK GRID MOD ANTIOCH 49 4 KV	Distribution	GR OH	4K Conversion	200,067.12	230,054.12	(16,459.53)	(13,527.47)	-	-	-	-	-	-	-	-
K:01303-0212.1	DLN-OK GRID MOD DRUMRIGHT 44 4KV	Distribution	GR OH	4K Conversion	92,877.01	91,590.09	-	1,286.92	-	-	-	-	-	-	-	-
K:01303-0214.1	DLN-OK GRID MOD MAUD TAP 21 4 KV	Distribution	GR OH	4K Conversion	123,911.73	124,179.99	-	-	-	(268.26)	-	-	-	-	-	-
K:01303-0216.1	DLN-OK GRID MOD SOUHTARD 47 4KV CONV.	Distribution	GR OH	4K Conversion	43,801.77	35,095.72	8,706.05	-	-	-	-	-	-	-	-	-
K:01303-0220.1	DLN-OGM WARICK 41 4KV CONV.	Distribution	GR OH	4K Conversion	35,722.33	35,722.33	-	-	-	-	-	-	-	-	-	-
K:01303-0115	TSB AUTO-MERIDIAN SUB OK GRID MOD	Substation	TSB Auto	Meridian	54,855.43	-	-	-	-	-	-	83,327.73	(28,944.15)	375.72	96.13	-
K:01303-0125	TSB AUTO-HANCOCK SUB OK GRID MOD	Substation	TSB Auto	Hancock	43,828.11	-	-	-	-	-	-	46,163.93	(3,801.19)	1,452.70	12.67	-
K:01303-0129	TSB AUTO-BEGGS SUB OK GRID MOD	Substation	TSB Auto	Beggs	142,386.39	129,296.15	6,682.55	1,881.38	1,470.13	526.75	-	-	257.70	2,271.73	-	-
K:01303-0187	TSB AUTO-BEELINE SUB OK GRID MOD	Substation	TSB Auto	Beeline	194,858.43	-	-	-	-	191,017.47	3,840.96	-	-	-	-	-
K:01303-0193	TSB AUTO-ARDMORE SUB OK GRID MOD	Substation	TSB Auto	Ardmore	269,444.99	-	230,953.05	(52,835.44)	45,482.33	(3,700.69)	2,133.72	56,993.08	(7,672.98)	(1,908.08)	-	-
K:01303-0222	TSB AUTO-CHECOTAH SUB OKLA GRID ENHANCE	Substation	TSB Auto	Checotah	44,013.88	-	-	-	-	-	-	37,753.74	6,285.19	(25.05)	-	-
K:01303-0232	DSB RESILIANCY-HEALDTON SUB-OKLAHOMA GRI	Substation	DSB GR	Healdton	302,410.13	291,500.90	207.91	-	156.30	10,388.87	-	-	-	-	109.26	46.89
K:01303-0233	DSB RESILIANCY-JAMESVILLE SUB-OKLAHOMA G	Substation	DSB GR	Jamesville	344,920.87	313,118.57	16,606.93	-	-	13,660.33	(310.81)	-	1,429.59	416.26	-	-
K:01303-0234	DSB RESILIANCY-BOWDEN SUB - OKLAHOMA GRI	Substation	DSB GR	Bowden	82,098.73	-	-	-	-	77,851.99	373.31	1,191.09	644.49	-	2,037.85	-
K:01303-0235	DSB RESILIANCY-TENNYSON SUB OKLAHOMA GRI	Substation	DSB GR	Tennyson	808,025.13	-	440,923.76	-	3,934.34	357,585.12	137.17	-	3,767.97	1,676.77	-	-
K:01303-0236	DSB RESILIANCY-CHECOTAH SUB OKLAHOMA GRI	Substation	DSB GR	Checotah	290,878.09	-	-	-	-	-	-	290,827.93	50.16	-	-	-
K:01303-0237	DSB RESILIANCY-ILLININOIS RIVER SUB OKLA	Substation	DSB GR	Illinois River	121,415.54	-	-	-	117,352.88	14,050.00	(10,926.40)	358.60	252.26	271.53	-	56.67
K:01303-0238	DSB RESILIANCY-LONE STAR OKLAHOMA GRIS M	Substation	DSB GR	Lone Star	151,133.24	-	-	149,034.63	943.73	85.84	-	99.14	969.90	-	-	-
K:01303-0239	DSB RESILIANCY-MERIDIAN SUB OK GRID MOD	Substation	DSB GR	Meridian	283,593.23	-	-	-	-	-	-	284,696.46	(1,103.23)	-	-	-
K:01303-0240	DSB RESILIANCY-WESTERN SUB OK GRID MOD	Substation	DSB GR	Western	567,220.44	-	-	-	527,080.21	34,195.31	451.80	165.59	421.66	4,905.87	-	-
K:01303-0241	DSB RESILIANCY-DEWEY SUB OK GRID MOD	Substation	DSB GR	Dewey	230,220.31	-	-	-	-	-	-	225,929.67	1,215.25	3,075.39	-	-
K:01303-0242	DSB RESILIANCY-HANCOCK SUB OK GRID MOD	Substation	DSB GR	Hancock	1,089,092.87	-	-	-	-	-	-	1,063,810.37	21,599.84	3,682.66	-	-
K:01303-0243	DSB RESILIANCY-BEGGS SUB OK GRID MOD	Substation	DSB GR	Beggs	115,643.60	114,095.61	258.45	-	185.37	469.50	-	634.67	-	-	-	-
K:01303-0244	DSB RESILIANCY-ROMAN NOSE SUB OK GRID MO	Substation	DSB GR	Roman Nose	76,168.79	71,137.61	995.09	3,387.80	342.99	305.30	-	-	-	-	-	-
K:01303-0245	DSB RESILIANCY-JENSEN ROAD SUB OK GRID M	Substation	DSB GR	Jensen Road	281,263.10	-	-	-	292,750.28	(22,768.90)	11,231.56	-	50.16	-	-	-
K:01303-0246	DSB RESILIANCY-MAY AVE SUB OK GRID MOD	Substation	DSB GR	May Ave	1,241,994.59	1,241,779.38	(1,135.04)	628.65	-	-	679.19	-	42.41	-	-	-
K:01303-0247	DSB RESILIANCY-HONOR HEIGHTS SUB OK GRID	Substation	DSB GR	Honor Heights	416,515.35	-	-	302,041.62	65,815.16	33,078.57	14,172.69	433.60	973.71	-	-	-
K:01303-0248	DSB RESILIANCY-TIBBENS ROAD SUB OK GRID	Substation	DSB GR	Tibbens Road	88,320.31	-	-	61,759.15	23,400.04	2,406.75	-	-	754.37	-	-	-
K:01303-0249	DSB RESILIANCY-FIXICO SUB OK GRID MOD	Substation	DSB GR	Fixico	26,717.30	26,675.93	-	-	-	-	-	41.37	-	-	-	-
K:01303-0252	DSB RESILIANCY-KELLYVILLE SUB OK GRID MO	Substation	DSB GR	Kellyville	77,215.31	-	57,705.66	8,665.08	8,800.19	1,024.48	5.10	-	148.57	866.23	-	-
K:01303-0254	DSB RESILIANCY-LITTLE RIVER SUB OK GRID	Substation	DSB GR	Little River	104,605.78	-	-	-	-	-	99,974.93	4,630.85	-	-	-	-
K:01303-0255	DSB RESILIANCY-EIGHTY FOURTH ST SUB OK G	Substation	DSB GR	Eighty Fourth	79,036.63	-	66,761.85	8,846.69	1,910.29	1,350.54	158.27	-	8.99	-	-	-
K:01303-0256	DSB RESILIANCY-RIVERSIDE SUB OK GRID MOD	Substation	DSB GR	Riverside	424,664.73	-	-	-	-	-	-	383,390.11	5,308.60	15,467.61	-	20,498.41
K:01303-0260	DSB RESILIANCY-NEWMAN AVE SUB OK GRID MO	Substation	DSB GR	Newman Ave	72,221.15	71,286.18	10.45	92.92	(75.55)	274.62	-	(0.06)	-	546.60	85.99	-
K:01303-0263	DSB RESILIANCY-STONEWALL SUB OK GRID MOD	Substation	DSB GR	Stonewall	343,506.20	-	-	-	-	-	-	-	-	-	313,598.98	29,907.22
K:01303-0264	DSB RESILIANCY-WOODWARD DIST SUB OK GRID	Substation	DSB GR	Woodward Dist	111,731.29	105,934.37	788.19	252.68	118.57	2,413.22	738.36	-	1,330.06	89.08	66.76	-
K:01303-0266	DSB RESILIANCY-GREEN PASTURES SUB OK GRI	Substation	DSB GR	Green Pastures	90,327.71	-	-	-	-	86,282.48	-	1,397.18	1,528.14	901.55	218.36	-
K:01303-0267	DSB RESILIANCY-ARDMORE SUB OK GRID MOD	Substation	DSB GR	Ardmore	125,679.53	-	92,952.38	16,413.90	4,954.43	885.09	-	1,119.87	9,353.86	-	-	-
K:01303-0268	DSB RESILIANCY-HOWE SUB OK GRID MOD	Substation	DSB GR	Howe	44,873.30	-	-	-	-	40,715.38	1.63	286.84	4,537.82	(668.37)	-	-
K:01303-0269	DSB RESILIANCY-CYPRESS SUB OK GRID MOD	Substation	DSB GR	Cypress	193,733.93	-	-	-	193,109.00	624.93	-	-	-	-	-	-
K:01303-0271	TSB RESILIANCY - BEGGS SUB OK GRID	Substation	TSB GR	Beggs	77,445.54	70,645.35	3,222.75	903.06	882.08	274.66	-	-	154.63	1,363.01	-	-
K:01303-0289	TSB-RESILIENCY MERIDIAN SUB	Substation	TSB GR	Meridian	71,453.99	-	-	-	-	-	-	71,003.87	(17.63)	363.58	104.17	-
K:01303-0291	TSB-RESILIENCY CHECOTAH SUB	Substation	TSB GR	Checotah	147,442.94	-	-	-	-	-	-	147,442.94	-	-	-	-
K:01303-0293	TSB-RESILIENCY ILLINOIS RIVER SUB	Substation	TSB GR	Illinois River	134,529.09	-	-	-	58,726.99	1,329.90	-	70,488.88	183.50	-	3,799.82	-
K:01303-0306	TSB-RESILIENCY ARDMORE SUB	Substation	TSB GR	Ardmore	441,847.88	-	314,780.40	37,667.91	54,369.52	2,655.34	508.24	2,059.04	29,807.43	-	-	-
K:01303-0314	TSB-RESILIENCY HANCOCK	Substation	TSB GR	Hancock	89,613.49	-	-	-	-	-	-	81,798.67	3,488.24	4,289.18	37.40	-
Multiple	K:01303 Distribution Removal	Distribution		Distribution Rmvl	9,851,155.23	7,218,307.53	402,852.91	659,186.69	4,450.05	512,156.58	860,868.79	122,215.69	(27,091.51)	105,949.03	1,012.34	(8,752.87)
Multiple	K:01303 Substation Removal	Substation		Substation Rmvl	1,583,005.84	1,007,285.18	95,241.44	110,570.10	108,404.09	109,744.02	46,947.52	42,349.01	5,624.66	25,506.66	20,442.76	10,890.40
Total					**87,639,678.05**	**30,470,796.74**	**3,402,323.14**	**5,736,745.47**	**3,605,808.98**	**3,264,901.42**	**4,054,441.67**	**10,268,353.54**	**3,730,395.44**	**9,116,859.98**	**8,380,531.82**	**5,608,519.85**

EFFECTIVE IN: All territory served.

PURPOSE: The purpose of the Grid Enhancement Mechanism ("GEM") is to recover the Oklahoma retail jurisdictional portion of the annual revenue requirement for grid enhancement capital expenditures associated with weather hardening, automation and related communication and technology systems placed in service through 2024. All cost recovery through the Mechanism shall be subject to true-up and refund in the Company's next general rate case.

APPLICABILITY: With the exception of the exemptions listed below, the GEM tariff will apply as follows: For distribution grid enhancement expenditures associated with FERC accounts 360 through 363 this mechanism is applicable to all Oklahoma retail rate classes in Service Levels 2, 3, 4 and 5. For distribution grid enhancement expenditures associated with FERC accounts 364 through 368 this mechanism is applicable to all Oklahoma retail rate classes in Service Levels 3, 4 and 5. For intangible, general, and transmission plant grid enhancement expenditures, this mechanism is applicable to all Oklahoma retail rate classes.

EXEMPTIONS: Customers subscribed to the Power and Light and Large Power and Light tariffs at Service levels 1 and 2 and customers who are qualified for LIHEAP program and are subscribed to the LIAP and Senior Citizen Discount programs are exempt from this mechanism and any costs that would have been allocated to those customers shall be foregone by the Company during the effectiveness of the GEM and shall not be reassigned to other customers or classes.

TERM: This GEM shall become effective upon a final order of the Commission in Cause No. PUD 202100164 and shall continue until July 1, 2025.

REVENUE REQUIREMENT: The revenue requirement shall include the return on rate base at the Commission's most recent authorized rate of return in cause PUD 202100164, associated depreciation expense, and property taxes. The rate base for the revenue requirement shall include plant-in-service, accumulated depreciation, and any associated accumulated deferred income taxes. The revenue requirement shall not include any operations and maintenance expenses.

REPORTING REQUIREMENTS: The Company shall submit a quarterly report of completed and in-service projects to the PUD, and all parties of record in Cause No. PUD 202100164, inclusive of the revenue requirement associated with all in-service projects. The first quarterly report shall be filed within 30 days after the issuance of a final order in Cause No. PUD 202100164. Thereafter, the quarterly reports shall be submitted after the close of each quarter on approximately January 15th, April 15th, July15th, and October 15th of each year. Each submission shall include a listing of projects included for recovery, the purpose of each project, and any authorizations for expenditures ("AFE").

FACTOR REDETERMINATION SCHEDULE: Factor redeterminations shall be submitted on a quarterly basis along with the report of completed in-service projects. The PUD, and all parties of record in Cause No. PUD 202100164, shall have thirty (30) calendar days to object to any project or calculation. Disagreements not resolved by the parties will be processed by a cause filed by the Company and items in dispute will not be included for recovery in the Mechanism until resolved. The PUD will endeavor to complete its review of the factors within 45 days. Recovery under the Mechanism cannot be implemented until PUD completes its review of the quarterly factor updates. The revised factors will become effective following the PUD's completed review.

FACTOR CALCULATION: The Company will calculate the GEM mechanism factors using the following formulas, on a per kilowatt-hour (kWh) basis for non demand-billed customers and on a per kilowatt (kW) basis for demand-billed customers, for each of the major rate classes, combined minor classes, and service level ("SL"). The factor shall reflect actual completed projects in service, with any accumulated over/under amortized over a 3-month period. No projections for upcoming projects may be included in the factor calculation. The GEM factors will be computed as follows:

$$\boldsymbol{GEM\ Factor}_{\boldsymbol{Class\ and\ SL}} = \frac{((\boldsymbol{A}*\boldsymbol{B})*\boldsymbol{C}) + \boldsymbol{D}_{\boldsymbol{Class\ and\ SL}}) + ((\boldsymbol{E}*\boldsymbol{F}) + \boldsymbol{G}_{\boldsymbol{Class\ and\ SL}}) + ((\boldsymbol{H}*\boldsymbol{I}) + \boldsymbol{J}_{\boldsymbol{Class\ and\ SL}}) + ((\boldsymbol{K}*\boldsymbol{L})*\boldsymbol{M}) + \boldsymbol{N}_{\boldsymbol{Class\ and\ SL}})}{\boldsymbol{O}_{\boldsymbol{Class\ and\ SL}}}$$

Where:

A = *Transmission Service Level Retail Revenue Requirement;*

B = *Oklahoma Jurisdiction Transmission Service Level Allocation = 91.0346%;*

C = *Oklahoma Transmission Service Level Demand Class and SL Allocator;*

D = *Transmission Service Level Annual True Up;*

And

E = *Distribution Service Level FERC Accounts 360-363 Revenue Requirement;*

F = *Distribution Service Level FERC Accounts 360-363 Class and SL Allocator;*

G = *Distribution Service Level FERC Accounts 360-363 Annual True Up;*

And

H = *Distribution Service Level FERC Accounts 364-368 Revenue Requirement;*

I = *Distribution Service Level FERC Accounts 364-368 Class and SL Allocator;*

J = *Distribution Service Level FERC Accounts 364-368 Annual True Up;*

And

K = *General and Intangible Plant Revenue Requirement;*

L = *Oklahoma Jurisdiction General and Intangible Plant Allocation = 91.5044%;*

M = *General and Intangible Plant Class and SL Allocator;*

N = *General and Intangible Plant Annual True Up;*

And

O = *Base kWh for each Applicable non demand-billed Class and SL or Base kW for each Applicable demand-billed Class and adjusted to exclude exempt demands for SL1&2 customers, and exempt kWhs for low income customer and senior discount customer kWhs.*

The revenue requirement items above (A, E, H, and K) shall be calculated as follows:

$$\boldsymbol{Revenue\ Requirement} \;=\; ((\boldsymbol{GEMCE} * \boldsymbol{RORB}) + \boldsymbol{DE} + \boldsymbol{AVT})$$

Where:

GEMCE = *Grid Enhancement Mechanism Capital Expenditures as described in the PURPOSE section above;*

RORB = *Authorized Rate of Return on Rate Base = 9.071%;*

DE = *Depreciation Expense associated with such Grid Enhancement Mechanism capital expenditures;*

AVT = *Ad Valorem Taxes associated with such Grid Enhancement Mechanism capital expenditures.*

RATE CLASSES: The applicable rate classes are as follows:

Rate Class	Distribution	Intangible, General Plant	Transmission
Residential	SL 2, 3, 4, 5	All SLs	All SLs
General Service	SL 2, 3, 4, 5	All SLs	All SLs
Power and Light	SL 3, 4, 5	SL 3, 4, 5	SL 3, 4, 5
Public School Large	SL 3, 4, 5	SL 3, 4, 5	SL 3, 4, 5
Large Power and Light	SL 3, 4, 5	SL 3, 4, 5	SL 3, 4, 5
Other	SL 2, 3, 4, 5	All SLs	All SLs

Combined Minor Rate Classes (Other) = *Oil and Gas Producers + Public Schools Small + Municipal Pumping + Municipal Lighting + Outdoor Security Lighting + LED Lighting; Power and Light = Power and Light Standard, Pawer and Light Time-of-Use, Back-Up and Maintenance Services*

BASE CLASS AND OTHER kWh AND kW: The applicable projected Oklahoma jurisdictional kWh and kW consistent with data from Cause No. PUD 202100164.

ALLOCATORS: The transmission, distribution FERC, and intangible and general plant allocators as determined in PUD 202100164.

Rate Class	Distribution FERC Accounts 360 - 363	Distribution FERC Accounts 364-368	Intangible, General Plant	Transmission (rebased to 100%)

Residential **	45.7875%	60.7752%	56.8958%	46.7693%
General Service*	8.2041%	13.4030%	10.2362%	8.4287%
Public Schools Large				
Service Level 3	0.0435%	0.0152%	0.0279%	0.0320%
Service Level 4	0.0825%	0.0348%	0.0503%	0.0550%
Service Level 5	0.8352%	0.8350%	0.6202%	0.6728%
Power and Light				
Service Level 1	0.0000%	0.0000%	0.0000%	0.0000%
Service Level 2	0.0000%	0.0000%	0.0000%	0.0000%
Service Level 3	2.2458%	0.7951%	1.8169%	2.4998%
Service Level 4	0.7857%	0.4010%	0.6908%	0.9657%
Service Level 5	18.5485%	19.4188%	17.0787%	20.7687%
Large Power & Light				
Service Level 1	0.0000%	0.0000%	0.0000%	0.0000%
Service Level 2	0.0000%	0.0000%	0.0000%	0.0000%
Service Level 3	1.9711%	0.6723%	1.6129%	2.2696%
Service Level 4	0.6533%	0.2659%	0.5457%	0.7703%
Service Level 5	0.9529%	0.7828%	0.8060%	1.0667%
Other*	3.5957%	2.6008%	2.6662%	2.1521%

* Service Levels 2 through 5 are combined.

** Residential allocators will be adjusted to reflect removal of Low Income and Senior customers and included for review in workpapers submitted to stipulating parties prior to recovery.

Direct Exhibit KS-4

OKLAHOMA GAS AND ELECTRIC COMPANY
P. O. Box 321
Oklahoma City, Oklahoma 73101

~~Original~~ 1st Revised Sheet No. 57.00
Replacing Original Sheet No. 57.00
Date Issued ~~November~~ XXXXXX ~~5~~XX, XXXX~~2020~~

STANDARD PRICING SCHEDULE: GEM **STATE OF OKLAHOMA**
GRID ENHANCEMENT MECHANISM

EFFECTIVE IN: All territory served.

PURPOSE: The purpose of the Grid Enhancement Mechanism ("GEM") is to recover the Oklahoma retail jurisdictional portion of the annual revenue requirement for grid enhancement capital expenditures associated with weather hardening, ~~-~~automation and related communication and technology systems ~~as described in Cause No. PUD 202000021 and~~ placed in service through~~in~~ 202~~0 and 2021~~4. All cost recovery through the Mechanism shall be subject to true-up and refund in the Company's next general rate case.

APPLICABILITY: With the exception of the exemptions listed below, the GEM tariff will apply as follows: For distribution grid enhancement expenditures associated with FERC accounts 360 through 363 this mechanism is applicable to all Oklahoma retail rate classes in Service Levels 2, 3, 4 and 5. For distribution grid enhancement expenditures associated with FERC accounts 364 through 368 this mechanism is applicable to all Oklahoma retail rate classes in Service Levels 3, 4 and 5. For intangible, general, and transmission plant grid enhancement expenditures, this mechanism is applicable to all Oklahoma retail rate classes.

EXEMPTIONS: Customers subscribed to the Power and Light and Large Power and Light tariffs at Service levels 1 and 2 and customers who are qualified for LIHEAP program and are subscribed to the LIAP and Senior Citizen Discount programs are exempt from this mechanism and any costs that would have been allocated to those customers shall be foregone by the Company during the effectiveness of the GEM and shall not be reassigned to other customers or classes.

TERM: This GEM shall become effective upon a final order of the Commission in Cause No. PUD ~~202000021~~ 202100164 and shall continue until ~~the earlier of either the implementation of rates resulting from a final order in OG&E's next base rate case or October 31, 2022~~July 1, 2025.

REVENUE REQUIREMENT: The revenue requirement shall include the return on rate base at the Commission's most recent authorized rate of return ~~of 9.071%~~in cause PUD 202100164, associated depreciation expense, and property taxes. The rate base for the revenue requirement shall include plant-in-service, accumulated depreciation, and any associated accumulated deferred income taxes. The revenue requirement shall not include any operations and maintenance expenses. ~~The annual revenue requirement to be recovered through the Mechanism shall be capped at a total of $7 million.~~

REPORTING REQUIREMENTS: The Company shall submit a quarterly report of completed and in-service projects to the PUD, and all parties of record in Cause No. PUD ~~202000021~~202100164, inclusive of the revenue requirement associated with all in-service projects. The first quarterly report shall be filed within 30 days after the issuance of a final order in Cause No. PUD ~~202000021~~202100164. Thereafter, the quarterly reports shall be submitted after the close of each quarter on approximately January 15th, April 15th, July15th, and October 15th of each year. Each

Rates Authorized by the Oklahoma Corporation Commission:

(Effective)	(Order No.)	(Cause/Docket No.)
~~February~~ xxxxxx ~~1~~xx, ~~2021~~xxxx	~~715188~~xxxxxx	PUD ~~202000021~~202100164

Public Utilities Division Stamp

submission shall include a listing of projects included for recovery, the purpose of each project, and any authorizations for expenditures ("AFE").

FACTOR REDETERMINATION SCHEDULE: Factor redeterminations shall be submitted on a quarterly basis along with the report of completed in-service projects. The PUD, and all parties of record in Cause No. PUD ~~202000021~~202100164, shall have thirty (30) calendar days to object to any project or calculation. Disagreements not resolved by the parties will be processed by a cause filed by the Company and items in dispute will not be included for recovery in the Mechanism until resolved. The PUD will endeavor to complete its review of the factors within 45 days. Recovery under the Mechanism cannot be implemented until PUD completes its review of the quarterly factor updates. The revised factors will become effective following the PUD's completed review.

FACTOR CALCULATION: The Company will calculate the GEM mechanism factors using the following formulas, on a per kilowatt-hour (kWh) basis for non demand-billed customers and on a per kilowatt (kW) basis for demand-billed customers, for each of the major rate classes, combined minor classes, and service level ("SL"). The factor shall reflect actual completed projects in service, with any accumulated over/under amortized over a 3-month period. No projections for upcoming projects may be included in the factor calculation. The GEM factors will be computed as follows:

$$\boldsymbol{GEM\ Factor}_{\boldsymbol{Class\ and\ SL}} = \frac{((\boldsymbol{A} * \boldsymbol{B}) * \boldsymbol{C}) + \boldsymbol{D}_{\boldsymbol{Class\ and\ SL}}) + ((\boldsymbol{E} * \boldsymbol{F}) + \boldsymbol{G}_{\boldsymbol{Class\ and\ SL}}) + ((\boldsymbol{H} * \boldsymbol{I}) + \boldsymbol{J}_{\boldsymbol{Class\ and\ SL}}) + ((\boldsymbol{K} * \boldsymbol{L}) * \boldsymbol{M}) + \boldsymbol{N}_{\boldsymbol{Class\ and\ SL}})}{\boldsymbol{O}_{\boldsymbol{Class\ and\ SL}}}$$

Where:

A = *Transmission Service Level Retail Revenue Requirement;*

B = *Oklahoma Jurisdiction Transmission Service Level Allocation = 91.0346%;*

C = *Oklahoma Transmission Service Level Demand Class and SL Allocator;*

D = *Transmission Service Level Annual True Up;*

And

E = *Distribution Service Level FERC Accounts 360-363 Revenue Requirement;*

F = *Distribution Service Level FERC Accounts 360-363 Class and SL Allocator;*

G = *Distribution Service Level FERC Accounts 360-363 Annual True Up;*

And

H = *Distribution Service Level FERC Accounts 364-368 Revenue Requirement;*

I = *Distribution Service Level FERC Accounts 364-368 Class and SL Allocator;*

J = *Distribution Service Level FERC Accounts 364-368 Annual True Up;*

And

K = *General and Intangible Plant Revenue Requirement;*

L = *Oklahoma Jurisdiction General and Intangible Plant Allocation = 91.5044%;*

M = *General and Intangible Plant Class and SL Allocator;*

N = *General and Intangible Plant Annual True Up;*

And

O = *Base kWh for each Applicable non demand-billed Class and SL or Base kW for each Applicable demand-billed Class and adjusted to exclude exempt demands for SL1&2 customers, and exempt kWhs for low income customer and senior discount customer kWhs.*

The revenue requirement items above (A, E, H, and K) shall be calculated as follows:

$$\boldsymbol{Revenue\ Requirement} = ((\boldsymbol{GEMCE} * \boldsymbol{RORB}) + \boldsymbol{DE} + \boldsymbol{AVT})$$

Where:

GEMCE = *Grid Enhancement Mechanism Capital Expenditures as described in the PURPOSE section above;*

RORB = *Authorized Rate of Return on Rate Base = 9.071%;*

DE = *Depreciation Expense associated with such Grid Enhancement Mechanism capital expenditures;*

AVT = *Ad Valorem Taxes associated with such Grid Enhancement Mechanism capital expenditures.*

~~The total Oklahoma jurisdictional revenue requirement for all GEM cost net of exempt classes (and without any reassignment to other classes) as described in the APPLICABILITY section above, and excluding any true-up balances, shall be subject to a $7.0 million annual cap.~~

RATE CLASSES: The applicable rate classes are as follows:

Rate Class	Distribution	Intangible, General Plant	Transmission
Residential	SL 2, 3, 4, 5	All SLs	All SLs
General Service	SL 2, 3, 4, 5	All SLs	All SLs
Power and Light	SL 3, 4, 5	SL 3, 4, 5	SL 3, 4, 5
Public School Large	SL 3, 4, 5	SL 3, 4, 5	SL 3, 4, 5
Large Power and Light	SL 3, 4, 5	SL 3, 4, 5	SL 3, 4, 5
Other	SL 2, 3, 4, 5	All SLs	All SLs

Combined Minor Rate Classes (Other) = *Oil and Gas Producers + Public Schools Small + Municipal Pumping + Municipal Lighting + Outdoor Security Lighting + LED Lighting; Power and Light = Power and Light Standard, Pawer and Light Time-of-Use, Back-Up and Maintenance Services*

BASE CLASS AND OTHER kWh AND kW: The applicable projected Oklahoma jurisdictional kWh and kW consistent with data from Cause No. PUD ~~201800140~~202100164.

ALLOCATORS: The transmission, distribution FERC, and intangible and general plant allocators as determined in PUD ~~201800140~~202100164.

Rate Class	Distribution FERC Accounts 360 - 363	Distribution FERC Accounts 364-368	Intangible, General Plant	Transmission (rebased to 100%)
Residential **	45.7875%	60.7752%	56.8958%	46.7693%
General Service*	8.2041%	13.4030%	10.2362%	8.4287%
Public Schools Large				
Service Level 3	0.0435%	0.0152%	0.0279%	0.0320%
Service Level 4	0.0825%	0.0348%	0.0503%	0.0550%
Service Level 5	0.8352%	0.8350%	0.6202%	0.6728%
Power and Light				
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Service Level 3	2.2458%	0.7951%	1.8169%	2.4998%
Service Level 4	0.7857%	0.4010%	0.6908%	0.9657%
Service Level 5	18.5485%	19.4188%	17.0787%	20.7687%
Large Power & Light				
Service Level 1	0.0000%	0.0000%	0.0000%	0.0000%
Service Level 2	0.0000%	0.0000%	0.0000%	0.0000%
Service Level 3	1.9711%	0.6723%	1.6129%	2.2696%
Service Level 4	0.6533%	0.2659%	0.5457%	0.7703%
Service Level 5	0.9529%	0.7828%	0.8060%	1.0667%
Other*	3.5957%	2.6008%	2.6662%	2.1521%

* Service Levels 2 through 5 are combined.

** Residential allocators will be adjusted to reflect removal of Low Income and Senior customers and included for review in workpapers submitted to stipulating parties prior to recovery.

Oklahoma 2022 Investment Plan

Forecasted Spend		
Grid Resiliency	$	86,600,000
Grid Automation	$	55,700,000
Communication Systems	$	39,400,000
Technology Platforms & Apps	$	7,400,000
	$	*189,100,000*

Forecasted Substation & Circuit Projects

Project ID	Substation	Circuit(s)
1	Stonewall	21, 22, 23, 29, 31
2	Belle Isle Sta	21, 25, 29, 31, 35
3	Glendale	22, 23, 24, 31
4	Tulsa Ave	21, 22, 23, 24, 25, 26
5	Sapulpa	21, 23, 29
6	SW 5th St	21, 62
7	Pauls Valley	21, 22, 24
8	Hickory Hill	21, 24
9	Meridian	21, 31, 33, 35
10	Washington Park	21, 23, 70
11	SW 22nd St	21, 22, 23, 24
12	Southgate	33, 35
13	NW 30th St	21, 22, 23
14	Bethany	27, 28
15	Woodlawn	22, 23, 24
16	Tangier	31
17	Otter	42
18	Porum	21
19	Western Ave	22, 26
20	Thirty Eighth St	21, 22, 27
21	Wilshire	21
22	Lakeside	21, 23
23	NE 10th St	29, 33
24	Warwick	42
25	Kellyville	29
26	Reno	24, 29
27	Wells	42
28	Eighty Fourth St	21, 22
29	Braden Park	23
30	May Ave	23
31	Sara	62, 64, 69, 71
32	Trosper	21, 25
33	Santa Fe Ave	29
34	Chisholm Creek	69, 71

Additional Forecasted Projects

Project ID	Project Name
35	Comm Site Availability
36	FAN Backbone Xtran
37	FAN Implementation
38	Advanced DMS Apps
39	Advanced EMS Apps
40	DER Assets in GIS
41	GIS Substation Model

2022 Investment Descriptions

Category	Investment Type	Description
Grid Resiliency	Animal Protection - Cover Up	Add advanced cover up at substations with the highest risk for outages caused by wildlife.
Grid Resiliency	Animal Protection - TransGaurd Fence	Add protective fence around substation equipment at substations with the highest risk for outages caused by animals.
Grid Resiliency	Bank Meter	Add bank meter to provide SCADA indication on substation transformer
Grid Resiliency	Distribution Line Reliability	Survey circuits with the highest condition and criticality rank and upgrade facilities to improve reliability.
Grid Resiliency	General Substation Equipment	Replace obsolete Arrestors, Bushings, Cabinets, Batteries, Battery chargers, HVAC, Switches, PT/CT/SPT, Surge Arrestors, LTC Controller, Ground Cover, Lighting, AC/DC Load Center, Oil Containment etc.
Grid Resiliency	Mobile Substations	Refurbishment of existing mobile sub fleet. Mobile substations 6 and 11 replace breakers and other smaller updates. Mobile substations 2, 4, and 5 replace high and low side switches.
Grid Resiliency	OH Conductor Replacement	Replace obsolete overhead conductor (8S3, 3X3, 7W3) on circuits with the highest customer count associated with obsolete overhead conductor.
Grid Resiliency	River Crossing Reinforcement	Reinforce river crossings at transmission structures (Note distribution structures requiring river crossing reinforcement will be done under DLR).
Grid Resiliency	Substation Breaker Replacement	Replace substation breakers that are obsolete (GE FKD, Westinghouse ESC, PRC, TSC, ES, and ESV. This included replacement of obsolete PCRs, Capacitor Switchers, and replacing substation transformer fuses with FISs.
Grid Resiliency	Substation Transformer Replacement	Replace poor performing substation transformers that are nearing end of life.
Grid Resiliency	Transformer Load Management	Replace distribution transformers that are overloaded according to engineering guide E204 for at least 40 hours per year.
Grid Resiliency	UG Cable Replacement	Replace unjacketed concentric neutral cable on circuits with the highest reliability impact.

Category	Investment Type	Description
Grid Automation	Add Communications to Capacitors	Add communications to existing capacitors on circuits in urban areas and circuits off the 69 kV transmission system to allow for greater voltage control.
Grid Automation	Add Communications to Regulators	Add communications to existing regulator stations to allow for greater voltage control.
Grid Automation	Add SCADA to ATOs	Add SCADA control and indication to distribution ATOs
Grid Automation	Automated Circuit Tie Lines	Install automated switches at normal open locations, behind stepdown transformers, and in areas that will allow commercial and industrial load to be isolated from residential load.
Grid Automation	Fault Location SCADA Inputs	Install SCADA points to allow for remote fault location analysis in the DMS system (aka FLISR).
Grid Automation	GPS Clock	Adding GPS clock or replacing obsolete clock for use with new SCADA and/or relay replacements.
Grid Automation	Network	Adding or upgrading the network conection to facilitate SCADA additions.
Grid Automation	RTU Replacement	Upgrade RTU
Grid Automation	SCADA	Install SCADA at substations where it does not exist today. This is a smaller standalone cabinet option for a SCADA installation at smaller substations. This will allow for better coordination and visibility of distribution automation.
Grid Automation	Smart Lateral Fuses	Install tripsavers on all laterals except ones with small load or minimal exposure. Install new fuses or change fuses as necessary.
Grid Automation	Substation Enclosures	Adding Control House or Protection Control Cabinets in locations they are needed.
Grid Automation	Substation Equipment Monitoring	Piloting remote DGA monitoring on substation transformer
Grid Automation	Substation Relay Replacement	Replace relays with technical bulletins from the manufacturer which have limited parts available or have known mis-operation issues.

Category	Investment Type	Description
Technology Platforms and Applications	Advanced DMS Apps	PROD environment in service with Planned Outage and Epilog Pro functionality.
Technology Platforms and Applications	Advanced EMS Apps	Implement new Transmission System Operator tools for Operator Log, Switch Order Management, and Automated Substation Entry Logging, for enhanced situational awareness.
Technology Platforms and Applications	DER Assets in GIS	Add customer-owned generation DER assets into ArcFM for a full view of DER assets connected to our grid.
Technology Platforms and Applications	GIS substation model	Add substation model to the DMS. This is Phase I of the project. Phase II will move the modeled substations to GIS.

Category	Investment Type	Description
Communication Systems	Communication Site Availability Upgrade	Assess the criticality and resiliency of power at communications sites and update standards and implement solutions as needed. Includes site visits to 102 sites. Standards development for backup power, and implementation of new standard solutions where r
Communication Systems	FAN Backbone Xtran	Upgrade substation communications using the fiber backbone deployed in 2021. Deploy new Xtran transport nodes, Palo Alto firewalls, and perform requisite rack and power upgrades at 41 substations connected to existing OG&E OPGW fiber now connected to the
Communication Systems	FAN implementation	Replace and update portions of the legacy 5.8GHz and Freewave WAN middle-tier infrastructure with LTE (or similar) links, greatly reducing latency, increasing reliability, and expanding reach and capacity for both fixed and mobile data services. Includes

PUD 202100164

CONFIDENTIAL

DIRECT EXHIBIT KS-6

FILED ON:

December 30, 2021

SUBMITTED TO THE COURT CLERK UNDER SEAL