BEFORE
THE PUBLIC SERVICE COMMISSION OF
NORTH CAROLINA

DOCKET NO. E-7 SUB 1214

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Carolinas, LLC	)	**JAY W. OLIVER**
For Adjustment of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North	)	**CAROLINAS, LLC**
Carolina	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jay W. Oliver. My business address is 400 South Tryon Street, Charlotte, North Carolina.

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

A. I am employed by Duke Energy Business Services, LLC ("DEBS") as General Manager, Grid Solutions Engineering and Technology. DEBS provides various administrative and other services to Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS GENERAL MANAGER, GRID SOLUTIONS ENGINEERING AND TECHNOLOGY FOR DUKE ENERGY.

A. My duties and responsibilities include planning for the grid and related system improvement efforts across Duke Energy.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I have a Bachelor of Science degree in Electrical Engineering from the Georgia Institute of Technology and a Master's degree in Business Administration from the University of South Florida. I am a licensed Electrical Engineer and a registered Professional Engineer in Florida. From 25 years working in the electric utility business, I have experience in electric transmission, distribution, and information technology and telecommunications systems that support utility transmission and distribution networks. I began working at Duke Energy in 1996, joining one of its predecessor companies, Florida Progress. Over the past 10 years, I have held the positions of Region General Manager, Director Distribution Services, Major Projects Manager, and Director, Grid Automation. I have been in my current role since January 2017.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR ANY OTHER REGULATORY BODIES?

A. Yes. I testified before the North Carolina Utilities Commission ("NCUC") in Duke Energy Progress, LLC's ("DE Progress") 2013 Demand Side Management/Energy Efficiency proceeding in Docket No. E-2, Sub 1030 and in DE Progress's 2014 Fuel Charge Adjustment proceeding in Docket No. E-2, Sub 1045. I also provided direct and rebuttal testimony in DE Progress and DE Carolinas' recent South Carolina base rate adjustment proceedings in Docket Nos. 2018-318-E and 2018-319-E.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying as an expert witness in this case in two separate capacities. In my capacity as the witness supporting ongoing operations, I describe and support the existing DE Carolinas' transmission and distribution ("T&D") system, the operation and performance of the T&D system, and the costs necessary to operate and maintain it. In my capacity as the witness supporting DE Carolinas' Grid Improvement Plan for North Carolina, I describe trends affecting the electric grid and how we plan to address those growing challenges through our Grid Improvement Plan.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Following the introduction above, my testimony is organized as follows:

I. First, I will provide a description of DE Carolinas' T&D system, describing notable investments made in our system since the Company's last rate case in North Carolina and an overview of the operational performance of the Company's T&D system.

II. Second, I will describe the trends affecting the electric grid in the 21st century, how we analyze those issues, and how they will impact our grid if addressed through traditional means alone.

III. Third, I will describe the tools available to address the trends, explain how programs in the Grid Improvement Plan are evaluated, and present a foundational overarching Plan which addresses the issues in a stakeholder-informed manner.

IV. Finally, I will provide a three-year work plan for our 2020-2022 grid improvements with defined projects. I note we are requesting a corresponding deferral on future Grid Improvement Plan costs as further explained below and by Witness McManeus.

Q. ARE YOU PROVIDING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I have attached 18 total exhibits, described below:

Exhibit 1: Maintain Base Transmission and Distribution System Work-describing what work the Company does as base-level maintenance work;

Exhibit 2: Megatrends Impacting North Carolina - detailing key trends relevant to the Grid Improvement Plan;

Exhibit 3: North Carolina Grid Improvement Plan Implications - discussing how Megatrends are impacting operations in North Carolina;

Exhibit 4: North Carolina Grid Improvement Plan Program Summaries – describing the projects and programs in the Grid Improvement Plan;

Exhibit 5: Portfolio Prioritization Methodology – detailing how the Grid Improvement Plan is prioritized;

Exhibit 6: Cost benefit and Cost Effectiveness Evaluation Execution Protocol – showing how the Company evaluates potential grid improvement projects;

Exhibit 7: Cost Benefit Analyses

Exhibit 8: North Carolina Grid Improvement Plan Portfolio Cost Benefit Analysis Summary

Exhibit 9: Grid Improvement Plan Benefits Pyramid

Exhibit 10: North Carolina Grid Improvement Plan;

Exhibit 11: June 25, 2018 Power Forward Carolinas Technical Workshop Report - containing the results of the Company's first North Carolina stakeholder workshop;

Exhibit 12: November 2018 North Carolina Grid Improvement Plan Workshop Pre-Read - containing materials provided to stakeholders prior to the November 18, 2018 workshop;

Exhibit 13: January 9, 2019 North Carolina Grid Improvement Plan Workshop Report - containing the results of the Company's second North Carolina stakeholder workshop;

Exhibit 14: April 25, 2019 Webinar Materials

Exhibit 15: May 16, 2019 North Carolina Grid Improvement Plan Workshop Pre-Read - containing materials provided to stakeholders prior to the May 16, 2019 workshop;

Exhibit 16: July 2, 2019 North Carolina Grid Improvement Plan Workshop Report - containing the results of the Company's third North Carolina stakeholder workshop held on May 16, 2019;

Exhibit 17: March 12, 2019 Rebuttal Testimony filed in Docket No. 2018-319-E; and

Exhibit 18: June 2019 Webinar Presentations.

Q. WERE EXHIBITS 1 THROUGH 18 PREPARED OR PROVIDED HEREIN BY YOU, UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. They were.

Q. DO THESE EXHIBITS CONTAIN ONLY INFORMATION ABOUT DE CAROLINAS?

A. No. Duke Energy has created a plan for the grid in North Carolina, and that includes both DE Progress and DE Carolinas. All information is shown in a utility-specific manner. I believe it is important to show these plans jointly as we think of the needs of customers in the state. Moreover, I believe it facilitates better discussions among parties and entities, who have interest in both service territories, to see the material presented together.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR OPERATIONAL TESTIMONY.

A. DE Carolinas reliably serves approximately 2.0 million customers in North Carolina through a multi-state electric system that includes approximately 13,100 miles of transmission lines, more than 105,000 miles of distribution lines, and more than 1,500 substations. For the DE Carolinas distribution system, approximately 1,393 distribution line miles and 12,847 transformers were added over the last two years.

As part of the Company's commitment to reliably serve customers and continually improve operations, DE Carolinas has invested $2.2 billion in electric plant in service for T&D infrastructure over the last two years. Maintenance work and reliability improvements included replacement of deteriorated wooden poles, replacement of obsolete line and substation equipment, and customer-driven line and substation expansions.

DE Carolinas also maintains a comprehensive vegetation management program across the state that works to proactively maintain trees both within and outside the rights-of-way on regular cycles. This work seeks to improve overall reliability, harden the grid against severe weather, and reduce the impact of vegetation which currently accounts for 20 to 30 percent of outages across the system.

Overall, the DE Carolinas grid is reliable and well-maintained. While the Company has worked hard to maintain the system and reliably meet the needs of customers, we also understand more must be done to improve the state's energy infrastructure to meet the energy challenges and opportunities that lie ahead.

Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S GRID IMPROVEMENT PLAN.

A. Through a comprehensive assessment of the state of the grid and influences affecting the region, the Company has identified emerging trends, which I refer to in my testimony as "Megatrends," that drive the need to make improvements now to the electric system in North Carolina.

North Carolina is a growing state, especially in urban and suburban areas, where residential and business growth is becoming concentrated. With that growth comes growing consumer expectations for more interaction with their electric company and more control over the way they use electricity. And along with that, a higher reliance on "perfect power" – power that stays on – and when an outage does occur, is restored faster than ever.

As recent events have reinforced, the Company must be ready for severe weather before it strikes and reduce the impact of storms that are worsening in frequency and intensity. The Company must be vigilant and prepare now for the very real threat of cyber and physical attacks. And as renewable energy and distributed energy technologies like solar energy, battery storage, microgrids, and electric vehicles become more affordable and accessible, it is important to take steps now to ready the grid to support the growth of these technologies that are important to the state's energy future.

These influences come at a time of increasing environmental commitments and compliance requirements that drive change for the Company and the industry. But they also come at a time when grid technology is rapidly advancing and becoming increasingly intelligent, providing new tools and new opportunities to improve the way the Company serves customers.

To deliver on customer expectations and address these trends, the Company believes that we must do more than maintain the power grid; the Company must make the appropriate investments to transform it, making strategic, data-driven improvements to power a smart-thinking grid that is more reliable, more resilient, and built to meet the energy needs of customers today and into the future.

DE Carolinas' Grid Improvement Plan was developed through a comprehensive analysis of the trends affecting our business in the state and the tools to best address those trends in a cost-effective and timely manner. The Grid Improvement Plan is built upon strategic, data-driven investments to improve reliability to avoid outages and speed restoration; harden the grid to protect against cyber and physical threats; expand solar and other innovative technologies across a two-way, smart-thinking grid; and give customers more options and control over their energy use and tools to save money. These foundational improvements will transform the grid and provide a new level of operation while providing benefits now and in the years to come.

Components of Duke Energy's Grid Improvement Plan operationally fall into one of three categories:

- Compliance-driven programs that **protect** the grid;
- Programs that leverage advanced technologies to **modernize** the grid; and
- Projects and programs that work to **optimize** the customer's experience.

1. Protect the grid

More must be done to harden and defend the grid against critical physical and cybersecurity risks. Compliance requirements in these areas are also driving improvements across the state. Examples of the Company's multi-layered improvements designed to protect the grid include installing protective devices to limit access to critical systems and minimize outages from physical or cyber-attack.

2. Modernize the grid

Technology is rapidly changing, and more must be done to incorporate and anticipate new technologies to better serve a growing state. Customers – more than ever – expect more options, greater reliability, and value. Self-selecting billing and payment dates, scheduling appointments, accessing real-time usage data, and information updates when outages occur are all examples of basic services consumers expect but require technology to deliver. And increasingly, consumers want access to information about how they use energy and tools to take control of that energy use and save money.

Examples of improvements designed to modernize the grid include:

- Smart meters to provide improved customer usage data, enhanced outage detection to improve customer service, and access to increased customer options to manage energy use and save money.
- Distribution automation and dispatch tools to improve power quality and reliability and support the growth of distributed energy resources and customer-owned technologies.
- Integrated system operations planning, automation, and system intelligence to prepare the grid for increased distributed resources and the dynamic power flows that these technologies bring.
- Communication improvements and expansions from high-speed, high-capacity backbone fiber optic and microwave networks to the wireless connections at the edge of the grid. These upgrades help build the secure communications required for the increasing number of smart components, sensors, and remotely activated devices on the transmission and distribution systems.

3. Optimize the customer experience

Customers want and deserve a better experience, built on the technology needed to meet their changing energy needs. To meet these expectations, we must optimize the total customer experience and transform the grid to prepare it for the energy opportunities that lie ahead.

Optimization upgrades in the grid improvement plan include:

- A self-optimizing, smart-thinking grid that anticipates outages and automatically reroutes service to keep power on for customers. Self-

Optimizing Grid technology can reduce outage impacts on customers by as much as 75 percent. It will also provide the foundation for the two-way power flows needed to support more rooftop solar, battery storage, electric vehicles, and microgrids – technologies that will increasingly power the lives of customers.

- Expanded energy storage capabilities and infrastructure, which will help to power self-optimizing technologies in areas where building a redundant power line may not be feasible.
- Electric vehicle charging infrastructure improvements to expand transportation options for customers across the state. This component is filed in a separate Docket, No. E-2, Sub 1197.
- Voltage optimization and distribution of power to customers to improve reliability, increase system intelligence and support the two-way power flow needed to grow distributed resources.
- Upgrading breakers, transformers, and other grid equipment, as well as using advanced data to strategically underground the most vulnerable, outage-prone lines on the distribution system.

The Company has constructed the stakeholder-informed Grid Improvement Plan to address the risks and opportunities that the analysis revealed. The Plan seeks to balance the pace, scope, location, and timing of our work to address a diverse set of customer and stakeholder needs. As we built the Grid Improvement Plan proposed in this case, the Company has also kept the needs of our rural and low-income customers in mind and sought to develop a strategy that maximizes benefits to all customers and the State, while keeping costs as low as possible.

In developing this informed plan, the Company layered data analytics with significant input from customer and advocacy groups, and other stakeholders. Finding common ground on important topics that affect all our customers is very important to Duke Energy. The Company realizes that plans that look good on paper may not translate the way we think they will when executed in the real world. That is why the Company has sought out customer and stakeholder perspectives, including multiple stakeholder workshops, as part of the process before presenting this plan.

Consistent with the Commission's Order in the last rate case, I describe the steps taken by the Company to collaborate with stakeholders to produce a list of projects, referred to as the North Carolina Grid Improvement Plan that I believe can effectively serve customers now and in the years ahead. Exhibit 10 shows numbers for a three-year plan for North Carolina based on budgeting methods, which differs from ratemaking allocations.

The Grid Improvement Plan is about making smart foundational choices now to make the state's energy grid more reliable, more secure, and ready for the energy opportunities that lie ahead. Just as the past decade modernized the way Duke Energy generates electricity, the years ahead will transform the way we deliver electricity and serve customers. With each improvement, we can improve the overall reliability of the grid and enhance service for every customer, regardless of the type of customer or their location.

I. DE CAROLINAS' T&D SYSTEM OVERVIEW AND INVESTMENTS SINCE THE COMPANY'S LAST RATE CASE IN NORTH CAROLINA

Q. PLEASE GENERALLY DESCRIBE DE CAROLINAS' T&D SYSTEM IN THE CAROLINAS.

A. DE Carolinas' T&D system delivers electric service to approximately 2.6 million retail customers located throughout a 24,000-square mile service area in central and western North Carolina and western South Carolina. Approximately 2 million of the Company's retail customers are in North Carolina. In addition to its retail customers, DE Carolinas also sells electricity at wholesale rates to municipal, cooperative, and other investor-owned utilities.

DE Carolinas operates as a single balancing authority to economically manage the Company's integrated electric delivery systems in both North Carolina and South Carolina, collectively. This system interconnects with other balancing authority areas[1] and includes approximately 13,100 circuit miles of transmission lines. The distribution system is comprised of approximately 66,600 miles of overhead distribution lines and 38,500 miles of underground distribution lines. DE Carolinas' T&D system also includes 170 transmission substations, and 1,339 distribution substations with a combined capacity of approximately 92 million KVA. In addition to power lines and substations, the system includes various other equipment and facilities such as control rooms,

[1] The PJM Regional Transmission Organization through American Electric Power ("AEP"), Duke Energy Progress ("CP&L East and CP&L West"), Dominion Energy South Carolina (formerly South Carolina Electric & Gas), South Carolina Public Service Authority, Southern Company, Tennessee Valley Authority ("TVA""), Cube Hydro Carolinas, and Southeastern Power Administration ("SEPA").

computers, poles, transformers, regulators, capacitors, street lights, meters, and protective relays. Together, these assets provide the Company considerable operational flexibility with its T&D system and allow DE Carolinas to provide safe, reliable, and economical power to the Company's customers in North Carolina.

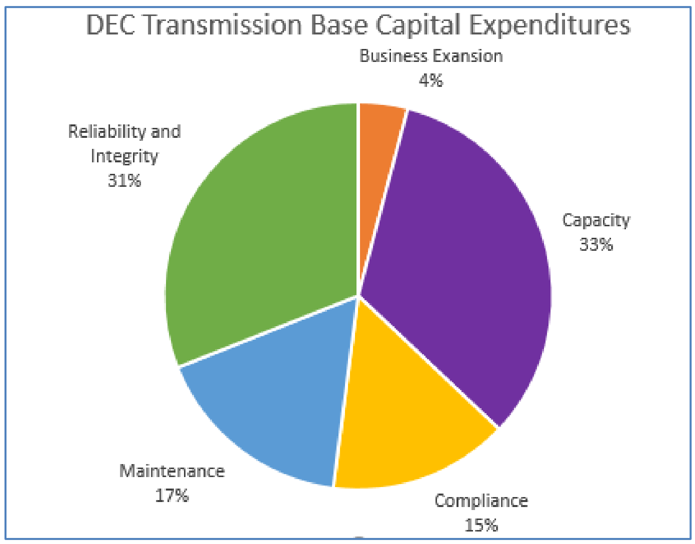
Q. HAS DE CAROLINAS' T&D SYSTEM GROWN SINCE THE LAST RATE CASE?

A. Yes. The T&D system has expanded over time to ensure adequate system voltage and capacity, based on projected system loading, and contingency requirements related to providing safe and reliable service to our customers. Transmission system growth has also occurred because of new generation and/or decommissioning of existing generation assets. For the DE Carolinas distribution system, approximately 1,393 distribution line miles and 12,847 transformers were added over the last two years. Overall, we have added approximately $2.2 billion to electric plant in service for T&D infrastructure in the last two years.

Q. CAN YOU PROVIDE MORE DETAIL ABOUT THE ADDITIONAL INVESTMENTS THE COMPANY HAS MADE IN ITS T&D SYSTEM SINCE THE LAST RATE CASE?

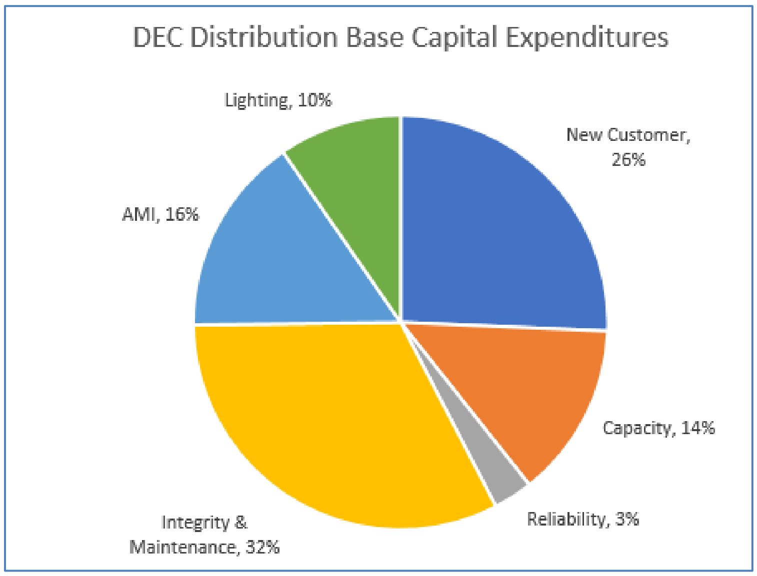
A. Additional investments in the Company's T&D system have been made to provide capacity to serve system growth, ensure adequate system voltage, support transmission-related infrastructure for both new generation and decommissioning of generation, and improve certain aspects of system reliability. Over the past two years, approximately $600 million was invested in the transmission system and $1.6 billion in the distribution system inclusive of additions through the Grid Improvement Plan which I discuss in the second part of my testimony.

The chart below illustrates the major categories of the transmission base system capital investment over the last two years.



In the transmission system, approximately 33 percent of investment was driven by capacity requirements to serve load and to meet the North American Reliability Council ("NERC") Planning Standards and generation driven by projects such as the Riverbend decommissioning and the addition of the Lee Combined Cycle Plant. Approximately 31 percent of investment was driven by standard reliability improvement programs. Approximately 17 percent of investment was driven by maintenance programs, including the replacement of deteriorated wood poles and replacement of obsolete substation and line equipment. Approximately 4 percent of the investment was driven by customer expansion work which includes new customer projects as well as line and substation upgrades driven by transmission service requests. Approximately 15 percent of the investment was driven by compliance projects including the ever-evolving cyber security and physical security programs driven by requirements defined in NERC CIP Standards CIP-002-5.1 and CIP-014-2.

The chart below illustrates the major categories of the distribution base system capital expenditures over the last two years.



North Carolina continues to be a desirable place to live and work, as evidenced by the more than 32,000 new retail customer meters added during the 12-month period ending December 31, 2018. Typically, new customers locate in areas where DE Carolinas must build new distribution facilities to serve them, including expenses for new customer connections or capacity work needed to support overall load growth. Approximately 49 percent of the Company's distribution expenditures over the last two years are for load expansion-related work, including serving new customers, lighting installations, and additional capacity.

Approximately 35 percent of the investments on the Company's system relate to base-level work around standard reliability and integrity programs that address safety and environmental requirements and maintenance including service restoration. Approximately 16 percent was for the deployment of AMI.

Q. CAN YOU PROVIDE DETAIL ABOUT HOW THE COMPANY DETERMINES WHAT IS TO BE CATEGORIZED AS BASE T&D SPENDING?

A. Yes. The type and scope of transmission and distribution "Maintain Base" work that we perform on our system can generally be thought about as a product of the following equation: [Safety Requirements] + [Load Service Requirements] + [Reliability Requirements] + [Environmental Requirements] = Type and Scope of Work. What work goes into the four elements of this equation may be dictated by mandatory external requirements (such as laws, codes, and regulations), internal company standards, national industry standards, or a combination of these requirements and standards, but any base-level work done on the transmission and distribution system fits into one of these four categories. In Exhibit 1 to my testimony, I have provided more detail as to what general work fits into each one of the categories.

Q. IN YOUR OPINION, ARE ALL THE T&D FACILITIES INCLUDED IN DE CAROLINAS' BASE RATE REQUEST USED AND USEFUL IN PROVIDING SERVICE TO DE CAROLINAS' RETAIL ELECTRIC CUSTOMERS IN NORTH CAROLINA?

A. Yes. Including the projects that will be completed prior to the evidentiary hearing in this case, all of the reasonable and prudent additions to DE Carolinas' T&D system requested for recovery in base rates are used and useful to its 2 million customers in North Carolina.

Q. HAVE THE T&D INVESTMENTS THAT THE COMPANY HAS MADE ALLOWED IT TO MEET ITS OPERATIONAL PERFORMANCE GOALS?

A. Yes. They have, but as I discuss later in my testimony, we are seeing unfavorable trends that are making these goals more challenging to meet. DE Carolinas' principal goal is to deliver safe and reliable electric service at reasonable prices. We measure this principal goal based on customer satisfaction, safety, and reliability of the Company's T&D systems, while responsibly managing operational and capital expenditures for the benefit of our customers.

Q. PLEASE EXPLAIN THE METRICS THE COMPANY USES TO MEASURE THE EFFECTIVENESS OF ITS T&D OPERATIONS.

A. DE Carolinas utilizes several industry-standard metrics to assess the overall effectiveness of its T&D operations. These metrics include reliability indices to measure the performance of the T&D system and customer satisfaction scores to determine how well the Company is meeting the needs of its customers.

The Company uses several industry-accepted transmission and distribution performance metrics as defined in IEEE Standard 1366-2012:

- **System Average Interruption Frequency Index ("SAIFI")** is a ratio that indicates how often the average customer experiences a sustained interruption over a predefined period of time.
- **System Average Interruption Duration Index ("SAIDI")** is a ratio that indicates the total duration of interruption for the average customer during a predefined period of time.
- **Customers Experiencing Multiple Interruptions ("CEMI 6")** is a measure of the percentage of customers who experience six or more outages in a 12-month period.

Q. HOW HAS DE CAROLINAS' TRANSMISSION AND DISTRIBUTION SYSTEM PERFORMED UNDER THESE METRICS?

A. Our system has performed well, and we have continued to provide safe, reliable, and affordable electric service to our customers. Over the past ten years, however, both SAIFI and SAIDI show an unfavorable trend, with the frequency and duration of outages increasing across the DE Carolinas system despite our efforts and investments that I have discussed previously. Graphs displaying the trends for these metrics are set forth below:

Figure 1 – Duke Energy Carolinas' Historic System Average Interruption Frequency Index (SAIFI)

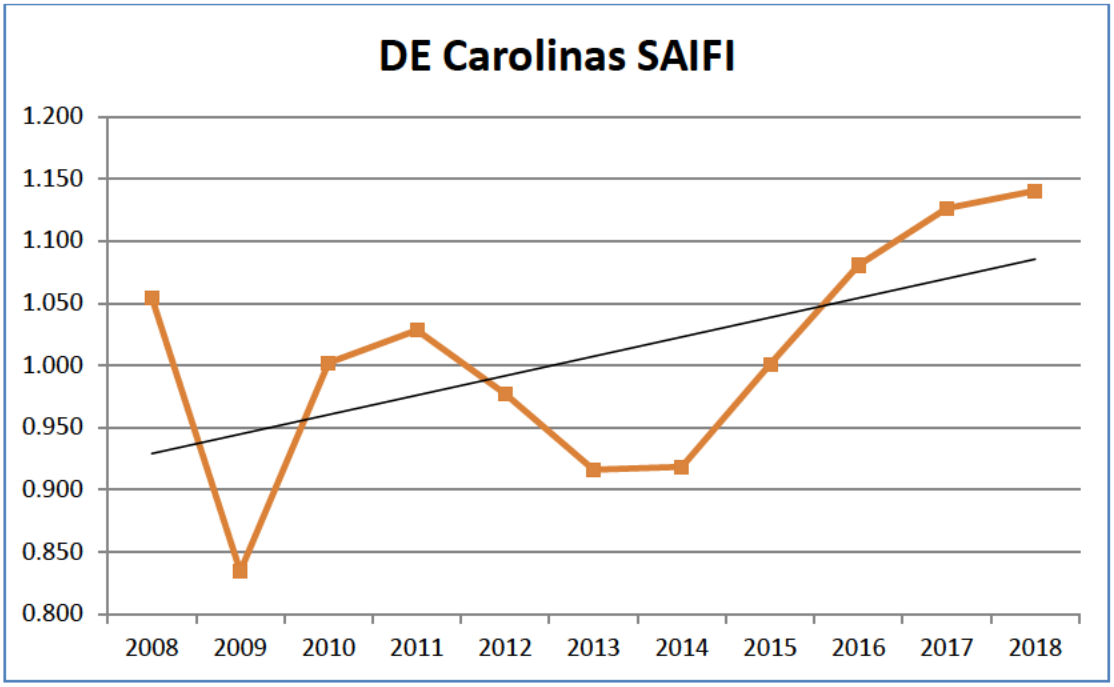
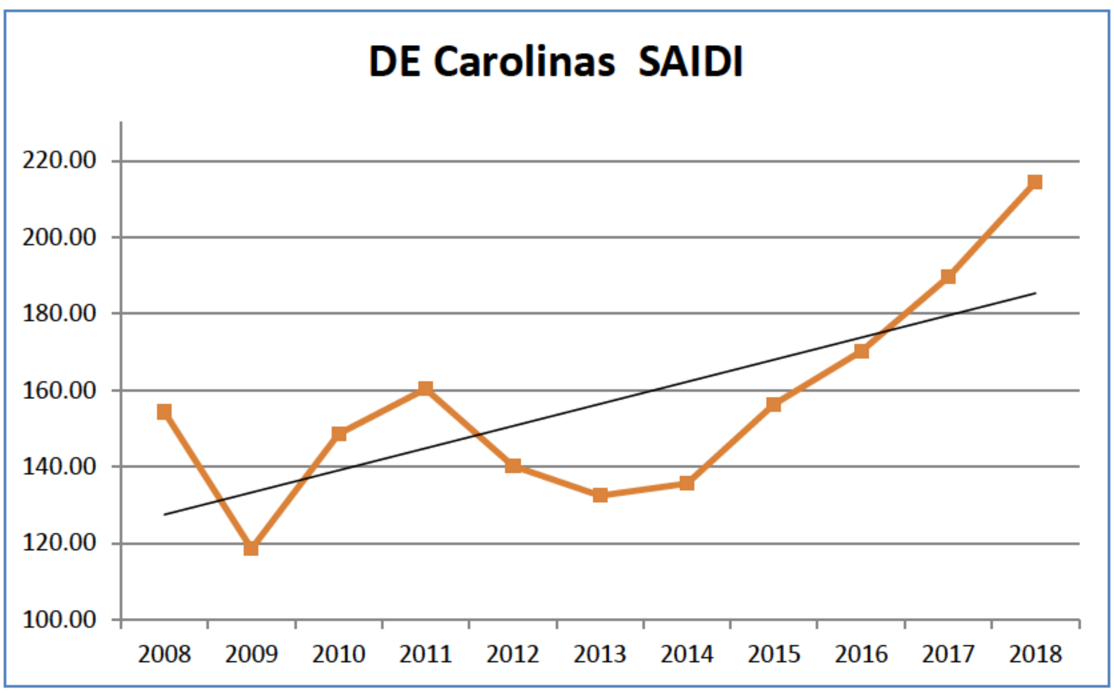


Figure 2 – Duke Energy Carolinas' Historic System Average Interruption Duration Index (SAIDI)



In summary, reliability performance is worsening due to the increase in the number of outage events. There are several factors and trends, which I address later in my testimony, contributing to the worsening reliability trends.

Q. WHAT ARE YOUR PROJECTIONS FOR DE CAROLINAS RELIABILITY PERFORMANCE IN 2019?

A. Based on performance through July 2019, we project DE Carolinas SAIDI to be 173 minutes. While this is a forecast, we feel confident that SAIDI for DE Carolinas will end 2019 between 157 and 193 minutes. This entire range represents a significant improvement from the 2018 performance of 214 minutes.

Q. CAN YOU EXPLAIN WHY RELIABILITY PERFORMANCE HAS IMPROVED?

A. In addition to system improvements such as Self-Optimizing Grid ("SOG"), Targeted Undergrounding ("TUG"), and other programs discussed in my testimony, there have been operational improvements focused on reducing outage durations. These improvements include refining the process by which crews are contacted during outages, developing more specific operational schedules, allowing employees to perform additional duties while on site during an outage, and weekly reviews of long duration outages.

Q. ARE THESE IMPROVEMENTS EXPECTED TO CONTINUE BEYOND 2019?

A. Yes. Our performance during the first six months of 2019 was driven in part by improvements in several processes and these changes have been institutionalized.

Q. PLEASE EXPLAIN THE COMPANY'S APPROACH TO DISTRIBUTION VEGETATION MANAGEMENT AND DESCRIBE ANY CHANGES THE COMPANY HAS MADE TO ITS APPROACH SINCE THE LAST RATE CASE.

A. Vegetation management is a critical component of the Company's customer delivery operations and the continued effort to drive performance for customers' benefit. DE Carolinas uses a combination of a reliability-based and a time-based prioritization model to drive its routine integrated vegetation management program. In addition to routine circuit maintenance, there are four other important components to the Company's overall vegetation management approach.

(1) Herbicide Program – The purpose of the annual Herbicide Program is to control re-growth of incompatible vegetation within the right-of-way "floor" in non-landscaped areas;

(2) Hazard Tree Program – This program is designed to identify/remove dead, dying, and diseased trees primarily located outside of the existing Distribution right-of-way;

(3) Reactive Program – This program is designed to address customer initiated requests as well as vegetation related power quality issues identified as part of outage follow-up investigations; and

(4) Disciplined vegetation management outage follow-up process tied to a formal internal reliability review process.

In 2013, Duke Energy completed a tree growth study, which established an optimal tree-trimming cycle with targeted trim dates by classification including old-urban 5-year cycle, mountain 7-year cycle, and other 9-year cycle, otherwise referred to by the Company as the 5/7/9 Plan.

Q. PLEASE MORE FULLY DESCRIBE THE 5/7/9 PLAN AND HOW DE CAROLINAS HAS IMPLEMENTED THIS PLAN.

A. The 5/7/9 plan is defined as follows:

- There are 2,171 old urban miles to be trimmed on the 5-year cycle. "Old Urban Circuits" are designated by Duke Energy as the overhead lines in older, high density neighborhoods or historic districts that consist of mature and/or over-mature, streetscape, and landscape trees. The line construction is typically in the public right-of-way along the street and rear, or in side lots along the property line between the neighborhood homes. Many trees on the Old Urban Circuits are directly under the line and are in direct conflict with the overhead distribution system. Thus, these trees will never be allowed to obtain normal form or development and have traditionally required height reduction pruning. Due to the reliability characteristics and clearance needed at the time of pruning, we target these circuits to be on a 5-year pruning schedule. The desired timeframe is driven by the growth characteristics of the trees and associated target clearance needs, as well as system reliability.

- There are 7,847 mountain miles to be trimmed on the 7-year cycle. "Mountain" circuits are characterized by a high percentage of the line miles being impacted by vegetation, lesser customer densities, and difficult terrain, as well as many of the lines being non-accessible to mechanized equipment.
- There are 41,686 other miles to be trimmed on the 9-year cycle. "Other" circuits are targeted for a 9-year average trim cycle and include all circuits that are not classified as Old Urban or Mountain.

The implementation of the 5/7/9 plan in 2018 created a "backlog" of miles that fell outside the targeted 5/7/9 trim cycles. To reconfirm its commitment to address this backlog by 2023, the Company filed its Revised Vegetation Management Plan, under Docket No. E-7, Sub 1146, detailing planned tree-trimming activities and spending from 2019-2023. The Revised Vegetation Management Plan reflects the Company's continued progress to eliminate the 13,467 miles of existing tree trimming backlog within five years, while still ensuring that all miles previously trimmed within their 5, 7, or 9-year timeframe based on the identified circuit category are trimmed on schedule per the Company's 5/7/9 Plan.

Q. DOES THE COMPANY PROPOSE AN INCREASE IN FUNDING FOR VEGETATION MANAGEMENT?

A. Yes. As explained by Witness McManeus, we have included a pro forma adjustment for the North Carolina retail portion of the incremental O&M expense associated with vegetation management. The need for the increase is two-fold. First, it will cover the known contract rate increases that took effect in 2019. The increase in contract rates is driven by a tightening labor market and the ability for vegetation suppliers to acquire and retain qualified workers, so we expect cost for vegetation management to further increase in the coming years. Second, the increase will cover the miles to be trimmed to meet the annual mileage requirements of the Company's 5/7/9 plan, which is higher than the mileage completed in the test year for this case due primarily to Hurricanes Florence and Michael and Winter Storm Diego.

We have also included a pro forma adjustment for the North Carolina portion of the incremental O&M expense for the Transmission Vegetation Management Program. This increase will cover known contract rate increases in 2019 and the requirement mileage for maintenance trimming and the herbicide program.

Q. WILL THE COMPANY'S 5/7/9 VEGETATION MANAGEMENT PLAN CURE ALL ADVERSE SYSTEM IMPACTS THAT THE COMPANY HAS SEEN DEVELOP IN THE RECENT PAST?

A. No. Vegetation events account for 20 to 30 percent of all outage events. It is important to understand that approximately 70 to 80 percent of all outages on the grid are due to other causes, such as equipment failure, public accidents, and environmental factors. In addition, for the events that are vegetation related, only 50 percent of these are related to vegetation inside the right-of-way where the Company can perform vegetation management. The other 50 percent occur due to trees outside the right-of-way that will fall into or otherwise impact distribution lines, and the Company does not have the ability to perform vegetation management on these trees that are located on private property. For the outages that occur because of trees inside the right-of-way, even a perfectly executed integrated vegetation management plan will not bring this number down to zero but instead will only help minimize vegetation outages.

Keeping these facts in mind, the Company engaged in the Tree Growth Study that I previously discussed to determine the optimal right-of-way trimming cycles for our geographical areas. Trimming more often than these now pre-determined, optimal cycles will only provide diminishing returns and would not be cost effective. Drastic clear cutting and going onto customer property and cutting down live trees via condemnation or negotiating with customers for rights on their property is also impractical and not cost effective. Instead, programs such as Targeted Undergrounding, which will be discussed in more detail later in my testimony, can be effectively used to address vegetation outages caused by trees outside of the right-of-way, where the base vegetation plan stops.

II. NEW TRENDS AFFECTING THE NORTH CAROLINA ELECTRIC GRID

Q. HAVING DESCRIBED THE EXISTING T&D SYSTEM AND HOW THE COMPANY MAINTAINS ITS BASE-LEVEL OF SYSTEM PERFORMANCE, WHAT ARE SOME SYSTEM-WIDE TRENDS YOU HAVE OBSERVED AS IMPACTING THE T&D GRID?

A. There are seven major trends that we call "Megatrends" impacting Duke Energy's grid in North Carolina. The trends are summarized below and are discussed individually in detail in Exhibit 2:

1. Population and business growth continues in North Carolina and is heavily concentrated in urban and suburban areas;
2. Technology is advancing at a rapid rate in the areas of renewables and distributed energy resources ("DERs"), which means there are new types of load and resources impacting the grid;
3. Technology is also advancing rapidly within the devices and systems that operate and manage the T&D grids, offering new capabilities and requiring new functionalities;
4. Customer expectations and use of the grid are very different from generations past;

5. There has been an increase in environmental commitments from the international to local level in DE Carolinas' service territory;
6. The number, severity and impact of weather events on DE Carolinas' customers has been increasing significantly; and
7. The threat of physical and cyber-attacks on grid infrastructure is more sophisticated and is on the rise.

These seven Megatrends are the factors that are driving the need for the Company to have a Grid Improvement Plan that goes beyond the work that the Company performs to maintain base-level operations.

Q. HOW DID THE COMPANY IDENTIFY AND VALIDATE THAT THESE MEGATRENDS EXIST?

A. Over the past several years, we have seen these Megatrends develop in the day-to-day operation of our business. Some of these Megatrends, such as the increased number and increased sophistication of attempted cyber-attacks on our system, are easily identified and are evident as they happen. Other changes, such as the way our customers are using and depending on the power we provide them, are subtler and can be harder to identify. With all these Megatrends, however, our first step was to inventory facts and information that we saw from operating our grid that appeared different than the facts and information we had seen in the previous years of operation.

Once we had conducted the aforementioned inventory, we then looked across the industry to see if other utilities and industry stakeholders were seeing the same Megatrends developing in their operations. As we suspected, the same new Megatrends that we are seeing develop in North Carolina are also being seen throughout the industry.

Q. HOW DID THE COMPANY GO ABOUT ESTABLISHING THAT THE FACTS AND INFORMATION IT WAS SEEING ROSE TO THE LEVEL OF ESTABLISHING WHAT YOU HAVE CALLED MEGATRENDS?

A. During this process of identifying and validating the Megatrends, we collected objective information from our own operations in North Carolina as well as from our companies that function in other jurisdictions. From North Carolina to Florida, and in Kentucky, Ohio, Indiana, and South Carolina, we began to see commonality in the facts and information that evidenced the existence of these Megatrends. From there, we then began to look at objective national information that non-Duke companies and industry stakeholders were sharing publicly. That information also confirmed the existence and validity of the Megatrends. In Exhibit 2 to my testimony, I have included summary data, citations, and information that the Company collected on each Megatrend.

The 2016 South Carolina State Energy Plan also noted the existence of many of these trends, as the following passage reveals:

"In developing this State Energy Plan, it has become very evident that electric utilities are facing expanding customer expectations, increasing environmental regulation, and new technologies that have to be integrated seamlessly into the grid. The grid of the rapidly approaching future will function in ways never imagined when the original wires were installed. If South Carolina is to participate in the innovation coming to fruition in the electric sector — such as distributed energy resources like solar panels, wind turbines, electric vehicles, and microgrids — then the state will require an advanced, integrated grid to manage and optimize the increasingly dynamic flow of electricity."[2] Furthermore, reports from independent third parties as well as stakeholder interactions in North Carolina show that the Company has correctly identified the megatrends that are impacting our system.[3]

Q. WHAT WAS THE NEXT STEP IN THE DEVELOPMENT OF THE GRID IMPROVEMENT PLAN AFTER THE COMPANY IDENTIFED AND VALIDATED THE EXISTENCE OF THE MEGATRENDS?

A. Once we found that the Megatrends we were seeing in North Carolina were valid, and that those Megatrends were also impacting utilities across the nation, we then had to analyze whether the Megatrends mattered. Said another way, the Company had to evaluate whether any or all the Megatrends caused any problems or issues that warranted work in North Carolina that was above and beyond the Company's base-level T&D plan that I have previously discussed.

Q. HOW DID THE COMPANY PERFORM THIS EVALUATION?

A. To determine whether one or more of these Megatrends warranted the Company to develop an incremental Grid Improvement Plan for the state, the Company first listed out all the implications that the Megatrends would logically and objectively have on providing our customers safe, reliable, and affordable electric service. For example, one of the facts we discovered was that customers

[2] http://www.energy.sc.gov/files/Energy%20Plan%20Appendicies%2003.02.2018.pdf
2016 South Carolina State Energy Plan, Appendices, Page 121.
[3] http://gridlab.us/wp-content/uploads/2019/04/GridLab_SC_GridMod.pdf, Page 20.

with higher usage and higher expectations for power quality and reliability were beginning to concentrate more and more in urban and suburban areas such as Charlotte and Raleigh. These customers are the most likely group to embrace technologies like roof top solar and electric vehicles. Given this seemingly undeniable fact, we had to ask the question of what this fact means to our T&D operations. What we found is that our business as usual approach to serving this new load would not address the implications created by the Megatrends. We also realized that the capital required to serve high growth areas can undermine investment in rural areas of the state, causing disparity between customer demographics and geography. In Exhibit 3 to my testimony, I have included our evaluations of these Megatrends and what implications they will have on the Company's grid operations.

III. GRID IMPROVEMENT PLAN

Q. ONCE THE COMPANY IDENTIFED AND VALIDATED THE MEGATRENDS AND THE IMPACTS THEY ARE HAVING ON THE GRID NOW AND IN THE FUTURE, WHAT PROCESS DID THE COMPANY USE TO PUT ALL THIS INFORMATION INTO A GRID IMPROVEMENT PLAN?

A. At this point in our evaluation, the Company took the following overall steps to develop a proactive plan that addresses impacts of the Megatrends:

1. Identified "tools" (i.e. utility projects and programs) available to address the Megatrend impacts. In Exhibit 4, I have included detailed

descriptions of the programs and projects that the Company considered as “tools” to address Megatrend implications;

2. Determined constraints that impacted the creation of the plan such as equipment availability, personnel limitations, available time and schedule, any applicable prescriptive requirements, interplay with base-level work needs, and price impact;
3. Selected “tools” to use in the plan in an iterative process that built up from a foundation of protecting the grid first and foremost; establishing foundational, system-level programs that are needed for all aspects of operations and that impact all customers next; and then focusing on projects and programs that help address the most number of Megatrend implications for the best value to customers. We called this phase of the plan development “protect,” “modernize,” and “optimize,” and I have included a series of graphics that help to explain this process as Exhibit 5 to my testimony; and
4. Developed a comprehensive Grid Improvement Plan that efficiently organizes the work to be completed based on where, when, and how much is appropriate.
5. Invited stakeholder feedback to ensure the plan addressed the diverse set of customer and stakeholder needs.

Q. YOU MENTIONED THAT THE FIRST STEP IN DEVELOPING THE GRID IMPROVEMENT PLAN WAS IDENTIFYING TOOLS THE COMPANY HAS TO ADDRESS THE MEGATRENDS. CAN YOU PROVIDE MORE DETAIL ON THIS PHASE OF THE PLAN DEVELOPMENT?

A. Yes. The programs and projects that are available to the Company to help address the implications of the Megatrends in North Carolina can be grouped into three basic categories based on how the Company brings those programs into its plan. These three categories are (1) compliance-driven programs that protect the grid, (2) rapid technology advancement programs that modernize the grid, and (3) various other projects and programs that work independently or together with other programs to optimize our customers' experience. I will further describe those categorizations below.

Q. WHAT CONSTITUTES COMPLIANCE-DRIVEN WORK THAT IS DESGINED TO PROTECT THE GRID?

A. Compliance-driven programs in the Grid Improvement Plan are efforts which need to be completed to reduce physical and cyber threats to the grid. These programs may be necessitated by an external law, rule, or regulation applicable to the company that requires the work; a binding legal obligation such as a contract, agency order, or other legal document that compels the work; or Operations Council approval of the work as being critical and imperative to the Company's operations. To qualify for inclusion in the Grid Improvement Plan, work in this category is limited to rapidly evolving threats to the grid that outpace the scope and timing of standard compliance work done in our base-level operations. The type of work to address these concerns includes applying physical and cyber protections to transmission substations and distribution assets that are not yet covered under mandatory federal regulations such as special protective fencing and barricades to help minimize the threat of gunshot attacks to equipment, intruder sabotage, and vehicle attacks to critical equipment, and installing tamper alarms and protective cyber "blocking devices" on electronic distribution equipment that are susceptible to hacking by a cybercriminal on our distribution assets in the field.

Q. HOW DO YOU EVALUATE COMPLIANCE-DRIVEN PROGRAMS?

A. When evaluating compliance-driven programs as part of the Grid Improvement Plan, we first focus on work that has a prescriptive mandate that dictates how, when, or where the work must be done. For example, if a federal regulation states that we must take certain activity on a certain set of grid assets at a certain time, we necessarily put that work into our plan first given that the Company has little discretion to do otherwise. Once that work is incorporated into the plan, the Company then focuses on non-prescriptive work that poses the highest risk to the grid and then continues to incorporate grid protection work into the plan on a risk-advised basis, taking plan constraints into consideration. Since this grid protection work must be done, the Company does not evaluate these compliance-based programs with cost benefit analyses, but instead takes measures to ensure that this work is done in a cost-effective manner. In Exhibit

6 to my testimony, I have included a "gating tool" that the Company uses to determine how to properly evaluate the costs and benefits of all the work in the Grid Improvement Plan. Compliance-driven programs include the following types of work and activities: electronic access blocking and gating restrictions on computerized systems and equipment; cyber defense computer programs and applications; physical access restrictions and protective devices to substations and critical equipment; and working with industry experts to determine best practices for electromagnetic pulse protections on certain critical assets.

Q. WHAT CONSTITUTES A RAPID TECHNOLOGY ADVANCEMENT PROGRAM THAT MODERNIZES THE GRID THAT YOU DESCRIBED AS THE SECOND CATEGORY OF WORK IN THE GRID IMPROVEMENT PLAN?

A. Rapid technology advancement work that is needed to modernize the grid consists of equipment, software, hardware, operating systems, or accepted system operating practices that have advanced at an atypical pace, causing the need for rapid and sometimes frequent changes within the utility at a system deployment level. Work in this category is usually related to system communication, automation, and intelligence and must be executed at a deliberate pace while ensuring not to deploy new technology before it has reached maturity. While not considered compliance activities, work in this category is essential for modern system operations. Rapid technology advancement programs include the following types of work and activities:

deploying new system-wide communications devices so that the transmission and distribution system can communicate back to us and with each other, replacing pneumonic and manually actuating equipment with modern electronic and intelligent equipment that is self-actuating and self-correcting, and installing advanced system intelligence devices that will allow our underground and overhead assets to proactively report their condition status and potential problems before they manifest into equipment failures.

Q. HOW DO YOU EVALUATE RAPID TECHNOLOGY ADVANCEMENT PROGRAMS?

A. In this area of the Grid Improvement Plan, the Company looks for "Enterprise" or system-level programs that enable interoperability and functionality to grid operations and thereby impact and provide value to all our customers. A grid that can communicate and provide information to us and our customers and that can automatically react to grid events is essential to meet the demands of our customers and the implications of the Megatrends in North Carolina. Programs that help the Company meet these requirements are selected for inclusion in this part of the Grid Improvement Plan. Since these programs are essential to enabling a modern-functioning grid, the Company ensures that they are deployed and selected in a cost-effective manner.

Q. WHAT CONSTITUTES A SYSTEM OPTIMIZATION PROGRAM THAT IS PART OF THE FINAL CATEGORY OF WORK IN THE GRID IMPROVEMENT PLAN?

A. Programs and projects in this category provide customers more benefits than costs and solve for one or more of the external Megatrends that can have negative impacts to customers and grid operations. Work in this category spans a wide range of assets but primarily includes a "bundled combination" of Integrated Volt/Var Control ("IVVC"), Self-Optimizing Grid deployments, and advanced power systems that, when working together, provide optimum system performance for our customers. The Self-Optimizing Grid, also known as the smart-thinking grid, redesigns key portions of the distribution system and transforms it into a dynamic self-healing network that ensures many issues on the grid can be isolated and customer impacts are limited to hundreds versus thousands. These grid capabilities are enabled by installing automated switching devices to divide circuits into switchable segments that will serve to isolate faults and automatically reroute power around trouble areas which call for expanding line and substation capacity to allow for two-way power flow and creating tie points between circuits. The IVVC program leverages the grid improvements from the self-optimizing technology and adds remotely-operated substation and distribution line devices such as regulator and capacitor controllable field devices that enable a grid operator to lower voltage as a way to reduce peak demand, thereby reducing the need to generate or purchase additional power at peak prices (peak shaving) or to operate in a conservation mode during periods of more typical electricity demand in order to reduce overall energy consumption and system losses.

Q. HOW DO YOU EVALUATE SYSTEM OPTIMIZATION PROGRAMS?

A. In selecting these programs for inclusion in the Grid Improvement Plan, the Company looks for programs that address the largest number of Megatrend implications at the lowest costs to customers. System optimization programs are justified by a qualitative and quantitative cost benefit analysis, and Exhibit 6 that I previously discussed provides more detail on how this is done at various stages of program implementation. When a system-level program like IVVC[4] or Self-Optimizing Grid[5] is deployed throughout our service territory in North Carolina, the Company utilizes a program-level cost benefit analysis. The Company also has a methodology for project-level cost benefit analysis, which examines the costs and benefits of deploying a specific project solution based on the nature of a specific site. For example, the Targeted Undergrounding[6] and Transmission Line Upgrade programs in the Grid Improvement Plan are evaluated on a site-by-site basis using project level cost benefit analyses. The

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[4] IVCC is particularly notable because it provides multiple benefits and savings to all our various customer classes while at the same time allowing the Company to have maximum flexibility to react to multiple system conditions on the grid.

[5] Self-Optimizing Grid is an example of investments with multiple layers of benefits as it helps customers save money in avoided system costs; allows more distributed energy resources (such as rooftop solar) to be on the grid; and provides containment and mitigation of outages by reducing thousands of impacted customers in an outage down to hundreds or less.

[6] Target Undergrounding is the process of burying certain lines for cost saving and reliability purposes, and not for aesthetic purposes, and could yield savings for all our customers over what they would otherwise pay to maintain and repair and overhead system in addition to the improved reliability that it will provide.

cost benefit analyses and the underlying data sources and work sheets for all the programs and projects in the "Optimize" portion of the Company's proposed Plan, which encompasses more than seventy percent of the costs for the Plan, were placed in a virtual data room available to interested stakeholders leading up to this filing. This data room is discussed in more detail in the Stakeholder Engagement portion of my testimony. The cost benefit analyses and underlying workpapers are located in Exhibit 7.

Exhibit 8 to this testimony shows that the programs in the Company's plan designed to optimize the North Carolina grid have a positive net present value benefit to cost ratio of 4.7. This means that for every dollar spent on these programs and projects, customers should receive a payback of $4.70 in primary benefits. Also in Exhibit 8 of this testimony, I have included a total primary benefit analysis of the entire Grid Improvement Plan portfolio, and this document shows that all the costs in the plan (costs to protect, modernize, and optimize the North Carolina grid) have a positive total net present value benefit ratio of 3.6. This means that for every dollar spent on the total Plan, North Carolina customers should receive a payback of $3.60 in primary benefits.

In Exhibit 8 to this testimony, I have also included an analysis of the secondary benefits that the Grid Improvement Plan should provide to customers and residents. If both the primary and secondary benefits of the Grid Improvement Plan are considered together, the total Grid Improvement Plan (cost to protect, modernize, and optimize the grid) should provide customers and residents a positive total net present value benefit ratio of 6.4, meaning that every dollar spent on the Plan should provide a payback of $6.40.

Q. IN YOUR DISCUSSION OF THE BENEFITS OF THE GRID IMPROVEMENT PLAN, YOU REFER TO PRIMARY (DIRECT) AND SECONDARY (INDIRECT) BENEFITS. WOULD YOU PLEASE EXPLAIN THE DISTINCTION BETWEEN THESE TWO SETS OF BENEFITS?

A. Yes. Primary benefits consist of value that is directly captured by the Company and by customers. Examples of primary benefits captured by the Company are things like avoided deployments of outage restoration crews, avoided equipment replacement costs, avoided operations and maintenance savings, and other "hard costs" that can be estimated and quantified. Examples of primary benefits captured by customers are things like avoided lost product, avoided damaged equipment costs, avoided lost wages, and other expenses that cost customers money. In Exhibit 9 to this testimony, I have included a graphic example of a "benefits pyramid" that shows how the benefits of electric utility projects are thought about and evaluated in the industry. As can be seen from this graphic and from the cost benefit results in Exhibit 8, the Company's proposed Grid Improvement Plan is justified in its entirety just on primary benefits alone.

However, the proposed Grid Improvement Plan for North Carolina also provides indirect, secondary benefits to customers through risk reduction; value to third parties, and value to society as a whole, which are reflected on the top three rungs of the benefits pyramid displayed on Exhibit 9. Of these indirect/secondary benefits, the Company has estimated the indirect value of the plan to third parties, and the results of this evaluation are reflected in Exhibit 8. However, the Company has not attempted to value the indirect benefits of risk reduction and the benefits to society as a whole for the Grid Improvement Plan, which means that the benefits of the plan are understated and are greater than what the Company has calculated.

Q. SHOULD THE GRID IMPROVEMENT PLAN HAVE QUANTIFIABLE TARGETS AND METRICS TO MEASURE THE PERFORMANCE AND RESULTS OF THE WORK IN THE PLAN?

A. Yes. The cost benefit analyses in Exhibit 7 to this testimony provide those metrics for each of the projects and programs that are appropriate for such metrics.[7] Specifically, the cost benefit analyses performed by the Company detail, among other things, the amount of O&M savings the Company anticipates from the plan; the amount of avoided capital costs the Company anticipates from the plan; and the amount of outages that each of the programs and projects within the plan are anticipated to avoid.

Q. HOW HAS THE COMPANY SHAPED THIS COLLECTION OF PROGRAMS INTO A HOLISTIC GRID IMPROVEMENT PLAN?

A. Once the Company had selected the programs and projects that could meet customers' needs in the manner that I have previously discussed, the Company

[7] Some programs/projects cannot be effectively measured by detailed performance metrics and targets. For example, computer hardware and software that enables grid assets to communicate with each other either works or does not work, and measures taken to prevent substations from flooding in major storms either keep water out or do not keep water out.

then had to develop a formal, year-over-year work plan that can be achieved given the resource constraints that I discussed earlier in my testimony. Further, the final Grid Improvement Plan had to be developed not only in a risk-advised manner, but in a manner that is fair to all our customers. For example, a Grid Improvement Plan that was too heavily weighted to address only one of the Megatrends impacting North Carolina could be viewed as short-sighted, while a Grid Improvement Plan that was too "diluted" and lacked strategic focus would be ineffective. Similarly, a Grid Improvement Plan that focused too heavily on one type or class of customer could be viewed as unfair. The Company had to balance these and other considerations when forming the final Grid Improvement Plan work.

Q. HOW DID DUKE ENERGY BALANCE DIVERSE CUSTOMER AND STAKEHOLDER NEEDS?

A. The Grid Improvement Plan for North Carolina is designed with programs that benefit all our customers, and that is one of the primary ways that we have balanced our customers' needs and interests. Over our three-year plan, we have also balanced the pace, scope, location, and timing of our work to ensure that customer and stakeholder needs are met. Further, we have kept the needs of our rural and low-income customers in mind as we developed our plan, and programs such as IVVC provide these customers both increases to reliability and resiliency while at the same time providing decreases in fuel costs, future capacity and carbon costs, and lower monthly energy usage.

Q. WHAT IS YOUR RESULTING GRID IMPROVEMENT PLAN FOR NORTH CAROLINA?

A. After completing all the steps in our plan development process, we arrived at our Grid Improvement Plan, which is presented in Exhibit 10.

Q., **IS THE GRID IMPROVEMENT PLAN THAT YOU ARE PROPOSING IN THIS CASE SIMILAR TO THE GRID IMPROVEMENT PLAN THAT THE COMPANY RECENTLY INTRODUCED IN SOUTH CAROLINA?**

A. Yes. By design, the Grid Improvement Plan for North Carolina is identical to the South Carolina plan in substance, so that the two plans can work together to provide benefits to DE Carolinas customers.

Q. **DID STAKEHOLDERS IN SOUTH CAROLINA HAVE ANY FEEDBACK ON THE DE CAROLINAS GRID IMPROVEMENT PLAN THAT YOU PROPOSED?**

A. Yes. While most of the feedback we received from South Carolina stakeholders focused on the method for cost recovery to be used for grid improvement investments, many stakeholders did provide useful substantive questions and input on the plan that I outlined and addressed in my rebuttal testimony in the South Carolina rate cases dockets. For ease of reference in this testimony, I have included my rebuttal testimony from South Carolina Docket 2018-319-E as Exhibit 17 to this testimony rather than recounting all those questions and inputs here.

Q. **WAS THE COMPANION GRID IMPROVEMENT PLAN FOR SOUTH CAROLINA APPROVED?**

A. In the DE Carolinas and DE Progress rate cases for South Carolina, the parties entered into a stipulation that affords deferral accounting treatment for the SC Grid Improvement Plan, and that calls for the ongoing tracking and reporting of costs and achieved benefits under the Plan as work is completed. This is the same treatment and procedure that the Company is requesting for DE Carolinas in this case.

IV. <u>STAKEHOLDER ENGAGEMENT AND COST RECOVERY OF GRID IMPROVEMENT INVESTMENTS</u>

Q. DID THE NORTH CAROLINA UTILTIES COMMISSION GIVE THE COMPANY ANY GUIDANCE ON THE RECOVERY OF FUTURE GRID IMPROVEMENT COSTS IN THE COMPANY'S LAST BASE RATE ADJUSTMENT PROCEEDING IN NORTH CAROLINA?

A. Yes. In Docket No. E-7, Sub 1146, the Commission issued an order stating:

> "With respect to deferral, the Commission acknowledges that, irrespective of its determination not to defer specific costs in this case, the Company may seek deferral at a later time outside the general rate case test year context to preserve the Company's opportunity to recover costs, to the extent not incurred during the test period. In that regard, were the Company in the future before filing its next rate case to request a deferral outside the test year and meet the test of economic harm, the Commission is willing to entertain a requested deferral for Power Forward, as opposed to customary spend, costs. Should a collaborative

undertaking with stakeholders as addressed herein produce a list of Power Forward projects, such designation would greatly assist the Commission in addressing a requested deferral. Were the Company to demonstrate that the costs can be properly classified as Power Forward and grid modernization, the Commission would seek to expeditiously address the request and to determine that the Company would meet the 'extraordinary expenditure' test and conceptually authorize deferral for subsequent consideration for recovery in a general rate case.

The Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied on other contexts. Consequently, with respect to demonstrated Power Forward costs incurred by DEC prior to the test year in its next case, the Commission authorizes expedited consideration, and to the extent permissible, reliance on leniency in imposing the 'extraordinary expenditure' test."

Q. WHAT STEPS HAS THE COMPANY TAKEN TO ADDRESS THE COMMISSION'S RECOMMENDATION FOR COLLABORATING WITH STAKEHOLDERS?

A. The Company has held three in-person stakeholder workshops in North Carolina and a series of webinars since the previous North Carolina rate case. The first workshop was conducted in response to the settlement agreement approved by the NCUC on February 23, 2018, in Docket No. E-2, Sub 1142 for the DE Progress general rate case, and was held on May 17, 2018. Acting as a neutral facilitator, a team from Rocky Mountain Institute ("RMI") convened 65 participants (inclusive of 18 Duke Energy and five RMI staff) for a day-long workshop. The objectives of this workshop were to develop understanding of proposed investments; hear and explore stakeholder feedback; and support a collaborative process going forward. At the conclusion of the workshop, RMI prepared a detailed, post project report which was filed with the Commission on June 26, 2018. I have included that report as Exhibit 11 to my testimony.

Q. DID THE WORKSHOP RESULT IN CHANGES TO THE COMPANY'S PLANS FOR GRID IMPROVEMENTS?

A. Yes. The feedback we received in this workshop led us to identify and validate the Megatrends as discussed earlier in my testimony. Because of the formalization of the Megatrends and stakeholder feedback, the Company made significant changes to the portfolio of investments. Most notably, the IVVC program was added, the Targeted Undergrounding program was significantly reduced, and much of the Distribution H&R work was moved out of the plan. In November 2018, the Company sent a detailed "pre-read package" to North Carolina stakeholders describing the development and proposed Grid Improvement Plan, in advance of the second North Carolina Stakeholder Workshop held on November 18, 2018. I have included that pre-read package as Exhibit 12. In this workshop, with RMI again acting as the neutral facilitator, 78 participants (inclusive of 19 Duke Energy and four RMI staff) convened for a day-long workshop. At the conclusion of that workshop, RMI prepared a detailed, post project report which was filed with the Commission on January 9, 2019, and I have included that report as Exhibit 13 to my testimony.

Q. WHAT ACTIONS DID THE COMPANY UNDERTAKE TO RESPOND TO THE LEARNINGS FROM THE SECOND STAKEHOLDER WORKSHOP?

A. The major themes we heard in the second workshop included: Grid Improvements should be supported by cost benefit analysis; the Company should provide further details on how it conducted its cost benefit analysis; and the Company should provide how much additional distributed energy and renewable resources the grid could support with the plan's improvements. In response, the Company provided cost benefit analysis and underlying data sources and work sheets for all applicable programs and projects in a virtual data room for stakeholders to review ahead of the third stakeholder workshop held on May 16, 2019. The Company also responded to the questions regarding distributed renewable energy resources. Prior to the May 16, 2019 workshop the company conducted a webinar with stakeholders on April 25, 2019 to address questions regarding the cost benefit analysis and gather feedback regarding the agenda for the next stakeholder workshop. The webinar materials are included in Exhibit 14.

Q. CAN YOU ELABORATE ON THE FEEDBACK RECEIVED FROM STAKEHOLDERS IN THE APRIL 25, 2019 WEBINAR?

A. Yes. During the webinar, the Company conducted a poll to determine what stakeholders wanted to discuss in detail in the May 16, 2019 workshop.

Seventy-six percent of the webinar participants stated that they wanted to discuss cost recovery issues regarding the Plan. Fifty-nine percent stated that they wanted more information and discussion regarding the Company's cost benefit analysis for the plan, and 41 percent stated that they wanted to further discuss plan prioritization and design. Finally, 55 percent stated that they wanted to further discuss distributed renewable energy resource enablement. Based on these responses, and with the help of RMI, the Company designed the agenda for the May 2019 workshop with these prioritized responses in mind. I have included that pre-read package as Exhibit 15.

Q. WHAT WERE THE RESULTS OF THE THIRD AND MOST RECENT STAKEHOLDER WORKSHOP?

A. In this workshop, with RMI again acting as the neutral facilitator, 52 participants (inclusive of 11 Duke Energy) convened for a day-long workshop. At the conclusion of that workshop, RMI prepared a detailed, post project report which was filed with the Commission on July 9, 2019 and I have included that report as Exhibit 16 to my testimony.

Q. WHAT ACTION HAS THE COMPANY TAKEN TO RESPOND TO STAKEHOLDERS' FEEDBACK IN THE THIRD WORKSHOP FOR MORE INFORMATION ON THE COST BENEFIT ANALYSES?

A. A series of three webinars focused on deep dives into the analysis behind Duke Energy's Grid Improvement Plan took place in June 2019. The first webinar took place on June 13 and focused on a deep dive into the Self-Optimizing Grid cost benefit analysis. The second webinar took place on June 17 and focused on a deep dive into the Targeted Undergrounding cost benefit analysis. The third webinar took place on June 24 and focused on a deep dive into several Transmission H/R projects. Highlights of the Grid Improvement Program were presented at the beginning of each meeting. Experts were on hand to guide participants through cost benefit analysis scenarios, address questions regarding the implementation, improvements and progress of the programs. Over 40 participants attended each webinar. The materials presented in the webinars are included in Exhibit 18.

Q. WHAT CONCLUSIONS HAVE YOU DRAWN BASED ON ALL THIS STAKEHOLDER ENGAGEMENT?

A. We have drawn several conclusions. First, it appears to us that stakeholders understand and accept the Megatrends that are facing the Company and our industry. Second, the combination of the substantive changes we made to the content of the plan and the detailed cost benefit analyses that we provided seems to have helped stakeholders gain a better consensus and understanding of our proposed three-year plan. Finally, most stakeholders remain highly interested in what future phases of the plan, if any, would contain and how costs for those phases would be recovered. We will keep this last observation front and center as we continue our stakeholder engagement efforts in the Carolinas.

Q. CAN YOU PROVIDE MORE DETAIL ON WHAT OTHER GRID IMPROVEMENT WORK THE COMPANY PLANS TO DO IN ADDITION TO THIS THREE-YEAR PLAN?

A. Yes. Our three-year Plan is a comprehensive package of well-coordinated grid improvements. It does not need a Phase 2 to be effective, and depending on what we see in the industry and what we hear from our stakeholders in our ongoing engagement with them, there may never be a second phase to the Grid Improvement Plan. That being said, the three-year Plan does set North Carolina up for other improvements that could warrant a second phase of the Plan, and we plan to engage and work with stakeholders before deploying any future phases of the Plan. Below are potential programs for consideration and stakeholder input:

1. **Phase 2 of Self-Optimizing Grid**. The current SOG plan enables approximately 344 - 430 circuits with approximately 628,000 - 785,000 customers. A Phase 2 project could focus on the next, most cost effective, group of circuits.
2. **Phase 2 of IVVC**. The current IVVC plan would enable approximately 152 - 190 substations and associated circuits. A Phase 2 project could focus on the next, most cost effective, group of substations and circuits.
3. **Increased Implementation of Power Electronics**. The current IVVC and SOG programs set up the basic capacity, automation, and Volt/VAR control mechanisms to manage the 21^{st} century grid. As privately owned

DER grows, power electronics will be essential to managing the rapid and dynamic effects of multiple, small scale intermittent resources.

4. **44 KV Upgrade Projects that Enable Solar Capacity**. Through continuing coordination with stakeholders and regulators, these projects may afford new opportunities that provide value to customers.

5. **ISOP Optimization**. As the Company and the industry continues to develop and deploy ISOP, best practices and lessons learned can be utilized to optimize the ISOP process.

6. **Increased use of Energy Storage.** Energy Storage is part of our three-year Plan but is still in a startup/pilot phase. We believe more opportunities may exist as batteries become more cost effective and as we learn more about their capabilities on the grid.

This list is certainly not comprehensive or prescriptive. It is intended to lay out options that build off the currently proposed three-year plan. Regardless, we are committed to continued stakeholder interaction to help inform any future actions that we may, or may not, take.

Q. WHAT COST RECOVERY MECHANISM IS THE COMPANY PROPOSING FOR FUTURE GRID IMPROVEMENT PLAN WORK?

A. As discussed more fully in the testimony of Witness McManeus, the Company is requesting deferral accounting treatment for the Grid Improvement Plan work as a mitigant to the debilitating effect that regulatory lag will have on the Plan absent a deferral.

Q. PLEASE EXPLAIN THE IMPACT THAT REGULATORY LAG WILL HAVE ON THE GRID IMPROVEMENT PLAN WORK ABSENT A DEFERRAL.

A. It is important for stakeholders to recognize that just like any other company that must manage a monthly budget and pay bills, a regulated utility has a limited amount of funds to pay a given amount of expenses. Unlike unregulated companies that can raise the price of their products as they see fit to cover incremental expenses, the Company's income stream to pay for projects needed to maintain a base level of service to customers in North Carolina is set by the Commission in base rate proceedings like this one and once that revenue stream is set, the Company cannot increase it without filing another base rate case. This means that every day, the Company must decide what projects and programs it will deploy and which ones that it will not, which, in turn, means that programs and projects must compete against each other for funding priority. Thus, to fund incremental work like the Grid Improvement Plan, the Company must obtain money between its rate cases to pay for new work, and obtaining money naturally comes with a cost.

In instances where the Company has large, centralized projects that take longer to complete (such as building a new power plant), I understand that regulatory rules allow the utility to apply a carrying charge to the funds that the Company must borrow and pay interest on to complete this work as a principle of fundamental fairness. In other words, one cannot reasonably expect the Company to borrow money and pay interest on that money on behalf of customers to build a power plant that will serve those customers and then not pay the Company back for the money it borrowed plus the interest it had to pay on it. However, I understand that smaller and quickly-installed project and programs, like many of those included in the Grid Improvement Plan, do not receive those same benefit for accumulating a carrying charge that apply to the large, time-intestive projects. To ensure that utilities are not discouraged from these smaller programs that deliver benefits more quickly to customers, I have seen regulators enact measures to avoid the problem of regulatory lag such as rider recovery, rate adjustment step ups, or deferral accounting treatment with returns for such projects.

Q. ARE YOU SUGGESTING THAT THE COMPANY WILL NOT PERFORM ANY OF THE WORK IN THE GRID IMPROVEMENT PLAN IF THE COMMISSION DOES NOT APPROVE SOME METHOD TO AVOID REGULATORY LAG ON THOSE PROJECTS?

A. No. However, without a reasonable means of mitigating the negative impacts of regulatory lag associated with significant ongoing and incremental spending under the Grid Improvement Plan, the Company would be required to reassess its ability to commit to the planned level of investment in this program given that the level of investment anticipated under the plan simply cannot be reasonably sustained in the absence of mitigation measures such as the deferral requested herein. As such, if the Commission determines not to grant the regulatory asset treatment for the Company's Grid Improvement Plan investment sought in this proceeding, the Company will be required to reassess its ability to implement that plan. In such a situation, the Company would have to try and perform small pieces of the Grid Improvement Plan over a much longer period with its existing revenues, which will delay important benefits and potentially essential improvements for customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

NORTH CAROLINA GRID IMPROVEMENT PLAN

MAINTAIN BASE TRANSMISSION AND DISTRIBUTION SYSTEM WORK

MAINTAIN BASE TRANSMISSION AND DISTRIBUTION SYSTEM WORK

Safety	Load Service	Reliability	Environment
Pole inspections and pole inspection repairs	New line extensions	Pole inspections and pole inspection repairs	Critical infrastructure review near waterways (210 gallons of oil within 100 ft. of active waterway)
End of life pole replacement	Line capacity upgrades/additions	End of life pole replacement	Surface mounted equipment inspections and maintenance
Surface mounted equipment inspections and maintenance	Substation capacity upgrades/additions	IR inspections	Below surface mounted equipment inspections and maintenance
Below surface mounted equipment inspections and maintenance	Circuit phase additions	Capacitor, regulator, recloser, breaker maintenance work	Capacitor, regulator, and recloser maintenance work
Voltage contact inspections and follow-up work	Corrective maintenance	Deteriorated conductor replacement	Corrective maintenance
Top of pole inspection & follow-up work		Top of pole inspection & follow-up work	Outage follow-up
Corrective maintenance		UG cable testing and follow-up	Proactive replacement of pad mount transformers
Outage follow-up		Vegetation maintenance program and danger tree program	
		Declared protection zones	

MAINTAIN BASE TRANSMISSION AND DISTRIBUTION SYSTEM WORK

Safety	Load Service	Reliability	Environment
		System protection work	
		UG cable repair, replacement and injection programs	
		Corrective maintenance	
		Outage follow-up	
		Declared protection zones	

DUKE ENERGY

MAINTAIN BASE TRANSMISSION AND DISTRIBUTION SYSTEM WORK

Safety	Load Service	Reliability	Environment
Required by law, rule, regulation, code	Required to serve all existing and new load in our territory via standard design	Required by law, rule, regulation, code	Required by law, rule, regulation, code
Public and worker safety is top priority for the Company	Required to account for mandatory reserves, margins, system impacts	National sources on what customers expect as minimum standards	Environmental protection and safety is top priority for the Company
High consequences with adverse occurrences	High consequences with adverse occurrences	Local sources on what customers expect as minimum standards	High consequences with adverse occurrences
Industry standard expectations	Industry standard expectations	Historical level of service that customers have been provided	Industry standard expectations
High stakeholder acceptance	High stakeholder acceptance	Solving for reliability as a system and not for individual areas or certain customer types	High stakeholder acceptance
		Direct feedback on what our customers care about	
		Recognition that a certain level of outages and interruptions is acceptable to avoid making the system too costly	

NORTH CAROLINA GRID IMPROVEMENT PLAN

MEGATRENDS IMPACTING NORTH CAROLINA

2019

TRENDS IN OUR SERVICE TERRITORY

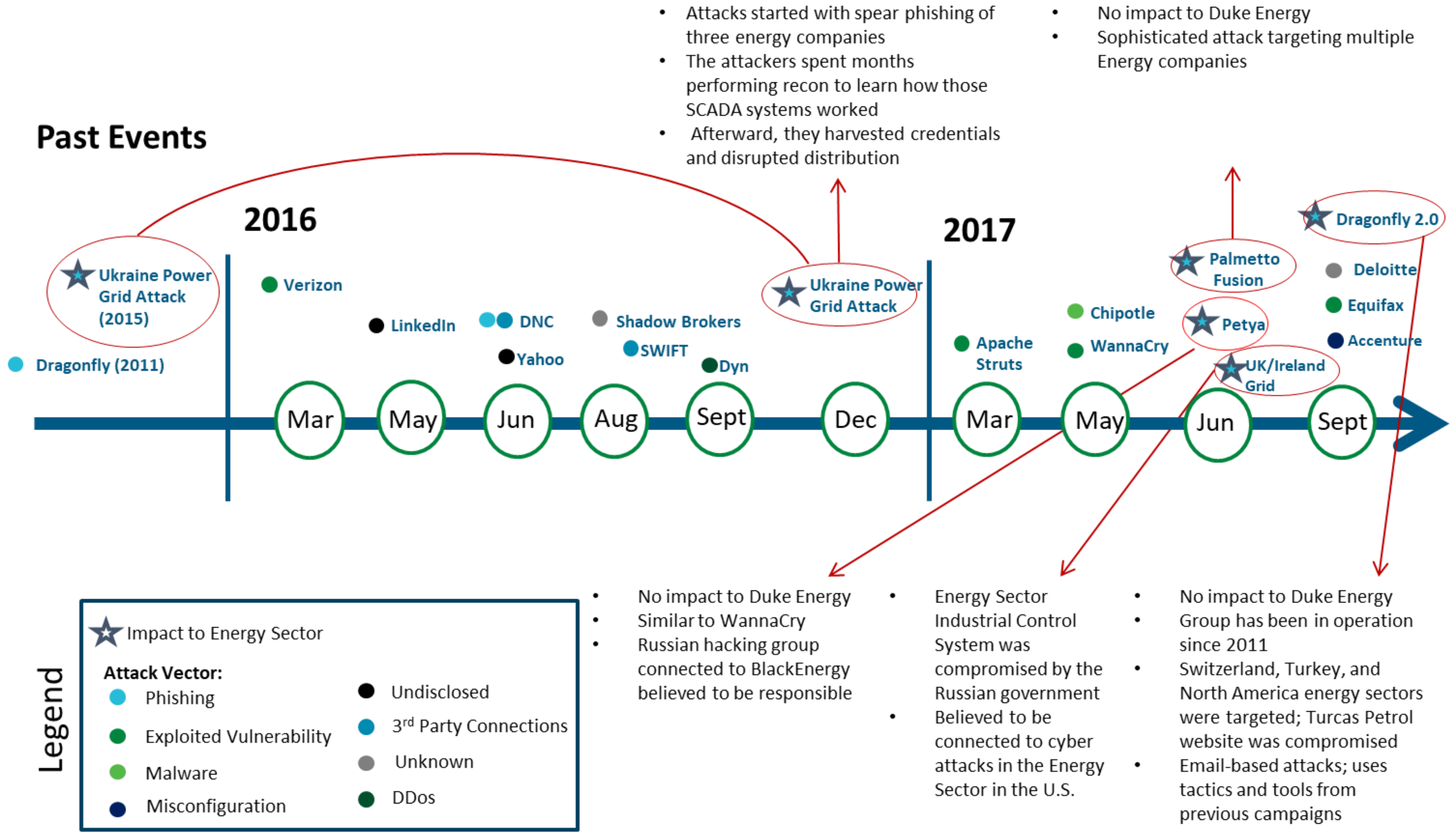
In the context of the emerging distributed electric system, Duke Energy has recognized multiple trends and facts that warrant recognition and analysis.

I	Threats to grid infrastructure
II	Technology advancements – Renewables and DER
III	Environmental trends
IV	Impact of weather events
V	Grid improvement
VI	Concentrated population growth
VII	Customer expectations

DUKE ENERGY

What is happening?

- Purposeful threats, both physical and cyber, to the electric grid are on the rise worldwide

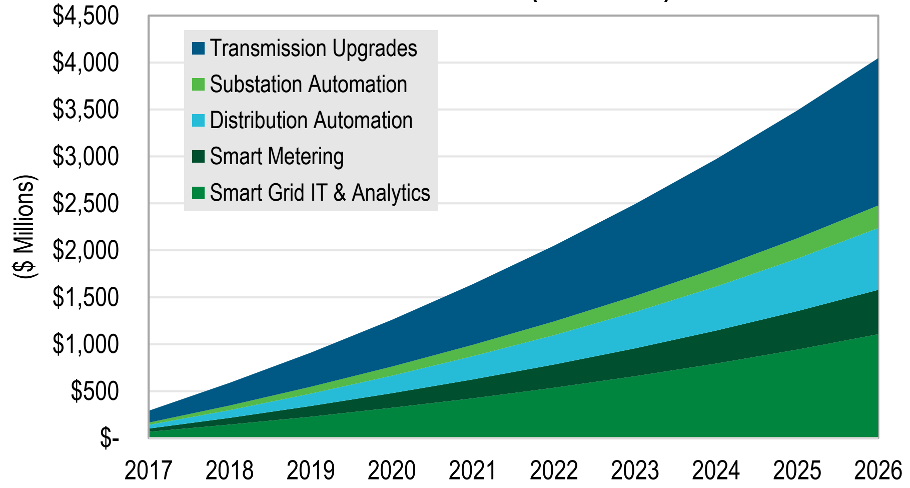


Source: Duke Energy[1]

What is happening?

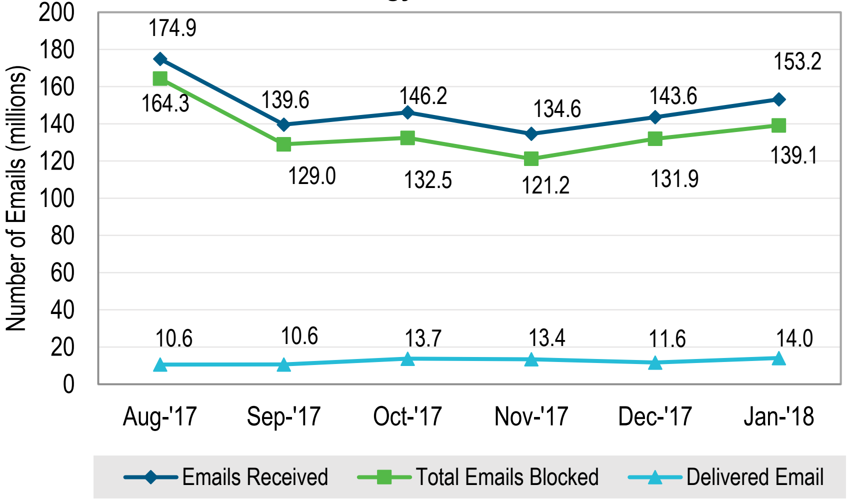
- Grid cybersecurity investment expected to grow from $300 million in 2017 to $4 billion by 2026[2]
- Increasing points of entry: as of November 2017, an estimated 378 million Internet of Things (IoT) devices were vulnerable to hacking[3]
- Ukrainian power grid attacks in 2015 and 2016 and more recent ransomware attacks driving utilities to expand beyond compliance-based management practices[4]
  - Industrial Control Systems Cyber Emergency Response Team estimates a similar incident in the US would result in damages totaling between $243 billion and $1 trillion[5]
- Cyber attacks impacting Southeast municipalities and utilities
  - Ransomware attacks in Mecklenburg County (Charlotte) and Atlanta impacted key government services including bill payments[6]
  - North Carolina fuel distribution company experienced $800,000 cyber heist[7]
  - Duke Energy protection solutions currently blocking +90% of incoming emails[8]

Cumulative Smart Grid Cybersecurity Investment in North America (2017-2026)



Source: Navigant Research Cybersecurity for the Digital Utility[9]

Duke Energy Email Protection

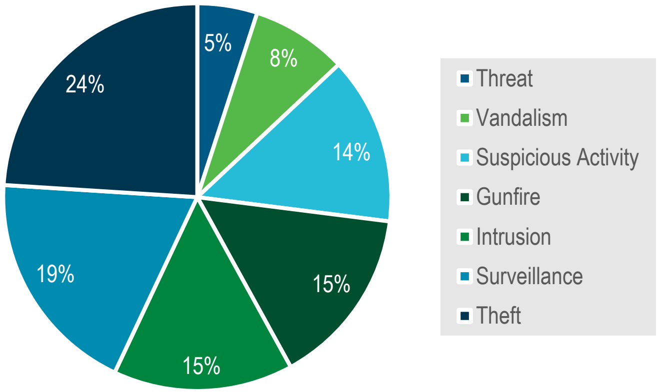


Source: Duke Energy[10]

What is happening?

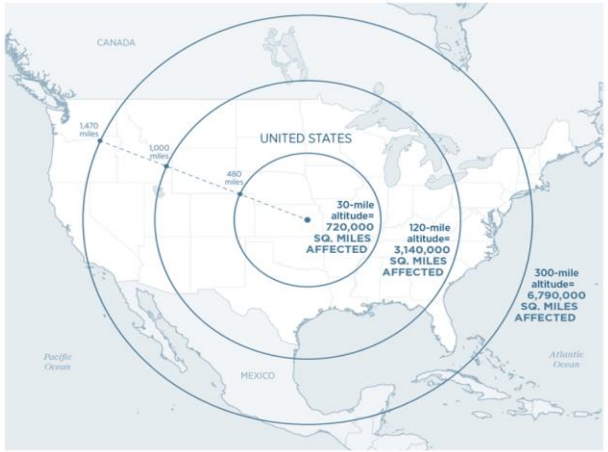
- Electricity Information Sharing and Analysis Center (E-ISAC) assesses that there will be an increase in theft, especially in areas more negatively impacted by socio-economic issues[11]
    - Theft was the top physical threat to the grid in 2017[12]
- The number of terrorist attacks is increasing
    - Physical/sniper attack on PG&E transmission station damaged 17 substation transformers, caused $15 million in damages, and led to $100 million in physical security investments[13]
- Electromagnetic Pulse (EMP) generated at an altitude of 30 miles above the earth can severely damage electronics within an area of about 720,000 square miles[14]
    - Currently there is limited protective equipment installed to address consequences of EMP-like events[15]
    - Have potential to cause wide-scale long-term losses with economic costs[16]
    - Cost of damage from the most extreme solar event is estimated to cost $1 trillion-$2 trillion with recovery time of 4-10 years[17]

Breakdown of Physical Security Incidents for 2017



Source: NERC[18]

Potential Magnitude of EMP Events



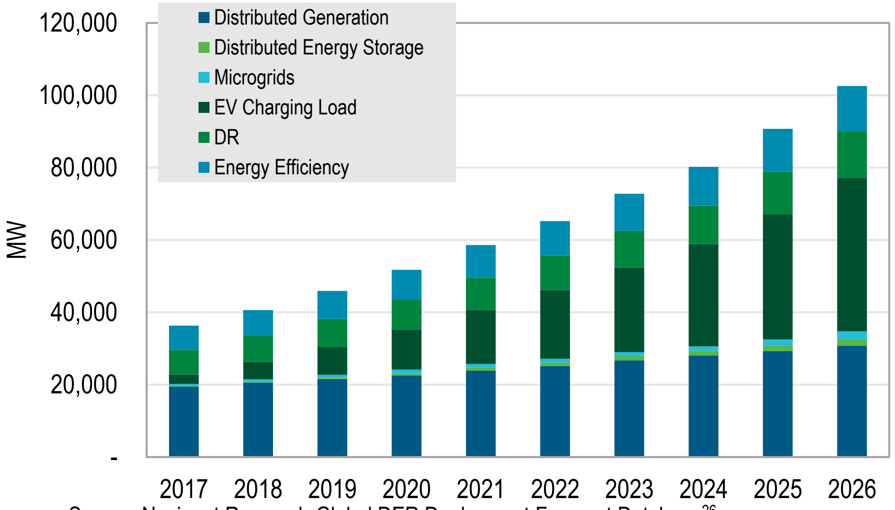
Source: The Heritage Foundation[19]

II. TECHNOLOGY ADVANCEMENTS – RENEWABLES AND DER

What is happening?

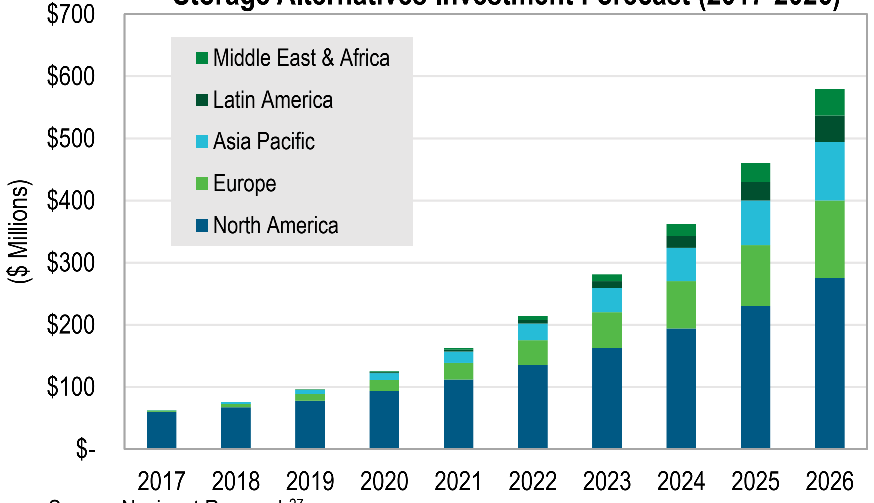
- Distributed energy resources (DER) expected to grow eight times faster than net new centralized generation in the next 10 years globally[20]
  - Distributed generation, including solar PV, remains a dominant contributor to this forecast
  - EVs and EV charging are the fastest growing segments
- Spending on energy storage solutions and alternatives is forecasted to increase at an annual rate of 18% over the next 10 years in North America[21]
- Renewables and DER becoming significant capacity resource for Duke Energy in North Carolina
  - Recent North Carolina Integrated Resource Plan (IRP) includes capacity from renewable resources, energy efficiency, and demand-side management, increasing from 8% in 2019 to 16% in 2033 (Duke Energy Carolinas (DEC)) and 18% in 2019 to 22% in 2033 (Duke Energy Progress (DEP))[22]
  - Duke Energy customer-sited solar programs totalling 10 MW in DEC and DEP approved in May 2018[23]
    - The customer-scale solar programs for both residential and commercial customers in both DEC and DEP reached the 10 MW cap for 2018 within three weeks[24]
  - The Duke Energy North Carolina interconnection queue for DEC and DEP combined represents approximately 12 GW[25]

Global DER Capacity Forecast (2017-2026)



Source: Navigant Research Global DER Deployment Forecast Database[26]

Storage Alternatives Investment Forecast (2017-2026)

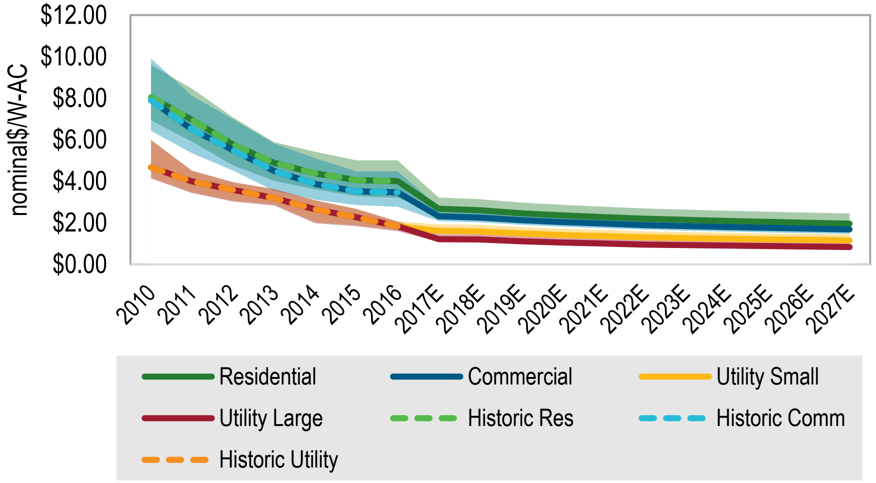


Source: Navigant Research[27]

What is happening?

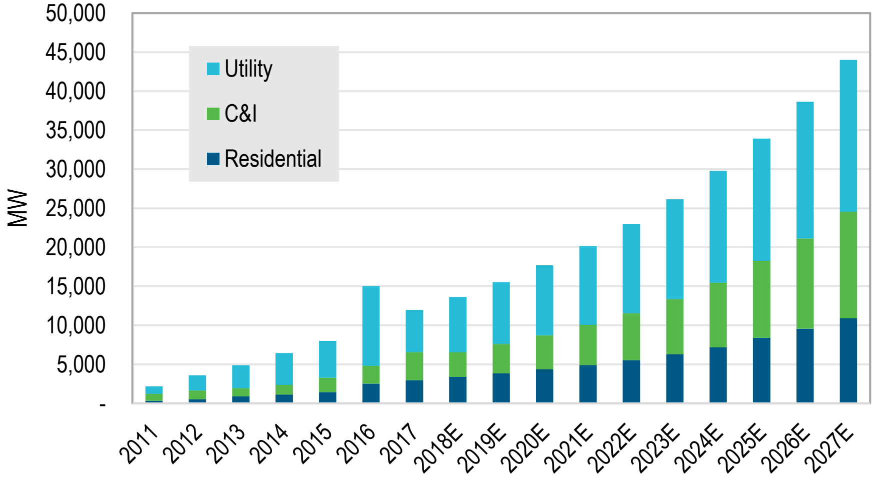
- Solar PV is becoming increasingly competitive[28]
  - Cost of utility-scale solar has dropped 66% since 2010 and is projected to decline by 3.6% per year in the next 10 years[29]
  - Cost of distributed solar has dropped 67% since 2010 and is projected to decline by 3.1% per year in the next 10 years[30]
- Solar PV efficiency has increased which lowers overall installed cost by minimizing the number of panels needed to achieve the same output
- Module efficiency has increased 2% annually since 2007[31]
  - Manufacturing is shifting to higher efficiency monocrystalline panels
- Distributed solar PV installations are projected to continue increasing in North Carolina
  - North Carolina ranked 2nd in the nation for the highest solar generation capacity[32]
  - Over 4,400 MW of solar currently installed in North Carolina[33]
  - Installed capacity in North Carolina is projected to increase 7% per year 2017-2026[34]

Solar PV Cost Declines (2010-2027)



Source: Navigant, NREL[35]

Historical and Forecasted Annual Solar PV Installed Capacity in US (2011-2027)



Source: Navigant Research Market Data: Global Distributed Solar PV[36]

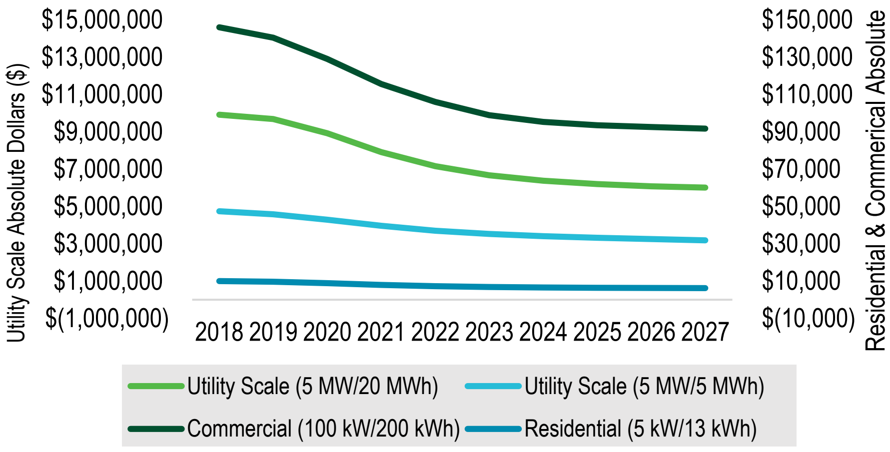
II. TECHNOLOGY ADVANCEMENTS – BATTERY STORAGE

DUKE ENERGY

What is happening?

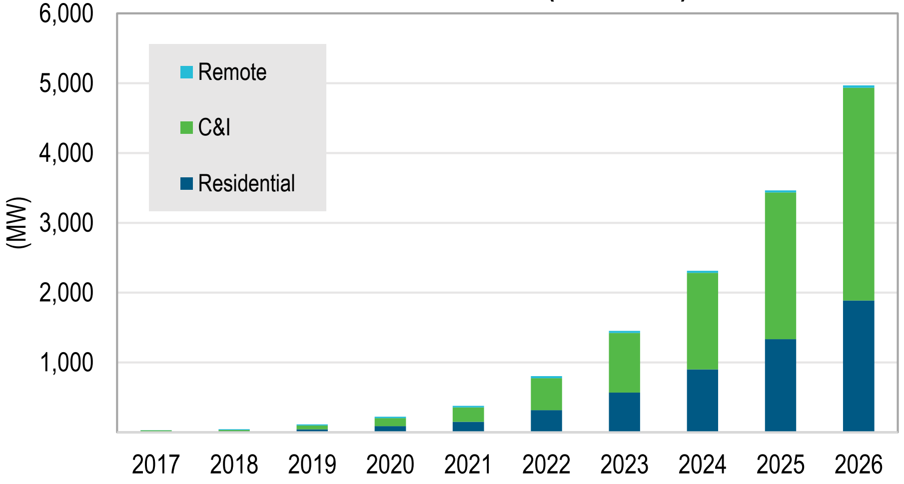
- Battery storage costs expected to decline over the next 10 years in the US
  - Cost of utility-scale storage is projected to decline by 5.4% per year, and utility investment in storage is likely to increase to provide more grid flexibility[37]
  - Cost of distributed storage projected to decline by 5% per year[38]
- Storage installations are projected to increase 2018-2027 in North America:
  - 35% per year for utility-scale[39]
  - 25% per year for distributed storage[40]
- Storage is increasingly installed co-located with renewable energy. Installed capacity of solar plus storage is projected to increase in North America:
  - 57% per year 2018-2026 for utility-scale[41]
  - 76% per year for distributed storage[42]
- Duke Energy's 15-year forecast includes 300 MW of battery energy for the Carolinas storage to improve reliability and grid support[43]

Li-Ion Battery Storage System Capital Cost Forecast (2018-2027)



Source: Navigant Research Large Commercial and Industrial Energy Storage [44]

Annual Solar PV + Storage Power Capacity and Revenue in North America (2017-2026)



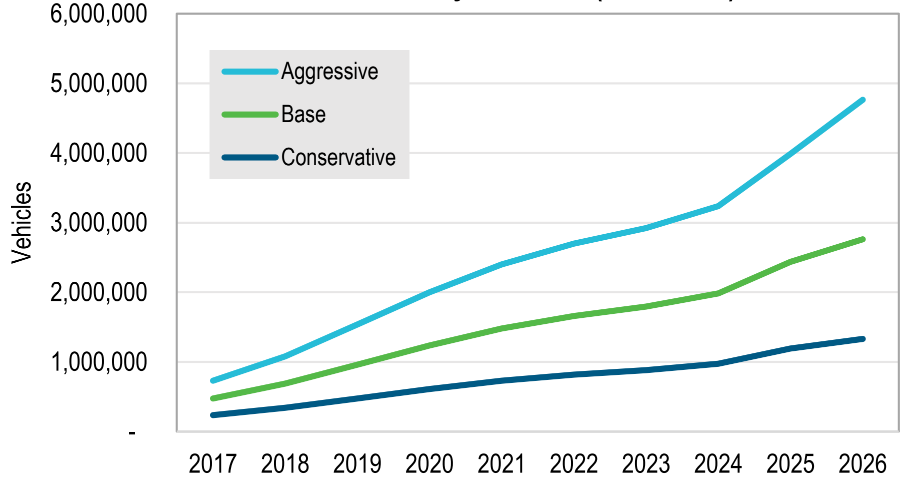
Note: Remote, off-grid solar plus storage typically serves loads of 5 kW or less in remote areas without grid access

Source: Navigant Research Distributed Solar PV plus Energy Storage Systems[45]

What is happening?

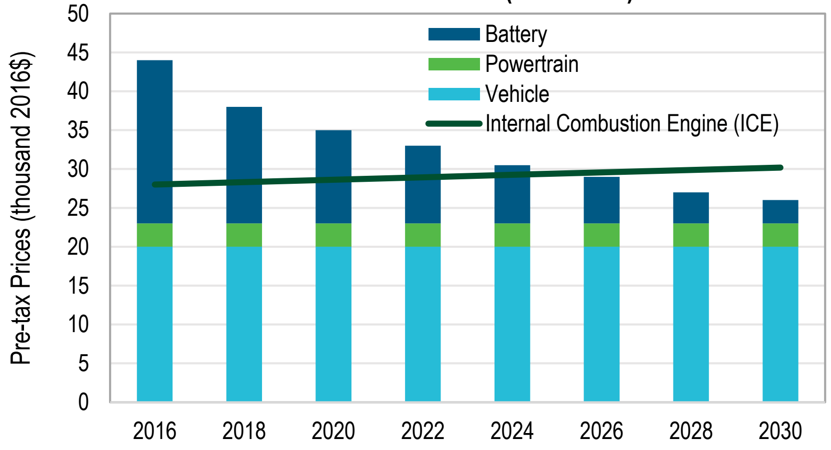
- Cost of EVs has decreased by 80% since 2010[46]
- EVs expected to be competitive with internal combustion engine (ICE) vehicles by 2030[47]
- General Motors announced all-electric, zero emissions future with 20 fully electric models by 2023[48]
  - "General Motors believes electric, self-driving, connected vehicles and shared mobility services will transform how we get around, and we are drawing the blueprint to advance our vision of a world of zero crashes, zero emissions, and zero congestion." – General Motors
- EV adoption is projected to increase
  - By 2027, there will be near 58M PEVs[49]
  - By end of 2018, over 5M PEVs will be on roads globally[50]
  - The number of US residential charging locations is estimated to reach ~6 million by 2025[51]
  - The global market of EVs should see continued sales growth at around 38% through 2020[52]
- EVs in North Carolina are projected to increase 42% annually[53]
  - ~8,500 PEVs are on North Carolina's roads today[54]
  - North Carolina Energy Policy Council recognizes that "the greatest impact of increased EV adoption will be on the distribution system, so whether there is high or low penetration, a modern grid will be required to support it."[55]

EV Sales in US by Scenario (2016-2025)



Source: Navigant Research EV Geographic Forecasts[56]

Battery Electric Vehicle (BEV) and Internal Combustion Engine (ICE) Price Forecast in the US (2010-2030)



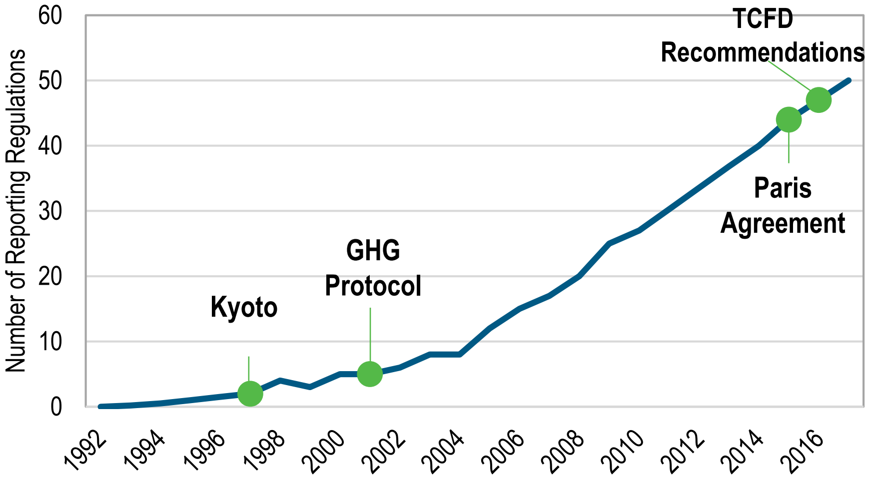
Note: Vehicle prices based on medium segment price

Source: Bloomberg New Energy Finance[57]

What is happening?

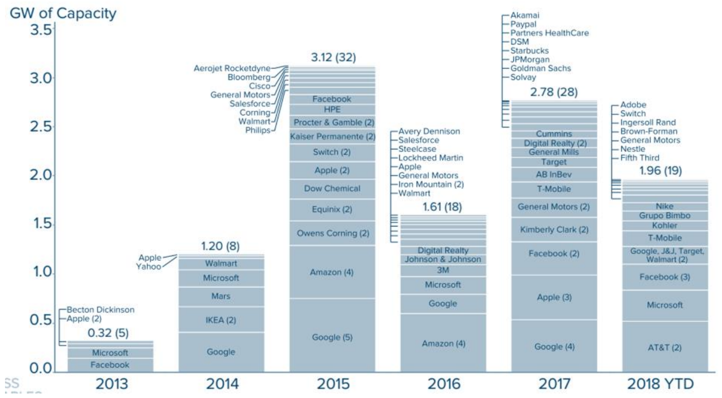
- Broad international commitment and pressure to reduce carbon emissions
- Cyclical federal environmental policy commitments (COP 21, CPP) but implementation of federal energy efficiency standards (transportation, lighting, etc.) underway
- Corporations making commitments and demanding renewable options
  - ~48% of Fortune 500 companies have sustainability and renewable energy commitments[58]
  - Leading NC corporations have set sustainability goals, including Bank of America, Lowe's, Owens Corning, Reynolds American, VF Corporation, Walmart, and Wells Fargo
  - 488 companies taking science-based climate action and 133 have approved targets[59]
  - 75 companies have committed to Corporate Renewable Energy Buyers' Principles with goal to "work with utilities and regulators to expand choices for buying renewable energy"[60]
- States and cities setting goals for renewables, low carbon transportation, and energy efficiency
  - Fifty percent are currently examining one or more of the following topics: (1) smart grid and advanced metering infrastructure (Smart Meters), (2) utility business model reform, (3) regulatory reform, (4) utility rate reform, (5) energy storage, (6) microgrids, and (7) demand response[61]
  - Electric utilities in North Carolina established a 40% carbon reduction goal from 2005 levels by 2030 with approximately 60% of electricity coming from carbon-free energy sources[62]
  - NC set renewable energy and energy efficiency portfolio standard (REPS) of 12.5% of 2021 sales[63]
  - Smart city initiatives being carried out in many NC cities, such as Charlotte and Cary
    - Envision Charlotte and Town of Cary Simulated Smart City projects are integrating energy efficient practices[64]

Growth in Reporting Related to Greenhouse Gas Emissions (1992-2017)



Source: World Business Council for Sustainable Development[65]

Contracted Capacity of Corporate Power Purchase Agreements, Green Tariffs, and Outright Project Ownership



Source: Business Renewables Center[66]

What is happening?

- North Carolina has faced major weather events, with Hurricanes Matthew (2016) and Florence (2018), and most recently Michael (2018) illustrating the magnitude of the challenge the grid faces today from weather
  - Approximately 715,000 outages in North Carolina during Hurricane Matthew[67]
  - Approximately 1.8 million total Duke Energy customer outages restored across the Carolinas during Hurricane Florence, ~1.6 million of which were Duke Energy customers in North Carolina[68]
    - ~ 45 transmission lines out, 185 miles of distribution lines down, and 10 substations flooded at peak of storm[69]
  - Approximately 1 million total Duke Energy customer outages restored across the Carolinas during Hurricane Michael[70]
- "From this devastation we must seize the opportunity to rebuild stronger, and smarter. We can repair the damage with more resilient buildings, roads, and homes."

- NC Governor Roy Cooper (10/10/2018)[71]

Hurricane Michael Impacts (2018)

Source: Citizen Times[72]

Hurricane Florence Impacts (2018)

Source: T&D World[73]

Hurricane Matthew Impacts (2016)

Source: Chicago Tribune[74]

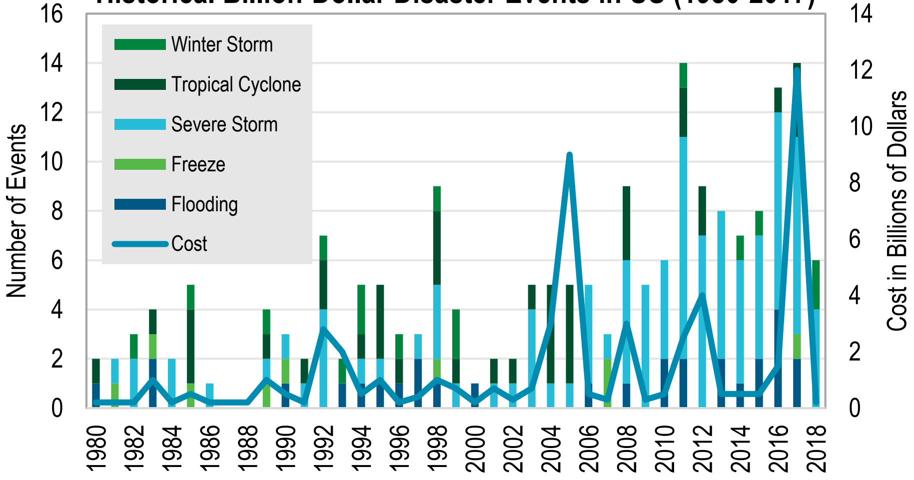
What is happening?

- North Carolina experienced over 300 bulk electric system outages related to weather events (2009-2017) and is part of a larger region that sees the most major storms[75]
- The number of customers impacted by weather events is increasing due to population growth in regions most affected by weather
- The average outage duration for each Duke customer served (SAIDI) in North Carolina increased by 20% (2012-2017)[76]
- Number of major event days (MEDs) have increased by 2% per year over the past 25 years[77]
- Number of Duke Energy NC customer outage events increased by 18% since 2012[78]

Temporary Flood Mitigation at 6 Carolinas East Station

Source: Duke Energy[79]

Historical Billion-Dollar Disaster Events in US (1980-2017)



Note: Costs are adjusted for Consumer Price index (inflation)

Source: NOAA[80]

What is happening?

- Grid improvement technology has advanced over the last decade, and has given utilities alternatives to traditional grid infrastructure options.
    - Grid improvement got a boost from $4 billion in Smart Grid Investment Grants under the American Recovery and Reinvestment Act of 2009 (the Stimulus Act) which, combined with industry spending, led to nearly $8 billion in related projects[81]
    - "Smart" grids are expected to increase the grids' efficiencies by 9% by 2030. This is equivalent to saving more than 400 billion kilowatt-hours each year[82]
    - Grid improvement deployments reduce peak demands by 13% to 24%[83]
    - Savings between $46 billion and $117 billion are expected over the next 20 years[84]
    - Smart meters are expected to save more than $150 billion/year by 2020 by reducing the cost of power interruptions by more than 75%[85]
- The global market for smart grid IT and analytics for software and services is expected to grow from approximately $12.8 billion in 2017 to more than $21.4 billion in 2026[86]

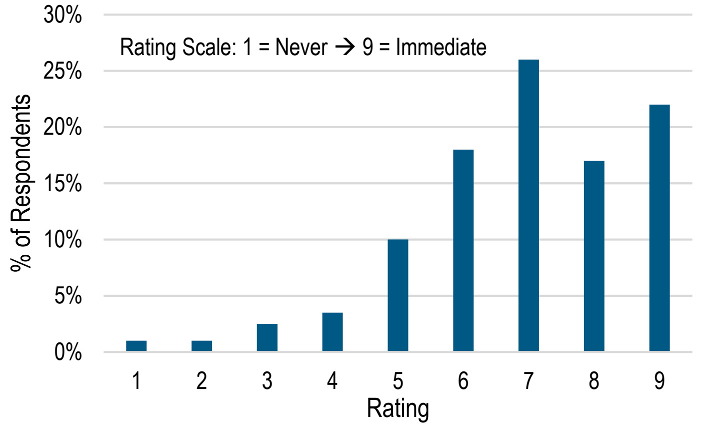
Rapidly Advancing Smart Grid Technologies

Intelligent Devices	Information Technology
• High speed communication networks (fixed and wireless) • Smart Meters • Distribution Automation including intelligent switches, capacitors, and remote fault identification	• Advanced Distribution Management Systems (ADMSs) • Integrated Volt/Volt-ampere reactive Control (IVVC) • Fault, location, isolation, and service restoration (FLISR) • Asset Management Systems (AMSs) • Customer Information Systems (CISs) • Demand Response Management Systems (DRMSs) • Distributed Energy Resources Management Systems (DERMSs) • Energy Management Systems (EMSs) • Geographic Information Systems (GISs) • Meter Data Management Systems (MDMSs) • Advanced Analytics (Asset, Grid Operation, Demand-side, Customer)

Source: Navigant[87]

"Pulse of Power" Survey of Readers

How soon should the power industry adapt to a clean, intelligent, mobile, and distributed grid?

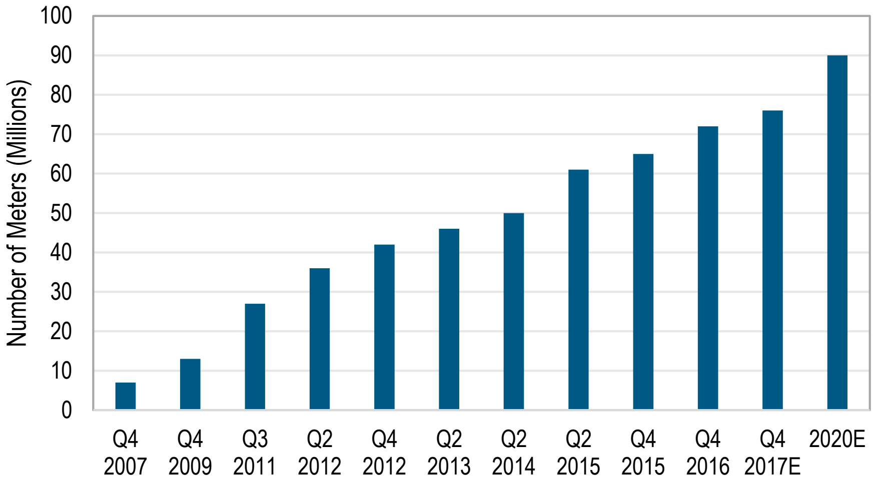


Source: Public Utilities Fortnightly[88]

What is happening?

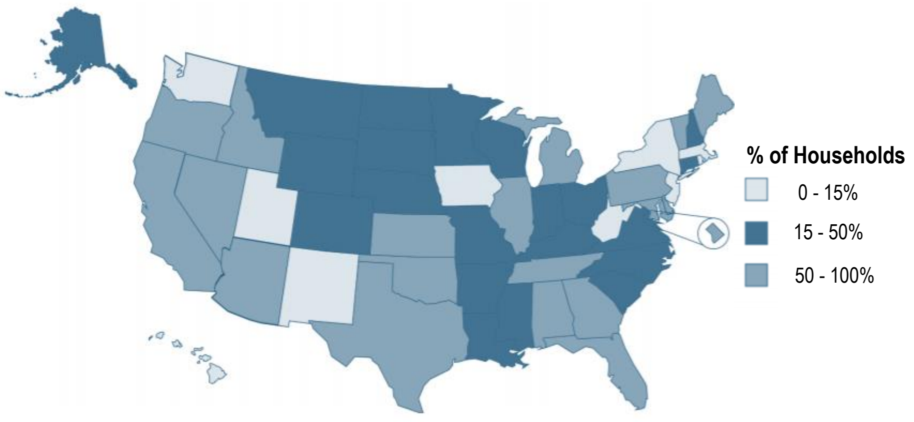
- Deployment of Smart Meters is an indicator of grid modernization adoption by utilities
  - Two-way Smart Meters allow utilities and customers to interact to support smart consumption applications using real-time or near real-time electricity data
  - Smart Meters support demand response and distributed generation, improve reliability, and provide information that consumers use to save money by managing their use of electricity
  - Smart Meter data provides utilities with detailed outage information in the event of a storm or other system disruption, helping utilities restore service to customers more quickly and reducing the overall length of electric system outages
- National Smart Meter installations are approaching 76 million and is projected to reach 90 million by 2020[89]
  - Currently, ~2 million North Carolina Duke Energy customers have Smart Meters installed (~1.8 million in DEC and ~0.16 million in DEP)[90]

US Smart Meter Installations (2007-2020)



Source: The Edison Foundation[91]

Residential Smart Meter Adoption Rates by State (2016)



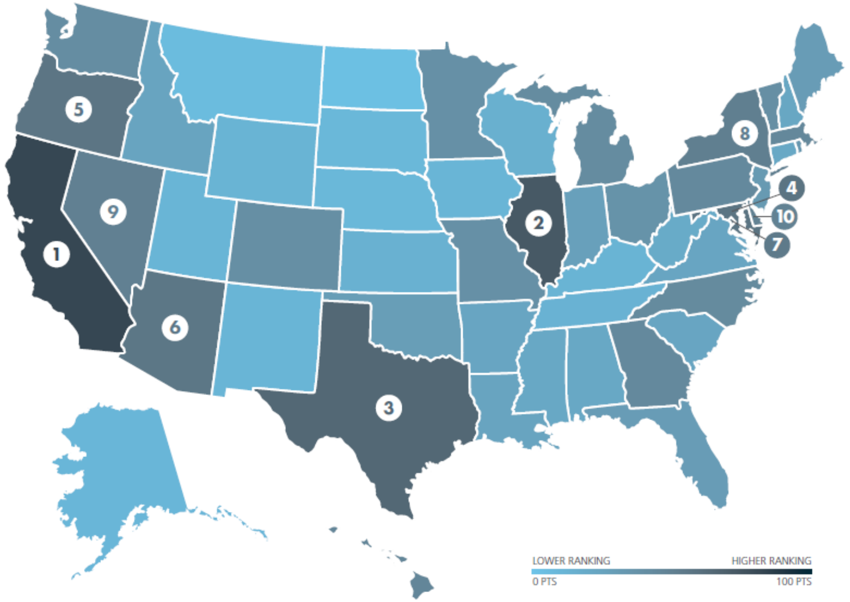
Source: The Edison Foundation[92]

V. GRID IMPROVEMENT – REGULATORY STATE POLICY ACTIONS

What is happening?

- NC Energy Policy Council states that "utility grid modernization is a solution to address the increased complexity and demands from operating a changing electric grid. Due to the transient nature and potential imbalances of intermittent distributed renewable generation, modernizing the grid can address these issues more effectively than legacy devices in substations and distribution feeders today"[93]
- In Q1 2018, 37 US states and the District of Columbia took grid modernization actions involving regulations and legislature. Most of these actions involved Smart Meters, energy storage, and utility business model reforms[94]
- North Carolina was ranked 15th in the nation on the GridWise Alliance's 2017 Grid Modernization Index, which evaluates the leading states using a three-part score based on state support, customer engagement, and grid operations[95]

Grid Modernization Index Across the US



Source: GridWise Alliance[96]

Sample of Targeted Cost Recovery Mechanisms for Grid Modernization Investment

State	Type of Investment
California	Research and technology development
Massachusetts	Grid modernization
Minnesota	Grid modernization
New Jersey	Hardening infrastructure modernization
Ohio	Grid modernization
Pennsylvania	Advanced metering

Source: Navigant[97]

V. GRID IMPROVEMENT – UTILITY BENCHMARKING

What is happening?

- Utilities are adopting grid technology to support increasing DER penetration
- There are varying types of grid modernization technology, many of which are listed in the table below

Benchmarking of Utility Grid Modernization

Smart Grid Investment	Utility 1	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6	Utility 7
DER Penetration*	5%	25%	32%	55%	4%	<1%	<1%
Smart Meters		●	○	N/A**	○	●	●
Demand Response	○	●	●	◐	◐		◐
Distribution Automation	●	◐	○	●		●	●
Substation Automation	◐	◐	○	◐	◐	●	●
Advanced Communications	●	◐	◐	◐	◐	●	○
Energy Storage	○	◐	◐	◐	○		◐
Electric Vehicle Charging	◐	◐	○	◐	○	○	◐
Volt VAR Optimization	○	○	○		○	◐	◐
Time-of-use Pricing		◐	○	N/A**	◐		●
DERMS/ADMS	○	○	○	○	○	○	○
Microgrids			◐	○			◐
Undergrounding of Circuits	◐		◐	●			◐
Recovery Mechanism	●	●	●	◐	●	●	●

● **Large Scale**: utility has deployed technology in majority of its jurisdiction, and has begun evaluating the impacts on its system.

◐ **Pilot/Small Scale**: utility has deployed technology in one to a few locations, and has not been implemented long enough to evaluate its impact.

○ **Planned**: utility has not deployed the technology yet, but has plans for implementation in their most recent smart grid filing.

Source: Navigant[98]

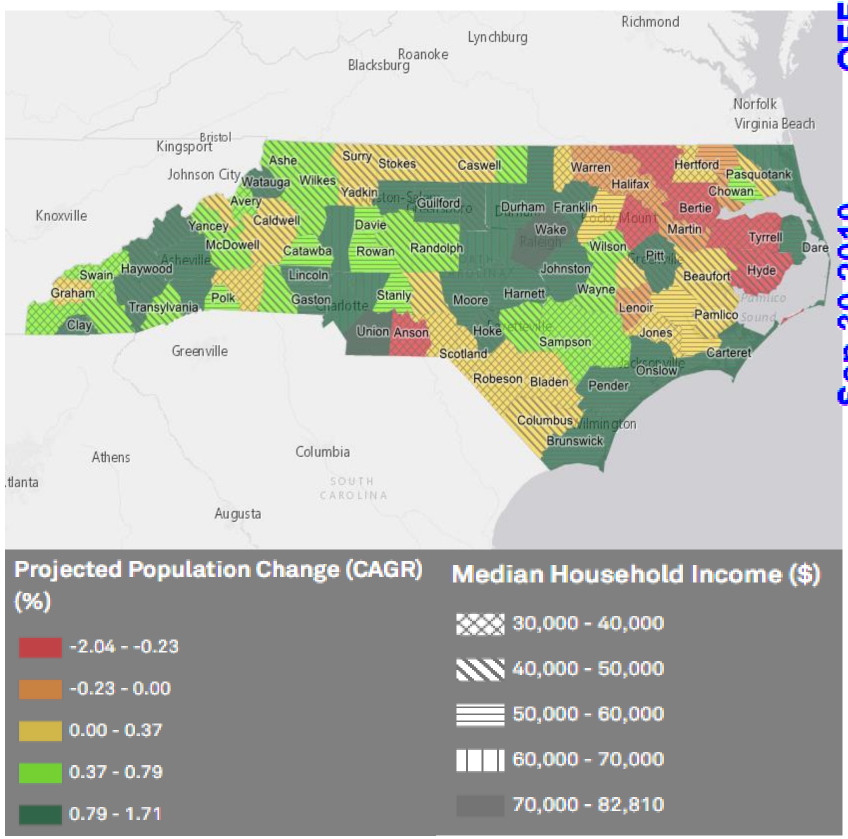
*As percentage of peak demand. Note that utilities may define DER resources somewhat differently.
**Utility 4 market structure does not allow them to deploy Smart Meters or TOU rates

VI. CONCENTRATED POPULATION GROWTH

What is happening?

- People, wealth, and jobs continue to concentrate in urban and suburban areas
  - Movement is being driven by shifting demographics and changing lifestyle preferences
  - Many suburban areas getting an urban makeover with mixed-use development, thoughtful public spaces, transit options, and community-focused street-level development
  - Businesses, industry, and construction are following suit to take advantage of increased population density and connectivity
- North Carolina's population is expected to grow by ~6% (2017-2026)[99]
  - Wake and Mecklenburg counties experienced high population growth of 19% and 17%, respectively (2010-2017)[100]
    - These two counties expect ~24% population growth through 2028[101]
  - Charlotte and Raleigh, the largest cities in North Carolina, accounted ~67% of NC's growth since 2010[102]
  - Even outside of economic development efforts so prevalent in North Carolina, a significant number of rural counties project stagnant or declining population
- Load is growing with population requiring new infrastructure
  - Load in Raleigh and Charlotte growing 3% and 6% per year, respectively[103]
  - There are challenges and costs siting new infrastructure in constrained areas

NC Projected Population and Income Demographics

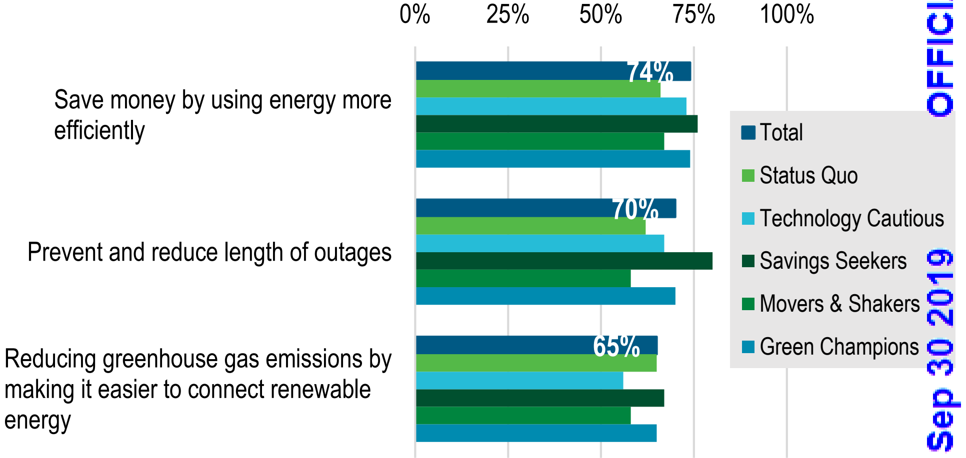


Source: S&P Global[104]

What is happening?

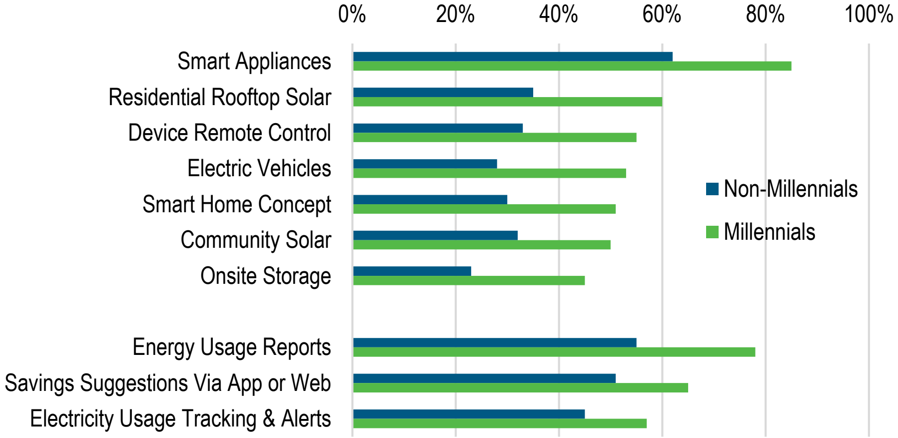
- Customers want to save money and reasonably reduce outages and greenhouse gas emissions[105]
  - Relative importance of these three may vary across customer personas, but they remain consistently the top factors
  - Customers want smart grid investments to reflect these needs
- To address these needs, customers are interested in new technology and increased control over their usage, including (1) smart appliances, (2) rooftop solar, and (3) device remote control[106]
- Millennials are far more interested in energy-related topics than non-millennials[107]
- Duke Energy's high growth business segments (advanced manufacturing, healthcare, data centers) requiring substantial mission-critical electrical infrastructure and cost-effective energy management services
- NC Energy Policy Council recognizes that "as the electric grid in North Carolina ages, it must keep pace with emerging technologies and customer expectations"[108]
- Percentage of Customers Experiencing Multiple Interruptions 6 or more times a year (CEMI-6) is projected to increase by 2% by 2023[109]

Factors customer perceive as important for utility supply



Note: These are the top 3 choices for all types of respondents
Source: Smart Energy Consumer Collaborative[110]

Interest in Energy-related Concepts

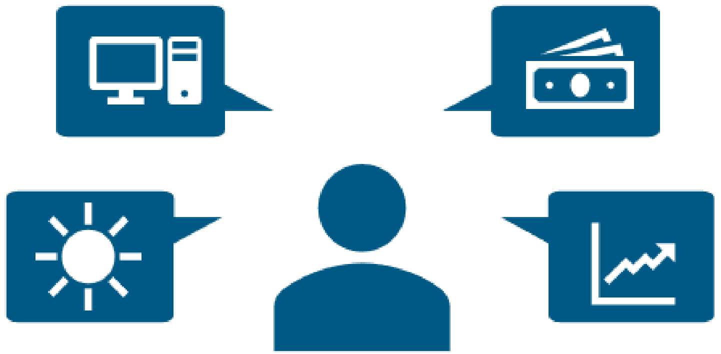


Source: Smart Energy Consumer Collaborative[111]

VII. CUSTOMER EXPECTATIONS

What is happening?

Today, in North Carolina:[112]



- Customers want their power to be on all the time as much as this is reasonably possible
- Customers want their power to be safe
- Customers do not want their power company to harm the environment
- Customers want their power to be as cheap as reasonably possible
- Customers want their interactions with the power company to be as easy and user-friendly as possible
- Customers want increases to their power bills to be minimal, infrequent, and predictable as possible
- Customers want to be informed of problems and issues in advance where possible and want to be updated with status reports as problems are being resolved
- Customers know and accept that there are things beyond our control that will cause power outages no matter what actions we take to prevent them
- Customers are more accepting of power outages when they know what caused the outage and how long it will take to restore power
- The frequency of outages and power quality issues are generally more important to customers than the duration of outages and events
- Most non-residential customers have built the effects of outages and power quality issues in to their business costs and are not willing to pay significantly more to prevent them
- Only some highly power-dependent customers (mostly complex businesses) have taken or are willing to take extraordinary measures to ensure a virtually uninterrupted supply of power

NORTH CAROLINA GRID IMPROVEMENT PLAN

APPENDIX

FOR STAKEHOLDER WORKSHOPS

11/8/18

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NORTH CAROLINA GRID IMPROVEMENT PLAN

IMPLICATIONS

2019

IMPLICATIONS TO OUR CUSTOMERS FROM THE MEGATRENDS

Our customers are impacted by the megatrends, and, under business as usual (BAU), our customers' expectations will not be met and we will miss the opportunity to optimally use advanced technology.

I	Increased costs
II	Reduced reliability and resiliency
III	Reduced ability to manage and integrate distributed energy resources (DER)
IV	Reduced ability to meet customer expectations and commitments
V	Reduced economic competitiveness for North Carolina
VI	Increased geographic and demographic disparity

I. INCREASED COSTS

Under business as usual, costs to customers may increase as compared to emerging alternatives.

Megatrend	BAU Threat	Opportunity
Concentrated Growth	Costs to build BAU infrastructure in urban and suburban areas with concentrated growth are increasing, and do not provide enhanced capabilities to meet expected future grid needs. These costs will be borne by all customers, including those in rural areas that are unaffected.	Advanced system controls, intelligence, planning, and automation would improve overall system efficiency using existing and new assets and thus lower costs for all customers from what they would otherwise be. Additionally, grid capacity needs and the need for two-way power flow can be addressed proactively.
Technology Advancements – Renewables and DER	Because DER is becoming more cost competitive, customers are installing DER and EVs, which, in turn, require improvements to the grid beyond BAU which increases costs if not done in a proactive and planned manner. The reduced load from DER can also lead to higher bills.	Advanced tools and technologies will enable greater application of DER on the grid. Effectively planning for and optimizing the installation of DER on the grid will lower costs for all customers from what they would otherwise be while maintaining safe and reliable operation of the grid.
Grid Modernization	"Like for like" replacement of technology will not lower costs beyond what it is today because capital and operating cost will be unchanged. Further, as the grid is impacted by other trends, existing grid technology may require more rapid replacement, thus increasing costs.	Using advanced grid technologies, system and operational efficiency are increased which lower costs to customers from what they would otherwise be.
Customer Expectations	Customers want to save money and under business as usual, costs will not decline and may go up. As the grid increasingly interconnects DER, interconnection costs of an individual project increase, making it cost prohibitive for customers to have more DER options.	With appropriate grid capabilities, such as ability to manage two-way power flow and intermittent resources, customers will have options that help them manage their costs better, including DER and usage management tools.
Environmental Commitments	Corporations and governments will not be able to meet their environmental goals and commitments if it becomes cost prohibitive to do so. And, in the case where interconnection costs are not incurred, such as with EV, costs to meet these goals and commitments are borne by all customers.	Advanced tools and technologies will enable greater application of DER on the grid, including renewable energy resources. Effectively planning for and optimizing the installation of DER on the grid will lower costs for all customers from what they would otherwise be while maintaining safe and reliable operation of the grid.
Impact of Weather Events	Absent resiliency and reliability improvements, customers will see increased costs from outages as they increase in number and severity. These costs include those incurred by the utility and by customers.	Proactively hardening the system and building advanced monitoring, smart control and grid intelligence can reduce the occurrence and duration of outages, saving customers money compared to business as usual.
Threats to Grid Infrastructure	Absent adequate protection against modern threats, costs to customers will increase due to increased attacks. These costs include those incurred by the utility and by customers.	By building cyber and physical protections that go beyond current compliance requirements to anticipate threats of the future, occurrence and duration of outages can be reduced saving customers money compared to business as usual.

When will implication occur under BAU? 2018 — 2028

Level of severity of implication: = Manageable = Some issues = Many issues

II. REDUCED RELIABILITY AND RESILIENCY

DUKE ENERGY

Under business as usual, reliability will not improve and may decrease.

Megatrend	BAU Threat	Opportunity
Concentrated Growth	In concentrated growth areas, reliability will decrease if improvements to the grid don't keep pace with concentrated load increases and DER penetration. Reliability will decrease in rural areas where flat load growth does not support traditional grid strategies.	Advanced system controls, intelligence, planning, and automation can improve overall system efficiency using existing and new assets and thus can improve reliability for all customers. .Additionally, grid capacity needs and the need for two-way power flow can be addressed proactively, which can improve reliability.
Technology Advancements – Renewables and DER	Because DER is becoming more cost competitive, customers are installing DER and EV at an increasing rate, which may decrease reliability due to voltage fluctuation and capacity limitations on the distribution system.	Using rapidly advancing technology and systems, the utility can provide active monitoring and control power flow and improved voltage fluctuation issues using "grid-edge" decision making. Non-traditional applications are also an opportunity to improve reliability.
Grid Modernization	"Like for like" replacement of existing grid infrastructure will not improve reliability beyond what it is today because functionality will not have improved. In particular, the number of customers that experience multiple interruption per year will increase (CEMI-6).	Rapidly advancing grid technologies are available to improve grid reliability, including improving visibility to a more granular level of where outages are occurring and enable grid-edge decision making and control.
Customer Expectations	Customer satisfaction will decrease with increased outages, and reduced power quality, as customers are inconvenienced or unable to work. These outages may be caused from voltage or power flow issues from DER, traditional infrastructure, or major events such as weather or cyber attack	Customers expectations of reduced outages (either short- or long-term) and better power quality would be addressed with the use of rapidly advancing grid technology and systems.
Environmental Commitments	Customers with environmental commitments will interconnect DER which could cause voltage and power flow issues on the grid resulting in reduced reliability. Conversely, if DER is curtailed to address the reliability issues, customers will be prevented from meeting their commitments.	Using advanced grid technologies and systems helps customers meet their environmental commitments without sacrificing reliability or resiliency.
Impact of Weather Events	The BAU approach of reacting to damage when storms occur will not improve resiliency. In particular, in concentrated areas, when storms damage equipment, it affects more customers.	Using advanced grid technologies and systems will reduce frequency of short-term outages and reduce time to recover from major storm-induced outages. Undergrounding or hardening the most outage prone lines reduces costs and major event duration for all customers from what they would otherwise be.
Threats to Grid Infrastructure	Cyber and physical threats to grid infrastructure are increasing rapidly. Failure to keep pace with these threats will result in compromised reliability and resiliency of the electric grid.	Aggressive development and implementation of advanced system protections and protocols will help the electric grid remain protected from the ever increasing number and variety of threats it faces every day. Also, in the event that a threat is successful, these measures will help minimize damage/disruption that could impact customers.

When will implication occur under BAU? 2018 — 2028

Level of severity of implication: = Manageable = Some issues = Many issues

III. REDUCED ABILITY TO MANAGE AND INTEGRATE DER

DUKE ENERGY

Business as usual limits the ability to manage and integrate DER, resulting in the need to curtail or issue moratoriums on customer-owned interconnection.

Megatrend	BAU Threat	Opportunity
Concentrated Growth	The existing constrained grid in urban areas limits the ability to interconnect DER for customers who are interested in renewable energy, storage and electric vehicles.	Advanced tools and technologies that enable two-way power flows will allow for increased application of DER on the grid. Effectively planning for and optimizing the installation of DER's on the grid will lower costs for all customers beyond what they would otherwise be while maintaining safe and reliable operation of the grid.
Technology Advancements – Renewables and DER	As more DER is connected to the grid, hosting capacity available for additional DER diminishes, causing customer interconnection costs to increase for future installations.	If the grid is able to handle two-way power flow by building capacity and using advanced monitoring and automation to manage DER, then DER can become a "tool in the toolbox" for grid operators.
Grid modernization	Current technology on the grid does not enable two-way power flow or voltage and power flow optimization needed to handle customer-sited, intermittent generation. This limits the ability for the grid to handle increasing capacity of DER.	With the use of advanced grid technologies (e.g. microprocessor based equipment), the grid could become a platform to connect and proactively use customer DER.
Customer Expectations	Customer satisfaction will decrease if customers are not given the option to connect DER, particularly renewables or EVs. If DER is not integrated properly, voltage fluctuations will cause DER to be curtailed.	If DER could be integrated, customers will have more energy options and be able to meet their individual needs such as to reduce greenhouse gases and reduce costs from what they would otherwise be.
Environmental Commitments	If customers, particularly corporations and governments, cannot interconnect renewable DER they will not meet their environmental goals.	By allowing customers to interconnect renewable generation, North Carolina will continue to be attractive to businesses with environmental commitments—this includes fast-growing sectors such as data centers, healthcare, and advanced manufacturing.
Impact of Weather Events	Grid-connected microgrids and other DER options for resiliency would not be able to be interconnected and used during severe weather events.	Customers will be able to leverage customer-owned resources in outages to improve resiliency by providing power in an outage at a local level.
Threats to Grid Infrastructure	Without proper protections, new "points of entry" that pose new cyber attack threat points, i.e. hacking a third-party resource, could impact the grid.	Duke Energy can work proactively with customers to build in protections upfront and over time as needs evolve.

When will implication occur under BAU? 2018 — 2028

Level of severity of implication: = Manageable = Some issues = Many issues

IV. REDUCED ABILITY TO MEET CUSTOMER EXPECTATIONS AND COMMITMENTS

DUKE ENERGY

Business as usual will limit customer options, resulting in higher costs and lower reliability.

Megatrend	BAU Threat	Opportunity
Concentrated Growth	As the demographics of customers in urban and suburban load growth areas evolve they place a higher priority on uninterrupted and personalized energy service. Strained traditional systems in these areas will not be able to meet customer expectations.	Advanced system controls, intelligence, planning, and automation would improve overall system efficiency using existing and new assets and thus improve reliability for all customers. Building capacity for two-way power flow enables options and grid resiliency.
Technology Advancements – Renewables and DER	Under business as usual costs of customer interconnection will increase and curtailment and/or moratoriums will eventually be required which will not meet customer expectations for renewables and DER.	Advanced technologies such as advanced monitoring and controls and solutions that increase hosting capacity will reduce need for curtailment or moratoriums and decrease the cost of interconnection from what they would otherwise be.
Grid Modernization	"Like for like" replacement of technology will not lower costs or improve reliability beyond what it is today because capabilities will be unchanged. Further, lack of visibility and control to customer-sited assets and outages will increase cost and reduce reliability.	Distribution automation, grid intelligence and other advanced technologies will minimize outages, accelerate power restoration, and open the opportunity to use DER.
Customer Expectations	Customers will be unhappy if expectations for affordability, reliability, and options are not met.	Access to new capabilities and offerings, as enabled by enhanced grid capabilities, enable customers to meet their expectations, encourage their participation in energy decisions and gives them more control over their energy use.
Environmental Commitments	The grid will increasingly have less ability to integrate DER and renewables which will cause customers to miss meeting their environmental commitments.	With enhanced grid capabilities, such as increased hosting capacity and the ability to integrate two-way power flow and intermittent resources (such as renewables), customers can meet their commitments with DER including solar, storage and EVs.
Impact of Weather Events	Absent resiliency and reliability improvements, customers will see increased costs and outages as storms and major weather events increase in number and severity. Increasing frequency of outages and increased costs lead to lower customer satisfaction.	By proactively hardening the system, undergrounding or hardening the most outage prone lines, and building advanced monitoring, control and grid intelligence, occurrence and duration of outages and associated costs can be reduced from what they would otherwise be.
Threats to Grid Infrastructure	Absent adequate protection against modern threats, customers will see increased costs and outages due to increased attacks. Increasing frequency of outages and increased costs lead to lower customer satisfaction.	By building cyber and physical protections that go beyond current compliance requirements to anticipate threats of the future, customers will be better protected from disruptions and costs of attack.

When will implication occur under BAU? 2018 2028

Level of severity of implication: = Manageable = Some issues = Many issues

V. REDUCED ECONOMIC COMPETITIVENESS FOR NORTH CAROLINA

DUKE ENERGY

Business as usual makes North Carolina less attractive for businesses and residents.

Megatrend	BAU Threat	Opportunity
Concentrated Growth	Growth will not be absorbed cost-effectively, thus increasing costs to all customers which drives North Carolina to be a less attractive place to live or do business. Additionally, businesses will be deterred from locating in urban areas (where employees are located) due to reliability issues.	Advanced grid technologies and grid capacity deployed in concentrated growth areas and throughout the system will help to maintain affordability across all customers and encourage business development and relocation to the State.
Technology Advancements – Renewables and DER	Due to the inability of the grid to handle increasing amounts of DER, options will be limited for businesses to deploy renewables and/or DER which will make the State less attractive for businesses that desire these options.	Advanced technologies such as advanced monitoring and controls and solutions that increase hosting capacity will allow more DER and renewables making it an attractive market for certain companies.
Grid Modernization	Businesses will not be attracted to do business in North Carolina if the electric grid is not reliable or energy costs are less affordable due to existing equipment and operations. Further, prospective businesses may perceive North Carolina as not embracing rapidly advancing technologies.	A more resilient, reliable and intelligent grid will represent a modern, competitive energy system to current and prospective employers and their employees.
Customer Expectations	Customer satisfaction will decrease if expectations of affordability, reliability and options are not met, which could lead to residents and businesses choosing not to locate in the State.	Programs to protect, modernize and optimize the grid will provide reliable operation and offer customers the options they seek.
Environmental Commitments	The inability to utilize DER to meet environmental goals could inhibit commercial and industrial growth in North Carolina, particularly from large corporations with high renewable energy goals and environmental commitments.	Advanced grid technologies that increase hosting capacity and help to manage intermittency of renewable energy will make it possible for customers to pursue their environmental and sustainability commitments and be interested in North Carolina.
Impact of Weather Events	Absent resiliency and reliability improvements, customers will see increased costs and outages as storms and major weather events increase in number and severity resulting in decreased business and consumer confidence in the ability to stay open during storms.	By proactively hardening the system; undergrounding or hardening the most outage prone lines; and building advanced monitoring, control and grid intelligence; the occurrence and duration of outages and associated costs can be reduced helping customers be confident they can do business in an areas subject to storms.
Threats to Grid Infrastructure	Absent adequate protection against modern threats, customers will see increased costs and potential outages due to increased attacks resulting in decreased business and consumer confidence.	By building cyber and physical protections that go beyond current compliance requirements to anticipate threats of the future, customers will be better protected from disruptions and costs of attack helping customers be confident they can do business despite threats.

When will implication occur under BAU? 2018 — 2028

Level of severity of implication: = Manageable = Some issues = Many issues

VI. INCREASED GEOGRAPHIC AND DEMOGRAPHIC DISPARITY

DUKE ENERGY.

Business as usual will not adequately meet the needs of rural customers in the future.

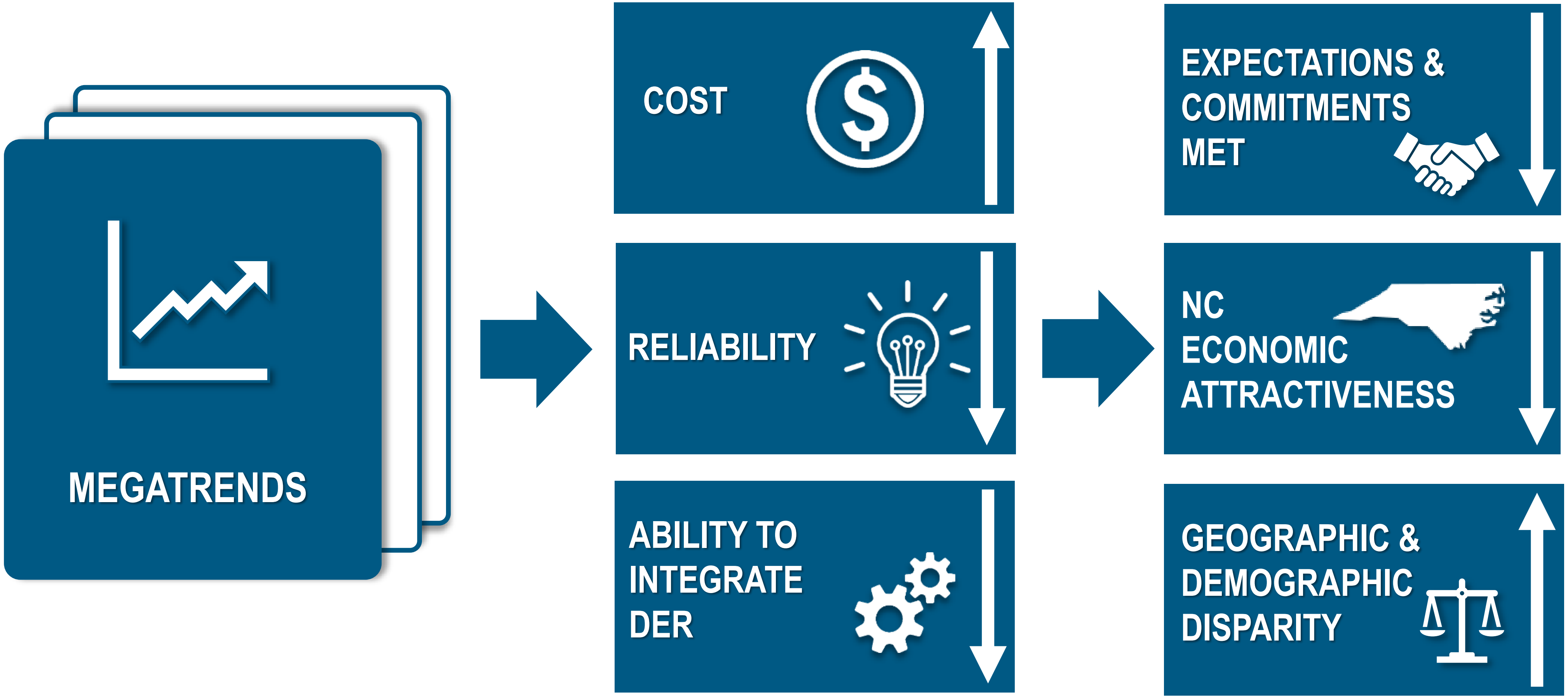
Megatrend	BAU Threat	Opportunity
Concentrated Growth	Capital demands to meet system expansion in high growth areas can undermine investment in rural areas of the state causing disparity between customer demographics and geography.	Advanced system controls, intelligence, planning, and automation would improve overall system efficiency using existing and new assets and thus improve reliability for all customers. Building grid capacity and the ability for two-way power flow enables options and grid resiliency.
Technology Advancements – Renewables and DER	Growth and demographic trends suggest that DER will predominate in urban and suburban centers that have an increasingly younger and higher-wealth demographic, leading to a lesser participation from and cost shifting to lower income or rural customers.	Advanced tools and technologies will enable greater application of DER on the grid. Effectively planning for and optimizing the installation of DER on the grid will lower costs for all customers from what they would otherwise be while maintaining safe and reliable operation of the grid.
Grid Modernization	Under business as usual, capital allocated for traditional system improvements necessarily goes to areas where there is highest load and customer count. As a result, rural areas see less timely improvements to the grid under legacy practice using traditional technology.	By optimally implementing new capabilities that reduce costs of improvements and operations in constrained urban areas, additional focus can be given to improvements in rural areas. In addition, grid automation will enhance ability to serve remote areas of the system.
Customer Expectations	Business as usual will not allow all customer classes to equally address their expectations for affordability, reliability and options.	Additional capabilities and programs can be used to proactively address the needs of all customer classes and open new opportunities for all customers.
Environmental Commitments	Under business as usual, only certain customers and businesses will be able to deploy DER or renewables needed to meet their commitments.	Advanced grid technologies that increase hosting capacity and help to manage intermittency of renewable energy will make it possible for all customer to have access to more DER or renewables.
Impact of Weather Events	Absent resiliency and reliability improvements, customers will see increased costs and outages as storms and major weather events increase. This is particularly challenging in rural areas where cost and times for repairs are higher due to longer radials and distance for crews to cover.	By proactively hardening the system, undergrounding or hardening the most outage prone lines, and building advanced monitoring, control and grid intelligence, the occurrence and duration of outages and associated costs can be reduced, particularly in hard-hit rural areas.
Threats to Grid Infrastructure	Absent adequate protection against modern threats, customers may see increased costs and outages due to increased attacks. In particularly, physical attacks will be more detrimental in radial systems, particularly in rural areas, due to singular failure points.	By building cyber and physical protections that go beyond current compliance requirements to anticipate threats of the future, customers will be better protected from disruptions and costs of attack in rural areas.

When will implication occur under BAU? 2018 2028

Level of severity of implication: = Manageable = Some issues = Many issues

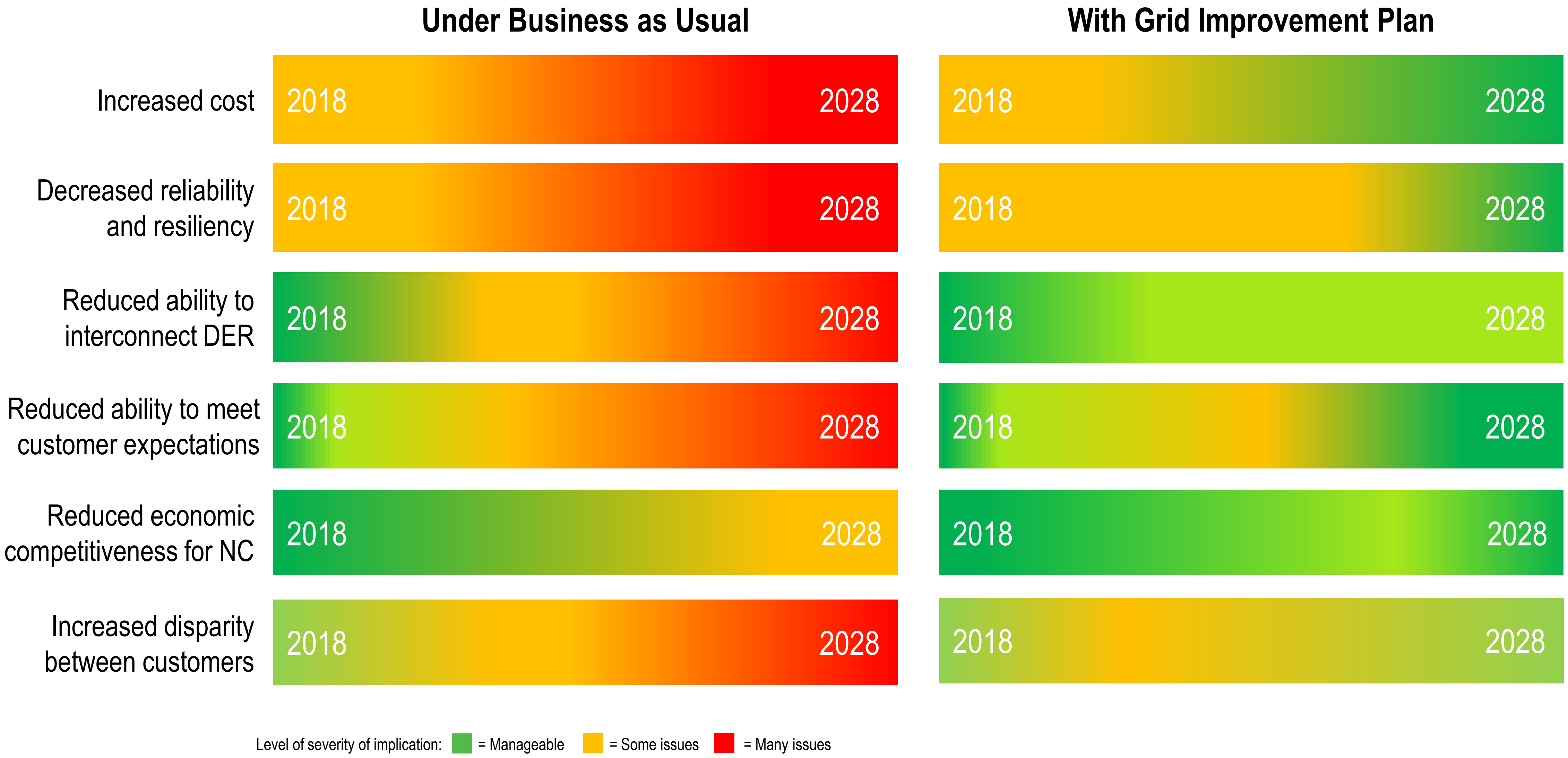
IMPLICATIONS OF MEGATRENDS

In summary, evolving megatrends will have implications on our **customers and the State.**



IMPACT OF GRID IMPROVEMENT PLAN ON IMPLICATIONS

Over time, the Grid Improvement Plan will reduce the degree of severity of the implications experienced under business as usual.



NORTH CAROLINA GRID IMPROVEMENT PLAN

PROGRAM SUMMARIES

2019

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PROGRAM: INTEGRATED VOLT/VAR CONTROL (IVVC)

DUKE ENERGY

The IVVC program establishes control of distribution equipment in substations and on distribution lines to optimize delivery voltages to customers and power factors on the distribution grid.

DESCRIPTION

IVVC allows the distribution system to optimize voltage and reactive power needs. The program employs remotely operated substation and distribution line devices such as voltage regulators and capacitors. The settings for thousands of these controllable field devices are optimized and dispatched via a distribution management system.

IVVC capabilities enable a grid operator to lower voltage as a way of reducing peak demand (peak shaving), thereby reducing the need to generate or purchase additional power at peak prices, or protecting the system from exceeding its load limitations. The current DEP **Distribution System Demand Response (DSDR)** program uses the peak shaving mode of IVVC to support emergency load reduction.

Another operational mode enabled by IVVC capabilities on the distribution system is **Conservation Voltage Reduction (CVR)**. CVR uses IVVC during periods of more typical electricity demand to reduce overall energy consumption and system losses.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

MORE ABOUT THE PROGRAM

The Distribution Management System (DMS), which manages the dispatch of IVVC functionality, can be designed to manage distribution circuits such that any impacts to customers with large motors sensitive to voltage control can be reduced. To maximize operational flexibility and value, the IVVC system can also have peak shaving capability and emergency modes of operation. Advanced DMS software upgrades will enable IVVC to operate in various modes to provide further customer benefit in the future.

DSDR to CVR in DEP

In 2014, Duke Energy implemented DSDR in DEP, achieving peak shaving voltage reduction of approximately 3.6% across the DEP distribution system. The DMS in DEP is capable of optimized modes (i.e., DSDR) or non-optimized (i.e., emergency) modes. When in emergency mode, the system can quickly provide a temporary voltage reduction capability of up to 5.0%.

DEP's initial implementation of DSDR also included a significant amount of circuit conditioning to optimize the system for DSDR mode (i.e., the installation of voltage regulating devices and capacitors, balancing of load on distribution circuits, and reconductoring of some distribution lines to larger wire sizes).

Because the substation, distribution, telecommunications, and IT infrastructure were put in place as part of the original DSDR implementation, this sub-program focuses on the deployment of the few additional device installations as well as the DMS upgrades required to support various operational modes, including the current DSDR mode and CVR mode, as well as Self Optimizing Grid and other distribution automation capabilities.

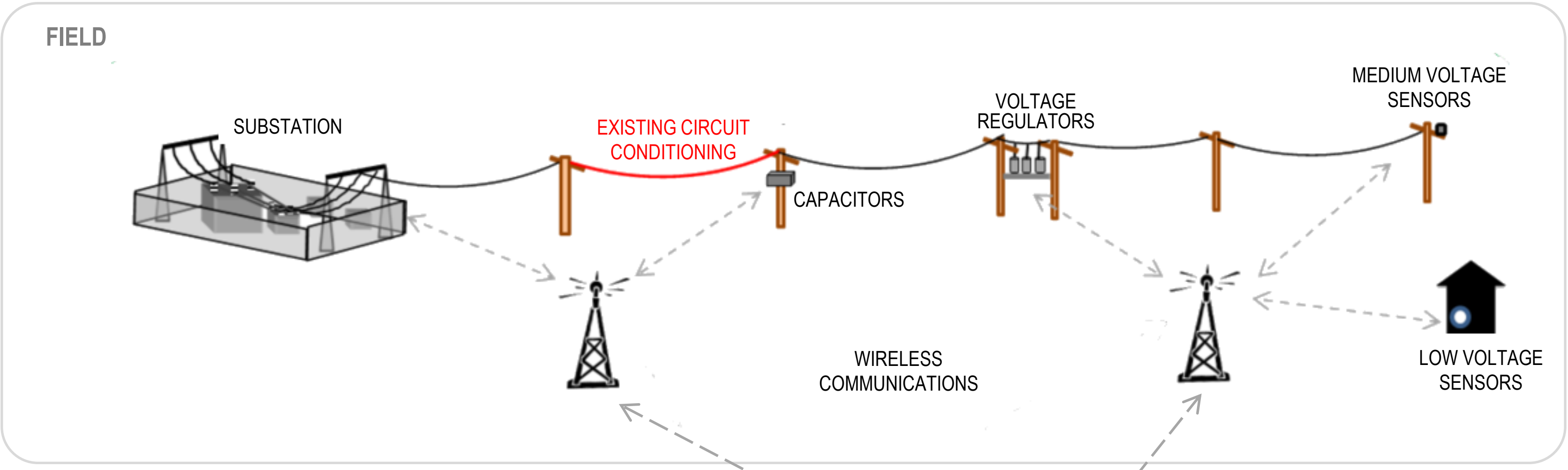
Through this sub-program, Duke Energy will enable 2% voltage reduction for energy conservation (an average of roughly 1.4% load reduction).

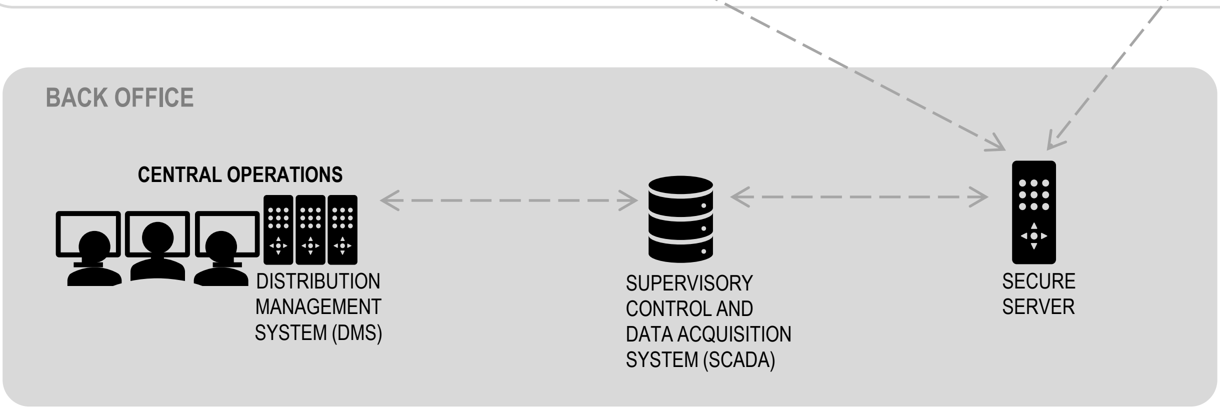
IVVC Project in DEC

The DEC IVVC pre-scale deployment project used real-time field conditions on a small scale to demonstrate the use of IVVC on the DEC system, and validate benefits in advance of its full-scale rollout. The small-scale demonstration validated voltage reductions of approximately 2% are possible with appropriate transmission and distribution system upgrades.

The DEC IVVC project will install communications and voltage control infrastructure at substations and associated distribution lines. The project will also leverage overlaps with efforts like Self Optimized Grid projects that deploy some of the infrastructure and capabilities necessary to enable IVVC.

PROGRAM: INTEGRATED VOLT/VAR CONTROL (IVVC)

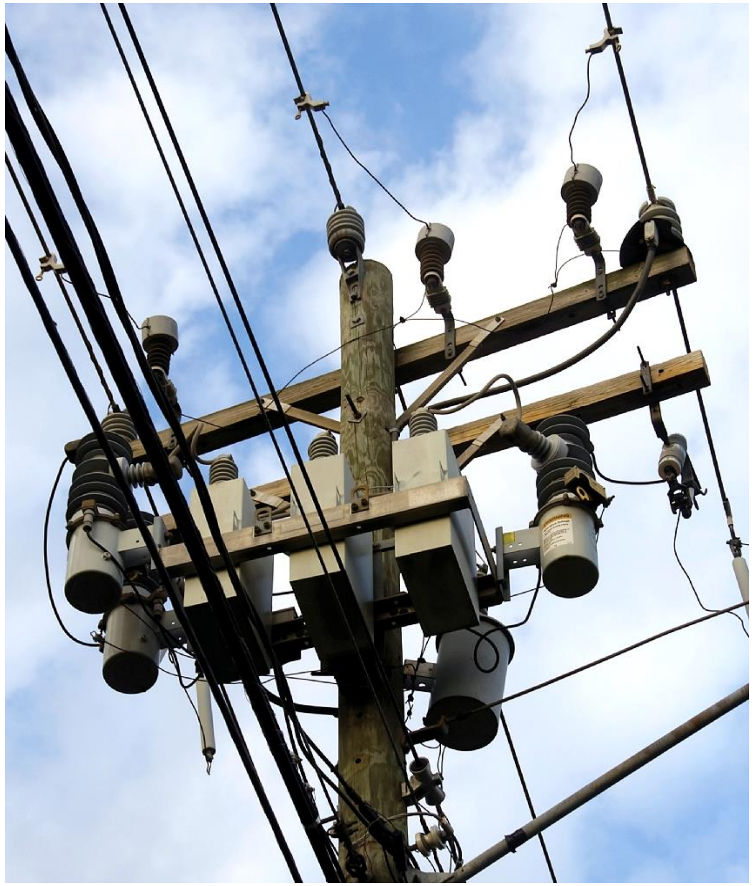




Functionality enabled

- Near real time automated control
- Situational awareness across the system
- Optimized voltage and power factor
- Two-way communication to field devices

SMART CAPACITOR BANK



PROGRAM: SELF-OPTIMIZING GRID (SOG)

DUKE ENERGY.

The self-optimizing grid program, also known as the smart-thinking grid, redesigns key portions of the distribution system and transforms it into a dynamic self-healing network.

DESCRIPTION

The current grid has limited ability to reroute or rapidly restore power and limited ability to optimize for the growing penetrations of distributed energy resources (DER). The SOG program is established to address both of these issues.

The SOG program consists of three (3) major components: grid capacity, grid connectivity, and automation and intelligence. The SOG program redesigns key portions of the distribution system and transforms it into a dynamic smart-thinking, self-healing grid. The grid will have the ability to automatically reroute power around trouble areas, like a tree on a power line, to quickly restore power to the maximum number of customers and rapidly dispatch line crews directly to the source of the outage. Self-healing technologies can reduce outage impacts by as much as 75 percent.

The **SOG Capacity projects** focus on expanding substation and distribution line capacity to allow for two-way power flow. **SOG Connectivity projects** create tie points between circuits. **SOG Automation projects** provide intelligence and control for the Self Optimizing Grid. Automation projects enable the grid to dynamically reconfigure around trouble and better mange local DER.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ IMPROVE RELIABILITY
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

MORE ABOUT THE PROGRAM

The SOG program, also known as the smart-thinking or self-healing gird, implements distribution system design guidelines that improve grid reliability and resiliency. SOG circuits will have automated switches to divide the circuit into switchable segments. Each segment is designed to consist of approximately 400 customers, three miles in circuit segment length, or serve 2MW of peak load. This design ensures that any issues on the system can be isolated, and customer impacts are limited. The long term vision is to serve 80% of customers by the Self-Optimizing Grid.

Advanced Distribution Management System (ADMS)

The ADMS subprogram is an enterprise-wide program to deploy a common distribution management system. Consolidating to a single platform for DMS and SCADA systems enables operational efficiency and the ability to integrate future solutions needed as demands on the distribution system evolve. The three main projects are: (1) **SCADA upgrade project** which upgrades the supervisory control and data acquisition system; (2) **DMS common platform project** which deploys a common version of DMS across DEC and DEP; and (3) **Closed loop FLISR project** which deploys DMS functionality that minimizes the area impacted by the resulting outage.

SOG Segmentation & Automation

This subprogram focuses on segmenting circuits in accordance with SOG design guidelines (segments should serve approximately 400 customers, are three miles in length or serve 2 MW of peak load) and equipping those segments with automated switching devices. The purpose is to limit the exposure of customers to power outages associated with faults on a line (e.g., a tree falling or vehicle-power pole collision). This is accomplished by sectionalizing a circuit by adding and/or re-configuring a number of protective devices on tap lines.

Circuit Capacity and Connectivity

This subprogram focuses on upgrading selected circuit feeders and tying them together to meet the SOG design philosophy. The circuit capacity activities involve upgrading the feeder conductor and voltage control devices to enable a circuit to carry its own customer load as well as portions of adjacent circuit customer load, as needed.

Substation Bank Capacity

This subprogram focuses on upgrading selected substations to meet the SOG design philosophy. The substation bank capacity activities involve upgrading existing substation transformers and other associated equipment to allow for a substation to service its normal customer load as well as any additional load it may pick up during a SOG isolation/reconfiguration event.

PROGRAM: POWER ELECTRONICS FOR VOLT/VAR

DUKE ENERGY

The Power Electronics program integrates protection and control technology, helps reduce power quality issues associated with high DER penetration, and ultimately improves reliability to customers.

DESCRIPTION

As the adoption of distributed energy resources (DER) (e.g., customer-owned solar and energy storage) reaches critical levels and microgrid technology matures, protective device technology must also advance to appropriately detect and respond to rapid voltage and power fluctuations that often accompany non-dispatchable resources such as solar.

As clouds move across the daytime sky and momentarily block sunlight from reaching solar panels, solar generation immediately ceases. As sunlight peaks through openings in the cloud cover, the solar panels begin generating, creating power spikes and voltage instability on the circuit. These intermittent power impacts occur and then change at rapid rates (in some cases sub-second) and frequently faster than the legacy electro-mechanical voltage management equipment like regulators and capacitors can handle.

Integrating advanced solid-state technologies like power electronics (i.e., static VAR compensators and other solid-state voltage support equipment), better equips the distribution system to manage power quality issues associated with increasing DER penetration.

The program is still in its early stages and current plans are small pre-scale deployments to validate capabilities and benefits.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

FIRST INSTALLATION OF MINIDVAR IN DEP TERRITORY

COST-EFFECTIVE UPGRADE FOR FEEDERS WITH HIGH SOLAR PV OR DG GROWTH

PROGRAM: DISTRIBUTION SYSTEM AUTOMATION (DA)

DUKE ENERGY

The DA program improves how the distribution system protects the public and itself from unsafe voltage and current levels and significantly reduces the impact experienced by customers due to grid issues.

DESCRIPTION

The capabilities offered through DA can transform what may have been an hour-long power outage for hundreds or even thousands of homes and businesses into a momentary outage – or potentially help avoid an outage altogether.

The DA consists of several complementary efforts that work in concert to support dynamic and growing distribution system loads in a more sustainable way while minimizing power quality issues that often accompany a large-scale transition to solar power. One of these projects, **Urban Underground System Automation,** modernizes the protection and control of underground power systems that serve critical high-density areas, such as urban business districts and airports.

The **Fuse Replacement** project focuses on replacing one-time use fuses with automatic operating devices capable of intelligently resetting themselves for reuse, thus eliminating unnecessary use of resources (inventory, time, gasoline, etc.). The **Hydraulic to Electronic Recloser** program replaces obsolete oil-filled (hydraulic) devices with modern, remotely operated reclosing devices that support continuous system health monitoring.

Such digital device upgrades offer further value through efforts like the **System Intelligence and Monitoring** pilot, which develops advanced diagnostic tools that help engineers and technicians address electrical disturbances on the distribution system and improve customer experience.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ IMPROVE RELIABILITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

MORE ABOUT THE PROGRAM

Through its suite of complementary efforts, the DA Program offers a way to deliver electricity to customers while avoiding preventable service interruption for thousands of customers.

Hydraulic to Electronic Recloser

Phases out existing hydraulic (oil-filled) reclosers to reduce the oil footprint and eliminate maintenance activities. The sub-program has two phases: (1) target all hydraulic reclosers rated 140 amps or greater and replace with electronic, solid-dielectric interrupter devices; and (2) focus on smaller hydraulic reclosers (those rated less than 100 amps) and replace them with similar electronic, solid-dielectric, reclosing devices as this technology becomes mature enough for full scale deployment.

System Intelligence and Monitoring Pre-Scale Effort

Leverages data from digital devices deployed as part of the Self-Optimizing Grid, Smart Meter, and other programs to build a database and system model that monitors electrical disturbances across the distribution system. While each grid device may only monitor a portion of a circuit, advanced analytics creates a larger picture of system activity and an end-to-end blended view of customer experience. When completed, this subprogram will create a new system diagnostic tool for troubleshooting problem areas and mitigating emerging issues as they occur, as well as for managing the integration of DER.

Fuse Replacements with Electronic Reclosers

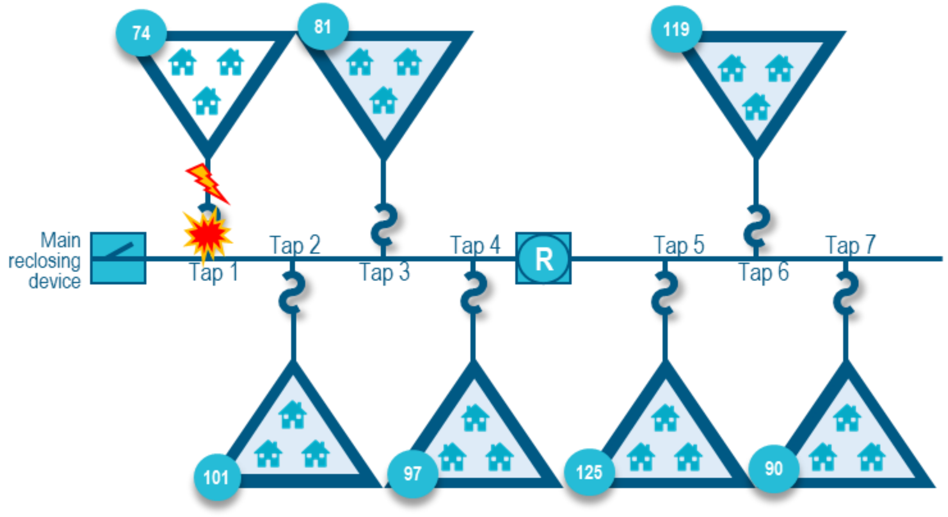
Replaces protective tap line fuses with small electronic sectionalizing devices on segments that can eliminate the most interruptions for customers. The small electronic reclosers serve to prevent customer outages by allowing temporary faults time to clear power lines before operating and initiating sustained outages. A protective fuse in this same tap line configuration is designed to actuate and initiate a sustained line outage at the first sign of a line fault; it must then be replaced before service can be restored. The fuse replacement with electronic recloser eliminates the mainline breaker from operating at all, eliminating unnecessary momentary interruptions and sustained outages.

Underground (UG) System Automation

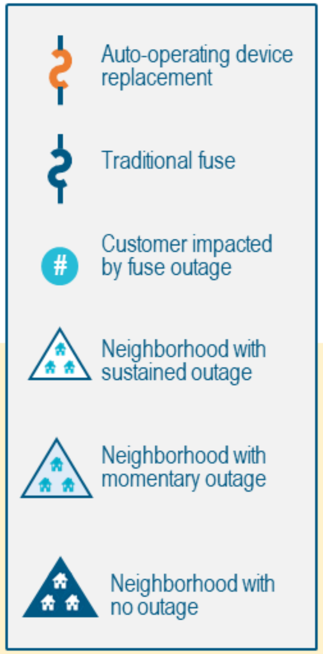
Replaces manually operated underground switchgear with remotely operated automated switchgear and deploys advanced automation schemes in urban downtown areas and other places with high density public use, such as airports and public entertainment areas. UG Automation enables automatic reconfiguration of underground systems for connecting to a new feeder or for isolating downstream system faults to minimize customer outages and impacts to the public. When completed, what might have been hours of service interruption can be reduced down to seconds.

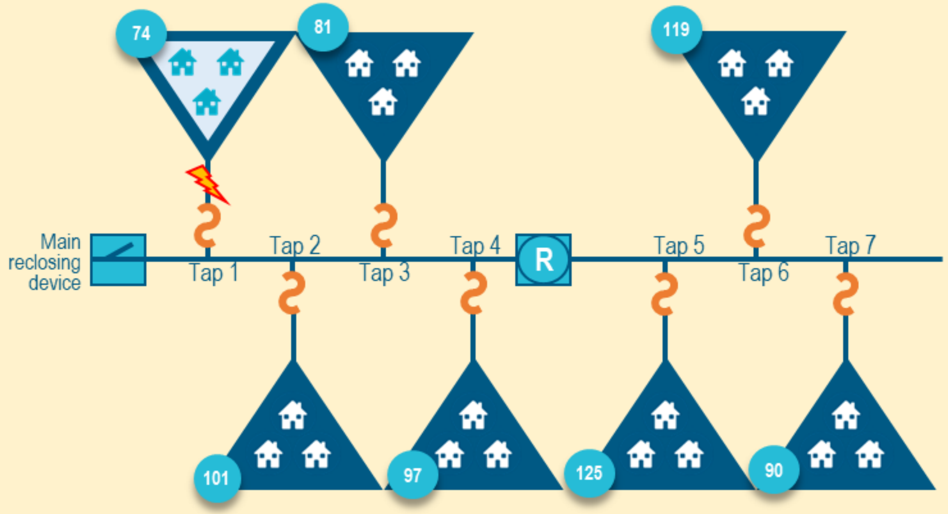
PROGRAM: DISTRIBUTION SYSTEM AUTOMATION (DA)

WITHOUT DEVICE REPLACEMENTS
(687 momentary interruptions, 74 sustained interruptions, one fuse replacement)



- Temporary fault Tap 1
- Main reclosing devices blinks
- All **687** customers experience a **momentary outage**
- The **74** customers of neighborhood 1 experience a **sustained outage** until the Tap 1 fuse is replaced





- Temporary fault Tap 1
- Main reclosing devices blinks
- Only the **74** customers experience a **momentary outage**
- Auto-operating device resets
- **Zero sustained outages**; no fuse replacement needed

WITH AUTOMATICALLY-OPERATING DEVICE REPLACEMENTS
(74 momentary interruptions only)

PROGRAM: ENERGY STORAGE

The Energy Storage program implements battery storage and other related non-traditional measures to defer, mitigate, or eliminate the need for traditional utility investments, such as line capacity upgrades.

DESCRIPTION

The program supports customer and utility initiatives through smart investments in storage for applications that deliver value to customers and the company. These applications include microgrid projects for preventing planned and unplanned outages, as well as long-duration outage projects for providing redundant power sources for vulnerable (rural and remote) communities, and circuit and bank capacity projects using substation-tied energy storage.

Given the multiple applications energy storage technology supports, projects within the Energy Storage program are designed and assessed on a case-by-case basis for the specific challenge being addressed (e.g., long duration outage support, microgrid or emergency power support, auxiliary service needs, etc.).

The Energy Storage program also includes the development and deployment of an energy storage control system to manage the fleet of energy storage resources.

GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY (DER Enablement)
- ✓ MODERNIZE GRID OPERATIONS & PLANNING
- ✓ EXPAND CUSTOMER OPTIONS AND CONTROL

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

MORE ABOUT THE PROGRAM

Energy storage provides several different forms of value when applied to the distribution grid. It can be used as a tool to improve reliability to remote communities and it can help increase the how much DER in the form of solar energy can be connected to the grid. It can also be used as a way to delay or mitigate the need to invest in more traditional resources to address transmission and distribution capacity needs.

Energy Storage Control System (ESCS)

By enabling grid operators to dispatch batteries, and batteries plus solar, as part of a diverse generation portfolio, the ESCS project creates the means for distributed energy resources to provide a more cost-effective, energy storage solutions for enhancing grid efficiency and reliability, along with bulk power operations effectiveness. The primary ESCS applications include: (1) Frequency regulation services, (2) Energy arbitrage (i.e., shifting to charge off-peak, discharge-on peak), and (3) Microgrid islanding for outage support and peak shaving.

Interrelation with Integrated System Ops Planning (ISOP)

Energy storage is a technology that offers the ability to support many valued requirements across the generation, transmission and distribution systems. The Integrated System Operation Planning (ISOP) effort will enable storage and microgrid projects to be deployed more effectively.

Example: Mt. Sterling Microgrid

The Mt. Sterling Microgrid project was developed to provide electric service to a remote customer in a reliable but more cost-effective way than via a traditional distribution feeder. The microgrid option meets customer needs through use of distributed energy resources, while enhancing both safety and productivity for utility workers by mitigating line maintenance activity in a high-risk, labor-intensive environment. With the maturity of energy storage technology, a microgrid with solar and storage components sized to support customer load for seven consecutive days (without solar generation) was designed, assessed, and determined to be a more reliable and cost effective option for meeting the customer’s need for service. The solution, a 10-kW solar PV array, a 95-kWh battery energy storage system and remote monitoring system, offers availability 99.95% of time, with 25-year asset life.

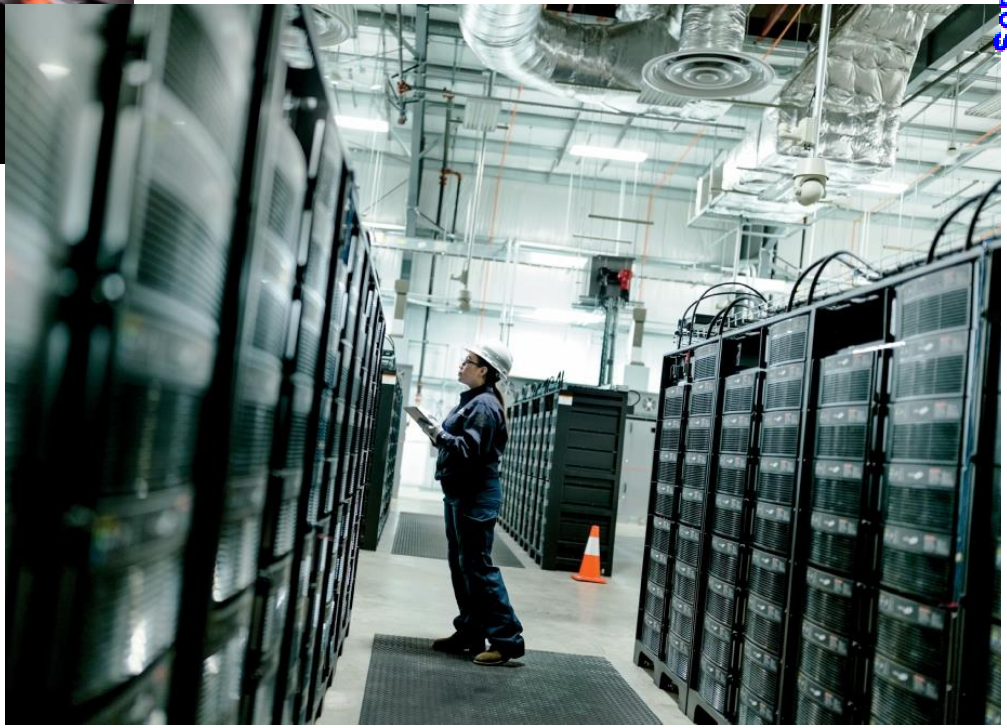
PROGRAM: ENERGY STORAGE

DUKE ENERGY

MCALPINE MICROGRID BATTERY SYSTEM

COMMUNITY BATTERY BACKUP SYSTEM

NOTREES BATTERY STORAGE FACILITY



The LDI/HIS program is designed to improve the reliability for parts of the grid with high potential for long duration outages as well as for high-impact customers like airports and hospitals.

DESCRIPTION

The LDI/HIS program is designed to improve the reliability in parts of the grid where the duration of potential outages is expected to be much higher than average. Focus areas for this program are radial feeds to entire communities or large groups of customers as well as inaccessible line segments (i.e. off road, swamps, mountain gorges, extreme terrain, etc.).

Many of the areas served by these long, rural, single-sourced feeders can experience significant impacts to the local economy and to quality of life when the entire town loses power. Further, operational and repair costs are generally higher than average in these areas due to the special equipment required.

While some sites may include extreme hardening, circuit relocations, new circuit ties and undergrounding, energy storage solutions may offer more cost-effective solutions for improving reliability and managing costs.

The LDS/HIS program is designed to improve the reliability of high- impact customers like airports and hospitals, and high-density areas that could require a variety of infrastructure solutions to improve power quality and reliability. Typical projects include substation upgrades, circuit ties, voltage conversions, and reconductoring.

GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ HARDEN FOR RESILIENCY

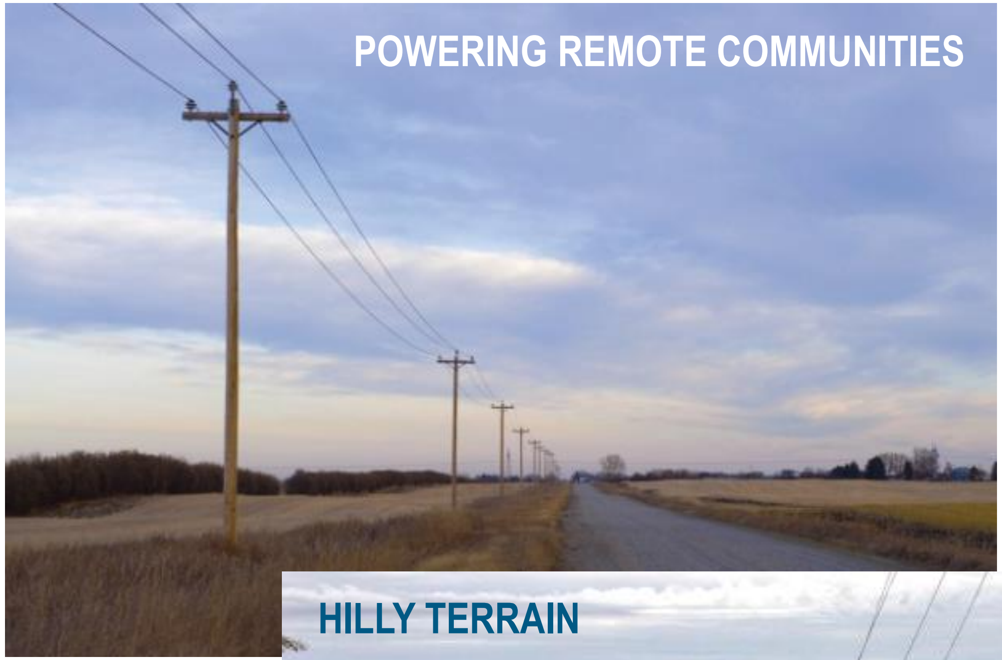
VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

PROGRAM: LONG DURATION INTERRUPTION / HIGH IMPACT SITES (LDI/HIS)



PROGRAM: INTEGRATED SYSTEM OPERATIONS PLANNING (ISOP)

DUKE ENERGY

The ISOP program integrates utility planning for generation, transmission, distribution, and customer programs to improve the valuation and optimization of energy resources across the system.

DESCRIPTION

Requirements for modern electric utility systems are evolving rapidly with the advent of emerging new energy technologies, changes in policy, and rapid advancements in information exchange and customer needs. Integrated System Operations Planning (ISOP) focuses on the integration of utility planning disciplines for generation, transmission, distribution and customer programs to improve the valuation and optimization of energy resources across all segments of the utility system to best serve electric customers.

The ISOP process addresses key operational and economic considerations across all segments of the system through integration and refinement of existing system planning tools and, in some cases, development of new analytical tools to assess characteristics that have not historically been captured or considered in long-term planning. Some examples include locational values for distributed resources, system ancillaries and reserves needed to support future operations, and energy resource flexibility to support new dynamic operational demands on the system.

ISOP is a multi-year development program to build the tools and processes needed to accommodate an increasingly integrated approach that will be required to optimize planning and operation of the electric utility system of the future.

GRID CAPABILITIES ENABLED

- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ IMPROVE RELIABILITY
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

PROGRAM: TARGETED UNDERGROUNDING (TUG)

The TUG program strategically identifies Duke Energy's most outage prone overhead power line sections and relocates them underground to reduce the number of outages experienced by customers.

DESCRIPTION

Overhead power line segments with a history of unusually high numbers of outages drive a disproportionate amount of momentary interruptions and outages that affect Duke Energy's customers. When these segments of lines fail, they cause problems for Duke Energy's customers directly served by them as well as customers upstream. Lines targeted to be moved underground are typically the most resource-intensive parts of the grid to repair after a major storm. Equipment on these line segments can experience shortened equipment life and additional equipment-related service interruptions.

The goal of the TUG program is to maximize the number of outage events eliminated. Converting outage prone parts of the system enables Duke Energy to restore service more quickly and cost effectively for all customers. Addressing areas with outlier outage performance improves service while lowering maintenance and restoration costs for all customers.

Criteria for consideration in the selection of targeted communities include:

- Performance of overhead lines
- Age of assets
- Service location (e.g., lines located in backyard where accessibility is limited)
- Vegetation impacts (e.g., heavily vegetated and often costly and difficult to trim)

GRID CAPABILITIES ENABLED

✓ IMPROVE RELIABILITY
✓ HARDEN FOR RESILIENCY
✓ MODERNIZE GRID OPERATIONS & PLANNING

VALUE TO OUR CUSTOMERS

✓ MAINTAIN REASONABLE RATES
✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

PROGRAM: TARGETED UNDERGROUNDING (TUG)

DOWNED POWER POLES

DAMAGE FROM HURRICANE MATTHEW

LINEMAN IN RAIN

IN AREAS INACCESSIBLE BY BUCKET TRUCK, LINEMEN HAVE TO CLIMB POLES TO MAKE REPAIR

PROGRAM: DISTRIBUTION TRANSFORMER RETROFIT

DUKE ENERGY

The Distribution Transformer Retrofit program converts existing overhead distribution transformers to deliver the same reliability benefits as a modern transformer installed today.

DESCRIPTION

Like the Self-Optimizing Grid program, the new sectionalization capability of a retrofitted transformer works to minimize the number of customers impacted by fault or failure on the power line. In addition, similar to the Targeted Undergrounding program, the new protective features that mitigate equipment vulnerabilities work to significantly lower the risk of an outage occurring at the transformer all together.

The core activities of the transformer retrofit program include the installation of a fuse disconnect device on the high-voltage side of every overhead transformer to protect upstream customers from a fault at or downstream of the transformer. In addition, through protective device coordination, the local fused disconnect can be set to prevent any upstream operations of reclosing devices (the source of momentary outages for customers not served by the retrofitted transformer.)

Consistent with modern transformer standards, the program also retrofits transformers with additional protective elements to reduce the risk of external factors such as lightning strikes and animal interference.

GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

PROGRAM: DISTRIBUTION TRANSFORMER RETROFIT

UN-RETROFITTED CSP TRANSFORMER

RETROFITTED TRANSFORMER

FUSED CUTOUT, ANIMAL GUARDS,
COVERED LEAD WIRE, NEW ARRESTER.

PROGRAM: DISTRIBUTION HARDENING & RESILIENCY – FLOOD HARDENING

The Distribution H&R – Flood Hardening program will be targeted to areas where an overlay of actual outage events from Hurricanes Matthew and Florence intersect with the 100-year flood plan.

DESCRIPTION

In hurricane events like Hurricane Floyd and more recently Hurricanes Matthew and Florence, significant flooding was a major factor impacting restoration. Smart, targeted investments can mitigate the scale of impacts on communities and customers adjacent to these areas prone to extreme flooding. Hardening lines and structures is a balanced approach that can keep power and critical services available to some portion of a community and prevent a widespread outage in an area until flooding recedes.

This program includes the following:

- Alternate power feeds for substations in flood-prone areas, and for radial power lines that cross into and through flood-prone areas
- Hardened river crossings where power lines are vulnerable to elevated water levels during extreme flooding
- Improved guying for at-risk structures within flood zones

GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ HARDEN FOR RESILIENCY
- ✓ IMPROVE PHYSICAL SECURITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

MORE ABOUT THE PROGRAM

Data analytics and geo-spatial analysis will assist Duke Energy in identifying patterns of repeat flood impact issues and allow a targeted basis for assessing hardening investments with a cost benefit analysis approach that delivers savings to Duke Energy customers and, at the same time, enhanced reliability for these flood-prone areas.

For a three-year window, this program will focus on hardest hit flood-prone areas from Hurricanes Matthew and Florence, defining opportunities to accomplish the following:

- Event elimination where hardening can demonstrably eliminate future outages events and repair work
- Resiliency options to re-route power and keep many people supplied with power while repairs to damaged facilities are made.

This program will be coordinated with other programs to ensure work scopes do not overlap.

PROGRAM: DISTRIBUTION HARDENING & RESILIENCY – FLOOD HARDENING

GOLDSBORO FLOODING DURING HURRICANE MATTHEW

FLOODING OF A SUBSTATION IN GOLDSBORO FOLLOWING HURRICANE MATTHEW (2016)

PROGRAM: SMART METERING INFRASTRUCTURE

The Smart Meter program is a metering solution (meters, communication devices and networks, and back office systems) used to create two-way communications between customer meters and the utility.

DESCRIPTION

Smart meters are digital electricity meters that have advanced features and capabilities beyond traditional electricity meters. Some of the advanced features include the capability for two-way communications, interval usage measurement, tamper detection, voltage and reactive power measurement, and net metering capability.

Duke Energy's standard smart meter system utilizes a radio frequency ("RF") mesh architecture, which is flexible in that the meters within the mesh network establish an optimized RF communication path to a collection point either through other meters, through network range extenders, or via a direct cellular connection.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ EXPAND CUSTOMER OPTIONS AND CONTROL

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

PROGRAM: SMART METERING INFRASTRUCTURE

DUKE ENERGY

PROGRAM: ELECTRIC TRANSPORTATION

The Electric Transportation effort is a proposed pilot program for North Carolina that will focus on advancing adoption of electric transportation in the State.

DESCRIPTION

The North Carolina program will establish a foundational level of public fast-charging infrastructure to advance electric vehicle adoption and inform best practices for cost-effective integration of various electric vehicle types with the electric system.

The ET pilot program will consist of five components: (1) Residential EV Charging Rebates, (2) Commercial Customer Charging Rebate, (3) Electric School Bus Infrastructure Investments, (4) Electric Transit Bus Infrastructure Investments, (5) DC Fast Charging Infrastructure. The bus components of the program will serve to financially support deployments of electric school and transit buses in conjunction with the Volkswagen Settlement.

The program will allow system planners to assess the impacts of different electric vehicle types, as well as various electric vehicle charging configurations. In addition to evaluating grid impacts, the pilot program will assess how all utility customers can benefit from increasing adoption of electric transportation through operational cost savings, enabled grid capabilities, improved air quality, and reduced transportation emissions.

GRID CAPABILITIES ENABLED

- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING
- ✓ EXPAND CUSTOMER OPTIONS AND CONTROL

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

MORE ABOUT THE PROGRAM

In 2011, Duke Energy conducted a plug-in electric vehicle charging station pilot in DEC. This pilot provided charging stations and up to $1,000 credit toward installation for customers who bought or leased a plug-in electric vehicle. Duke Energy analyzed the distribution impact and ways to mitigate those impacts as electric vehicles come into its service territory; the technical capabilities that the charging stations can offer to help mitigate those potential impacts; and when, where, how long, and how often a customer charges their electric vehicle.

Fast Charging Deployment Needed for Market Growth

Electric vehicles are coming to North Carolina as sales growth through the end of 2017 continued with a compound annual growth rate of 62% since 2011. Lack of charging stations is commonly cited as a barrier to purchasing an EV. The program estimates that approximately 1,000 public direct-current fast charging ("DCFC") plugs will be necessary by 2025 to support current forecasts of EV market growth. Currently, there are only 64 open-standard, publicly available DCFC plugs in North Carolina.

Volkswagen Environmental Mitigation Trust

In 2016, Volkswagen agreed to spend up to $14.7 billion to settle allegations of cheating emissions standards. Of that amount, $2.9 billion was used to establish an Environmental Mitigation Trust, which states and U.S. territories may use to invest in transportation projects that will reduce NOx emissions. Of that amount, $92 million was allocated to North Carolina as a beneficiary under the Settlement Trust. In August 2018, the NCDEQ released the final draft of the state's Beneficiary Mitigation Plan ("BMP"). Eligible mitigation actions under the BMP include replacing or repowering diesel school buses, transit buses, and heavy-duty on-road and off-road vehicles. In addition, beneficiaries may utilize up to 15% of their total allocation on costs relating to light duty, zero-emission vehicle supply equipment.

Other States Are Embracing Electric Vehicles

The Florida PSC approved an EV Infrastructure Pilot proposed by DEF, including public Level 2 and DC Fast Charging; in New York, ConEdison is supporting the deployment of electric school and transit buses, planned fast charging networks, and residential customer charging research. In Orlando, Florida, the Orlando Utilities Commission has deployed one of the largest municipal EV infrastructure programs in the country. Other examples of states that have embraced EVs in a pilot or otherwise include Maryland, Massachusetts, Oregon, Kentucky, Ohio, and California. Georgia Power has installed 25 public fast charging stations, facilitating EV adoption across the state of Georgia. By installing DC Fast Charging stations in the Carolinas, the ET Pilot would build on neighboring networks and allow EV drivers to seamlessly traverse along the crucial interstate corridors.

PROGRAM: CUSTOMER DATA ACCESS

DUKE ENERGY.

The Customer Data Access program focuses on preparing key data systems for sharing data in a manner that aligns with prevailing data access protocols such as the Green Button standard.

DESCRIPTION

Currently, the Company offers a method for customers to download their trailing energy usage data into an XML format. The Customer Data Access program will incorporate modern data access protocols such as the current "**Green Button-Download My Data**" functionality.

"**Green Button-Connect My Data** (CMD)" is a regular automatic transfer of a customer's interval usage data to a third party upon authorization by the customer. The Customer Data Access program will evaluate deployment of CMD or functionality like CMD based on several factors and requirements relevant to North Carolina customers and stakeholders.

GRID CAPABILITIES ENABLED

✓ EXPAND CUSTOMER OPTIONS AND CONTROL

VALUE TO OUR CUSTOMERS

✓ MAINTAIN REASONABLE RATES

✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY

✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

PROGRAM: CUSTOMER DATA ACCESS

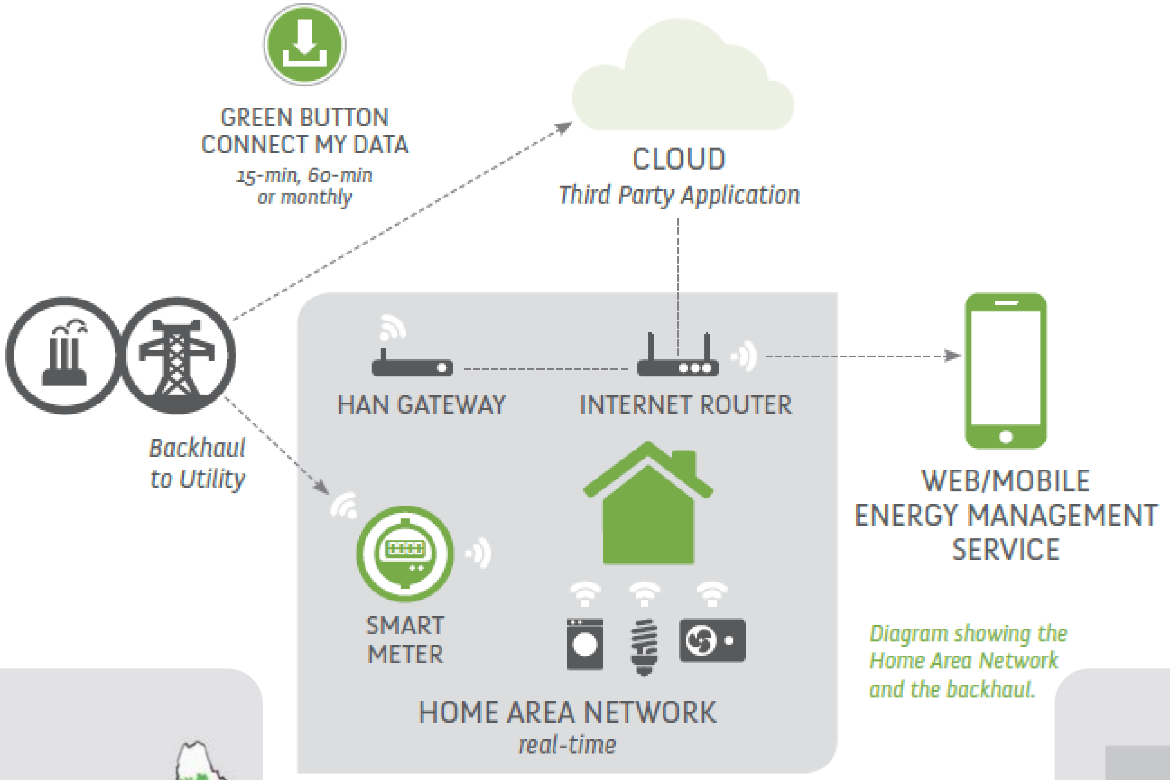
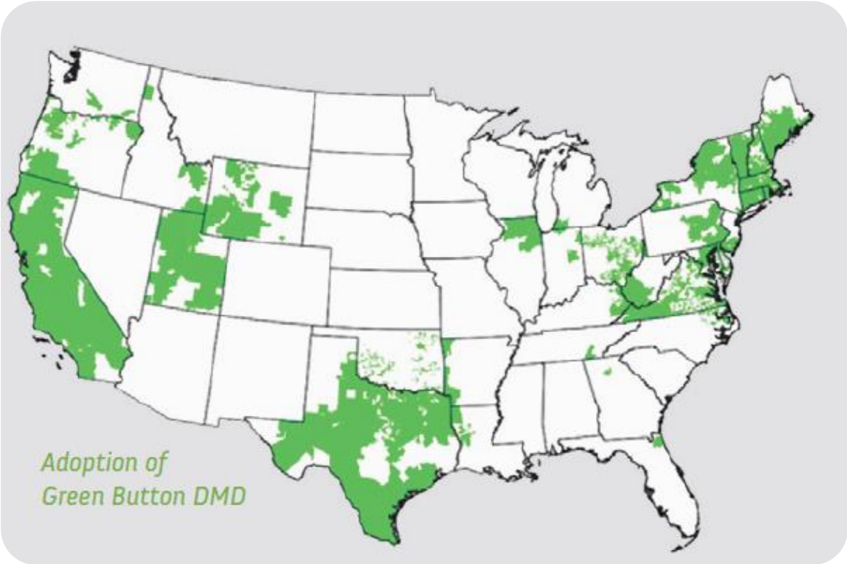
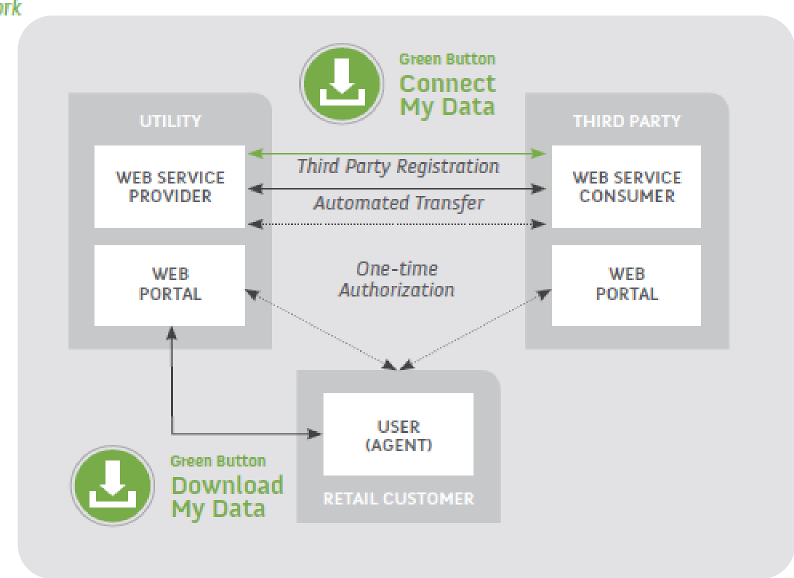


Diagram showing the Home Area Network and the backhaul.





Source: Murry, M. and Hawley, J., Got Data? The Value of Energy Data Access to Consumers. More Than Smart. January 2016. <Retrieved from http://www.missiondata.org/s/Got-Data-value-of-energy-data-access-to-consumers.pdf>

PROGRAM: TRANSMISSION SYSTEM INTELLIGENCE

DUKE ENERGY

The Transmission System Intelligence program deploys transformational system monitoring and control equipment to enable faster response to outages and more intelligent analysis of issues on the grid.

DESCRIPTION

Transmission grid automation improvements will reduce the duration and impacts associated with transmission system issues.

Improvements in transmission system device communication capabilities enable better protection and monitoring of system equipment. The data collected from intelligent communication equipment helps better assess and optimize transmission asset health.

The Transmission System Intelligence program includes 1) the **replacement of electromechanical relays** with remotely operated digital relays, 2) the implementation of **intelligence and monitoring technology** capable of providing asset health data and driving predictive maintenance programs, 3) the deployment of **remote monitoring and control** functionality for substation and transmission line devices, which support rapid service restoration, and 4) **resiliency projects** that leverage state of the art equipment such as digital relays, gas breakers and other equipment enabled with SCADA communication and remote monitoring and control capabilities to rapidly respond to system outages or disturbances. This subprogram helps to minimize the severity and consequences of outages or disturbances and increases the ability to quickly isolate trouble spots on the system and/or enable rapid restoration to normal system conditions.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

MORE ABOUT THE PROGRAM

System Intelligence and Monitoring

This subprogram focuses on a machine-learning platform that can determine when equipment maintenance or repair is needed. Health and Risk Monitoring (HRM) of the transmission system allows asset managers to proactively address equipment issues before catastrophic equipment failures occur. The HRM platform utilizes Condition Based Monitoring (CBM) – the continuous remote monitoring of asset health data which is used to extend asset life or execute mitigating activities to prevent equipment failures. HRM supplements CBM data with information from Digital Fault Recorders (DFR), which record the details of transmission system faults to support the types of post-fault event analysis that drives future system performance improvements.

Electromechanical to Digital Relays

This subprogram replaces noncommunicating electromechanical and solid state relays with digital relays. Modern relay design with communications capabilities and microprocessor technology enables quicker recovery from events than the design of the existing electromechanical relays. One digital relay is capable of replacing a variety of legacy single-function electromechanical relays. Two-way communications and event recording capabilities allow them to provide device performance information following a system event to support continuous system design and operational improvements. Additionally, they identify line fault locations, which is the ability to use device data to calculate the distance down a line to a line fault, rather than manually assessing and patrolling transmission lines.

Remote Substation Monitoring

This subprogram enables operators to remotely monitor and control substations. This includes the installation or upgrade of supervisory control and data acquisition system (SCADA) interfaces for substation devices, called remote terminal units (RTUs), and upgrades to associated data communication channels. This subprogram is a critical enabler for programs like Integrated Volt/Var Control and Distribution Automation. This subprogram also upgrades serial communication to IP communication for existing RTUs to collect more data and support more devices.

Remote Control Switches

This subprogram replaces non-communicating switches with modern switches enabled with SCADA communication and remote control capabilities. Transmission line switches are currently manually operated in most substations and cannot be remotely monitored or controlled. Switching, a grid operation often used to section off portions of the transmission system in order to perform equipment maintenance or isolate trouble spots to minimize impacts to customers, has historically required a technician to go to a substation and manually operate one or more line switches. This subprogram increases the number of remote controlled switches to support faster isolation of trouble spots on the transmission system and more rapid restoration following line faults.

PROGRAM: TRANSMISSION HARDENING & RESILIENCY (H&R)

DUKE ENERGY.

The Transmission (H&R) program works to create a stronger and more resilient transmission grid capable of withstanding or quickly recovering from extreme external events, natural or man-made.

DESCRIPTION

Each Transmission H&R sub-program works to address unique challenges in ways that harden the system, and not only minimize impacts to customers, but enhance their electric service experience. The **44-kV System Upgrade** subprogram both protects the 44-kV system from extreme weather, but also paves the way for more DER interconnections by creating additional capacity on the system to transport generation from large scale solar sites. Similarly, the **Targeted Line Rebuild for Extreme Weather** subprogram protects some of the higher voltage transmission lines from extreme weather by addressing vulnerable wooden structures.

The **Networking Radially Served Substations** subprogram builds in more resiliency to the transmission system by creating alternative ways to provide customers with reliable electricity supply in the case of an issue with the primary transmission feed; the **Substation Flood Mitigation** subprogram builds in protection for substations most vulnerable to flood damage; and the **Animal Mitigation** subprogram installs equipment specifically designed to prevent animal induced events from impacting customers directly through an outage or indirectly through a system perturbation such as a voltage depression. Altogether, these H&R efforts not only enhance the functionality of individual assets, but substantially improve the overall functionality of the system, particularly under extreme weather conditions. The long-term plan for hardening and resiliency is to relocate or strengthen at-risk assets or other solutions such as raising the flood plane at that site.

GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ HARDEN FOR RESILIENCY
- ✓ IMPROVE PHYSICAL SECURITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

MORE ABOUT THE PROGRAM

44kV System Upgrades

Rebuilds and upgrades targeted portions of the 44-kV system to both harden the system against extreme weather, position the system to support DER, and make the overall system more resilient. This will be accomplished in three phases:

- PHASE I (infrastructure upgrades): structurally rebuilds the system, replacing wood structures with taller/stronger steel or concrete structures to better withstand damage in extreme weather conditions. Rebuilding 44-kV lines to 100-kV standards improves performance due to greater elevation and clearance from vegetation. The increased conductor spacing between each of the phases and the addition of basic insulation decreases impacts of lightning events.
- PHASE II (voltage conversions): converts specific circuits of the 44-kV system to 100-kV, making them more capable of supporting large scale solar, storage and other DER. These conversions also require converting the substations served by these lines, which generally involves installing high rated equipment such as transformers and breakers. Portions of the 44-kV system, particularly in rural areas that are prime locations for utility scale solar development, are capacity constrained and unable to support additional interconnections.
- PHASE III (circuit looping): builds in circuit ties between upgraded and converted circuits. This creates a looped circuit design capable of feeding power to these circuits from other sources, as needed, to provide additional system resiliency.

Networking Radially Served Substations

Increases resiliency of radially served substations where outage duration is higher than average, including~~:~~ networked lines sectionalized into separate radial lines, and lines designed as radial feeders. Networked radial lines can be re-networked by replacing the conductor with higher ampacity and by upgrading the protective relaying. Lines designed as radial feeders will be networked to existing lines into another substation. Substations served by networked transmission lines can be served from either end of the line and the line can be sectionalized to isolate an interruption and restore the majority, if not all, of customers before the full line is restored.

PROGRAM: TRANSMISSION HARDENING & RESILIENCY (H&R)

DUKE ENERGY

MORE ABOUT THE PROGRAM

Substation Flood Mitigation

Systematically reviewing and prioritizing substations at risk of flooding to determine the proper mitigation solution, which may include elevating or modifying equipment in substations or relocating substations altogether.

Targeted Line Rebuilds for Extreme Weather Events

Specific transmission lines require rebuilding to withstand extreme weather (including wind and ice) and mitigate the risk of unplanned outages. Lines are targeted based on risk-advised decisions along with selection criteria including: tower height, tower condition, and age of asset. Proactive replacement of wooden poles to steel poles that comply with the National Electrical Safety Code (NESC) achieve benefits such as protecting extreme weather and reducing O&M costs.

TRANSMISSION POLE REPLACEMENTS

69 KV WOOD POLE CONSTRUCTION

NEW 69 KV STEEL POLE CONSTRUCTION

PROGRAM: TRANSFORMER BANK REPLACEMENT

The Transformer Bank Replacement program leverages new system intelligence capabilities to target transformers before they fail.

DESCRIPTION

Predictive and proactive replacement programs like Transformer Bank Replacement significantly reduce the impacts and costs of replacement when compared to performing the same work following a catastrophic failure.

The objective of this program is to anticipate future transformer failures and replace those transformers in an orderly fashion, avoiding the cost and customer outage minutes associated with these failures. Catastrophic failures often result in significant oil spills, requiring expensive cleanup and other mitigation. Proactive replacement also reduces contingent material inventory needed, since replacements have a 12-24 month manufacturing lead time.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

PROGRAM: OIL BREAKER REPLACEMENT

The Oil Breaker Replacement program identifies and replaces oil-filled circuit breakers on the transmission and distribution systems with modern technology.

DESCRIPTION

The purpose of this program is to replace these legacy assets with breaker technology capable of two-way communications and remote operations.

Transmission level oil breakers will be replaced with the modern sulfur hexafluoride gas (SF_6) circuit breaker technology. The medium voltage distribution level oil-filled breakers will be replaced with modern vacuum circuit breaker technology.

The new communication and control capabilities of this modern technology better positions the transmission and distribution systems to work with grid automation systems to better respond to electric grid events. Looking forward, these fast-response gas and vacuum breakers are better suited for protecting circuits with higher solar and other variable energy resource penetration.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

The Physical and Cyber Security program protects against the potential risks and impacts of attacks on the electric grid.

DESCRIPTION

The program focuses on hardening above the standard compliance requirements. Transmission elements of the program include:

- **Transmission substation physical security**
- **Windows-based change outs** to address cyber security standards for older Windows-based relays.
- **Cyber security enhancements for non-bulk electric system substations**
- **Electromagnetic Pulse and Intentional Electromagnetic Interference (EMP/IEMI) Protection**

At the distribution system level, much of the focus involves securing and improving risk mitigation of remotely controlled field equipment. An example is enabling door alarms and entry notifications. Programs include:

- **Device Entry Alert System** (DEAS)
- **Distribution Line Device Cyber Protection**
- **Secure Access Device Management** (SADM) - a single tool to remotely and securely perform device management activities and event record retrieval on the entire transmission and distribution device inventory.

GRID CAPABILITIES ENABLED

- ✓ HARDEN FOR RESILIENCY
- ✓ IMPROVE CYBER SECURITY
- ✓ IMPROVE PHYSICAL SECURITY
- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

PROTECT to reduce threats to the grid

MORE ABOUT THE PROGRAM

Transmission Substation Physical Security

This subprogram enhances the grid resiliency as part of the overall Transmission Security program. Tier 1 site enhancements include high security perimeter fencing and lighting, intrusion detection technology, new security enclosure buildings, hardening of existing control houses, security cameras, and access control. Tier 2 site enhancements include high security perimeter fencing and lighting.

Windows-based Unit Change Outs

The Windows-based Unit Change Outs effort replaces older Windows-based relays that cannot be upgraded due to technology constraints (such as insufficient memory or relay condition). Following these upgrades, the new devices will operate in a Linux environment and be compliant with standards.

Cyber Security Enhancements for non-BES

Cyber Security Enhancements for non-bulk electric system (BES) substations implements protective measures against possible cyber-attacks at those non-BES substations that have Internet-Protocol (IP) routable devices. Such measures include the installation of firewalls and the replacement of vulnerable devices.

EMP/IEMI Protection

Electromagnetic pulses (EMP) and Intentional Electromagnetic Interference (IEMI) can create disruptions for electronic equipment. The measures taken to protect against them focus on hardening and protecting targeted equipment. The electric industry is engaged in significant research, led by the Electric Power Research Institute (EPRI), focused on improving cost-effective and feasible mitigation against EMP/IEMI. This subprogram will focus on pre-scaled implementation of industry research findings.

MORE ABOUT THE PROGRAM

Device Entry Alert System (DEAS)

The Device Entry Alert System (DEAS) project will install an entry door alarm head-end system and deliver processes to enhance physical and cyber security on the distribution systems' intelligent electronic devices (IEDs). This tool will ensure that all physical access of IEDs and related infrastructure in the field are being tracked and monitored.

Secure Access and Device Management (SADM)

SADM provides a tool to remotely and securely perform device management activities and event record retrieval on our entire device inventory in transmission and distribution. The goal of the project is to improve the security of field devices and increase compliance with North American Electric Reliability Corporation critical infrastructure protection (NERC CIP) and other security requirements.

SADM also provides process and labor efficiencies associated with device management, and improves post-event resolution. Within this program, we will standardize systems and processes for secure remote access to field devices, implement device management tasks (including password management, firmware management, configuration management), manage post-fault and other operational event records, and implement a common solution and support model across all jurisdictions within transmission and distribution.

Distribution Line Device Cyber Protection

The Distribution Line Device Cyber Protection projects address physical and cyber security risks for thousands of SCADA-controlled line devices (e.g., regulators, capacitors, reclosers, etc.). The focus of the projects in this workstream is targeted replacement of legacy control equipment with Enterprise Security and Advanced Distribution Management System compliant equipment. The newer installed equipment meets or exceeds Duke Energy Industrial Control System (ICS) enterprise security requirements and also provides a platform for future asset management enhancements, such as remote firmware and device settings management, reducing the need to travel physically to a site to perform a system upgrade. Examples of equipment being replaced include capacitor and distribution (recloser) control devices.

COCHRANE FENCE & MAIN ENTRANCE CRASH GATE

PROGRAM: ENTERPRISE COMMUNICATIONS ADVANCED SYSTEMS

DUKE ENERGY

The Enterprise Communications program modernizes and secures the critical communications between intelligent grid management systems, data and controls systems, and sensing and control devices.

DESCRIPTION

The program addresses technology obsolesce, secures vulnerabilities, and provides new workforce-enabling capabilities. This program includes improvement and expansion of the entire communications network from the high-speed, high-capacity backbone fiber optic and microwave networks to the wireless connections at the edge of the grid. These upgrades help build the secure communications required for the increasing number of smart components, sensors, and remotely activated devices on the transmission and distribution systems.

Key communication efforts are: (1) **Mission Critical Transport** which strategically upgrades the infrastructure required for high-speed, reliable, sustainable, interoperable communications for grid devices and personnel; (2) **Grid Wide Area Network (Grid WAN)** which improves network reliability, performance and security for current grid management/control applications; (3) **Mission Critical Voice** which replaces current Land Mobile Radio systems with enhanced, reliable, sustainable, interoperable communications across all service territories; and (4) **Next Generation Cellular** which replaces obsolete 2G/3G cellular technology with the more reliable and secure 4G/5G technology required for modern grid devices in the field.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ IMPROVE CYBER SECURITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

MORE ABOUT THE PROGRAM

Mission Critical Transport

Implements the strategic advancements to the backbone of the communication network to ensure reliable, sustainable, interoperable communications for grid devices and personnel. Replaces end-of-life fiber cable, optical systems, and microwave systems; strategically expands high-capacity fiber to new, targeted routes; and investigates alternatives for faster or more cost-effective fiber deployments.

Business Wide Area Network

Updates data network architecture to improve reliability and performance of the core business. Assesses capacity and redundancy requirements and evaluates network options for the core business network and associates area network structures. Supports growing demands for workforce mobility, real-time video capture, data transport needs, and mitigating communication network congestion.

Grid-wide Area Network (Grid WAN)

Improves network reliability, performance and security for grid control, O&M applications by replacing end-of-life data network hardware and converting substations to an IP network architecture. Employs a network redesign, providing capacity and resiliency, and positioning the network to support Field Area Network (FAN) and Neighborhood Area Network (NAN) needed for enabling a smart cities future.

Mission Critical Voice

Strategic replacement and improvement of mission-critical voice (radio) communications to provide reliable, sustainable, interoperable communications for all jurisdictions and businesses. The new radio system will provide increased functionality and interoperability between regions, allowing field workers to use the same radio system to help another region during major storms.

Next Generation Cellular

Addresses the need to migrate 2G/3G communication networks (to be decommissioned by cellular service providers) to updated 4G/5G. Replaces existing network devices located on distribution line devices. In addition to supporting communication continuity through network decommissioning, these upgrades provide greater network bandwidth, lower data latency, and better cybersecurity protection.

PROGRAM: ENTERPRISE COMMUNICATIONS ADVANCED SYSTEMS

COMMUNICATION TOWER (LEFT) &
POLE-MOUNTED COMMUNICATION NODE

PROGRAM: ENTERPRISE APPLICATIONS

DUKE ENERGY

The Enterprise Applications program deploys the systems and upgrades needed to monitor the health and security of the grid and analyze data to enable grid automation and optimization technologies.

DESCRIPTION

Upgrades to existing enterprise applications enable system optimization and overall better system performance. Within the program, there are two main components responsible for the delivery of enterprise technology solutions that support transmission, distribution, and other critical lines of business: (1) **Enterprise Systems** and (2) **Grid Analytics**.

This effort focuses on delivering transformative, cross-functional technical solutions to the enterprise in non-disruptive ways. Elements within the portfolio include the Integrated Tools for Outage Applications (iTOA), which works to drive standardization and coordination of grid control center tools and the Targeted Management Tool (TMT), which facilitates efficient workflows via asset management and mapping system upgrades.

Grid Analytics optimizes the electric system health and performance through the deployment of the Health Risk Management (HRM) tool and Enterprise Distribution System Health (EDSH) tool. These tools help to prevent equipment failures and improve asset performance on the transmission and distribution systems, respectively.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ IMPROVE RELIABILITY
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ IMPROVE PHYSICAL SECURITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

MORE ABOUT THE PROGRAM

Integrated Tools for Operations Application (ITOA)

ITOA is a new platform that optimizes current processes and drives standardization regarding system functionality, work processes, and configuration. This project also upgrades and consolidates outage coordination as well as planned switching and logging applications for transmission and distribution control centers.

Targeted Management Tool (TMT)

The TMT automates manual processes and facilitates faster and more efficient workflow by integrating asset management systems. The product enhances the existing enterprise systems for tracking TUG work and creates new mapping capabilities. The mapping enables visualization of the ongoing targeted underground work and consistency in reporting.

Health and Risk Management (HRM)

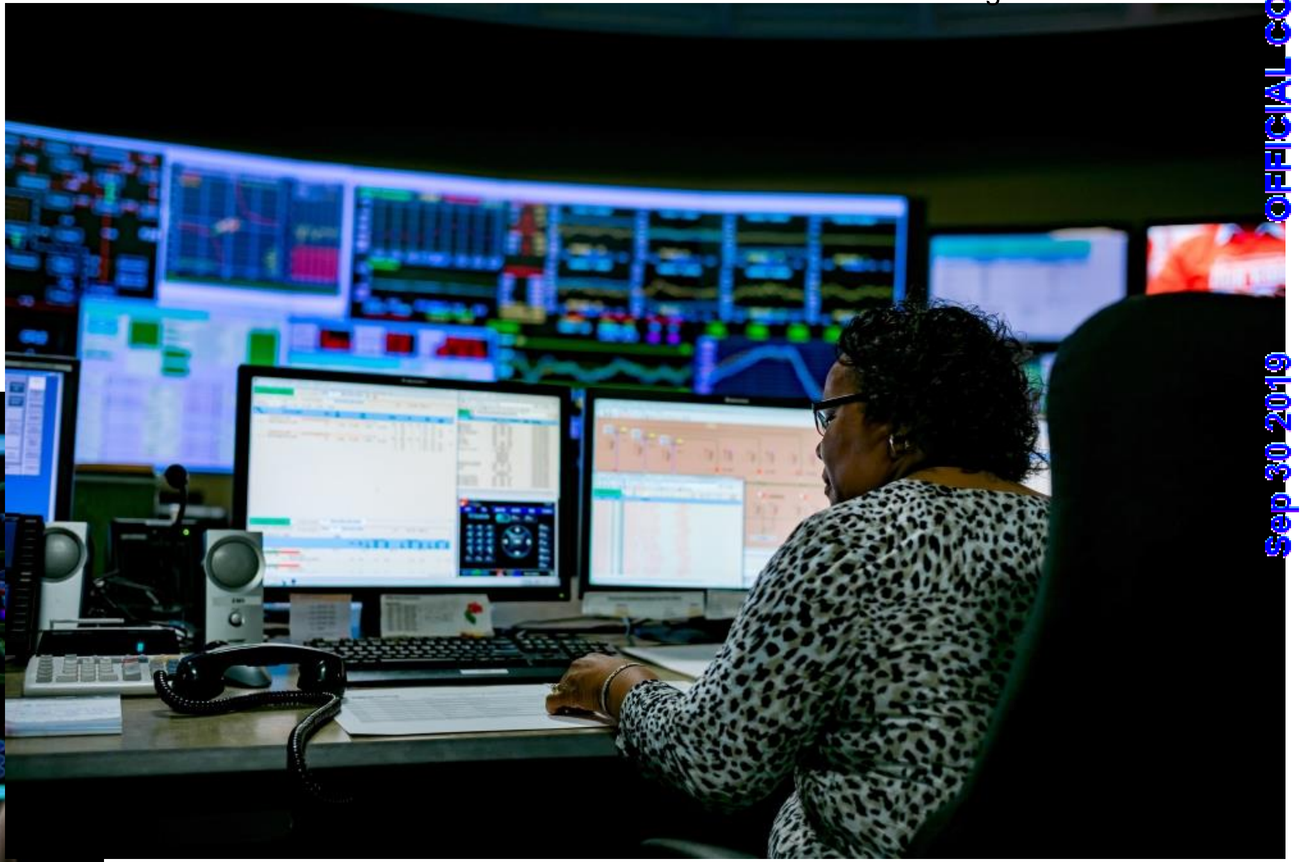
HRM will provide a new platform for collecting data and applying analytics optimization for managing transmission system assets. This sub-program will collect and analyze data to improve the management of assets by using predictive and prescriptive analytics and take proactive steps to prevent or mitigate disruptive events..

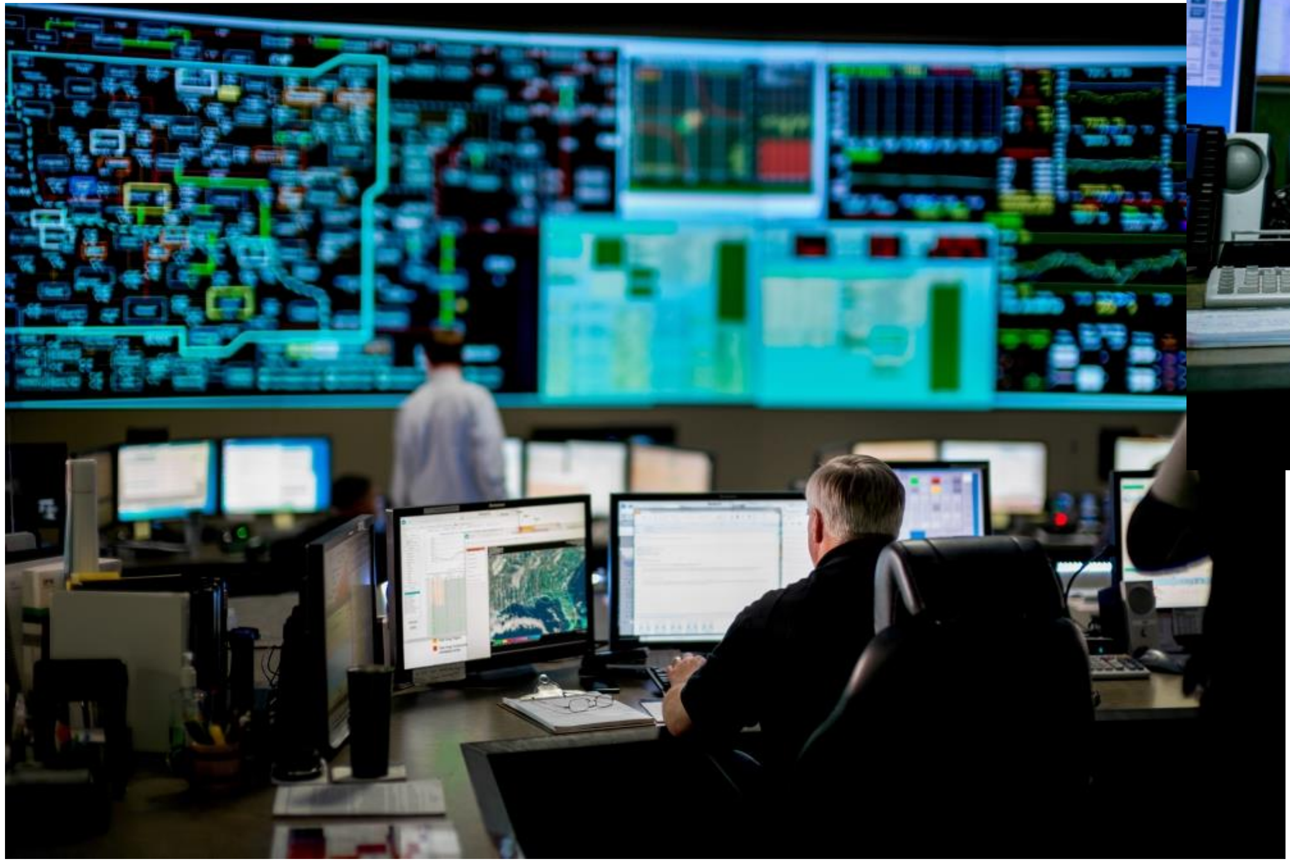
Enterprise Distribution System Health (EDSH)

EDSH provides a platform that enables PQR&I Planning, Governance, and Customer Delivery to improve reliability and customer satisfaction. It will enable customer-centric reliability planning and provide a basis for optimizing investments using predictive and prescriptive analytics and allow Duke Energy to take proactive steps to prevent or mitigate disruptive events.

PROGRAM: ENTERPRISE APPLICATIONS

DUKE ENERGY





PROGRAM: DER DISPATCH ENTERPRISE TOOL

The DER Dispatch Enterprise Tool is a software-based solution that provides operators with the ability to monitor and manage both transmission and distribution connected DERs.

DESCRIPTION

This tool will coordinate with the Distribution Management System (DMS) and Energy Management System (EMS) to improve the way DERs are integrated in the energy supply mix, both at the Distribution and the bulk power level.

By providing system-wide visualization and control of large-scale DERs, the DER Dispatch Tool will enable system operators to model, forecast, and dispatch a portfolio of distributed energy resources, like solar generation, biofuel generation and energy storage, based on system conditions and real-time customer demand. This tool will help meet the need to match energy demand with supply, especially in emergency conditions.

Current processes and tools provide system operators with a rudimentary ability to quickly shed large blocks of solar generation in emergency conditions to meet standards for real power control (BAL-001-2). The proposed solution will provide operators with a more automated and refined toolset to optimize management of both utility and customer owned DERs to meet system stability requirements.

This system will replace an existing tool in DEP that is used to dispatch distribution connected solar in 50 MW increments

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ EXPAND CUSTOMER OPTIONS AND CONTROL

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

PROGRAM: DER DISPATCH ENTERPRISE TOOL

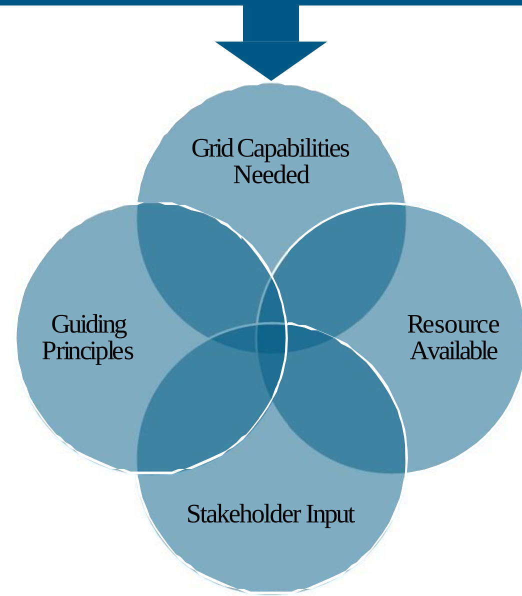
PORTFOLIO PRIORITIZATION METHODOLOGY

DUKE ENERGY

The programs in our portfolio were selected based on alignment with our framework and prioritization criteria.

Grid Improvement Plan

Megatrends and Implications



Programs are considered based on fit with framework and justification methodology:

- Protect: required for compliance
- Modernize: technology has rapidly advanced and is now mature
- Optimize: program provides attractive benefits

Customer-Focused Programs are selected and funded based on:

- Grid capabilities that are needed to address megatrends
- Scope and budgets right-sized to available resources
- Stakeholder input
- Alignment with guiding principles

Cost-Benefit and Cost-Effectiveness Justified (Optimize)

Programs and projects in this category provide customers more net benefits than net costs and solve for one or more external "megatrends."

Rapid Technology Advancement-Cost Effectiveness Justified (Modernize)

Equipment, software, hardware, operating systems, and/or accepted system operating practice has advanced at an atypical pace in this category causing the need for rapid and sometimes frequent changes within the utility at a system deployment level. Work in this category is usually related to system communication, automation, and intelligence and must be executed at a deliberate pace while ensuring not to deploy new technology before it has reached operational and price point maturity. While not technically compliance work, work in this category is essential for modern system operations.

Compliance-Cost Effectiveness Justified (Protect)

i. An external law, rule, or regulation applicable to the company requires the work;

ii. A binding legal obligation such as a contract, agency order, or other legal document compels the work; or

iii. The Operations Council has approved the work as being critical and imperative to the Company's operations

Maintain Base (Maintain)

Programs and investments to serve customers in a manner that meets industry safety, reliability, and environmental standards.

PORTFOLIO PRIORITIZATION METHODOLOGY

DUKE ENERGY.

The programs in our portfolio were selected based on alignment with our framework and prioritization criteria.

Megatrends

	GIP PROGRAMS	I - Phys & Cyber Threats	II - Adv Tech (Solar/Battery)	III - Environmental Policy	IV - Weather	V - Grid Improvement Techn.	VI - Concentrated Growth	VII - Customer Expectation	NC - DEC Total ($M)	NC - DEP Total ($M)	NC TOTAL ($M)	
Protect	Physical Security	x	x			x		x	$58.0	$64.7	$122.7	
	Cyber Security	x	x			x		x	$7.0	$4.0	$11.0	
Optimize	Self-Optimizing Grid	x	x	x	x	x	x	x	$420.0	$302.0	$722.5	1st
	Integrated Volt/VAR Control	x	x	x	x	x	x	x	$207.0	$10.0	$217.0	2nd
	Harden &Resiliency [T]		x	x	x			x	$102.4	$31.3	$133.7	
	Targeted Underground				x			x	$59.8	$54.7	$114.5	
	Energy Storage*		x	x	x		x	x	$56.5	$72.5	$129.0	
	Transformer Retrofit [D]				x			x	$8.3	$109.7	$118.0	
	Long Duration Interruptions				x			x	$11.3	$15.8	$27.1	
	Transformer Bank Repl [T]		x	x				x	$33.6	$82.7	$116.3	
	Oil Breaker Rpl [T]			x		x		x	$101.6	$42.8	$144.4	
	Oil Breaker Rpl [D]			x		x		x	$13.9	$42.0	$55.9	
Modernize	Enterprise Communications	x	x	x	x	x	x	x	$103.8	$108.0	$211.8	3rd
	Distribution Automation		x	x	x	x		x	$118.4	$70.9	$189.3	4th
	System Intelligence [T]		x	x		x		x	$62.7	$23.7	$86.4	
	Enterprise Applications		x	x		x		x	$17.0	$10.8	$27.8	
	ISOP		x	x		x	x	x	$4.1	$2.5	$6.6	
	DER Dispatch		x	x		x		x	$4.5	$2.9	$7.4	
	Electic Transportation*		x	x					$38.2	$25.2	$63.4	
	Power Electronics		x	x		x		x	$0.7	$1.1	$1.8	
											$2,314.2	

******Note:** Energy Storage Projects and Electric Transportation have been excluded from these totals. These programs are important components of grid improvement but not included in the costs for the GIP given that they are being reviewed and evaluated in separate forums.*

MEGATRENDS

1. Rise and sophistication of threat of physical and cyber attacks on grid infrastructure
2. Rapid advancement and impacts of technology of renewables and distributed energy resources (DERs)
3. Increases in environmental commitments from the international, and customer communities
4. Significant increase in number, severity and impact of weather events
5. Rapid advancement and new capabilities / functionalities of devices and systems that operate and manage the T&D grids
6. Heavily concentrated population and business growth in urban and suburban areas
7. Shifts in customer expectations and use of the grid from generations past

Cost/Benefit and Cost Effectiveness Evaluation Execution Protocol

A. **DEFINITIONS**

Cost Benefit Analysis-"Go/No Go" Level: A analysis that compares quantitative and qualitative factors associated with taking a given course of action or not taking it (e.g. should I go to college or not).

Cost Benefit Analysis-"Path Selection" Level: A analysis that compares quantitative and qualitative factors associated with taking a certain path within a given course of action that the Company has decided to do (e.g. now that I have decided to go to college, which one should I go to).

Cost Effectiveness Analysis: A analysis that ensures a selected path, within a given course of action, is executed in a reasonable and prudent manner (e.g. now that I have selected to go to college and now that I have chosen to go to Energy University, how can I do so for the least cost and still obtain the results I desire).

B. **STEPS FOR DEPLOYING THE MODEL**

(***Step 1***). **Is the "Go/No Go" course of action you are evaluating mandatory (i.e. Compliance) or discretionary?**

A course of action is considered mandatory (or Compliance) if:

i. An external law, rule, or regulation applicable to the company requires it;

ii. A binding legal obligation such as a contract, agency order, or other legal document compels it; or

iii. The Operations Counsel has approved the activity as being critical and imperative to the Company's operations.

If the "Go/No Go" course of action being considered is mandatory, proceed to *Step 3*. If discretionary, proceed to *Step 2*.

(***Step 2***). **Is the "Go/No Go" course of action you are evaluating justified by the "Go/No Go" Cost Benefit Analysis Model below ?**

If "yes," proceed to *Step 3*. If "no," don't pursue this course of action.

1. **Will This Activity Financially Benefit Customers?**

A. By creating an opportunity to lower customer bills from what they would otherwise be?
B. By lowering customer energy use and thus, their bills from what they would otherwise be?
C. By avoiding other costs which would be borne by customers?
D. By making customers money (e.g. rebates or incentive payments for a given activity)?

If "yes," go to 2. If no, go to 3.

2. **Does the estimated net present value of the financial benefit outweigh the estimated cost?**

   If "yes," this activity presumptively is justified. If no, go to 3.

3. **Are There Objective or Subjective Qualitative Benefits to the Customer That Nonetheless Justify the Activity?**

   A. Objective in that no reasonable customer would not want this?
   B. Subjective desire from a customers that can be demonstrated?

   If "yes," this activity presumptively is justified. If no, go to 4.

4. **Are There Objective Qualitative or Quantitative Benefits to the Company Only That Nonetheless Justify the Activity?**

   A. Would not doing this activity cause material harm to the Company which, in turn, would have a material, and direct negative impact on customers? (e.g. increased cost of debt to the Company, negative credit ratings, material investor flight)

   If "yes," this activity presumptively is justified. If no, go to 5.

5. **Are There Objective Qualitative or Quantitative Benefits to Third Parties That Nonetheless Justify the Activity?**

   A. Would not doing this activity cause material harm to third parties which, in turn, would have a material, and direct negative impact on customers?

   B. Would doing this activity cause material benefit to third parties which, in turn, would have a material, and direct positive impact on customers? (e.g. economic development and expansion)

   If "yes," this activity may be justified, but usually calls for a policy decision by policy makers.

(***Step 3A***). **Is the path you have chosen to achieve the "Go/No Go" course of action at issue mandatory (i.e. Compliance Prescriptive)?**

If "yes," proceed to *Step 4*. If "no," proceed to *Step 3B*.

A path to achieve is considered mandatory (or Compliance Prescriptive) if:

i. An external law, rule, or regulation applicable to the company requires it;

ii. A binding legal obligation such as a contract, agency order, or other legal document compels it; or

iii. The Operations Counsel has approved the path to achieve as being critical and imperative to the Company's operations.

(***Step 3B***). **Is the path you have chosen to achieve the "Go/No Go" course of action at issue justified by the "Path Selection" Cost Benefit Analysis Model below?**

If "yes," proceed to *Step 4*. If "no," don't pursue this path to achieve and find another path to achieve to evaluate.

I. **Are There Other Paths to Achieve the Course of Action at Issue?**

A. If "no," conclude this analysis and proceed to *Step 4*.

B. If "yes," continue this analysis.

II. **Is The Chosen Path to Achieve More Favorable Than Other Paths to Achieve On a Risk-Adjusted, Net Present Value Basis?**

A. If "yes," conclude this analysis and proceed to *Step 4*.

B. If "no," continue this analysis.

III. **Do Objective and Provable Qualitative Factors Justify the Use of the Chosen Path to Achieve Notwithstanding Its Net Present Value Results?**

A. If "yes," proceed to *Step 4*.

B. If "no," do not proceed with the chosen path to achieve and find another path to achieve to evaluate.

(***Step 4***). **Can you prove that the chosen path to achieve the chosen course of action will be executed in a reasonable and prudent fashion given the factors and considerations listed below?**

If "yes," your analysis is complete. If "no," redesign your plan of execution.

I. Have the external materials and labor needed in your execution plan been competitively bid? If not, do you have objective justification as to why not?

II. Have you optimized resource deployment, logistics, and mobilization/de-mobilization of work?

III. Have pertinent risks been identified and evaluated?

IV. Has your execution plan been objectively reviewed by other business groups or third parties?

V. Have contingencies been evaluated and incorporated into your plan of execution?

VI. Does your plan of execution have scoping for scheduling, progress checkpoints, and performance measurement metrics in place?

NC COST-BENEFIT ANALYSIS - PORTFOLIO SUMMARY
Net Present Value (Primary Costs and Benefits) and IMPLAN (Secondary Benefits)

Program/Project Name	Total NPV Costs	Total NPV Benefits	NPV Benefit-Cost Ratio	Total IMPLAN Benefits	NPV + IMPLAN Benefit-Cost Ratio
PROGRAMS					
Targeted Underground	**169,296,365**	**2,041,165,916**	**12.1**	**1,654,759,146**	**21.8**
Druid Hills	4,434,479	28,624,383	6.5	21,047,667	11.2
Lake Crest Drive	1,019,161	17,187,055	16.9	14,510,579	31.1
Pine Island Road	742,021	17,768,298	23.9	14,602,795	43.6
Bent Creek	8,948,325	46,976,054	5.2	36,097,959	9.3
Foxcroft	2,954,186	11,973,254	4.1	8,007,961	6.8
Kings Grant	11,068,448	137,506,926	12.4	114,610,800	22.8
Barcelona Ave	471,904	2,527,138	5.4	1,862,148	9.3
Foxcroft Forsyth	737,886	8,211,995	11.1	6,421,412	19.8
Grimesdale	2,839,722	6,773,228	2.4	4,510,350	4.0
Raintree	1,655,953	33,649,923	20.3	27,970,520	37.2
Smallwood	866,764	14,402,822	16.6	11,108,158	29.4
Stonehaven	4,569,521	8,855,862	1.9	5,012,083	3.0
Alan Street	1,018,192	27,605,654	27.1	23,138,449	49.8
Beverly Hills	2,849,840	40,308,549	14.1	32,680,862	25.6
Biltmore South	3,638,721	230,913,822	63.5	199,072,750	118.2
Glen Arden	1,929,307	40,236,404	20.9	33,442,030	38.2
Princess Place Belvedere	2,378,110	28,029,609	11.8	21,999,078	21.0
Elizabeth	897,573	36,515,101	40.7	30,692,791	74.9
Hendrix Street	558,195	4,826,681	8.6	3,382,416	14.7
Louise Rd	1,334,986	6,632,920	5.0	4,402,093	8.3
Mountainbrook	7,638,244	26,024,947	3.4	16,730,676	5.6
Sedgefield & Marsh	16,700	1,503,137	90.0	675,981	130.5
Town and Country	5,343,299	31,285,464	5.9	23,468,614	10.2
Westview	4,204,748	9,647,690	2.3	6,382,947	3.8
Windsor Park	14,414,949	42,354,274	2.9	26,495,223	4.8
Woodlark Lane	949,220	18,635,273	19.6	15,000,273	35.4
Brookhaven	4,139,559	51,477,656	12.4	41,515,853	22.5
Harbor Island	1,667,210	105,626,356	63.4	91,249,181	118.1
Russell Hills	4,303,558	164,185,388	38.2	140,672,979	70.8
Town Mountain	17,673,971	136,982,475	7.8	109,125,947	13.9
Tramwood	746,115	3,931,840	5.3	2,742,557	8.9
Vance Street	6,078,585	57,522,247	9.5	46,608,855	17.1
Wrightsville Ave Newton St	644,017	7,421,341	11.5	5,841,533	20.6
Bonclarken	1,941,867	9,883,022	5.1	7,173,114	8.8
Chanteloupe Dr	545,312	1,641,817	3.0	958,676	4.8
Colony Park Beech Hill	1,430,456	15,143,121	10.6	12,200,739	19.1
Colony Woods	3,687,947	13,960,818	3.8	9,253,829	6.3
Ewing Ave near East Blvd	1,295,305	56,293,242	43.5	47,538,767	80.2
Green Knolls	608,536	3,526,492	5.8	2,536,272	10.0
Lake Lure N of 74	3,206,817	38,747,325	12.1	31,877,034	22.0
Philip St	371,444	8,951,352	24.1	7,435,121	44.1
Queens Rd W	4,574,543	54,773,941	12.0	42,762,148	21.3
Remount at Camp Green St	924,659	32,132,436	34.8	26,715,602	63.6
Rick St off Rankin Rd	442,572	6,104,715	13.8	4,850,097	24.8
River Crest Dr	616,439	1,338,653	2.2	578,120	3.1
Riverwood Hills	742,889	2,501,908	3.4	1,110,178	4.9
Rolling Roads	2,222,407	31,173,489	14.0	25,133,178	25.3
Westover Hills	2,101,508	56,768,465	27.0	46,717,578	49.2
Biltmore North	6,090,048	135,096,676	22.2	113,110,641	40.8
Lakeview Park	6,652,359	122,664,120	18.4	102,241,978	33.8
Mockingbird Rd	1,603,946	6,905,449	4.3	4,809,672	7.3
Royal Pines	7,503,843	37,435,111	5.0	26,672,881	8.5
Transformer Retrofit	**169,085,013**	**250,004,884**	**1.5**	**210,463,061**	**2.7**
IVVC	**467,493,417**	**546,504,878**	**1.2**	**242,173,363**	**1.7**
DSDR	**6,574,130**	**232,348,694**	**35.3**	**147,329,969**	**57.8**
SOG - DEC	**452,807,789**	**1,129,535,184**	**2.5**	**1,044,796,273**	**4.8**
SOG - DEP	**313,576,143**	**959,229,534**	**3.1**	**765,012,924**	**5.5**
Transmission - Oil Breaker Replacements	**95,903,742**	**152,204,290**	**1.6**	**68,767,661**	**2.3**
DEP Asset Replacements	34,767,288	54,341,285	1.6	27,131,271	2.3
DEC Asset Replacements	61,136,454	97,863,006	1.6	41,636,390	2.3
Transmission - Transformer Bank Replacements	**61,780,265**	**56,433,908**	**0.9**	**11,926,552**	**1.1**
DEP Asset Replacements	41,983,862	33,221,648	0.8	4,424,166	0.9
DEC Asset Replacements	19,796,404	23,212,261	1.2	7,502,387	1.6
Transmission - Flooded Substation (Reinforce)	**9,432,915**	**19,788,759**	**2.1**	**-**	**2.1**

Program/Project Name	Total NPV Costs	Total NPV Benefits	NPV Benefit-Cost Ratio	Total IMPLAN Benefits	NPV + IMPLAN Benefit-Cost Ratio
PROJECTS					
LDI/HIS	**63,287,200**	**1,859,603,889**	**29.4**	**1,652,446,969**	**55.5**
Central 9	5,683,127	720,342	0.1	631,865	0.2
Central 10	960,638	7,257,180	7.6	6,365,806	14.2
Central 11	3,300,000	17,052,577	5.2	14,958,069	9.7
Central 12	2,470,000	13,600,731	5.5	11,930,201	10.3
Central 13	652,900	21,307,034	32.6	18,689,966	61.3
Central 14	1,200,000	21,426,491	17.9	18,794,750	33.5
Central 15	807,164	12,449,350	15.4	10,920,240	29.0
Central 16	650,000	1,562,430	2.4	1,370,522	4.5
Coastal 14	1,500,000	132,704,788	88.5	116,405,123	166.1
Coastal 15	1,452,247	94,490,901	65.1	82,884,915	122.1
Coastal 16	1,307,022	45,777,406	35.0	40,154,728	65.7
Coastal 18	900,000	11,885,898	13.2	10,425,995	24.8
Coastal 19	2,904,494	164,101,074	56.5	143,945,113	106.1
Mountain 16	434,000	663,870	1.5	582,329	2.9
Mountain 17	332,081	1,211,981	3.6	1,063,118	6.9
Mountain 18	22,800	4,279,093	187.7	3,753,507	352.3
Triad 12	170,500	370,951	2.2	325,389	4.1
Triad 13	1,100,000	11,308,042	10.3	9,919,114	19.3
Triad 14	92,850	8,453,094	91.0	7,414,830	170.9
Triad 16	305,000	9,792,910	32.1	8,590,081	60.3
Triad 17	378,950	4,983,497	13.2	4,371,391	24.7
Triad 18	203,000	17,394,324	85.7	15,257,840	160.8
Triad 19	1,452,247	8,213,474	5.7	7,204,641	10.6
Triad 20	1,275,000	7,824,540	6.1	6,863,479	11.5
Triangle 25	11,617,978	255,258,231	22.0	223,905,756	41.2
Triangle 26	400,000	7,844,352	19.6	6,880,858	36.8
Central 7	60,861	6,895,876	113.3	6,048,880	212.7
Central 8	318,352	10,262,293	32.2	9,001,812	60.5
Coastal 1A	655,431	41,754,645	63.7	36,626,068	119.6
Coastal 1B	1,843,755	52,585,055	28.5	46,126,217	53.5
Coastal 4	1,835,706	64,260,143	35.0	54,097,825	64.5
Coastal 6	1,223,804	7,250,656	5.9	6,104,012	10.9
Coastal 8	730,337	63,741,908	87.3	51,501,015	157.8
Triad 9	1,029,963	10,046,235	9.8	8,812,291	18.3
Central 1	701,370	16,260,517	23.2	14,263,295	43.5
Coastal 2	2,367,125	64,164,787	27.1	56,283,651	50.9
Coastal 3	245,480	230,563,031	939.2	202,243,781	1,763.1
Coastal 5	298,082	9,437,749	31.7	8,278,543	59.4
Coastal 7	679,042	42,042,900	61.9	36,878,917	116.2
Coastal 10	197,260	105,993,827	537.3	92,974,976	1,008.7
Mountain 1	2,630,139	2,871,377	1.1	2,624,358	2.1
Mountain 4	61,370	19,217,406	313.1	17,564,171	599.3
Mountain 5	39,452	17,514,531	443.9	27,476,823	1,140.4
Triad 8	1,536,333	7,942,768	5.2	6,967,186	9.7
Triangle 10	473,425	7,499,476	15.8	16,386,678	50.5
Triangle 11	414,247	12,246,267	29.6	11,192,745	56.6
Triangle 17	166,575	11,863,323	71.2	10,406,193	133.7
Triangle 18	315,617	781,226	2.5	685,270	4.6
Coastal 9	50,074	459,323	9.2	402,906	17.2
Coastal 12	164,178	54,381,572	331.2	47,702,074	621.8
Mountain 0	810,654	5,382,017	6.6	5,125,371	13.0
Mountain 3	287,312	268,138	0.9	255,352	1.8
Triangle 1	387,872	11,951,909	30.8	11,381,973	60.2
Triangle 16	1,510,042	13,633,828	9.0	12,460,937	17.3
Triangle 19	49,254	6,854,479	139.2	6,264,802	266.4
Triangle 21	632,087	79,542,067	125.8	72,699,222	240.9
Transmission - Flooded Substation (Relocate)	**8,962,714**	**5,851,288**	**0.7**	**1,303,877**	**0.8**
Whiteville 115 (Relocate)	8,962,714	5,851,288	0.7	1,303,877	0.8
Transmission - DEP Line Projects	**26,659,806**	**89,066,144**	**3.3**	**66,454,852**	**5.8**
Weatherspoon-Raeford Repl OHGW	6,134,585	6,713,606	1.1	5,888,997	2.1
SumterSCEGEastover RepOHGWu19	1,553,725	13,985,572	9.0	596,164	9.4
Raeford	1,937,788	2,613,036	1.3	2,292,086	2.5
Sutton-Delco	2,342,128	2,286,709	1.0	2,005,840	1.8
Cape Fear Plant - Method	4,065,124	12,158,590	3.0	10,665,193	5.6
Folkstone-Jacksonville 115kV	8,376,692	22,635,995	2.7	19,855,695	5.1
Rocky Mount - Wilson	2,249,763	28,672,637	12.7	25,150,877	23.9
Transmission - DEC Line Projects	**131,800,308**	**1,899,313,965**	**14.4**	**1,345,519,102**	**24.6**
Duke Univ 44kV Undergnd System	2,487,424	2,804,961	1.1	2,460,437	2.1
Spindale 44kV Rebld FairviewT	5,796,374	89,565,123	15.5	78,564,152	29.0
Rockford Level Cr 44 kV Ln Rbld	4,222,598	89,489,273	21.2	78,497,618	39.8

Program/Project Name	Total NPV Costs	Total NPV Benefits	NPV Benefit-Cost Ratio	Total IMPLAN Benefits	NPV + IMPLAN Benefit-Cost Ratio
Spindale 44 kV Line Rebuild	4,050,664	66,760,114	16.5	58,560,202	30.9
Cabin Creek – Stevens Tap Rebld	3,317,160	79,094,660	23.8	69,379,739	44.8
Quebec 44 kV Line	20,551,443	185,199,362	9.0	162,451,972	16.9
Capps–Hendersonville Line Rbld	5,992,098	151,502,663	25.3	132,894,121	47.5
Hankins Line 44 kV Line Rebuild	3,063,822	60,394,833	19.7	52,976,747	37.0
Camp Creek-Cherokee Line	5,864,273	34,245,001	5.8	30,038,807	11.0
Cabin Creek 44 kV Line Rtlg Rd	1,920,393	43,068,527	22.4	37,778,570	42.1
Shoals 44 kV Line Rebuild	8,654,812	127,303,781	14.7	111,667,503	27.6
Lawson Fork to Pacolet Retl	7,894,275	161,018,467	20.4	141,241,132	38.3
Rocky Creek #1 44 kV Line Rbld	3,246,095	35,934,449	11.1	31,520,746	20.8
BlueRidge EC Del 16 44 kV Ln Rb	1,750,903	19,586,780	11.2	859,050	11.7
Liberty 44 kV Line Rebuild	9,413,056	131,016,830	13.9	5,746,225	14.5
Wick #2 44 kV Line Rebuild	5,447,853	67,984,744	12.5	2,981,721	13.0
Bessemer 44 kV Line Rebuild	12,018,149	166,030,721	13.8	7,281,887	14.4
Sigsbee A&B 44 kV Line Rebuild	8,926,135	126,868,830	14.2	111,285,976	26.7
Jackson 44 kV Line Rebuild	11,812,667	188,809,228	16.0	165,618,452	30.0
Rockford Line Rebuild Chatham	5,370,115	72,635,621	13.5	63,714,042	25.4
Total Programs/Projects with CBAs (Optimize)	**1,976,659,808**	**9,241,051,333**	**4.7**	**7,210,953,749**	**8.3**
Other (Modernize/Protect)	**586,371,681**				
Total Portfolio	**2,563,031,489**	**9,241,051,333**	**3.6**	**7,210,953,749**	**6.4**

Benefits from Improving the Grid

Societal

- Lower impact to global environment
- Avoided water impacts
- Avoided land impacts
- Reduced blackouts *(security & well-being)*
- Improved quality of life
- Improved access to data
- Better customer experience

Indirect (to third parties)

- Improved economics for the state
- Increased competitiveness for the state
- Increased employment for the state
- Increased global DER enablement
- Increased transportation electrification enablement

Indirect Value (risk reduction)

- Increased system redundancy
- Improved power quality
- Improved system stability
- Avoided ancillary services
- Improved employee safety
- Reduced chance of environmental incident
- Reduced remediation costs
- Increased public safety

Direct value (captured by customer)

- Avoided business revenue loss
- Avoided equipment damage
- Avoided spoilage
- Avoided ancillary costs *(hotel, generator, lost work)*
- Increased customer-owned DER enablement
- Decreased energy use or use off peak

Direct value (captured by utility)

- Avoided transmission capacity
- Avoided transmission losses
- Avoided distribution capacity
- Avoided distribution losses
- Avoided generation capacity
- Avoided fuel costs
- Deferred capital cost
- Avoided power purchase
- Lower restoration costs
- Theft reduction
- Improved utility operations *(i.e., lower O&M)*
- Avoided CO_2
- SO_2 emission reduction
- NO_X emission reduction
- Hg emission reduction
- Particulate matter emission reduction

DUKE ENERGY GRID IMPROVEMENT PLAN

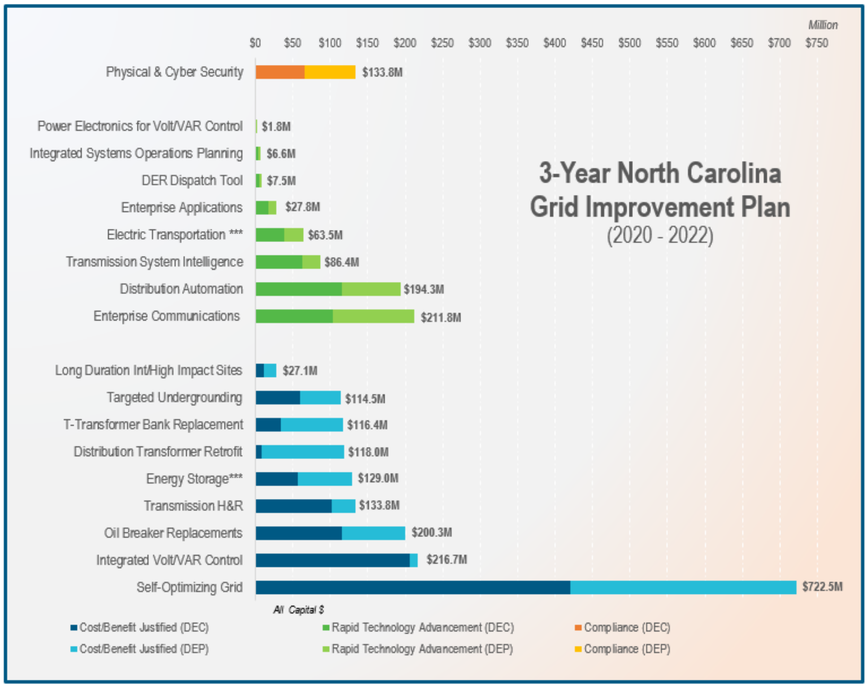
NORTH CAROLINA

2019

Contents

2020-2022 GRID IMPROVEMENT PLAN OVERVIEW

Duke Energy's 2020-2022 North Carolina Grid Improvement Plan and associated three-year investments are summarized below. Additional program level details are provided in the section that follows.



GIP Capital Budget Summary

NC Budget

Capital $ in thousands (rounded to nearest thousand)

	3-Yr Total	2020 DEC	2020 DEP	2021 DEC	2021 DEP	2022 DEC	2022 DEP
TOTAL	**$2,319,227**	**$326,765**	**$227,735**	**$454,473**	**$331,469**	**$550,148**	**$428,638**
Optimize	**$1,649,216**	**$178,600**	**$160,748**	**$353,672**	**$225,746**	**$425,741**	**$304,708**
Self-Optimizing Grid	$722,475	$90,604	$61,528	$153,733	$86,057	$175,802	$154,752
Integrated Volt/VAR Control	$216,658	$30,797	$0	$86,311	$5,000	$89,550	$5,000
Transmission H&R	$133,750	$13,986	$8,934	$20,418	$9,569	$68,059	$12,785
Targeted Undergrounding	$114,543	$6,424	$8,628	$15,313	$19,524	$38,104	$26,550
Energy Storage***	$129,003	$8,199	$8,122	$6,199	$24,122	$42,100	$40,261
Distribution Transformer Retrofit	$118,018	$0	$30,105	$0	$42,053	$8,293	$37,568
Long Duration Int/High Impact Sites	$27,095	$2,354	$6,881	$5,725	$4,978	$3,245	$3,912
T-Transformer Bank Replacement	$116,391	$6,193	$25,019	$18,174	$38,514	$9,274	$19,217
Oil Breaker Replacements	$200,287	$28,244	$19,654	$53,998	$20,051	$33,415	$44,925
Modernize	**$536,253**	**$96,253**	**$53,304**	**$89,928**	**$81,758**	**$122,105**	**$92,905**
Enterprise Communications	$211,818	$26,990	$25,807	$35,878	$32,282	$40,896	$49,965
Distribution Automation	$194,288	$36,142	$16,322	$17,863	$32,881	$61,382	$29,696
Transmission System Intelligence	$86,410	$24,008	$6,829	$30,290	$11,311	$8,414	$5,559
Enterprise Applications	$27,847	$4,348	$1,361	$3,140	$3,211	$9,555	$6,232
Integrated Systems Operations Planning	$6,649	$3,028	$1,830	$379	$233	$749	$431
DER Dispatch Tool	$7,448	$1,738	$1,118	$2,032	$1,307	$762	$490
Electric Transportation ***	$63,478	$19,117	$12,623	$19,117	$12,623	$0	$0
Power Electronics for Volt/VAR Control	$1,794	$0	$36	$347	$532	$347	$532
Protect	**$133,758**	**$51,911**	**$13,683**	**$10,873**	**$23,965**	**$2,302**	**$31,024**
Physical & Cyber Security	$133,758	$51,911	$13,683	$10,873	$23,965	$2,302	$31,024

*** ***Note**: Energy Storage Projects and Electric Transportation have been excluded from these totals. These programs are important components of grid improvement but not included in the costs for the GIP given that they are being reviewed and evaluated in separate forums.*

Exhibit 10 shows numbers for North Carolina based on budgeting methods, which may vary from ratemaking allocations.

PROGRAM DESCRIPTIONS & SCOPES

The remaining sections of this document describe the each of the North Carolina Grid Improvement programs and sub-programs, as well as their detailed three-year project scopes for years 2020 through 2022.

Note: Shifts of scope may occur between years to optimize benefits delivery to customers and execution efficiencies.

Notes:

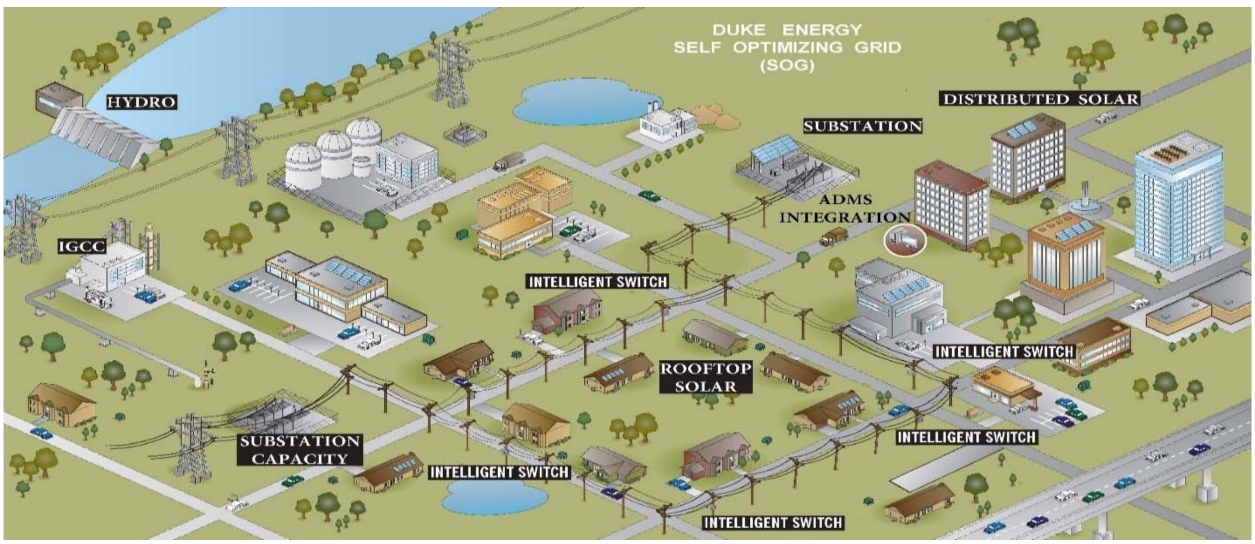
1) Costs shown are approximate capital costs
2) Units shown represent approximate number of units

I. Self-Optimizing Grid (SOG)

The current grid has limited ability to reroute or rapidly restore power and limited ability to optimize for the growing penetrations of distributed energy resources (DER). The Self-Optimizing Grid (SOG) program is established to address both of these issues.

The SOG program consists of three (3) major components: grid capacity, grid connectivity, and automation and intelligence. The SOG program redesigns key portions of the distribution system and transforms it into a dynamic smart-thinking, self-healing grid. The grid will have the ability to automatically reroute power around trouble areas, like a tree on a power line, to quickly restore power to the maximum number of customers and rapidly dispatch line crews directly to the source of the outage. Self-healing technologies can reduce outage impacts by as much as 75 percent.

The SOG Capacity projects focus on expanding substation and distribution line capacity to allow for two-way power flow. SOG Connectivity projects create tie points between circuits. SOG Automation projects provide intelligence and control for the Self Optimizing Grid. Automation projects enable the grid to dynamically reconfigure around trouble and better manage local DER. The Advanced Distribution Management System (ADMS) is the application that orchestrates and manages the SOG Automation projects. This software leverages the intelligence from the grid with information from substation equipment, intelligent switches and distributed energy resources to optimize power flow and minimize the impact to customers when faults occur. ADMS is the centralized system for managing the grid.



3-Year Scope *(Self Optimizing Grid)*

The charts below outline the 3-Year SOG Scope in North Carolina (DEC and DEP):

	DEC			DEP		
Self-Optimizing Grid	2020	2021	2022	2020	2021	2022
Totals	$90,603,864	$153,732,655	$175,802,143	$61,527,693	$86,056,772	$154,751,794
Automation & Segmentation	$24,974,704	$75,345,656	$76,150,984	$36,114,420	$44,359,236	$49,137,603
Approx. No. of Switches	*492*	*1484*	*1500*	*589*	*723*	*801*
Modular Dist Control Device POC	$90,358	$60,800	-	-	-	-
Capacity & Connectivity	$56,211,816	$69,533,247	$88,134,348	$19,395,590	$36,039,782	$98,203,792
Advanced DMS***	$9,326,986	$8,792,952	$11,516,811	$6,017,683	$5,657,754	$7,410,399

*** required for SOG scalability and IVVC functionality

2020-2022 Proposed DEC Locations *(Self Optimizing Grid)*

NC DEC	Circuit Name	Circuit ID	Approx. No. Automated Switches
Durham	Barbee Chapel Rd Ret 2402	14232402	2
Durham	Brassfield Ret 2404	14152404	6
Durham	Brassfield Ret 2411	14152411	3
Durham	Brassfield Ret 2412	14152412	5
Durham	Brassfield Ret 2413	14152413	7
Durham	Butner Ret 2403	14042403	5
Durham	Cameron Ave SS 1201	19011201	4
Durham	Crest St Ret 1212	14031212	4
Durham	Eno Ret 2402	14102402	4
Durham	Fairntosh Ret 2410	14142410	4
Durham	Garrett Rd Ret 2411	14202411	5
Durham	Garrett Rd Ret 2413	14202413	10
Durham	Garrett Rd Ret 2414	14202414	2
Durham	Green St Ret 1202	14121202	2
Durham	Green St Ret 1209	14121209	4
Durham	Green St Ret 1210	14121210	3
Durham	Grey Ret 1207	19091207	3
Durham	Hillsborough Ret 1201	19081201	2
Durham	James St Ret 1205	19031205	5
Durham	Oxford Rd Ret 1211	14091211	3
Durham	Pope Rd Ret 2403	14082403	6
Durham	Pope Rd Ret 2404	14082404	7
Durham	Pope Rd Ret 2410	14082410	4
Durham	Research Triangle Ret 2402	14052402	3
Durham	Research Triangle Ret 2408	14052408	6
Greensboro	Colfax Ret 2406	09502406	4
Greensboro	Colfax Ret 2412	09502412	2
Greensboro	Denny Rd Ret 2403	09252403	2
Greensboro	Denny Rd Ret 2404	09252404	6
Greensboro	Denny Rd Ret 2409	09252409	4
Greensboro	Denny Rd Ret 2412	09252412	6
Greensboro	Fairfax Rd Ret 2403	09032403	-
Greensboro	Fairfax Rd Ret 2405	09032405	3
Greensboro	Fairfax Rd Ret 2408	09032408	6
Greensboro	Fairfax Rd Ret 2411	09032411	3
Greensboro	Greensboro Main 2402	09012402	-
Greensboro	Greensboro Main 2405	09012405	5
Greensboro	Greensboro Main 2412	09012412	4
Greensboro	Greensboro Main 2416	09012416	2
Greensboro	Greensboro Main 2417	09012417	2
Greensboro	Greensboro Main 2418	09012418	3
Greensboro	Groomtown Ret 1209	09121209	2
Greensboro	Groomtown Ret 1210	09121210	2

NC DEC	Circuit Name	Circuit ID	Approx. No. Automated Switches
Greensboro	Groomtown Ret 2403	09122403	4
Greensboro	Groomtown Ret 2406	09122406	3
Greensboro	Jessuptown Ret 2407	09072407	7
Greensboro	Jessuptown Ret 2408	09072408	9
Greensboro	Jessuptown Ret 2409	09072409	8
Greensboro	Jessuptown Ret 2414	09072414	6
Greensboro	Jessuptown Ret 2416	09072416	6
Greensboro	Kildare Ret 2405	09082405	3
Greensboro	Kildare Ret 2406	09082406	3
Greensboro	Kildare Ret 2409	09082409	3
Greensboro	Kildare Ret 2410	09082410	7
Greensboro	Kimesville Ret 1201	09111201	-
Greensboro	Lake Townsend Ret 2401	09302401	1
Greensboro	Lake Townsend Ret 2402	09302402	4
Greensboro	Lake Townsend Ret 2407	09302407	4
Greensboro	Lake Townsend Ret 2408	09302408	6
Greensboro	Merritt Dr Ret 2405	09242405	5
Greensboro	Merritt Dr Ret 2407	09242407	1
Greensboro	Monticello Ret 1202	09571202	2
Greensboro	Pleasant Garden Ret 1202	09791202	1
Greensboro	Pleasant Garden Ret 1203	09791203	-
Greensboro	Randolph Ave Ret 2404	09042404	1
Greensboro	Randolph Ave Ret 2405	09042405	2
Greensboro	Randolph Ave Ret 2406	09042406	4
Greensboro	Randolph Ave Ret 2407	09042407	10
Greensboro	Randolph Ave Ret 2410	09042410	6
Greensboro	Randolph Ave Ret 2411	09042411	2
Greensboro	Randolph Ave Ret 2412	09042412	5
Greensboro	Rudd Ret 2403	09262403	2
Greensboro	Rudd Ret 2408	09262408	4
Greensboro	Rudd Ret 2409	09262409	4
Greensboro	Summerfield Ret 2405	09102405	3
Greensboro	Summerfield Ret 2410	09102410	4
Greensboro	Tabernacle Church Ret 1208	09411208	-
Greensboro	Tarrant Rd Ret 2403	09202403	3
Greensboro	Tarrant Rd Ret 2406	09202406	4
Greensboro	Vandalia Ret 2403	09052403	1
Greensboro	Vandalia Ret 2404	09052404	4
Greensboro	Vandalia Ret 2409	09052409	7
Greensboro	Vandalia Ret 2410	09052410	9
Kernersville	Beckerdite Tie 1203	03021203	2
Kernersville	Beckerdite Tie 1204	03021204	2
Kernersville	Broad St Ret 1202	03411202	2
Kernersville	Broad St Ret 1204	03411204	3
Kernersville	Brookwood Ret 1205	03031205	4

NC DEC	Circuit Name	Circuit ID	Approx. No. Automated Switches
Kernersville	Buxton St Ret 2407	03052407	-
Kernersville	Cassell St SS 1203	03061203	1
Kernersville	Cassell St SS 1209	03061209	4
Kernersville	Fiddlers Creek Ret 1205	03101205	1
Kernersville	Fiddlers Creek Ret 1208	03101208	4
Kernersville	Fiddlers Creek Ret 1210	03101210	3
Kernersville	Goodwill Church Rd Ret 1202	03111202	2
Kernersville	Guthrie Ret 1203	03131203	2
Kernersville	Guthrie Ret 1204	03131204	2
Kernersville	Guthrie Ret 1207	03131207	3
Kernersville	Kernersvillee Ret 1203	03171203	3
Kernersville	Kernersvillee Ret 1205	03171205	3
Kernersville	Oak Ridge Ret 1206	03241206	3
Kernersville	Oak Ridge Ret 1207	03241207	1
Kernersville	Oak Ridge Ret 1208	03241208	4
Kernersville	Sedge Garden Ret 1201	03291201	4
Kernersville	Sedge Garden Ret 1202	03291202	2
Kernersville	Sedge Garden Ret 1206	03291206	6
Kernersville	Sedge Garden Ret 1207	03291207	3
Kernersville	Sedge Garden Ret 2404	03292404	3
Kernersville	Southbound Ret 1201	03461201	3
Kernersville	Southbound Ret 1204	03461204	-
Kernersville	Triad Park Ret 1206	03331206	3
Kernersville	Walkertown Ret 1202	03361202	2
Kernersville	Walkertown Ret 1204	03361204	3
Kernersville	Walkertown Ret 1207	03361207	3
Kernersville	Welcome Ret 1201	03391201	1
Lewisville	Advance Ret 1202	03011202	3
Lewisville	Advance Ret 1207	03011207	4
Lewisville	Advance Ret 1208	03011208	1
Lewisville	Clemmons Ret 1205	03071205	2
Lewisville	Clemmons Ret 1209	03071209	2
Lewisville	Ebert Rd Ret 1203	03081203	-
Lewisville	Griffith Rd Ret 1207	03121207	3
Lewisville	Griffith Rd Ret 1212	03121212	2
Lewisville	Griffith Rd Ret 1214	03121214	2
Lewisville	Hager Rd Ret 1203	03661203	1
Lewisville	Hawthorne Rd Ret 1203	03141203	3
Lewisville	Hawthorne Rd Ret 1205	03141205	4
Lewisville	Hawthorne Rd Ret 2412	03142412	-
Lewisville	Hinshaw Ret 1204	03151204	2
Lewisville	Hinshaw Ret 1206	03151206	2
Lewisville	Hinshaw Ret 1207	03151207	3
Lewisville	Hinshaw Ret 1208	03151208	4
Lewisville	Hinshaw Ret 1210	03151210	3

NC DEC	Circuit Name	Circuit ID	Approx. No. Automated Switches
Lewisville	Lewisville Ret 1205	03201205	2
Lewisville	Lewisville Ret 1206	03201206	2
Lewisville	Lewisville Ret 1207	03201207	1
Lewisville	Lewisville Ret 1209	03201209	1
Lewisville	Lewisville Ret 1211	03201211	3
Lewisville	Lewisville Ret 1212	03201212	3
Lewisville	Mar-Don Dr Ret 1203	03211203	6
Lewisville	Mar-Don Dr Ret 1207	03211207	5
Lewisville	Mar-Don Dr Ret 1208	03211208	3
Lewisville	Mar-Don Dr Ret 2401	03212401	3
Lewisville	Mocksville Main 2401	03552401	3
Lewisville	Mocksville Main 2402	03552402	-
Lewisville	Mt Tabor Ret 1203	03221203	2
Lewisville	Mt Tabor Ret 1208	03221208	2
Lewisville	Mt Tabor Ret 1209	03221209	2
Lewisville	Peace Haven Rd Ret 1201	03251201	1
Lewisville	Peace Haven Rd Ret 1205	03251205	3
Lewisville	Peace Haven Rd Ret 1206	03251206	2
Lewisville	Pfafftown Ret 1201	03271201	2
Lewisville	Pfafftown Ret 1203	03271203	2
Lewisville	Swaimtown Ret 1201	03321201	4
Lewisville	Swaimtown Ret 1202	03321202	3
Lewisville	Swaimtown Ret 1207	03321207	2
Lewisville	Swaimtown Ret 1208	03321208	3
Lewisville	Turnersburg Ret 1202	03651202	-
Lewisville	Winston Tie 1209	03441209	1
Lewisville	Winston Tie 1210	03441210	3
LittleRock	Beatties Ford Ret 1208	01671208	2
LittleRock	Bellhaven Ret 1203	01291203	3
LittleRock	Bellhaven Ret 1205	01291205	3
LittleRock	Bellhaven Ret 1210	01291210	3
LittleRock	Briar Creek Ret 1209	01151209	4
LittleRock	Briar Creek Ret 1212	01151212	4
LittleRock	Coffey Creek Ret 2408	01492408	9
LittleRock	Elizabeth Ave Ret 1204	01041204	2
LittleRock	Elizabeth Ave Ret 1209	01041209	2
LittleRock	Graham St Ret 2407	01052407	6
LittleRock	Hill St Ret 2408	01012408	14
LittleRock	Kenilworth Ret 1208	01281208	4
LittleRock	Kenilworth Ret 1209	01281209	3
LittleRock	Kenilworth Ret 1210	01281210	4
LittleRock	Kenilworth Ret 1211	01281211	1
LittleRock	Kenilworth Ret 1212	01281212	3
LittleRock	Lakewood Ret 1205	01071205	3
LittleRock	Lakewood Ret 1206	01071206	2

NC DEC	Circuit Name	Circuit ID	Approx. No. Automated Switches
LittleRock	Lakewood Ret 1208	01071208	3
LittleRock	Lakewood Ret 1209	01071209	2
LittleRock	Little Rock Ret 1206	01351206	-
LittleRock	Little Rock Ret 1212	01351212	5
LittleRock	Montclaire Ret 2404	01392404	8
LittleRock	Montclaire Ret 2405	01392405	4
LittleRock	Montclaire Ret 2408	01392408	8
LittleRock	Park Rd Ret 1213	01161213	7
LittleRock	Remount Rd Ret 1203	01191203	2
LittleRock	Remount Rd Ret 1204	01191204	4
LittleRock	Remount Rd Ret 1210	01191210	2
LittleRock	Remount Rd Ret 1211	01191211	2
LittleRock	Remount Rd Ret 1213	01191213	2
LittleRock	Rozzelles Ret 1201	01371201	1
LittleRock	Rozzelles Ret 1202	01371202	4
LittleRock	Rozzelles Ret 1207	01371207	2
LittleRock	Steele Creek Ret 2403	01482403	6
LittleRock	Thrift Ret 1205	01381205	4
LittleRock	Thrift Ret 1206	01381206	3
LittleRock	Thrift Ret 1209	01381209	3
LittleRock	Thrift Ret 1210	01381210	5
LittleRock	Withers Ret 2406	01652406	5
LittleRock	Woodlawn Tie 1205	01241205	4
LittleRock	Woodlawn Tie 1210	01241210	3
Matthews	Carmel Rd Ret 1208	01261208	-
Matthews	Matthews Ret 2407	01102407	8
Matthews	McAlpine Creek Ret 2410	01302410	6
Matthews	Monroe Main 2403	01112403	2
Matthews	Monroe Rd Ret 1201	01121201	3
Matthews	Monroe Rd Ret 1212	01121212	5
Matthews	Morning Star Tie 2406	01212406	6
Matthews	Park Rd Ret 1204	01161204	3
Matthews	Sharon Ret 2404	01442404	4
Matthews	Springfield Ret 2408	01472408	3
Newell	Bancroft Ret 1203	01361203	-
Newell	Bancroft Ret 1204	01361204	3
Newell	Bancroft Ret 1205	01361205	2
Newell	Bancroft Ret 1207	01361207	2
Newell	Bancroft Ret 1208	01361208	2
Newell	Beatties Ford Ret 2402	01672402	2
Newell	Commonwealth Ret 1202	01311202	4
Newell	Commonwealth Ret 1205	01311205	4
Newell	Commonwealth Ret 1208	01311208	4
Newell	Commonwealth Ret 1210	01311210	3
Newell	Commonwealth Ret 1211	01311211	4

NC DEC	Circuit Name	Circuit ID	Approx. No. Automated Switches
Newell	Davidson Ret 1202	01721202	2
Newell	Derita Ret 2406	01452406	10
Newell	Derita Ret 2407	01452407	7
Newell	Derita Ret 2412	01452412	6
Newell	Eastfield Rd Ret 1203	01431203	4
Newell	Eastfield Rd Ret 2405	01432405	10
Newell	Four Seasons Ret 2405	01402405	5
Newell	Four Seasons Ret 2406	01402406	11
Newell	Furr Rd Ret 1202	01731202	2
Newell	Hickory Grove Ret 1203	01061203	5
Newell	Hickory Grove Ret 1205	01061205	2
Newell	Hickory Grove Ret 1206	01061206	5
Newell	Hickory Grove Ret 1207	01061207	10
Newell	Hickory Grove Ret 1209	01061209	3
Newell	Hickory Grove Ret 1212	01061212	4
Newell	Hickory Grove Ret 1213	01061213	2
Newell	Hickory Grove Ret 1214	01061214	1
Newell	Mallard Creek Ret 1205	01271205	2
Newell	Mallard Creek Ret 1206	01271206	1
Newell	Mallard Creek Ret 1208	01271208	3
Newell	Mallard Creek Ret 1209	01271209	3
Newell	Mallard Creek Ret 1210	01271210	3
Newell	Mallard Creek Ret 1211	01271211	1
Newell	Mine Shaft Ret 2403	01502403	6
Newell	Mine Shaft Ret 2414	01502414	9
Newell	Mine Shaft Ret 2415	01502415	3
Newell	N Charlotte Ret 1205	01141205	1
Newell	N Charlotte Ret 1206	01141206	4
Newell	Newell Ret 2406	01342406	10
Newell	Newell Ret 2411	01342411	6
Newell	Newell Ret 2412	01342412	7
Newell	Reames Rd Ret 2401	01522401	1
Newell	Reames Rd Ret 2408	01522408	5
Newell	Speedway Ret 2412	22282412	7
Newell	Sunset Ret 1207	01321207	1
Newell	Sunset Ret 1208	01321208	5
Newell	Sunset Ret 1210	01321210	4
Newell	Sunset Ret 1211	01321211	3
Newell	Sunset Ret 1212	01321212	1
Newell	Wallace Rd Ret 2401	01552401	3
Newell	Wallace Rd Ret 2403	01552403	2
Newell	Wilgrove Ret 2406	01332406	7
Newell	Wilgrove Ret 2412	01332412	7
Newell	Wilgrove Ret 2413	01332413	2

NC DEC	Circuit Name	Circuit ID	Approx. No. Automated Switches
North Wilkesboro	Hays Ret 1202	44051202	1
RuralHall	Buxton St Ret 1213	03051213	4
RuralHall	King Ret 1205	03191205	3
RuralHall	King Ret 1207	03191207	2
RuralHall	King Ret 1210	03191210	1
RuralHall	Lunsford Rd Ret 1203	03451203	2
RuralHall	Montroyal Rd Ret 1212	03471212	1
RuralHall	Montroyal Rd Ret 1213	03471213	2
RuralHall	Montroyal Rd Ret 1214	03471214	3
RuralHall	Mt Tabor Ret 1204	03221204	4
RuralHall	N Winston Ret 1202	03231202	2
RuralHall	N Winston Ret 1203	03231203	3
RuralHall	N Winston Ret 1204	03231204	1
RuralHall	N Winston Ret 1208	03231208	3
RuralHall	Rural Hall Ret 1202	03281202	1
RuralHall	Rural Hall Ret 1204	03281204	1
RuralHall	Seward Ret 2404	03312404	2
RuralHall	Shattalon Sw Sta 1206	03301206	4
RuralHall	Shattalon Sw Sta 1208	03301208	4
RuralHall	Shattalon Sw Sta 1210	03301210	5
RuralHall	Shattalon Sw Sta 1212	03301212	3
RuralHall	Walnut Cove Tie 2401	03372401	2
RuralHall	Walnut Cove Tie 2402	03372402	2
Spindale	Paradise Ret 1202	15161202	1

2020-2022 Proposed DEP Locations *(Self Optimizing Grid)*

NC DEP	Substation Name	Circuit Name	Circuit ID	Approx. No. Automated Switches
Asheville	ARDEN 115KV	AIRPORT ROAD 24KV	T0690B01	1
Asheville	ASHEVILLE ROCK HILL 115KV	HENDERSONVILLE ROAD 23KV	T0764B01	1
Asheville	ASHEVILLE ROCK HILL 115KV	SWEETEN CREEK 23KV	T0764B02	5
Asheville	AVERY CREEK 115KV	SCHENCK PARKWAY 24KV	T0784B12	4
Asheville	AVERY CREEK 115KV	VISTA BOULEVARD 24KV	T0784B13	8
Asheville	BALDWIN 115KV	HOOPERS CREEK 23KV	T0350B03	5
Asheville	BALDWIN 115KV	HOWARD GAP 23KV	T0350B01	2
Asheville	BALDWIN 115KV	WATSON 23KV	T0350B02	1
Asheville	BARNARDSVILLE 115KV	JUPITER 12KV	T0362B02	-
Asheville	BEAVERDAM 115KV	MERRIMON AVENUE 23KV	T0371B03	10

NC DEP	Substation Name	Circuit Name	Circuit ID	Approx. No. Automated Switches
Asheville	BEAVERDAM 115KV	PIEDMONT 23KV	T0371B02	3
Asheville	BILTMORE 115KV	LONDON ROAD 13KV	T0372B03	3
Asheville	BILTMORE 115KV	REED STREET 13KV	T0372B02	2
Asheville	BLACK MOUNTAIN 115KV	BLACK MOUNTAIN 12KV	T0375B03	2
Asheville	BLACK MOUNTAIN 115KV	MCCOY 12KV	T0375B01	2
Asheville	CANTON 115KV	PENLAND STREET 24KV	T0400B23	6
Asheville	CANTON 115KV	DUTCH COVE 24KV	T0400B12	5
Asheville	ELK MOUNTAIN 115KV	CRAGGY 24KV	T0510B11	2
Asheville	ELK MOUNTAIN 115KV	DIVISION STREET 24KV	T0510B21	1
Asheville	ELK MOUNTAIN 115KV	LAKESHORE 24KV	T0510B13	2
Asheville	ELK MOUNTAIN 115KV	LOOKOUT ROAD 24KV	T0510B12	4
Asheville	EMMA 115KV	BINGHAM ROAD 12KV	T0515B03	-
Asheville	EMMA 115KV	HAZELMILL ROAD 12KV	T0515B02	2
Asheville	EMMA 115KV	LOUISIANNA AVENUE 12KV	T0515B01	3
Asheville	FAIRVIEW 115KV	CHURCH ROAD 12KV	T0535B02	1
Asheville	FAIRVIEW 115KV	FAIRVIEW 12KV	T0535B01	-
Asheville	FAIRVIEW 115KV	GARREN CREEK 12KV	T0535B04	6
Asheville	FAIRVIEW 115KV	OLD FORT ROAD 12KV	T0535B03	-
Asheville	LEICESTER 115KV	JENKINS VALLEY 24KV	T0665B22	2
Asheville	LEICESTER 115KV	LEICESTER 24KV	T0665B11	6
Asheville	MONTE VISTA 115KV	MIDDLEMONT 24KV	T0700B01	9
Asheville	MONTE VISTA 115KV	MONTE VISTA 24KV	T0700B04	-
Asheville	MONTE VISTA 115KV	PISGAH VIEW 24KV	T0700B03	5
Asheville	MONTE VISTA 115KV	SAND HILL 24KV	T0700B05	5
Asheville	NEW SALEM 115KV	NEW SALEM 12KV	T0733B02	8
Asheville	NEW SALEM 115KV	BEETREE 12KV	T0733B01	4
Asheville	OTEEN 115KV	AZALEA 12KV	T0750B13	-
Asheville	OTEEN 115KV	BEVERLY 12KV	T0750B14	2
Asheville	OTEEN 115KV	OAKLEY 12KV	T0750B06	6
Asheville	REYNOLDS 115KV	REYNOLDS 12kV	T0745B12	1
Asheville	SKYLAND 115KV	HIGHWAY 25 23KV	T0781B05	4
Asheville	SKYLAND 115KV	MILLS GAP 23KV	T0781B01	7
Asheville	SKYLAND 115KV	ROYAL PINES 23KV	T0781B02	6
Asheville	SPRUCE PINE 115KV	GRASSY CREEK 23KV	T0791B05	2
Asheville	SWANNANOA 115KV	BLUE RIDGE ROAD 12KV	T0810B06	-
Asheville	SWANNANOA 115KV	HIGHWAY 70 12KV	T0810B07	2
Asheville	SWANNANOA 115KV	LYTLE 12KV	T0810B03	-
Asheville	SWANNANOA 115KV	STATE HOSPITAL 12KV	T0810B02	1
Asheville	VANDERBILT 115KV	CHERRY STREET 12KV	T0840B06	3
Asheville	VANDERBILT 115KV	KIMBERLY 12KV	T0840B08	3
Asheville	WEAVERVILLE 115KV	CHURCH STREET 12KV	T0870B02	3
Asheville	WEAVERVILLE 115KV	MONTICELLO 12KV	T0870B01	-

NC DEP	Substation Name	Circuit Name	Circuit ID	Approx. No. Automated Switches
Asheville	WEAVERVILLE 115KV	WEAVER BOULEVARD 12KV	T0870B04	-
Asheville	WEST ASHEVILLE 115KV	PATTON AVENUE 12KV	T0340B18	2
Asheville	WEST ASHEVILLE 115KV	STATE ST 12KV	T0340B16	2
Asheboro	ASHEBORO NORTH 115KV	LIBERTY ROAD 23KV	T0965B01	4
Asheboro	ASHEBORO WEST 115KV	MOUNTAIN 23KV	T0955B04	6
CapeFear	BENSON 230KV	BAILEYS CROSSROADS 23KV	T5480B02	2
CapeFear	BENSON 230KV	BLACKMANS CROSSROADS 23KV	T5480B04	4
CapeFear	BENSON 230KV	SOUTH JOHNSTON 23KV	T5480B01	-
CapeFear	BUIES CREEK 230KV	BUIES CREEK 23KV	T5504B01	1
CapeFear	BUIES CREEK 230KV	COATS 23KV	T5504B02	3
CapeFear	CLIFDALE 230KV	FILYAW ROAD 23KV	T1890B03	4
CapeFear	CLIFDALE 230KV	LAGRANGE 23KV	T1890B05	2
CapeFear	DUNN 230KV	ELLIS AVENUE 23KV	T5660B05	3
CapeFear	DUNN 230KV	HWY 421 EAST 23KV	T5660B02	1
CapeFear	DUNN 230KV	JONESBORO RD 23KV	T5660B01	1
CapeFear	EDMONDSON 230KV	JOHNSON CROSSROADS 24KV	T5670B21	2
CapeFear	EDMONDSON 230KV	MCGEES CROSSROADS 24KV	T5670B02	4
CapeFear	ERWIN 230KV	HWY 55 23KV	T5650B20	-
CapeFear	ERWIN 230KV	MASONIC ROAD 24KV	T5650B21	-
CapeFear	FAYETTEVILLE SLOCOMB 115KV	SLOCOMB 12KV	T2480B01	-
CapeFear	GODWIN 115KV	GODWIN 23KV	T5749B01	-
CapeFear	HOPE MILLS CHURCH ST. 115KV	HOPE MILLS 23KV	T2080B01	2
CapeFear	HOPE MILLS ROCKFISH RD. 230KV	CUMBERLAND 23KV	T2082B01	4
CapeFear	HOPE MILLS ROCKFISH RD. 230KV	STONEY POINT 23KV	T2082B02	4
CapeFear	LILLINGTON 115KV	MAMERS 24KV	T5860B02	-
CapeFear	LILLINGTON 115KV	NC 210 NORTH 24KV	T5860B03	1
CapeFear	LILLINGTON 115KV	SHAWTOWN 24KV	T5860B01	-
CapeFear	SPRING LAKE 230KV	MANCHESTER 23KV	T2495B12	4
CapeFear	SPRING LAKE 230KV	SPRING LAKE NORTH 23KV	T2495B11	5
Clinton	ROSEBORO 115KV	SALEMBURG 23KV	T5600B02	1
Clinton	CLINTON NORTH 115KV	MCKOY STREET 23KV	T5570B01	8
Fuquay	AMBERLY 230KV	CARY GLEN 24KV	T4604B11	4
Fuquay	AMBERLY 230KV	GREEN HOPE 24KV	T4604B13	8
Fuquay	AMBERLY 230KV	STONEWATER 24KV	T4604B14	7
Fuquay	AMBERLY 230KV	YATES STORE 24KV	T4604B12	5
Fuquay	ANGIER 230KV	ANGIER 23KV	T5427B01	-
Fuquay	ANGIER 230KV	KENNEBEC 23KV	T5427B02	2
Fuquay	ANGIER 230KV	PEARIDGE 23KV	T5427B04	-

NC DEP	Substation Name	Circuit Name	Circuit ID	Approx. No. Automated Switches
Fuquay	APEX 230KV	APEX HIGHWAY 55 24KV	T4530B04	3
Fuquay	AUBURN 230KV	MT. MORIAH 23KV	T4501B03	5
Fuquay	AUBURN 230KV	ROCK QUARRY RD. 23KV	T4501B01	2
Fuquay	BYNUM 230KV	ANDREWS STORE RD 24KV	T1025B22	10
Fuquay	BYNUM 230KV	CHAPEL HILL 24KV	T1025B01	3
Fuquay	BYNUM 230KV	BYNUM 24KV	T1025B02	1
Fuquay	CARALEIGH 230KV	CAROLINA PINES 23KV	T4595B03	6
Fuquay	CARALEIGH 230KV	SUMMIT AVENUE 23KV	T4595B01	1
Fuquay	CARY 230KV	CARY 23KV	T4600B01	9
Fuquay	CARY 230KV	CHAPEL HILL ROAD 23KV	T4600B03	6
Fuquay	CARY 230KV	HIGH HOUSE ROAD 23KV	T4600B05	3
Fuquay	CARY 230KV	WEST CHATHAM STREET 23KV	T4600B02	6
Fuquay	CARY EVANS ROAD 230KV	EVANS ROAD 24KV	T4602B01	4
FUQUAY	CARY EVANS ROAD 230KV	JAMES JACKSON 24KV	T4602B23	5
Fuquay	CARY EVANS ROAD 230KV	NORTH HARRISON 24KV	T4602B03	8
Fuquay	CARY EVANS ROAD 230KV	SILVERTON 24KV	T4602B04	7
Fuquay	CARY EVANS RD. 230KV	WESTON 23KV	T4602B02	10
Fuquay	CARY PINEY PLAINS 230KV	LOCHMERE 24KV	T5111B05	4
Fuquay	CARY PINEY PLAINS 230KV	SWIFT CREEK 24KV	T5111B23	2
Fuquay	CARY PINEY PLAINS 230KV	WALNUT HILLS 24KV	T5111B01	4
Fuquay	CARY TRIANGLE FOREST 230KV	CHURCHILL 23KV	T4605B03	5
Fuquay	CARY TRIANGLE FOREST 230KV	MACARTHUR 23KV	T4605B05	5
Fuquay	CARY TRIANGLE FOREST 230KV	PARKWAY 23KV	T4605B01	7
Fuquay	CARY PINEY PLAINS 230KV	WAVERLY 24KV	T5111B04	7
Fuquay	CARY PINEY PLAINS 230KV	WELLINGTON 24KV	T5111B22	2
Fuquay	CARY REGENCY PARK 230KV	SOUTHCHASE 23KV	T4599B24	3
Fuquay	CARY TRIANGLE FOREST 230KV	TWO CREEKS 23KV	T4605B02	4
Fuquay	CARY TRENTON ROAD 230KV	TRINITY ROAD 24KV	T4610B12	1
Fuquay	CLAYTON 115KV	BARBOUR MILL 23KV	T5640B04	3
Fuquay	CLAYTON 115KV	TV 23KV	T5640B02	2
Fuquay	DUNCAN 230KV	DUNCAN 24KV	T4630B13	3
Fuquay	DUNCAN 230KV	ROUSE ROAD 24KV	T4630B11	3
Fuquay	EDMONDSON 230KV	MT. PLEASANT 24KV	T5670B01	3
Fuquay	EDMONDSON 230KV	OLD DRUG STORE 24KV	T5670B22	1
Fuquay	FUQUAY 230KV	HOLLAND ROAD 23KV	T4710B04	-

NC DEP	Substation Name	Circuit Name	Circuit ID	Approx. No. Automated Switches
Fuquay	FUQUAY BELLS LAKE 230KV	HILLTOP 23KV	T4866B04	4
Fuquay	FUQUAY BELLS LAKE 230KV	OPTIMIST FARM 23KV	T4866B01	3
Fuquay	FUQUAY BELLS LAKE 230KV	S.R. 1010 23KV	T4866B03	3
Fuquay	GARNER 115KV	CRESCENT 23KV	T4720B04	4
Fuquay	GARNER 115KV	GARNER 23KV	T4720B01	1
Fuquay	GARNER 115KV	RANDS MILL 23KV	T4720B06	7
Fuquay	GARNER 115KV	WOODLAND ROAD 23KV	T4720B02	10
Fuquay	GARNER I-40 230KV	BARWELL ROAD 24KV	T4723B12	8
Fuquay	GARNER I-40 230KV	NEW HOPE 24KV	T4723B13	4
Fuquay	GARNER PANTHER BRANCH 230KV	BUFFALOE ROAD 23KV	T4692B01	5
Fuquay	GARNER PANTHER BRANCH 230KV	HWY 50 SOUTH 23KV	T4725B03	4
Fuquay	GARNER TRYON HILLS 115KV	LOOP ROAD 24KV	T5314B13	6
Fuquay	GARNER TRYON HILLS 115KV	YEARGAN ROAD 24KV	T5314B12	6
Fuquay	GARNER WHITE OAK 230KV	RAYNOR ROAD 24KV	T4730B12	4
Fuquay	GREEN LEVEL 230KV	GREEN LEVEL 24KV	T4603B11	2
Fuquay	GREEN LEVEL 230KV	WIMBERLY ROAD 24KV	T4603B13	8
Fuquay	HOLLY SPRINGS 230KV	ARBOR CREEK 24KV	T4795B03	4
Fuquay	HOLLY SPRINGS 230KV	BRACKENRIDGE 24KV	T4795B21	8
Fuquay	HOLLY SPRINGS 230KV	FELTONSVILLE 24KV	T4795B23	6
Fuquay	HOLLY SPRINGS 230KV	HOLLY SPRINGS 24KV	T4795B01	4
Fuquay	HOLLY SPRINGS 230KV	SURRY RIDGE 24KV	T4795B22	5
Fuquay	HOLLY SPRINGS INDUSTRIAL 230KV	TWELVE OAKS 24KV	T4796B12	3
Fuquay	MILBURNIE 230KV	ROGERS LANE 23 KV	T5000B45	4
Fuquay	MORRISVILLE 230KV	CARPENTER 23KV	T5010B01	5
Fuquay	MORRISVILLE 230KV	PRESTON 23 KV	T5010B04	7
Fuquay	NEW HILL 230KV	HARRIS PLANT 23KV	T5911B02	-
Fuquay	PITTSBORO 230KV	NORTHWOOD 23KV	T2250B03	3
Fuquay	RALEIGH OAKDALE 230KV	CROSS COUNTRY 23KV	T5136B05	5
Fuquay	RALEIGH OAKDALE 230KV	PLAZA WEST 23KV	T5136B01	5
Fuquay	RALEIGH OAKDALE 230KV	ROYLENE 23KV	T5136B02	6
Fuquay	RALEIGH OAKDALE 230KV	SUN GATE 23KV	T5136B04	3
Fuquay	RALEIGH SOUTH 115KV	LAKE WHEELER RD. 23KV	T5145B02	11
Fuquay	RALEIGH SOUTH 115KV	TRYON ROAD 23KV	T5145B03	4
Fuquay	RALEIGH WORTHDALE 230KV	LITTLE JOHN 23KV	T5168B01	4
Fuquay	RALEIGH WORTHDALE 230KV	ROSE LANE 23KV	T5168B02	5
Fuquay	WAKE TECH 230KV	MCCULLERS 24KV	T4426B12	5
Goldsboro	BELFAST 115KV	BELFAST 24KV	T5465B01	4

NC DEP	Substation Name	Circuit Name	Circuit ID	Approx. No. Automated Switches
Goldsboro	BELFAST 115KV	BUCK SWAMP 24KV	T5465B05	1
Goldsboro	BELFAST 115KV	ELEVENTH ST 24KV	T5465B04	1
Goldsboro	BELFAST 115KV	NAHUNTA 24KV	T5465B02	-
Goldsboro	FREMONT 115KV	AYCOCK 12KV	T5740B02	1
Goldsboro	GOLDSBORO HEMLOCK 115KV	ELM STREET 12KV	T5790B04	2
Goldsboro	GOLDSBORO LANGSTON 115KV	WAYNE MEMORIAL 24KV	T5754B03	1
Goldsboro	GRANTHAM 230KV	GRANTHAM 23KV	T5770B01	-
Goldsboro	MT. OLIVE 115KV	CHESTNUT 12KV	T5890B04	-
Goldsboro	NEW HOPE 115KV	BERKELEY 23KV	T5912B02	3
Goldsboro	NEW HOPE 115KV	ELROY 23KV	T5912B03	-
Goldsboro	NEW HOPE 115KV	PINEWOOD 23KV	T5912B04	2
Goldsboro	ROSEWOOD 115KV	ROSEWOOD 24KV	T5752B13	4
Goldsboro	WARSAW 230KV	KENANSVILLE 23KV	T6070B01	-
HENDERSON	FRANKLINTON 115KV	COLLEGE STREET 23KV	T4700B12	2
HENDERSON	FRANKLINTON 115KV	MITCHINERS CROSSROADS 23KV	T4700B11	2
Henderson	HENDERSON 230KV	CLARK STREET 24KV	T4790B25	8
Henderson	HENDERSON 230KV	CYPRESS DRIVE 23KV	T4790B18	5
Henderson	HENDERSON EAST 230KV	EAST ANDREWS 23KV	T4785B01	7
Henderson	HENDERSON EAST 230KV	GILLBURG 23 KV	T4785B06	4
Henderson	HENDERSON EAST 230KV	HIGHWAY 1 NORTH 23KV	T4785B03	3
Henderson	HENDERSON NORTH 115KV	FARM ST 23KV	T4770B04	3
Henderson	HENDERSON NORTH 115KV	GARNETT STREET 23KV	T4770B02	3
Henderson	HENDERSON NORTH 115KV	WILLIAMSBORO 23KV	T4770B05	7
Henderson	LITTLETON 115KV	LITTLETON 23KV	T4915B01	4
Henderson	OXFORD NORTH 230KV	OXFORD EAST 23KV	T5090B01	4
Henderson	OXFORD NORTH 230KV	STOVALL 23KV	T5090B02	4
Henderson	OXFORD SOUTH 230KV	PINE TREE ROAD 23KV	T5085B03	4
Henderson	OXFORD SOUTH 230KV	STEM 23KV	T5085B02	5
Henderson	STALLINGS CROSSROADS 115KV	CENTERVILLE 23KV	T5302B02	4
Henderson	STALLINGS CROSSROADS 115KV	MAPLEVILLE 23KV	T5302B03	7
Henderson	WARRENTON 115KV	HWY 401 NORTH	T5360B01	3
Henderson	WARRENTON 115KV	NORLINA 23KV	T5360B03	3
Henderson	YOUNGSVILLE 115KV	HARRIS CROSSROADS 24KV	T5401B01	6
Henderson	YOUNGSVILLE 115KV	POKOMOKE 24KV	T5401B02	3
Jacksonville	JACKSONVILLE NORTHWOODS 115KV	HENDERSON DR. EXT. 23KV	T4273B06	1
Jacksonville	JACKSONVILLE CITY 115KV	MAPLE STREET 23KV	T4210B13	5
Jacksonville	JACKSONVILLE NORTHWOODS 115KV	FOREST HILLS 23KV	T4070B04	3

NC DEP	Substation Name	Circuit Name	Circuit ID	Approx. No. Automated Switches
Maxton	PEMBROKE 115KV	ODUM STREET 23KV	T2247B03	3
Maxton	PEMBROKE 115KV	PEMBROKE CITY 23KV	T2247B01	4
NewBern	CHOCOWINITY 230KV	GRIMESLAND 23KV	T4130B01	2
NewBern	NEW BERN WEST 230KV	FORT BARNWELL 23KV	T4255B05	2
Raleigh	CHESTNUT HILLS 115KV	COUNTRY CLUB 23KV	T4620B17	6
RALEIGH	CHESTNUT HILLS 115KV	FARRIOR HILLS 23KV	T4620B15	9
RALEIGH	CHESTNUT HILLS 115KV	HICKORY HILLS 23KV	T4620B14	4
RALEIGH	CHESTNUT HILLS 115KV	NORTHCHASE 23KV	T4620B07	5
Raleigh	CHESTNUT HILLS 115KV	NORTHCLIFT 23KV	T4620B16	6
RALEIGH	CHESTNUT HILLS 115KV	NORTH GLEN 23KV	T4620B11	3
RALEIGH	CHESTNUT HILLS 115KV	QUAIL RIDGE 23KV	T4620B13	4
RALEIGH	CHESTNUT HILLS 115KV	SANDY FORKS ROAD 23KV	T4620B12	3
RALEIGH	CHESTNUT HILLS 115KV	SWEETBRIAR 23KV	T4620B10	3
Raleigh	FALLS 230KV	FOREST PINES 24KV	T4686B13	5
RALEIGH	FALLS 230KV	RICHLAND CREEK 24KV	T4686B12	3
Raleigh	FALLS 230KV	WAKEFIELD 24KV	T4686B11	5
Raleigh	LAKESTONE 115KV	COLEY FOREST 12KV	T4870B05	2
Raleigh	LEESVILLE WOOD VALLEY 230KV	BAILEYWICK ROAD 23KV	T5165B05	11
Raleigh	LEESVILLE WOOD VALLEY 230KV	MACON ROAD 23KV	T5165B02	6
Raleigh	LEESVILLE WOOD VALLEY 230KV	WILDWOOD 24KV	T5165B04	1
Raleigh	METHOD 230KV	CAMERON VILLAGE 12KV	T4990B36	7
Raleigh	METHOD 230KV	DIXIE TRAIL 12KV	T4990B39	4
Raleigh	NEUSE 115KV	NEUSE 23KV	T5060B01	6
Raleigh	PINE LAKE 230KV	BOULEVARD CENTER 24KV	T5108B01	2
Raleigh	PINE LAKE 230KV	HIGHWAY 401 24KV	T5108B03	3
Raleigh	PINE LAKE 230KV	OAK FOREST ROAD 24KV	T5108B05	10
Raleigh	RALEIGH BLUE RIDGE 230KV	CREEDMOOR RD 23KV	T5122B01	7
Raleigh	RALEIGH BLUE RIDGE 230KV	KIDDS HILL 23KV	T5122B02	5
Raleigh	RALEIGH BRIER CREEK 230KV	ARNOLD PALMER 24KV	T5119B22	4
Raleigh	RALEIGH FOXCROFT 230KV	BUFFALOE ROAD 23KV	T4692B01	5
Raleigh	RALEIGH FOXCROFT 230KV	JANE LANE 23KV	T4692B02	6
Raleigh	RALEIGH FOXCROFT 230KV	SOUTH HALL 23KV	T4692B03	5
Raleigh	RALEIGH HOMESTEAD 230KV	GRESHAM LAKE 23KV	T5125B01	5
Raleigh	RALEIGH HONEYCUTT 230KV	HONEYCUTT 24KV	T5123B12	3
Raleigh	RALEIGH HONEYCUTT 230KV	LITCHFORD ROAD 24KV	T5123B13	7

NC DEP	Substation Name	Circuit Name	Circuit ID	Approx. No. Automated Switches
Raleigh	RALEIGH LEESVILLE ROAD 230KV	GLENDOWER 24KV	T4910B21	5
Raleigh	RALEIGH LEESVILLE ROAD 230KV	LAUREL MOUNTAIN 24KV	T4910B23	6
Raleigh	RALEIGH LEESVILLE ROAD 230KV	LEESVILLE ROAD 23KV	T4910B03	4
Raleigh	RALEIGH NORTHSIDE 115KV	BOULEVARD 12KV	T5131B01	3
Raleigh	RALEIGH NORTHSIDE 115KV	FIVE POINTS 12KV	T5131B08	7
Raleigh	RALEIGH PRISON FARM 230KV	DURALEIGH ROAD 23KV	T5112B06	7
Raleigh	RALEIGH SIX FORKS 230KV	BAYLEAF 23KV	T5285B04	1
Raleigh	RALEIGH TIMBERLAKE 115KV	STARMOUNT 23KV	T5311B02	8
Rockingham	HAMLET 230KV	HAMLET SOUTH 23KV	T1440B25	2
Rockingham	HAMLET 230KV	HAMLET EAST 24KV	T1190B04	5
Sanford	SANFORD HORNER BLVD. 230KV	CHATHAM STREET 23KV	T2440B03	5
Sanford	SANFORD GARDEN STREET 230KV	SOUTH HORNER 23KV	T2432B04	4
Southern Pines	ABERDEEN 115KV	MCCAIN 23KV	T0900B01	4
Southern Pines	CANDOR 115KV	BRUTONVILLE 23KV	T1850B02	-
Southern Pines	LAKEVIEW 115KV	CAMERON 24KV	T1549B12	3
Southern Pines	LAKEVIEW 115KV	LAKEVIEW MOUNT PLEASANT 24KV	T1549B13	4
Southern Pines	PINEHURST 115KV	LINDEN ROAD 24KV	T2249B02	2
Southern Pines	PINEHURST 115KV	MANOR CARE 24KV	T2249B03	-
Southern Pines	SOUTHERN PINES 115KV	MANLY 24KV	T1550B04	1
Southern Pines	SOUTHERN PINES CENTER PARK 115KV	PINECREST 23KV	T1548B04	4
Southern Pines	SOUTHERN PINES CENTER PARK 115KV	STEPHENS ST. 23KV	T1548B01	4
Southern Pines	WEST END 230KV	PINEWILD 23KV	T1700B13	3
Southern Pines	WEST END 230KV	SEVENLAKES 23KV	T1700B11	1
Southern Pines	WEST END 230KV	ST. ANDREWS 23KV	T1700B14	-
Southern Pines	WEST END 230KV	TAYLORTOWN 23KV	T1700B12	2
Whiteville	WHITEVILLE 115KV	TRAM ROAD 23KV	T6670B04	7
Whiteville	LAKE WACCAMAW 115KV	HALLSBORO 23KV	T4233B02	2
Whiteville	WHITEVILLE 115KV	BRUNSWICK 23KV	T6670B02	12
WilmingtonN	BURGAW 115KV	BURGAW 23KV	T6160B01	3
WilmingtonN	CASTLE HAYNE 230KV	BLUE CLAY 23KV	T6205B22	4
WilmingtonN	CASTLE HAYNE 230KV	NORTH CHASE 23KV	T6205B13	4
WilmingtonN	CASTLE HAYNE 230KV	WRIGHTSBORO 23KV	T6205B11	2
WilmingtonN	DELCO 115KV	DELCO 24KV	T6250B02	-
WilmingtonN	LELAND 115KV	NAVASSA 24KV	T6445B02	1
WilmingtonN	LELAND INDUSTRIAL 115KV	LANVALE 24KV	T6446B22	4

NC DEP	Substation Name	Circuit Name	Circuit ID	Approx. No. Automated Switches
WilmingtonN	LELAND INDUSTRIAL 115KV	MACO 24KV	T6446B23	-
WilmingtonN	MASONBORO 230KV	LONG LEAF 23KV	T6455B12	7
WilmingtonN	MURRAYSVILLE 230KV	KINGS GRANT 23KV	T6471B12	2
WilmingtonN	MURRAYSVILLE 230KV	PARKWOOD 23KV	T6471B11	4
WilmingtonN	ROCKY POINT 230KV	ATKINSON 23 KV	T6385B13	4
WilmingtonN	SCOTTS HILL 230KV	SCOTTS HILL LOOP RD 24KV	T6387B11	2
WilmingtonN	TOPSAIL 230KV	BELVEDERE 23KV	T6389B01	4
WilmingtonN	TOPSAIL 230KV	HAMPSTEAD 23KV	T6389B03	2
WilmingtonN	TOPSAIL 230KV	OLDE POINT 23KV	T6389B02	6
WilmingtonN	VISTA 115KV	TOPSAIL GREENS 24KV	T6386B12	3
WilmingtonN	WILMINGTON EAST 230KV	AIRPORT 23KV	T6320B03	5
WilmingtonN	WILMINGTON EAST 230KV	KENWOOD 23KV	T6320B04	3
WilmingtonN	WILMINGTON EAST 230KV	SPRING VIEW 23KV	T6320B02	4
WilmingtonN	WILMINGTON NINTH AND ORANGE 230KV	NORTH WILMINGTON 23KV	T6466B02	13
WilmingtonN	WILMINGTON OGDEN 230KV	BRITTANY WOODS 23 KV	T6470B06	4
WilmingtonN	WILMINGTON OGDEN 230KV	GORDON ROAD 23KV	T6470B03	4
WilmingtonN	WILMINGTON OGDEN 230KV	MARKET STREET 23KV	T6470B05	4
WilmingtonN	WILMINGTON SUNSET PARK 115KV	ECHO FARMS 23KV	T4325B04	6
WilmingtonN	WILMINGTON WINTER PARK 230KV	SANDERS ROAD 23KV	T6720B22	7
WilmingtonN	WRIGHTSVILLE BEACH 230KV	SHELL ISLAND 24KV	T6740B15	1
WilmingtonS	CAROLINA BEACH 115KV	CAROLINA BEACH 23KV	T6201B01	4
WilmingtonS	CAROLINA BEACH 115KV	HWY 421 23KV	T6201B03	5
WilmingtonS	CAROLINA BEACH 115KV	KURE BEACH 23KV	T6201B02	5
WilmingtonS	CAROLINA BEACH 115KV	SNOWS CUT 23KV	T6201B05	4
WilmingtonS	EAGLE ISLAND 115KV	CASTLE ST 24KV	T6310B23	6
WilmingtonS	EAGLE ISLAND 115KV	S. FRONT ST. 24KV	T6310B21	2
WilmingtonS	MASONBORO 230KV	OLEANDER 23KV	T6455B04	2
WilmingtonS	SOUTHPORT 230KV	HWY 133 23KV	T6561B05	3
WilmingtonS	WILMINGTON CEDAR AVE. 230KV	PARK AVENUE 23KV	T6662B04	2
WilmingtonS	WILMINGTON EAST 230KV	LULLWATER 23KV	T6320B01	7
WilmingtonS	WILMINGTON NINTH AND ORANGE 230KV	ANN STREET 23KV	T6466B03	2
WilmingtonS	WILMINGTON NINTH AND ORANGE 230KV	ORANGE STREET 23KV	T6466B01	5
WilmingtonS	WILMINGTON OGDEN 230KV	BAYSHORE 23KV	T6470B04	2
WilmingtonS	WILMINGTON OGDEN 230KV	MIDDLE SOUND 23KV	T6470B01	4
WilmingtonS	WILMINGTON OGDEN 230KV	PORTERS NECK 23KV	T6470B02	4

NC DEP	Substation Name	Circuit Name	Circuit ID	Approx. No. Automated Switches
WilmingtonS	WILMINGTON SUNSET PARK 115KV	INDEPENDENCE 23KV	T4325B05	4
WilmingtonS	WILMINGTON WINTER PARK 230KV	LANSDOWNE 23KV	T6720B03	3
WilmingtonS	WILMINGTON WINTER PARK 230KV	SILVER LAKE 23KV	T6720B24	5
WilmingtonS	WILMINGTON WINTER PARK 230KV	TANGLEWOOD 23KV	T6720B07	3
WilmingtonS	WRIGHTSVILLE BEACH 230KV	DUCK HAVEN 24KV	T6740B03	4
WilmingtonS	WRIGHTSVILLE BEACH 230KV	LANDFALL 23KV	T6740B02	5
WilmingtonS	WRIGHTSVILLE BEACH 230KV	WRIGHTSVILLE BEACH 23KV	T6740B01	5
Zebulon	ARCHER LODGE 230KV	COVERED BRIDGE ROAD 24KV	T4500B12	8
Zebulon	CASTALIA 230KV	HOLLISTER 24KV	T6040B13	3
Zebulon	FOUR OAKS 230KV	HOLTS LAKE 24KV	T5732B01	3
Zebulon	FOUR OAKS 230KV	KEEN ROAD 24KV	T5732B03	2
Zebulon	KNIGHTDALE 115KV	KNIGHTDALE 23KV	T4850B01	7
Zebulon	KNIGHTDALE 115KV	KNIGHTDALE INDUSTRIAL 23KV	T4850B02	8
Zebulon	KNIGHTDALE 115KV	PLANTERS WALK 23KV	T4850B04	6
Zebulon	KNIGHTDALE SQUARE D 230KV	EAGLE ROCK 24KV	T4852B11	-
Zebulon	NASHVILLE 115 KV	CORINTH 23KV	T5900B05	4
Zebulon	RALEIGH YONKERS ROAD 115KV	SUNNYBROOK ROAD 24KV	T5126B11	3
Zebulon	ROLESVILLE 230KV	MITCHELL MILL 24KV	T5205B04	1
Zebulon	ROLESVILLE 230KV	WAKE CROSSROADS 24KV	T5205B03	7
Zebulon	ROLESVILLE 230KV	WATKINS ROAD 24KV	T5205B01	6
Zebulon	SELMA 230KV	FIELDCREST 23KV	T5970B06	-
Zebulon	SELMA 230KV	MICRO 23KV	T5970B08	2
Zebulon	SPRING HOPE 115KV	TAYLORS CROSSROADS 23KV	T6041B03	9
Zebulon	WILSON MILLS 230KV	GLENDALE 24KV	T5385B02	3
Zebulon	WILSON MILLS 230KV	WEST SMITHFIELD 24KV	T5385B04	-
Zebulon	ZEBULON 115KV	PILOT 23KV	T6090B04	-
Zebulon	ZEBULON 115KV	WAKEFIELD STREET 23KV	T6090B10	-
Zebulon	ZEBULON 115KV	ZEBULON WEST 23KV	T6090B11	1

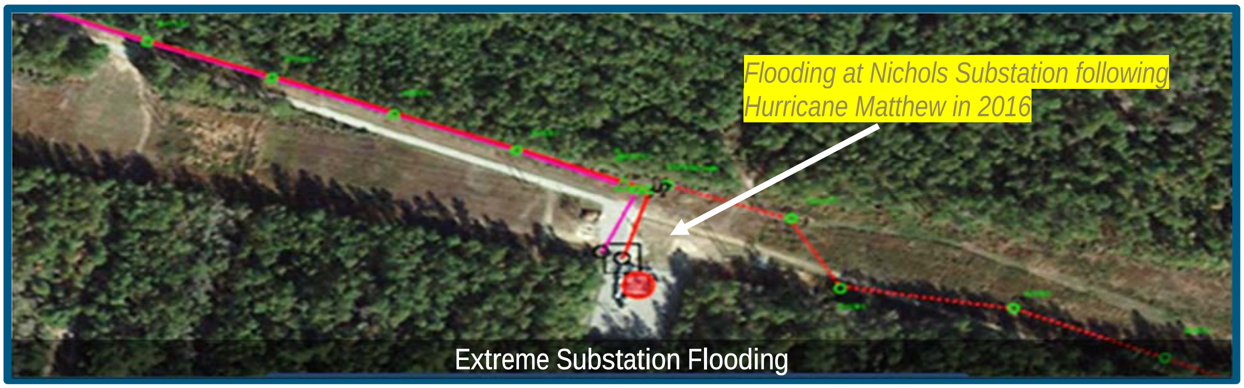
Automated Switching Device and Wire Capacity Upgrades are an initial statistical estimate. Quantities will be refined as each circuit progresses through detailed analysis and design.

II. Distribution Hardening and Resiliency (H&R) – Flood Hardening

In hurricane events like Hurricane Floyd and more recently Hurricanes Matthew and Florence, significant flooding was a major factor impacting restoration. Smart, targeted investments can mitigate the scale of impacts on communities and customers adjacent to these areas prone to extreme flooding. Hardening lines and structures is a balanced approach that can keep power and critical services available to some portion of a community and prevent a widespread outage in an area until flooding recedes.

The Distribution Hardening and Resiliency (H&R) – Flood Hardening program includes the following:

- Alternate power feeds for substations in flood-prone areas, and for radial power lines that cross into and through flood-prone areas
- Hardened river crossings where power lines are vulnerable to elevated water levels during extreme flooding
- Improved guying for at-risk structures within flood zones

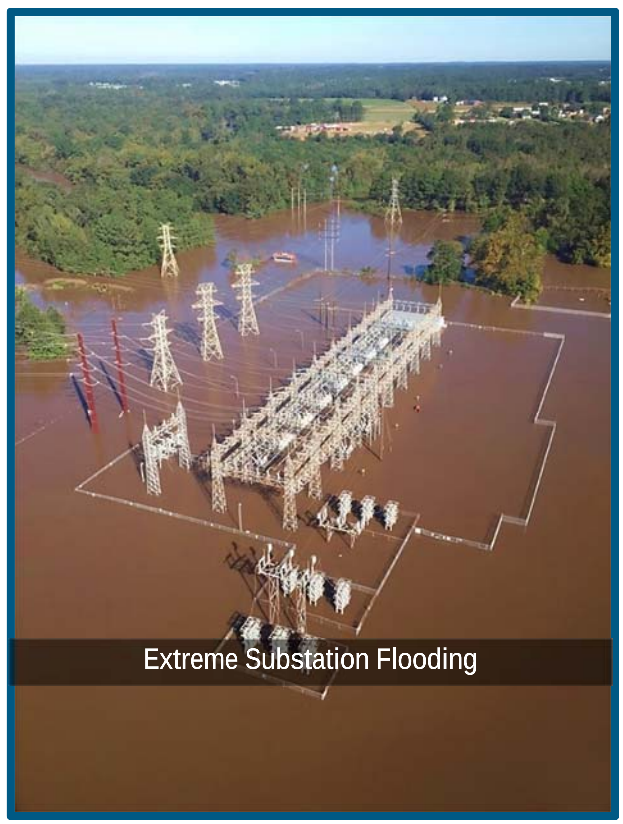


Extreme Substation Flooding

Locations *(Distribution H&R – Flood Hardening)*

- As candidate projects are identified, they will be considered for inclusion into the Long Duration Interruption/High Impact Site program 3-year budget.


Substation Flood Mitigation


Extreme Substation Flooding

III. Distribution Transformer Retrofit

Like the Self-Optimizing Grid program, the new sectionalization capability offered by the Distribution Transformer Retrofit program minimizes the number of customers impacted by a fault or failure on the power line. In addition, the new protective features that mitigate equipment vulnerabilities work to significantly lower the risk of an outage occurring at the transformer altogether.

The core activities of the transformer retrofit program include the installation of a fuse disconnect device on the high-voltage side of every overhead transformer to protect upstream customers from a fault at or downstream of the transformer. In addition, through protective device coordination, the local fused disconnect can be set to prevent any upstream operations of reclosing devices (the source of momentary outages for customers not served by the retrofitted transformer).

Consistent with modern transformer standards, the program also retrofits transformers with additional protective elements to reduce the risk of external factors such as lightning strikes and animal interference.


Non-Retrofitted Transformer

Retrofitted Transformer

3-Year Scope *(Transformer Retrofit)*

The NC specific detailed implementation plan for 2020 – 2022 is as follows:

DEC Retrofits	2020	2021	2022
Costs	-	-	$8,292,608
Units	-	-	*4,591*
DEP Retrofits	**2020**	**2021**	**2022**
Costs	$30,104,000	$42,052,872	$37,568,000
Units	*15,052*	*21,026*	*18,784*

2022 DEC Locations *(Transformer Retrofit)*

Ops Center	Substation Name	Circuit Name	Circuit ID	Approx. # Overhead Transformers
Durham	BARBEE CHAPEL RD RET	Barbee Chapel Rd Ret 2401	14232401	111
Durham	CREST ST RET	Crest St Ret 1210	14031210	52
Durham	DURHAM MN	Durham Main 1204	14011204	41

Ops Center	Substation Name	Circuit Name	Circuit ID	Approx. # Overhead Transformers
Durham	ELLERBEE RET	Ellerbee Ret 1202	14251202	27
Durham	ELLERBEE RET	Ellerbee Ret 1203	14251203	26
Durham	ENO RET	Eno Ret 2402	14102402	296
Durham	ENO RET	Eno Ret 2403	14102403	382
Durham	HOPE VALLEY RET	Hope Valley Ret 1206	14061206	10
Durham	OXFORD RD RET	Oxford Rd Ret 1205	14091205	141
Durham	PARKWOOD RET	Parkwood Ret 2402	14262402	41
Durham	POPE RD RET	Pope Rd Ret 2408	14082408	57
Durham	STALLINGS RD RET	Stallings Rd Ret 1202	14281202	91
Kannapolis	BALL PARK RET	Ball Park Ret 1202	22211202	25
Kannapolis	BALL PARK RET	Ball Park Ret 1204	22211204	122
Kannapolis	BRANTLEY RD RET	Brantley Rd Ret 1205	22271205	452
Kannapolis	EASY ST RET	Easy St Ret 1201	22191201	57
Kannapolis	ENOCHVILLE RET	Enochville Ret 1202	22251202	194
Kannapolis	MANCHESTER RET	Manchester Ret 1203	22311203	159
Kannapolis	MT PLEASANT RET	Mt Pleasant Ret 1201	22321201	9
Kannapolis	MT PLEASANT RET	Mt Pleasant Ret 1202	22321202	51
Kannapolis	ROBERTA RD RET	Roberta Rd Ret 1203	22261203	91
Kannapolis	ROBERTA RD RET	Roberta Rd Ret 1204	22261204	131
Kannapolis	WATERTOWER RET	Watertower Ret 1203	22291203	79
Kannapolis	WINECOFF RET	Winecoff Ret 1202	22231202	65
LittleRock	BRIAR CREEK RET	Briar Creek Ret 1209	1151209	77
LittleRock	LAKEWOOD RET	Lakewood Ret 1208	1071208	81
LittleRock	MONTCLAIRE RET	Montclaire Ret 2408	1392408	201
LittleRock	PARK RD RET	Park Rd Ret 1202	1161202	39

Ops Center	Substation Name	Circuit Name	Circuit ID	Approx. # Overhead Transformers
LittleRock	PARK RD RET	Park Rd Ret 1212	1161212	20
LittleRock	REMOUNT RD RET	Remount Rd Ret 1213	1191213	284
LittleRock	REMOUNT RD RET	Remount Rd Ret 1214	1191214	90
Mooresville	BRAWLEY SCHOOL RET	Brawley School Ret 2407	80752407	9
Mooresville	BRAWLEY SCHOOL RET	Brawley School Ret 1201	80751201	1
Mooresville	BRAWLEY SCHOOL RET	Brawley School Ret 2401	80752401	169
Mooresville	DUNBAR RET	Dunbar Ret 1205	80711205	105
Mooresville	ELMWOOD RET	Elmwood Ret 2404	80862404	96
Salisbury	FAITH RET	FAITH RET 1203	21431203	100
Salisbury	LONG FERRY RET	LONG FERRY RET 1203	21091203	362
Salisbury	LONG FERRY RET	LONG FERRY RET 1208	21091208	92
Salisbury	W NORWOOD RET	W NORWOOD RET 1201	21611201	155

2020-2022 DEP Candidate Locations (Transformer Retrofit)

Ops Center	Substation Name	Circuit ID	Approx. # Overhead Transformers
Asheboro	RAMSEUR 115KV	T1390B03	384
Asheville	ARDEN 115KV	T0690B01	24
Asheville	ASHEVILLE BENT CREEK 115KV	T0322B01	93
Asheville	AVERY CREEK 115KV	T0784B11	102
Asheville	BILTMORE 115KV	T0372B04	18
Asheville	BLACK MOUNTAIN 115KV	T0375B03	48
Asheville	EMMA 115KV	T0515B03	66
Asheville	LAKE JUNALUSKA 115KV	T0651B03	3
Asheville	REYNOLDS 115KV	T0745B13	63
Asheville	SPRUCE PINE 115KV	T0791B04	690
Asheville	SWANNANOA 115KV	T0810B06	210
Asheville	VANDERBILT 115KV	T0840B05	18
Asheville	WEST ASHEVILLE 115KV	T0340B14	12
CapeFear	CLIFDALE 230KV	T1890B01	360
CapeFear	CLIFDALE 230KV	T1890B03	288
CapeFear	CLIFDALE 230KV	T1890B05	240
CapeFear	CLIFDALE 230KV	T1890B02	204

Ops Center	Substation Name	Circuit ID	Approx. # Overhead Transformers
CapeFear	CLIFDALE 230KV	T1890B04	360
CapeFear	ERWIN 230KV	T5650B20	540
CapeFear	ERWIN 230KV	T5650B21	768
Fuquay	CARALEIGH 230KV	T4595B06	12
Fuquay	CARALEIGH 230KV	T4595B03	120
Fuquay	CARALEIGH 230KV	T4595B04	12
Fuquay	CARALEIGH 230KV	T4595B05	72
Fuquay	CARALEIGH 230KV	T4595B02	24
Fuquay	CARALEIGH 230KV	T4595B01	72
Fuquay	CARY REGENCY PARK 230KV	T4599B25	24
Fuquay	CARY REGENCY PARK 230KV	T4599B22	12
Fuquay	CARY REGENCY PARK 230KV	T4599B23	6
Fuquay	CARY REGENCY PARK 230KV	T4599B21	12
Fuquay	CARY REGENCY PARK 230KV	T4599B24	24
Fuquay	DUNCAN 230KV	T4630B13	552
Fuquay	DUNCAN 230KV	T4630B11	72
Fuquay	DUNCAN 230KV	T4630B12	132
Fuquay	FUQUAY 230KV	T4710B01	24
Fuquay	FUQUAY 230KV	T4710B04	288
Fuquay	FUQUAY 230KV	T4710B02	36
Fuquay	FUQUAY 230KV	T4710B03	216
Fuquay	FUQUAY 230KV	T4710B05	96
Fuquay	NEW HILL 230KV	T5911B02	8
Fuquay	NEW HILL 230KV	T5911B01	396
Henderson	BAHAMA 230KV	T4555B01	504
Henderson	HENDERSON EAST 230KV	T4785B02	60
Henderson	HENDERSON EAST 230KV	T4785B01	300
Henderson	HENDERSON EAST 230KV	T4785B15	8
Henderson	HENDERSON EAST 230KV	T4785B03	480
Henderson	HENDERSON EAST 230KV	T4785B04	384
Henderson	OXFORD SOUTH 230KV	T5085B04	168
Henderson	OXFORD SOUTH 230KV	T5085B01	6
Henderson	OXFORD SOUTH 230KV	T5085B03	324
Henderson	OXFORD SOUTH 230KV	T5085B02	504
Kinston	KORNEGAY 115KV	T4225B02	8
Kinston	KORNEGAY 115KV	T4225B01	408
Morehead City	BEULAVILLE 115KV	T5490B01	456
Morehead City	BEULAVILLE 115KV	T5490B02	6
Morehead City	BRIDGETON 115KV	T4074B02	336
Morehead City	BRIDGETON 115KV	T4074B01	408
Morehead City	HAVELOCK 230KV	T4190B11	168
Morehead City	HAVELOCK 230KV	T4190B12	240
Morehead City	RHEMS 230KV	T4276B03	192
Morehead City	RHEMS 230KV	T4276B02	312

Ops Center	Substation Name	Circuit ID	Approx. # Overhead Transformers
Morehead City	RHEMS 230KV	T4276B01	24
Rockingham	FAIRMONT 115KV	T1980B01	504
Rockingham	FAIRMONT 115KV	T1980B03	468
Rockingham	FAIRMONT 115KV	T1980B02	288
Rockingham	FAIRMONT 115KV	T1980B04	432
Rockingham	ST. PAULS 115KV	T2520B01	264
Rockingham	ST. PAULS 115KV	T2520B02	468
Rockingham	WADESBORO BOWMAN SCHOOL 230KV	T1672B01	192
Zebulon	SPRING HOPE 115KV	T6041B01	240
Zebulon	SPRING HOPE 115KV	T6041B03	636
Zebulon	WENDELL 230KV	T5378B01	492
Zebulon	WENDELL 230KV	T5378B03	336
Zebulon	WENDELL 230KV	T5378B02	612

Ops Center	Substation Name	Circuit ID	Approx. No. of Overhead Transformers
Asheboro	RAMSEUR 115KV	T1390B04	456
Asheboro	RAMSEUR 115KV	T1390B07	360
Asheville	ARDEN 115KV	T0690B02	156
Asheville	ASHEVILLE BENT CREEK 115KV	T0322B02	114
Asheville	CANDLER 115KV	T0390B02	192
Asheville	ELK MOUNTAIN 115KV	T0510B11	258
Asheville	HAZELWOOD 115KV	T0611B03	228
Asheville	OTEEN 115KV	T0750B12	39
Asheville	OTEEN 115KV	T0750B11	36
Asheville	SKYLAND 115KV	T0781B03	57
Asheville	SPRUCE PINE 115KV	T0791B02	153
Asheville	SWANNANOA 115KV	T0810B05	72
Asheville	SWANNANOA 115KV	T0810B01	57
Asheville	VANDERBILT 115KV	T0840B06	18
Asheville	WEST ASHEVILLE 115KV	T0340B11	36
CapeFear	CLINTON NORTH 115KV	T5570B02	120
CapeFear	CLINTON NORTH 115KV	T5570B04	324
CapeFear	CLINTON NORTH 115KV	T5570B03	528
CapeFear	CLINTON NORTH 115KV	T5570B01	360
CapeFear	ERWIN 230KV	T5650B22	228
CapeFear	HOPE MILLS CHURCH ST. 115KV	T2080B01	384
CapeFear	ROSEBORO 115KV	T5600B03	288
CapeFear	ROSEBORO 115KV	T5600B01	324
CapeFear	ROSEBORO 115KV	T5600B02	216
Chatham	PITTSBORO 230KV	T2250B02	132
Chatham	SILER CITY 115KV	T1530B04	252

Ops Center	Substation Name	Circuit ID	Approx. No. of Overhead Transformers
Chatham	SILER CITY 115KV	T1530B03	360
Chatham	SILER CITY 115KV	T1530B01	672
Chatham	SILER CITY 115KV	T1530B02	216
Chatham	SILER CITY 115KV	T1530B05	360
Henderson	HENDERSON EAST 230KV	T4785B06	552
Henderson	LOUISBURG 115KV	T4930B03	480
Henderson	LOUISBURG 115KV	T4930B02	348
Henderson	WARRENTON 115KV	T5360B01	324
Henderson	WARRENTON 115KV	T5360B04	252
Henderson	WARRENTON 115KV	T5360B03	360
Henderson	WARRENTON 115KV	T5360B02	156
NewBern	BAYBORO 230KV	T4050B02	456
NewBern	BAYBORO 230KV	T4050B01	384
NewBern	BAYBORO 230KV	T4050B03	156
Rockingham	LAURINBURG 230KV	T2200B23	96
Rockingham	LAURINBURG 230KV	T2200B22	264
Rockingham	LAURINBURG 230KV	T2200B24	240
Rockingham	MT. GILEAD 115KV	T1360B02	204
Rockingham	MT. GILEAD 115KV	T1360B03	144
Rockingham	MT. GILEAD 115KV	T1360B01	192
Rockingham	PEMBROKE 115KV	T2247B03	252
Rockingham	PEMBROKE 115KV	T2247B01	252
Rockingham	PEMBROKE 115KV	T2247B02	120
Rockingham	WADESBORO BOWMAN SCHOOL 230KV	T1672B02	408
WilmingtonN	WALLACE 115KV	T4410B12	12
WilmingtonN	WALLACE 115KV	T4410B13	252
WilmingtonN	WALLACE 115KV	T4410B11	312
WilmingtonN	WALLACE 115KV	T4410B10	624
WilmingtonN	WILMINGTON EAST 230KV	T6320B03	48
WilmingtonN	WILMINGTON EAST 230KV	T6320B04	96
WilmingtonN	WILMINGTON EAST 230KV	T6320B06	24
WilmingtonN	WILMINGTON EAST 230KV	T6320B01	84
WilmingtonN	WILMINGTON EAST 230KV	T6320B07	36
WilmingtonN	WILMINGTON EAST 230KV	T6320B02	180
WilmingtonS	SOUTHPORT 230KV	T6561B03	12
WilmingtonS	SOUTHPORT 230KV	T6561B02	156
WilmingtonS	SOUTHPORT 230KV	T6561B04	12
Zebulon	CASTALIA 230KV	T6040B13	288
Zebulon	CASTALIA 230KV	T6040B12	276
Zebulon	FOUR OAKS 230KV	T5732B02	288
Zebulon	FOUR OAKS 230KV	T5732B03	480
Zebulon	ROCKY MOUNT 230KV	T5940B26	528
Zebulon	ROCKY MOUNT 230KV	T5940B27	156

Ops Center	Substation Name	Circuit ID	Approx. No. of Overhead Transformers
Zebulon	SAMARIA 115KV	T6045B12	360
Zebulon	SAMARIA 115KV	T6045B13	396
Asheville	ELK MOUNTAIN 115KV	T0510B21	48
Asheville	EMMA 115KV	T0515B02	78
Asheville	HAZELWOOD 115KV	T0611B01	366
Asheville	LAKE LURE RET	15201201	3
Asheville	MAGGIE VALLEY 115KV	T0668B01	246
Asheville	MONTE VISTA 115KV	T0700B02	183
Asheville	SKYLAND 115KV	T0781B05	75
Asheville	SWANNANOA 115KV	T0810B07	45
Asheville	VANDERBILT 115KV	T0840B04	6
Asheville	VANDERBILT 115KV	T0840B03	72
Asheville	WEAVERVILLE 115KV	T0870B03	66
CapeFear	HOPE MILLS CHURCH ST. 115KV	T2080B03	60
CapeFear	HOPE MILLS CHURCH ST. 115KV	T2080B02	228
CapeFear	HOPE MILLS ROCKFISH RD. 230KV	T2082B01	240
CapeFear	HOPE MILLS ROCKFISH RD. 230KV	T2082B02	120
CapeFear	VANDER 115KV	T2580B01	384
CapeFear	VANDER 115KV	T2580B02	132
Chatham	BYNUM 230KV	T1025B02	396
Chatham	BYNUM 230KV	T1025B01	480
Chatham	BYNUM 230KV	T1025B12	120
Chatham	BYNUM 230KV	T1025B03	192
Chatham	PITTSBORO 230KV	T2250B03	240
Chatham	PITTSBORO 230KV	T2250B01	540
Goldsboro	BELFAST 115KV	T5465B01	324
Goldsboro	BELFAST 115KV	T5465B05	132
Goldsboro	BELFAST 115KV	T5465B02	168
Goldsboro	BELFAST 115KV	T5465B03	108
Goldsboro	ROSEWOOD 115KV	T5752B12	132
Goldsboro	ROSEWOOD 115KV	T5752B13	372
Sanford	LIBERTY 115KV	T1330B03	480
WilmingtonS	ELIZABETHTOWN 115KV	T6330B02	240
WilmingtonS	ELIZABETHTOWN 115KV	T6330B01	276
WilmingtonS	GARLAND 230KV	T6360B02	192
WilmingtonS	GARLAND 230KV	T6360B01	168
WilmingtonS	LAKE WACCAMAW 115KV	T4233B01	312
WilmingtonS	LAKE WACCAMAW 115KV	T4233B02	312
WilmingtonS	SOUTHPORT 230KV	T6561B05	288
Zebulon	FOUR OAKS 230KV	T5732B01	576
Zebulon	SELMA 230KV	T5970B07	480
Zebulon	SELMA 230KV	T5970B06	192
Zebulon	SELMA 230KV	T5970B09	48

Ops Center	Substation Name	Circuit ID	Approx. No. of Overhead Transformers
Zebulon	SELMA 230KV	T5970B08	432
Zebulon	SELMA 230KV	T5970B17	288
Zebulon	SELMA 230KV	T5970B10	24
Zebulon	WILSON MILLS 230KV	T5385B02	672
Zebulon	WILSON MILLS 230KV	T5385B03	192
Zebulon	WILSON MILLS 230KV	T5385B04	96
Zebulon	WILSON MILLS 230KV	T5385B01	168

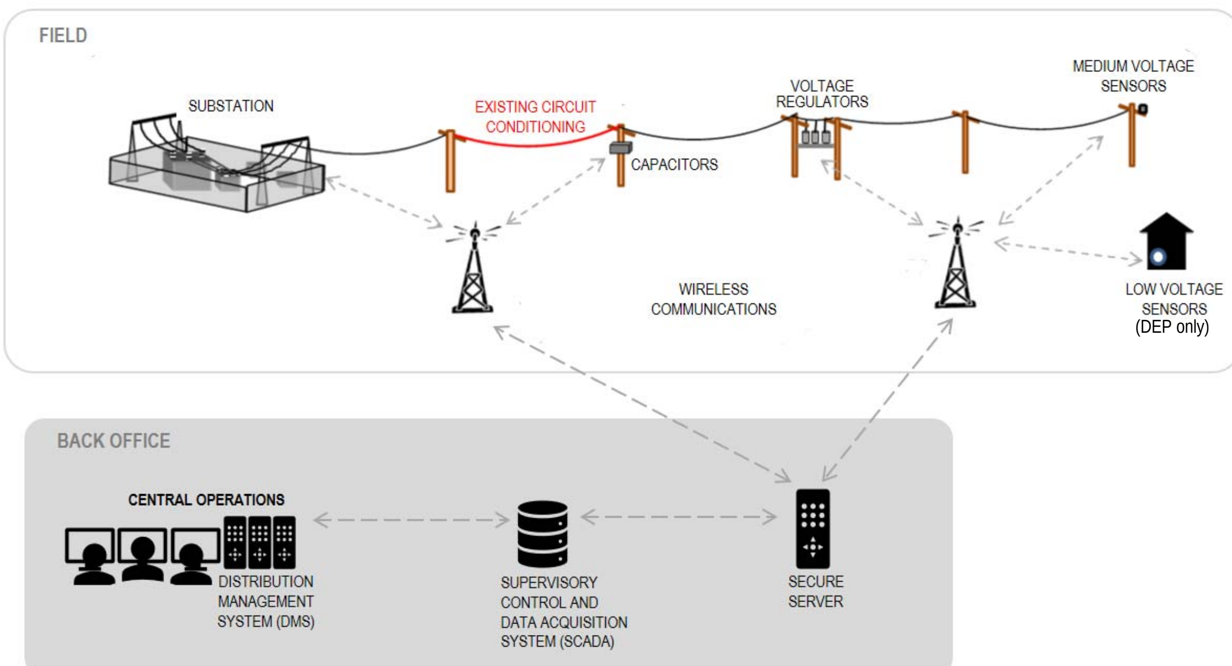
Circuits will be selected in accordance with overhead work in other programs such as SOG and IVVC for efficiency of construction resources.

IV. Integrated Volt/VAR Control (IVVC)

Integrated Volt/VAR Control (IVVC) allows the distribution system to optimize voltage and reactive power needs. The program employs remotely operated substation and distribution line devices such as voltage regulators and capacitors. The settings for thousands of these controllable field devices are optimized and dispatched via a distribution management system.

IVVC capabilities enable a grid operator to lower voltage as a way of reducing peak demand (peak shaving), thereby reducing the need to generate or purchase additional power at peak prices, or protecting the system from exceeding its load limitations. The current DEP Distribution System Demand Response (DSDR) program uses the peak shaving mode of IVVC to support emergency load reduction.

Another operational mode enabled by IVVC capabilities on the distribution system is Conservation Voltage Reduction (CVR). CVR uses IVVC during periods of more typical electricity demand to reduce overall energy consumption and system losses.



3 -Year Scope *(Integrated Volt/VAR Control)*

The North Carolina specific 3-year scope includes the following capital budget and scope. Note, that the DEC IVVC program will be implemented over a four-year period (2020 – 2023) with 2019 serving as a planning year.

	Duke Energy Carolinas			Duke Energy Progress		
Integrated Volt/VAR Control	2020	2021	2022	2020	2021	2022
Costs	$30,796,522	$86,311,294	$89,550,084	-	$5,000,000	$5,000,000
Approx. No. of Substation	*35*	*70*	*85*	-	-	-
Approx. No. of Circuits	*134*	*439*	*412*	-	-	-

DEC Candidate Locations 2020-2022 *(Integrated Volt/VAR Control)*

Area	Substation Name	Approx. No. of Circuits
Burlington	BURLINGTON MN	6
Burlington	FRIEDEN RET	4
Burlington	GILBREATH RET	5
Burlington	GLEN RAVEN MN	6
Burlington	HOPEDALE DIST	1
Burlington	KIMESVILLE RET	2
Burlington	OAKWOOD ST RET	2
Burlington	SAXAPAHAW RET	2
Burlington	SEVENTH ST RET	5
Burlington	ST MARKS RET	8
Burlington	SWEPSONVILLE TIE	3
Burlington	TROLLINGWOOD RET	1
Burlington	WHITSETT RET	4
Durham	ASHE ST SW STA	4
Durham	BARBEE CHAPEL RD RET	2
Durham	BINGHAM RET	5
Durham	BRANTLEY RD RET	1
Durham	BRASSFIELD RET	5
Durham	BROWNS FORD RET	2
Durham	BUTNER RET	4
Durham	CAMERON AVE SS	3
Durham	CREST ST RET	3
Durham	DACIAN AVE RET	2
Durham	DURHAM MN	2
Durham	EASTGATE RET	8
Durham	ELLERBEE RET	1
Durham	ELLIS RD RET	1
Durham	ENO RET	1
Durham	FAIRNTOSH RET	2
Durham	GARRETT RD RET	6
Durham	GENELEE RET	5
Durham	GREEN ST RET	4
Durham	GREY RET	7
Durham	HILLSBOROUGH RET	2
Durham	HOMESTEAD RET	4
Durham	HOPE VALLEY RET	4
Durham	HORTON RD RET	3
Durham	IMPERIAL RET	8
Durham	JAMES ST RET	2
Durham	JULIAN RD RET	1
Durham	KIT CREEK RET	6
Durham	MCGUIRE RET	1
Durham	NELSON RET	2


Smart Capacitor Bank

Durham	OXFORD RD RET	4
Durham	PARKWOOD RET	2
Durham	POPE RD RET	4
Durham	RESEARCH TRIANGLE RET	9
Durham	STALLINGS RD RET	3
Durham	TREYBURN RET	4
Durham	WEAVER RET	3
Cherokee	BROWNS FORD RET	1
Cherokee	CAMP CREEK RD RET	2
Cherokee	CHEROKEE RESERVATION RET	3
Cherokee	CULLOWHEE RET	3
Cherokee	JENKINS BRANCH RET	1
Cherokee	S SYLVA RET	1
Gastonia	BELMONT TIE	3
Gastonia	BRANTLEY RD RET	0
Gastonia	BROWNS FORD RET	1
Gastonia	HARTFORD AVE RET	3
Gastonia	LINCOLNTON TIE	2
Gastonia	MCADENVILLE JCT TIE	1
Gastonia	N STANLEY RET	3
Gastonia	NEW HOPE RET	1
Gastonia	NORTH DENVER RET	3
Gastonia	RANKIN AVE RET	2
Gastonia	S GASTONIA RET	2
Gastonia	TRIANGLE RET	4
Gastonia	W GASTONIA RET	3
Gastonia	WEBBS CHAPEL RET	2
Greensboro	BROWNS FORD RET	1
Greensboro	COLFAX RET	4
Greensboro	DENNY RD RET	4
Greensboro	FAIRFAX RD RET	7
Greensboro	FRIENDSHIP RET	7
Greensboro	GREENSBORO MN	11
Greensboro	GROOMTOWN RET	4
Greensboro	JESSUPTOWN RET	6
Greensboro	JULIAN RD RET	2
Greensboro	KILDARE RET	7
Greensboro	KIMESVILLE RET	0
Greensboro	LAKE TOWNSEND RET	4
Greensboro	MERRITT DR RET	7
Greensboro	RAGSDALE RET	1
Greensboro	RANDOLPH AVE RET	9
Greensboro	RUDD RET	4
Greensboro	SUMMERFIELD RET	3
Greensboro	TABERNACLE CHURCH RET	1
Greensboro	TARRANT RD RET	4

Greensboro	VANDALIA RET	7
Hendersonville	ASHEVILLE HWY RET	10
Hendersonville	BRANTLEY RD RET	0
Hendersonville	BREVARD RET	3
Hendersonville	NIX RD RET	4
Hendersonville	SPARTAN HEIGHTS RET	4
Hickory	BROWNS FORD RET	1
Hickory	CATFISH RET	1
Hickory	CLAREMONT RET	3
Hickory	FIRST ST RET	1
Hickory	LONGVIEW RET	1
Hickory	MTN VIEW RET	2
Hickory	N HICKORY RET	4
Hickory	OYAMA RET	3
Hickory	ROCKETT RET	1
Hickory	S HICKORY RET	4
Hickory	ST STEPHENS RET	4
Hickory	SWEETWATER RET	2
Hickory	TAYLORSVILLE TIE	1
Hickory	THIRD AVE RET	2
HighPoint	ADVANCE RET	4
HighPoint	CLEMMONS RET	3
HighPoint	DENTON RET	2
HighPoint	E THOMASVILLE RET	2
HighPoint	FAIR GROVE RET	3
HighPoint	GLENOLA RET	1
HighPoint	GLENWAY SS	1
HighPoint	GRIFFITH RD RET	3
HighPoint	HAWTHORNE RD RET	11
HighPoint	HEATH RET	5
HighPoint	HINSHAW RET	3
HighPoint	HOLLY HILL RET	3
HighPoint	KIVETT DR RET	1
HighPoint	LEXINGTON MN	1
HighPoint	LINDEN ST SW STA	4
HighPoint	MCGUIRE RET	0
HighPoint	MILLIS RET	2
HighPoint	MOCKSVILLE MN	2
HighPoint	PEACE HAVEN RD RET	3
HighPoint	RAGSDALE RET	3
HighPoint	RANDLEMAN RD RET	2
HighPoint	SWAIMTOWN RET	1
HighPoint	TRIAD PARK RET	1
HighPoint	WILLOW CREEK RET	2
HighPoint	WINSTON TIE	1
Kannapolis	BRANTLEY RD RET	4
Kannapolis	EASTFIELD RD RET	1

Kannapolis	EASY ST RET	2
Kannapolis	ENOCHVILLE RET	3
Kannapolis	MANCHESTER RET	3
Kannapolis	PITTS SCHOOL RET	4
Kannapolis	POPLAR TENT RET	5
Kannapolis	ROBERTA RD RET	3
Kannapolis	SPEEDWAY RET	5
Kannapolis	WATERTOWER RET	2
Kannapolis	WINECOFF RET	2
Kernersville	BROAD ST RET	7
Kernersville	BROOKWOOD RET	1
Kernersville	CASSELL ST SS	4
Kernersville	COLFAX RET	1
Kernersville	FIDDLERS CREEK RET	5
Kernersville	GUTHRIE RET	4
Kernersville	KernersvilleE RET	3
Kernersville	OAK RIDGE RET	6
Kernersville	SEDGE GARDEN RET	5
Kernersville	SOUTHBOUND RET	10
Kernersville	TRIAD PARK RET	2
Kernersville	TYSINGER RD RET	3
Kernersville	WALKERTOWN RET	4
Lewisville	ADVANCE RET	2
Lewisville	BRANTLEY RD RET	1
Lewisville	CLEMMONS RET	2
Lewisville	GRIFFITH RD RET	3
Lewisville	HAWTHORNE RD RET	3
Lewisville	HINSHAW RET	4
Lewisville	LEWISVILLE RET	6
Lewisville	MAR-DON DR RET	4
Lewisville	MOCKSVILLE MN	2
Lewisville	MT TABOR RET	3
Lewisville	PEACE HAVEN RD RET	2
Lewisville	SWAIMTOWN RET	4
Lewisville	WINSTON TIE	2
LittleRock	BEATTIES FORD RET	2
LittleRock	BELLHAVEN RET	7
LittleRock	BRIAR CREEK RET	3
LittleRock	BROWNS FORD RET	0
LittleRock	COFFEY CREEK RET	5
LittleRock	ELIZABETH AVE RET	16
LittleRock	GRAHAM ST RET	15
LittleRock	HILL ST RET	10
LittleRock	KENILWORTH RET	7
LittleRock	KUDZU RET	4
LittleRock	LAKEWOOD RET	5
LittleRock	LITTLE ROCK RET	9

LittleRock	MONTCLAIRE RET	7
LittleRock	PARK RD RET	4
LittleRock	PIONEER AVE RET	3
LittleRock	REMOUNT RD RET	8
LittleRock	ROYAL RET	3
LittleRock	ROZZELLES RET	6
LittleRock	STEELE CREEK RET	1
LittleRock	THRIFT RET	5
LittleRock	WITHERS RET	1
LittleRock	WOODLAWN TIE	8
MarionNC	GLENWOOD RET	6
MarionNC	MARION MN	3
MarionNC	OLD FORT RET	3
Matthews	ASHCRAFT AVE RET	1
Matthews	BEAVER DAM RET	4
Matthews	CARMEL RD RET	7
Matthews	LEAFCREST RET	1
Matthews	MATTHEWS RET	7
Matthews	MCALPINE CREEK RET	3
Matthews	MONROE RD RET	6
Matthews	MORNING STAR TIE	6
Matthews	PARK RD RET	8
Matthews	PIPER GLEN RET	1
Matthews	PROVOL RET	10
Matthews	SHARON RET	8
Matthews	SPRINGFIELD RET	3
Matthews	STOUTS RET	6
Matthews	WILGROVE RET	1
Mooresville	BRANTLEY RD RET	1
Mooresville	BRAWLEY SCHOOL RET	6
Mooresville	DEERFIELD RET	1
Mooresville	DUNBAR RET	2
Mooresville	LANGTREE RET	1
Mooresville	MURDOCK RD RET	1
Mooresville	TRIPLETT RET	1
Mt. Airy	BANNERTOWN TIE	5
Mt. Airy	DOBSON RET	2
Mt. Airy	JULIAN RD RET	0
Mt. Airy	TOAST RET	5
Newell	BEATTIES FORD RET	1
Newell	BRANTLEY RD RET	0
Newell	COMMONWEALTH RET	9
Newell	COTTONWOOD RET	3
Newell	DAVIDSON RET	3
Newell	DERITA RET	6
Newell	EASTFIELD RD RET	3
Newell	FOUR SEASONS RET	4

Newell	FURR RD RET	2
Newell	HICKORY GROVE RET	9
Newell	IBM CHARLOTTE PL SS	3
Newell	JULIAN RD RET	0
Newell	MALLARD CREEK RET	7
Newell	MCGUIRE RET	2
Newell	MINE SHAFT RET	10
Newell	N CHARLOTTE RET	6
Newell	NEWELL RET	6
Newell	REAMES RD RET	5
Newell	SPEEDWAY RET	2
Newell	SUNSET RET	7
Newell	WALLACE RD RET	2
Newell	WILGROVE RET	5
NorthWilkesboro	BROOK ST RET	7
NorthWilkesboro	BROWNS FORD RET	4
NorthWilkesboro	CANOE CREEK RET	2
NorthWilkesboro	CRUMP RD RET	3
NorthWilkesboro	FAIRPLAINS RET	6
NorthWilkesboro	SAWMILLS RET	3
NorthWilkesboro	VALDESE RET	3
NorthWilkesboro	VALMEAD RET	3
Reidsville	REIDSVILLE RET	2
Reidsville	WENTWORTH RET	1
RuralHall	FALL CREEK RET	1
RuralHall	KING RET	4
RuralHall	MONTROYAL RD RET	3
RuralHall	MT TABOR RET	1
RuralHall	N WINSTON RET	4
RuralHall	RURAL HALL RET	3
RuralHall	SEWARD RET	1
RuralHall	SHATTALON SW STA	5
RuralHall	WALNUT COVE TIE	2
Salisbury	ALBEMARLE SW STA	2
Salisbury	BRANTLEY RD RET	1
Salisbury	BROWNS FORD RET	1
Salisbury	CHINA GROVE RET	3
Salisbury	CLEVELAND RET	3
Salisbury	ENOCHVILLE RET	1
Salisbury	FAITH RET	1
Salisbury	JULIAN RD RET	2
Salisbury	LOCUST RET	2
Salisbury	LONG FERRY RET	2
Salisbury	MAJOLICA RD RET	1
Salisbury	MOCKSVILLE MN	1
Salisbury	RICHFIELD RET	2
Salisbury	ROCKWELL RET	2

Salisbury	SALISBURY MN	6
Salisbury	STATESVILLE RD RET	4
Salisbury	SUMNER RET	2
Salisbury	W NORWOOD RET	1
Shelby	BETHWARE RET	3
Shelby	BLANTON RET	4
Shelby	CHERRYVILLE RET	1
Shelby	FLAY RET	2
Shelby	OAK GROVE RET	1
Shelby	PATTERSON SPRINGS RET	6
Shelby	S SHELBY SS	1
Spindale	CLEGHORN SS	2
Spindale	LAKE LURE RET	3
Spindale	OAKLAND RD RET	6
Spindale	TANNER RET	4
	TOTAL:	1016

Circuits selected in accordance with overhead work in other programs such as SOG for efficiency of construction resources.

IVVC Substations and Circuits selected based on an initial statistical estimate. Quantities will be refined as each Substation/Circuit progresses through detailed analysis and design.

V. Transmission Hardening and Resiliency (H&R)

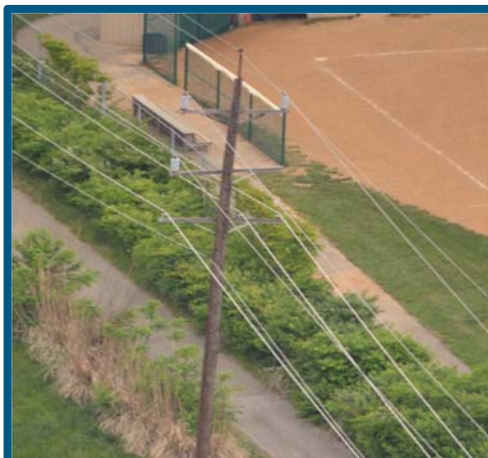
Each of the Transmission H&R sub-programs work to address unique challenges in ways that harden the system, and not only minimize impacts to customers, but enhance their electric service experience. The **44 kV System Upgrade** subprogram both protects the 44 kV system from extreme weather, but also begins to pave the way for more DER interconnections. Similarly, the **Targeted Line Rebuild for Extreme Weather** subprogram protects transmission line assets from extreme weather by addressing vulnerable wooden structures.

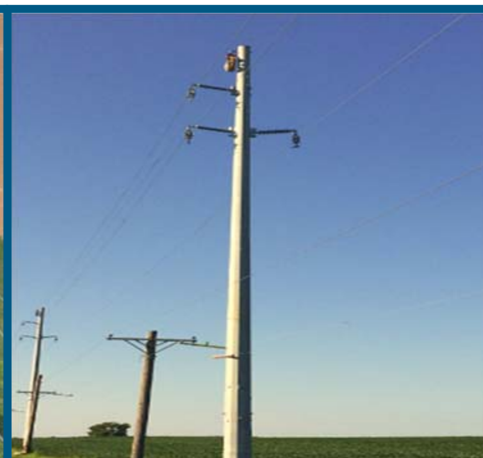
The **Networking Radially Served Substations** subprogram builds in more resiliency to the transmission system by creating alternative ways to provide customers with reliable electricity supply in the case of an issue with the primary transmission feed. The **Substation Flood Mitigation** subprogram builds in protection for substations most vulnerable to flood damage. For sites particularly vulnerable to flooding, the long-term solution is to relocate them to suitable locations less susceptible to flood waters that could damage equipment. The **Animal Mitigation** subprogram installs equipment specifically designed to prevent animal induced events from impacting customers directly through an outage or indirectly through a system perturbation such as a voltage depression. This equipment includes fences inside or around substations as well as apparatus and transmission pole/tower devices that prevent animal outages. Altogether, these H&R efforts not only enhance the functionality of individual assets, but substantially improve the overall functionality of the system, particularly under extreme weather conditions.

3-Year Scope *(Transmission Hardening and Resiliency)*

Actual costs will be captured on a per-site basis. This approach allows the Company to bundle multiple programs at the same site for better cost efficiency. The table below represents a high-level approximation of costs by category. The state dollars represented are based on an allocation methodology as Transmission's work is recorded on a system basis and not a state specific basis.

	Duke Energy Carolinas			Duke Energy Progress		
Transmission H&R	2020	2021	2022	2020	2021	2022
Total Cost	$13,985,730	$20,417,670	$68,058,900	$8,933,625	$9,568,905	$12,785,010
Line H&R	$11,966,400	$20,417,670	$68,058,900	$595,575	$8,735,100	$10,799,760
Substation Flooding H&R	-	-	-	$8,338,050	$794,100	$1,588,200
Substation Animal Mitigation	*$2,019,330*	-	-	-	$39,705	$397,050


69 kV Wood Pole Construction


69 kV Steel Pole Construction

VI. Transformer Bank Replacement

Predictive and proactive replacement programs like Transformer Bank Replacement significantly reduce the impacts and costs of replacement when compared to performing the same work following a catastrophic failure.

The objective of this program is to anticipate future transformer failures and replace those transformers in an orderly fashion, avoiding the cost and customer outage minutes associated with these failures. Catastrophic failures often result in significant oil spills, requiring expensive cleanup and other mitigation. Proactive replacement also reduces contingent material inventory needed, since replacements have a 12-24-month manufacturing lead time.

Typical Transmission-to-Transmission Transformer

Typical Transmission-to -Distribution Transformer

3-Year Scope *(Transformer Bank Replacement)*

Actual costs will be captured on a per-site basis. This approach allows the Company to bundle multiple programs at the same site for better cost efficiency. The table below represents a high-level approximation of costs by category. The state dollars represented are based on an allocation methodology as Transmission's work is recorded on a system basis and not a state specific basis.

	Duke Energy Carolinas			Duke Energy Progress		
Trans Bank Replacement	2020	2021	2022	2020	2021	2022
Total Cost	$6,192,612	$18,173,970	$9,273,960	$25,018,934	$38,513,850	$19,217,220
Total Bank Replacements (T&D)	$6,192,612	$18,173,970	$9,273,960	$25,018,934	$38,513,850	$19,217,220

VII. Transmission System Intelligence

The Transmission System Intelligence program will reduce the duration and impacts associated with transmission system issues. Improvements in transmission system device communication capabilities enable better protection and monitoring of system equipment. The data collected from intelligent communication equipment helps better assess and optimize transmission asset health.

The Transmission System Intelligence program includes: 1) the replacement of electromechanical relays with remotely operated **digital relays**, 2) the implementation of **intelligence and monitoring technology** capable of providing asset health data and driving predictive maintenance programs, 3) the deployment of **remote monitoring and control** functionality for substation and transmission line devices, which supports rapid service restoration, and 4) **resiliency projects** that leverage state of the art equipment such as digital relays, gas breakers and other equipment enabled with SCADA communication and remote monitoring and control capabilities to rapidly respond to system outages or disturbances. This subprogram helps to minimize the severity and consequences of outages or disturbances and increase the ability to quickly isolate trouble spots on the system and/or enable rapid restoration to normal system conditions.

Electromechanical Relays (Typical)

Digital Relays

3-Year Scope *(Transmission System Intelligence) – projected NC portion of project costs*

Actual costs will be captured on a per-site basis. This approach allows the Company to bundle multiple programs at the same site for better cost efficiency. The table below represents a high-level approximation of costs by category. The state dollars represented are based on an allocation methodology as Transmission's work is recorded on a system basis and not a state specific basis.

	Duke Energy Carolinas			Duke Energy Progress		
Transmission System Intelligence	2020	2021	2022	2020	2021	2022
Transmission SI	$24,007,590	$30,289,950	$8,413,875	$6,829,260	$11,310,810	$5,558,700

VIII. Oil Breaker Replacement

The purpose of the Oil Breaker Replacement program is to replace these legacy assets with breaker technology capable of two-way communications and remote operations. Transmission level oil breakers will be replaced with the modern sulfur hexafluoride gas (SF6) circuit breaker technology. The medium voltage distribution level oil-filled breakers will be replaced with modern vacuum circuit breaker technology. The new communication and control capabilities of this modern technology better positions the transmission and distribution systems to work with grid automation systems to better respond to electric grid events. Looking forward, these fast-response gas and vacuum breakers are better suited for protecting circuits with higher solar and other variable energy resource penetration.

Typical Transmission Oil Breaker

Typical Transmission SF_6 Gas Breaker

3-Year Scope *(Oil Breaker Replacement)*

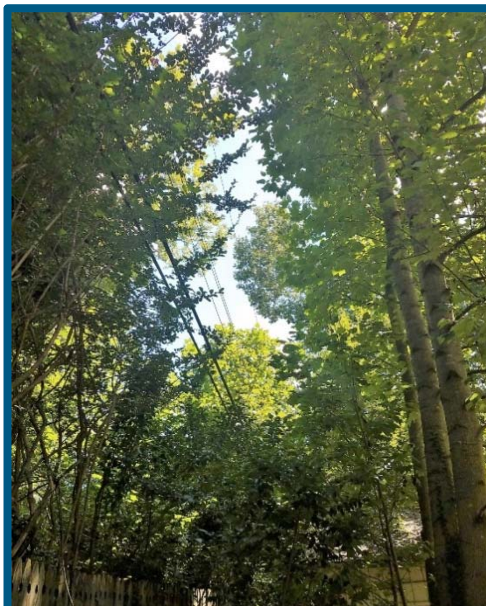
Actual costs will be captured on a per-site basis. This approach allows the Company to bundle multiple programs at the same site for better cost efficiency. The table below represents a high-level approximation of costs by category. The state dollars represented are based on an allocation methodology as Transmission's work is recorded on a system basis and not a state specific basis.

	Duke Energy Carolinas			Duke Energy Progress		
Oil Breaker Replacements	2020	2021	2022	2020	2021	2022
Total Cost	$28,243,818	$53,998,380	$33,414,676	$19,653,975	$20,051,025	$44,924,779
T Class Oil Replacement	$22,432,635	$48,206,642	$31,021,396	$9,529,200	$7,941,000	$25,072,279
D Class Oil Replacement	$5,811,183	$5,791,738	$2,393,280	$10,124,775	$12,110,025	$19,852,500

IX. Targeted Undergrounding (TUG)

Overhead power line segments with a history of unusually high numbers of outages drive a disproportionate amount of momentary interruptions and outages that affect Duke Energy's customers. When these segments of lines fail, they cause problems for Duke Energy's customers directly served by them as well as customers upstream. Lines targeted to be moved underground are typically the most resource intensive parts of the grid to repair after a major storm. Equipment on these line segments can experience shortened equipment life and additional equipment-related service interruptions.

The goal of the TUG program is to maximize the number of outage events eliminated. Converting outage prone parts of the system enables Duke Energy to restore service more quickly and cost effectively for all customers. Addressing areas with outlier outage performance improves service while lowering maintenance and restoration costs for all customers.


Backlot Distribution Lines

Criteria for consideration in the selection of targeted communities include:

- Performance of overhead lines
- Age of assets
- Service location (e.g., lines located in backyard where accessibility is limited)
- Vegetation impacts (e.g., heavily vegetated and often costly and difficult to trim)

3-Year Scope *(Targeted Undergrounding)*

	Duke Energy Carolinas			Duke Energy Progress		
Targeted Under Grounding	2020	2021	2022	2020	2021	2022
Costs	$6,424,000	$15,312,803	$38,104,000	$8,628,000	$19,524,437	$26,550,000
Approx. Line Miles (Over Head Miles Removed)	7 miles	16 miles	39 miles	10 miles	23 miles	29 miles

2020 – 2022 Proposed Locations (*TUG – Individual*, less complex tap lines)

Year	Jur	Target ID	Neighborhood/Area	Total Approx. Miles to UG	Approx. 2020	Approx. 2021	Approx. 2022	Approx. No. of Cust. Affected
2020-2022	DEC	38539753	931 W. Vandalia Rd (Galway & Mc Kelvey)	0.30	0.30			33
2020-2022	DEC	38668522	Edenburg St	0.36			0.36	27
2020-2022	DEC	38934559	Wilson Ave	0.27			0.27	27
2020-2022	DEC	38753428	Furman Place	0.45			0.45	58
2020-2022	DEC	38663155	Mountain Valley	0.12			0.12	95
2020-2022	DEC	38665161	Newton PL	0.43		0.43		31
2020-2022	DEC	38665747	Pennsylvania Ave, Hendersonville	0.51	0.32			35
2020-2022	DEC	38508573	208 Shadow Valley Rd. High Point, NC	0.18		0.18		11
2020-2022	DEP	429335897	Richmond Ave Swannanoa	0.27			0.27	25
2020-2022	DEC	38768466	340 Radio Rd. Charlotte, NC	0.71	0.24			33

2020 – 2022 Proposed Locations (*Neighborhoods or logical groupings* justified by cost benefit analysis)

Year	Jur	Target ID	Neighborhood/Area	Total Approx. Miles to UG	Approx. 2020	Approx. 2021	Approx. 2022	Approx. No. of Cust. Affected
2020-2022	DEP	428815436	Kings Grant	13.60	3.12	4.480	4.40	1158
2020-2022	DEP	427897510	Bent Creek	10.62	2.24	2.53	2.36	586
2020-2022	DEC	38789069	Raintree	1.93	1.93			1181
2020-2022	DEP	429058097	Beverly Hills	3.44	1.33	1.61	0.50	393
2020-2022	DEP	432521218	Alan Street, Angier	1.19	1.19			83

Year	Jur	Target ID	Neighborhood/Area	Total Approx. Miles to UG	Approx. 2020	Approx. 2021	Approx. 2022	Approx. No. of Cust. Affected
2020-2022	DEP	427643060	Biltmore South	4.43	1.13	2.30	1.00	283
2020-2022	DEC	38743242	Smallwood	1.01	1.01			304
2020-2022	DEC	38846388	Foxcroft Forsyth	0.86	0.86			77
2020-2022	DEC	38841296	Druid Hills	5.45	0.68	1.745	2.70	1083
2020-2022	DEP	431710864	Foxcroft	3.34	0.58			146
2020-2022	DEC	38527799	Barcelona Ave	0.55	0.55			33
2020-2022	DEC	38754302	Stonehaven	5.62	0.53	2.000	3.09	784
2020-2022	DEC	38669031	Grimesdale	3.51	0.35	1.460	1.70	212
2020-2022	DEP	427643159	Glen Arden	2.36	0.30	1.56	0.50	335
2020-2022	DEP	429061573	Princess Place Belvedere Wilmington	3.05	0.11	0.500	0.99	364
2020-2022	DEC	38778253	Pine Island Road	0.83				93
2020-2022	DEC	38435364	Lake Crest Drive	1.14				278
2020-2022	DEC	38935952	River Crest Dr Sylva	0.78			0.78	19
2020-2022	DEC	38663842	Chanteloupe Dr Hendersonville	0.69			0.69	27
2020-2022	DEC	38683533	Lake Lure N of 74	4.27			0.8	213
2020-2022	DEC	38666943	Bonclarken	2.52			1.00	201
2020-2022	DEC	38758197	Windsor Park	19.16		3.000	3.50	2371
2020-2022	DEC	38760368	Queens Rd W	5.91			3.00	845
2020-2022	DEC	38415447	Westview Winston-Salem	5.30		1.750	2.45	392
2020-2022	DEC	38765606	Mountainbrook	9.81		1.230	4.00	1109
2020-2022	DEC	38772231	Woodlark Lane	1.19		0.280	0.91	144
2020-2022	DEC	38411279	Louise Rd Winston-Salem	1.66		0.749	0.91	194
2020-2022	DEC	38769077	Elizabeth	1.09		1.090		297
2020-2022	DEC	38720833	Rick St off Rankin Rd	0.56			0.56	59
2020-2022	DEC	38416199	Philip St Winston-Salem	0.47			0.47	48
2020-2022	DEC	38758616	Westover Hills	2.71			1.50	300
2020-2022	DEC	38763567	Ewing Ave near East Blvd	1.68			0.69	321
2020-2022	DEC	38762649	Remount at Camp Green St	1.17			1.17	163
2020-2022	DEC	38764274	Sedgefield & Marsh	0.98		0.98		108

Year	Jur	Target ID	Neighborhood/Area	Total Approx. Miles to UG	Approx. 2020	Approx. 2021	Approx. 2022	Approx. No. of Cust. Affected
2020-2022	DEC	38528014	Colony Park Beech Hill	1.81			1.81	304
2020-2022	DEC	38534316	Hendrix Street	1.17		0.670	0.50	318
2020-2022	DEC	38579276	Town and Country	7.03		0.435	2.00	581
2020-2022	DEC	38578791	Colony Woods	4.79			1.80	404
2020-2022	DEC	38554017	Rolling Roads	2.89			1.00	383
2020-2022	DEC	38594223	Green Knolls	0.77			0.77	97
2020-2022	DEP	429056675	Town Mountain	24.97		1.00	2.09	1883
2020-2022	DEP	427639499	Royal Pines	10.01			2.00	973
2020-2022	DEP	429337970	Lakeview Park	8.86			2.00	675
2020-2022	DEP	427384733	Biltmore North	8.08			2.33	483
2020-2022	DEP	429336507	Mockingbird Rd Swannanoa	2.08			1.00	85
2020-2022	DEP	428802808	Coleman Street Weaverville	0.45			0.45	44
2020-2022	DEP	426657861	Vance Street, Sanford	7.72		2.595	2.50	829
2020-2022	DEP	435768628	Brookhaven, Raleigh	5.30		1.360	1.50	327
2020-2022	DEP	426849854	Wrightsville Ave Newton St	0.81		0.180	0.63	99
2020-2022	DEP	426850257	Harbor Island	2.10		0.505	1.59	358
2020-2022	DEP	432521311	Tramwood, Angier	0.94		0.170	0.77	50
2020-2022	DEP	433216267	Russell Hills, Cary	5.33		3.210	2.12	762

***Total approximate miles (UG) as show in this document includes work beyond 2022

X. Energy Storage

The program supports customer and utility initiatives through smart investments in storage for applications that deliver value to customers and the company. These applications include microgrid projects for preventing planned and unplanned outages, as well as long duration outage projects for providing redundant power sources for vulnerable (rural and remote) communities, and circuit and bank capacity projects using substation-tied energy storage.

Given the multiple applications energy storage technology supports, projects within the Energy Storage program are designed and assessed on a case by case basis for the specific challenge being addressed (e.g., long duration outage support, microgrid or emergency power support, auxiliary service needs, etc.).

The Energy Storage program also includes the development and deployment of an energy storage control system to manage the fleet of energy storage resources.

3-Year Scope *(Energy Storage)*

	Duke Energy Carolinas			Duke Energy Progress		
Energy Storage	2020	2021	2022	2020	2021	2022
TOTAL	$8,199,237	$6,199,237	$42,099,619	$8,122,113	$24,122,113	$40,261,057
Energy Storage Mgmt. Sys	$199,237	$199,237	$99,619	$122,113	$122,113	$61,057
Energy Storage Projects	$8,000,000	$6,000,000	$42,000,000	$8,000,000	$24,000,000	$40,200,000

Candidate Locations *(Energy Storage Deployment)*

Candidate locations and number of sites for 2020-2022 are currently being planned.

XI. Long Duration Interruptions / High Impact Sites

The Long Duration Interruption / High Impact Sites (LDI/HIS) program is designed to improve the reliability in parts of the grid where the duration of potential outages is expected to be much higher than average. Focus areas for this program are radial feeds to entire communities or large groups of customers as well as inaccessible line segments (i.e. off road, swamps, mountain gorges, extreme terrain, etc.).

Many of the areas served by these long, rural, single-sourced feeders can experience significant impacts to the local economy and to quality of life when the entire town loses power. Further, operational and repair costs are generally higher than average in these areas due to the special equipment required.

While some sites may include extreme hardening, circuit relocations, new circuit ties and undergrounding, energy storage solutions may offer more cost effective solutions for improving reliability and managing costs.

The LDS/HIS program is also designed to improve the reliability of high- impact customers like airports and hospitals, and high-density areas that could require a variety of infrastructure solutions to improve power quality and reliability. Typical projects include substation upgrades, circuit ties, voltage conversions, and reconductoring.

3-Year Scope *(Long Duration Interruptions / High Impact Sites)*

	Duke Energy Carolinas			Duke Energy Progress		
LDI / HIS	2020	2021	2022	2020	2021	2022
Costs	$2,353,500	$5,725,000	$3,245,000	$6,881,167	$4,978,277	$3,911,558

2020-2022 Candidate Locations *(Long Duration Interruptions / High Impact Sites)*

Juris	Ops Center	Circuit ID	LDI / HIS Project Scope
DEC	HighPoint	10151211	Create Circuit Tie
DEC	Mooresville	80711210	Reconductor 4672' of primary line and install an electronic recloser
DEC	Newell	01452412	Remove a set of manual disconnects and install electronic reclosers at a circuit tie point
DEC	Lewisville	03651203	Reconductor 28,220' of existing 3ph and relocate to roadside
DEC	Marion	90301203	Create circuit tie
DEC	Robbinsville	67083403	Relocate the main feed off the horse's face/along pipeline to Winding Stairs Rd
DEC	Salisbury	21372405	Create Circuit tie
DEC	Durham	19081201	Brock Dr & NC 57 Relocate Primary to make accessible
DEC	Franklin	67131203	Ulco Dr to Dowdle Mtn - reconductor 4727' of a mixture of #4,#2 and 1/0 wire 3 phase
DEC	Robbinsville	67083403	Old Roughy and Line on Island relocation

Juris	Ops Center	Circuit ID	LDI / HIS Project Scope
DEC	Spindale	15021203	Harden Pole line 2221 White Oak Mountain Rd Columbus NC, 28722. Sta
DEP	Maxton	T2210B03	Lumberton Hospital reliability improvements
DEP	Rockingham	T2480B02	Install tie point between ansonville 23kv feeder and west norwood retail 2412
DEP	Rockingham	T1672B03	Relocate wire out of backlots and move to opposite side of Quail Trail with existing single phase.
DEP	Rockingham	T1672B03	Relocate this section of feeder out to Woodland Drive
DEP	Rockingham	T1672B03	Move line off mountain between riverview rd and hwy 52 in norwood, nc.
DEP	Rockingham	T1672B03	Rebuild/redesign where Ansonville 23KV feeder crosses Rocky River. Going back with steel poles.
DEP	Rockingham	T1672B03	Relocate from woods to alongside road row
DEP	Whiteville	T4233B01	Relocate 13,700 feet of the feeder to alongside roadway
DEP	WilmingtonS	T6387B21	Figure 8 Island rebuild, harden
DEP	Asheboro	T0965B05	Relocate conductor from off road
DEP	CapeFear	T2480B01	Convert feeder exit OH to UG from substation to C089AE
DEP	Henderson	T4770B03	Rebuild line from woods and waterways to alongside road
DEP	Maxton	T2200B24	Move section of Wagram 23kV feeder to road and out of swamp due to long duration outages
DEP	Maxton	T2215B02	Relocate feeder from woods
DEP	Maxton	T2215B02	Relocate feeder from woods to along Deep Branch rd
DEP	Morehead City	T4272B01	Relocate Double Circuit from wood to the edge of Hwy 70.
DEP	Raleigh	T4620B11	Re-route feeder from out of wooded low bottom area to road
DEP	Raleigh	T4720B04	Create circuit tie
DEP	Sanford	T2440B05	Relocate the three phase out to the road
DEP	Southern Pines	T2249B03	Install 3 new g&w's to make feeder tie with Pinehurst hospital
DEP	CapeFear	T2480B02	Convert feeder exit OH to UG
DEP	Goldsboro	T5890B03	Relocate approx 800 feet 477 feeder out of back lots.
DEP	Henderson	T5090B04	Relocate and fuse conductor that runs cross country through woods
DEP	Morehead City	T4242B12	Replace feeder behind Belks with underground. Poles are inaccessible with normal digger derricks.
DEP	Sanford	T2440B05	Relocate 3-phase line out to the road
DEP	Sanford	T2440B05	Phase 2 of 4 AJ66AC-AJ90AC Relocate the three phase out to the road.
DEP	Sanford	T2440B05	Phase 3 of 4 AJ90AC-AL13AC Relocate the three phase out to the road
DEP	Sanford	T2440B05	Phase 4 of 4 AL13AC-AM44AC Relocate the three phase out to the road

XII. Enterprise Communications

The Enterprise Communications Improvements program focuses on modernizing and securing the critical communications networks between intelligent grid management systems located at grid operation centers, data and controls systems located at substations, and sensing and control devices across the entire electric power network. This program will:

- address technology obsolescence, secure vulnerabilities, and provide new workforce-enabling capabilities.
- improve and expand the entire communications network from the high speed, high capacity backbone fiber optic and microwave networks to the wireless connections at the edge of the grid.
- build the secure communications required for the increasing number of smart components, sensors, and remotely activated devices on the transmission and distribution systems.


Communication Tower and Comm Device

Key communication modernization efforts are:

- Mission Critical Transport which strategically uplifts the infrastructure required for high-speed, reliable, sustainable, interoperable communications for grid devices and personnel;
- Business Wide Area Network (BizWAN) which updates data network architecture to improve reliability, performance, and security of the core business network (i.e., communication networks used by transmission and distribution operations centers and control centers, data centers, power plants, customer care centers and regional offices);
- Grid Wide Area Network (GridWAN) which improves network reliability, performance and security for current Grid management/control applications;
- Mission Critical Voice which replaces current Land Mobile Radio systems with enhanced, reliable, sustainable, interoperable communications across all service territories, enabling field workers from one region to use the same radio system in support of storm reparations in another region during major storms;
- Next Generation Cellular (NGC) which replaces obsolete 2G/3G cellular technology with the more reliable and secure 4G/5G technology required for modern grid devices in the field;
- Towers, Shelters and Power Supplies which upgrades key infrastructure used for mission critical communications systems and upgrades power supplies that ensure communications equipment stays up during outages;
- Network Asset Systems which adds the tools needed to test, monitor and manage grid communications assets and systems;
- Vehicle Area Network (VAN) which implements a vehicle area network to enable more efficient telematics, routing, and location information to improve fleet management/restoration processes.

<u>3 Year Scope:</u> Charts of 2020-2022 financials:

Enterprise Communications	Duke Energy Carolinas 2020	Duke Energy Carolinas 2021	Duke Energy Carolinas 2022	Duke Energy Progress 2020	Duke Energy Progress 2021	Duke Energy Progress 2022
TOTAL	$26,989,547	$35,877,889	$40,895,277	$25,807,467	$32,282,117	$49,964,961
Next Gen Cellular*	$1,765,025	$2,918,856	$1,430,751	$2,617,183	$2,617,183	$255,978
Mission Critical Voice	$227,406	-	$10,084,885	$146,103	$12,948,245	$29,061,474
POC	$394,315	-	-	$256,149	-	-
BizWAN	-	$149,505	$149,505	-	$158,741	$158,741
GridWAN*	$4,214,704	$1,208,846	$747,900	$5,198,889	$2,617,544	$79,410
Mission Critical Transport	$16,784,625	$24,107,526	$23,408,744	$13,322,647	$11,355,628	$18,129,300
Towers Shelters Pow Sup	$2,450,868	$6,961,068	$4,815,343	$3,515,481	$2,317,612	$2,110,765
Network Asset Systems	$312,240	$407,387	$258,149	$202,832	$267,165	$169,294
Vehicle Area Network	$840,364	$124,600	-	$548,182	-	-

* The portions of this work associated with DSDR assets will not be recovered under GIP but instead will be separately evaluated and recovered under the DSDR rider.

XIII. Distribution Automation

The capabilities offered through Distribution Automation (DA) can transform what may have been an hour-long power outage for hundreds or even thousands of homes and businesses into a momentary outage – or potentially help avoid an outage altogether.

The DA program consists of several complementary efforts that work in concert to support dynamic and growing distribution system loads in a more sustainable way while minimizing power quality issues that often accompany a large scale transition to solar power. One of these projects, **Underground System Automation**, modernizes the protection and control of underground power systems that serve critical high-density areas, such as urban business districts and airports.

The **Fuse Replacement** project focuses on replacing one-time use fuses with automatic operating devices capable of intelligently resetting themselves for reuse, thus eliminating unnecessary use of resources (inventory, time, gasoline, etc.). The **Hydraulic to Electronic Recloser** program replaces obsolete oil-filled (hydraulic) devices with modern, remotely operated reclosing devices that support continuous system health monitoring.

Such digital device upgrades offer further value through efforts like the **System Intelligence and Monitoring** pilot, which develops advanced diagnostic tools that help engineers and technicians address electrical disturbances on the distribution system and improve customer experience.

3-Year Scope *(Distribution Automation)*

	Duke Energy Carolinas			Duke Energy Progress		
Distribution Automation	2020	2021	2022	2020	2021	2022
TOTAL	$36,142,118	$17,863,200	$61,382,482	$16,332,037	$32,881,457	$29,696,405
Hydraulic to Electronic Recloser	$27,012,832	-	$10,155,200	$8,958,226	$4,034,168	$949,216
Approx. No. of Units	*532*	-	*200*	*151*	*68*	*16*
Sys Intel and Monitoring	$1,847,286	$854,200	$2,500,114	$563,811	$725,489	$1,664,752
Fuse Replacement	$4,552,000	$14,296,000	$42,120,000	$5,000,000	$23,800,00	$22,000,000
Approx No. of Units	569	1,787	*5,265*	*625*	*2,975*	*2,750*
UG Sys Automation	$2,730,000	$2,713,000	$6,607,168	$1,800,000	$4,321,800	$5,082,437
Approx No. of Vaults	*7*	*7*	*16*	*3*	*7*	*8*

HYDRAULIC TO ELECTRONIC RECLOSER REPLACEMENT

2020-2022 DEC Candidate Locations *(Hydraulic to Electronic Recloser Replacement)*

Area	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Burlington	EFLAND RET	Efland Ret 1201	11241201	1
Burlington	FRIEDEN RET	Frieden Ret 2405	11172405	2
Burlington	FRIEDEN RET	Frieden Ret 2406	11172406	1
Burlington	GILBREATH RET	Gilbreath Ret 1202	11221202	1
Burlington	GILBREATH RET	Gilbreath Ret 2409	11222409	1
Burlington	GILBREATH RET	Gilbreath Ret 2410	11222410	1
Burlington	HOPEDALE DIST	Hopedale Dist 1201	11091201	4
Burlington	KIMESVILLE RET	Kimesville Ret 1202	11161202	2
Burlington	KIMESVILLE RET	Kimesville Ret 1203	11161203	1
Burlington	OAKWOOD ST RET	Oakwood St Ret 1204	11261204	1
Burlington	OSSIPEE DIST	Ossipee Dist 1203	11141203	1
Burlington	PLEASANT GROVE RET	Pleasant Grove Ret 1202	11181202	2
Burlington	PLEASANT GROVE RET	Pleasant Grove Ret 1203	11181203	2
Burlington	SAXAPAHAW RET	Saxapahaw Ret 1203	11151203	2
Burlington	SWEPSONVILLE TIE	Swepsonville Tie 1202	11191202	1
Burlington	SWEPSONVILLE TIE	Swepsonville Tie 1203	11191203	2
Burlington	TROLLINGWOOD RET	Trollingwood Ret 2414	11082414	1
Durham	BINGHAM RET	Bingham Ret 1206	19251206	1
Durham	BINGHAM RET	Bingham Ret 1211	19251211	1
Durham	BRASSFIELD RET	Brassfield Ret 2404	14152404	1
Durham	BRASSFIELD RET	Brassfield Ret 2412	14152412	1
Durham	BUTNER RET	Butner Ret 2409	14042409	1
Durham	CAMERON AVE SS	Cameron Ave SS 1206	19011206	1
Durham	CREST ST RET	Crest St Ret 1203	14031203	1
Durham	ELLIS RD RET	Ellis Rd Ret 2410	14192410	1
Durham	ENO RET	Eno Ret 2401	14102401	1
Durham	GARRETT RD RET	Garrett Rd Ret 2414	14202414	1
Durham	GENELEE RET	Genelee Ret 2404	14242404	3
Durham	GENELEE RET	Genelee Ret 2407	14242407	1
Durham	GREEN ST RET	Green St Ret 1201	14121201	1
Durham	GREEN ST RET	Green St Ret 1210	14121210	1
Durham	HILLSBOROUGH RET	Hillsborough Ret 1201	19081201	3
Durham	HOMESTEAD RET	Homestead Ret 1208	19061208	1
Durham	HOPE VALLEY RET	Hope Valley Ret 1204	14061204	1

Area	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Durham	HOPE VALLEY RET	Hope Valley Ret 1205	14061205	1
Durham	IMPERIAL RET	Imperial Ret 2409	14162409	1
Durham	IMPERIAL RET	Imperial Ret 2411	14162411	2
Durham	OXFORD RD RET	Oxford Rd Ret 1206	14091206	1
Durham	RESEARCH TRIANGLE RET	Research Triangle Ret 2402	14052402	1
Durham	RESEARCH TRIANGLE RET	Research Triangle Ret 2412	14052412	1
Durham	WHITE CROSS RET	White Cross Ret 1203	19051203	2
Cherokee	CAMP CREEK RD RET	Camp Creek Rd Ret 1208	67521208	3
Cherokee	CHEROKEE RESERVATION RET	Cherokee Reservation Ret 1201	67431201	1
Cherokee	CHEROKEE RESERVATION RET	Cherokee Reservation Ret 1206	67431206	3
Cherokee	CULLOWHEE RET	Cullowhee Ret 1202	67321202	2
Cherokee	E BRYSON RET	E Bryson Ret 1202	67311202	1
Cherokee	E SYLVA RET	E Sylva Ret 1201	67351201	3
Cherokee	E SYLVA RET	E Sylva Ret 1202	67351202	4
Cherokee	E SYLVA RET	E Sylva Ret 1203	67351203	1
Cherokee	GATEWAY RET	Gateway Ret 1201	67371201	1
Cherokee	JENKINS BRANCH RET	Jenkins Branch Ret 1201	67391201	1
Cherokee	JENKINS BRANCH RET	Jenkins Branch Ret 1202	67391202	2
Cherokee	JENKINS BRANCH RET	Jenkins Branch Ret 1203	67391203	3
Cherokee	JENKINS BRANCH RET	Jenkins Branch Ret 1204	67391204	3
Cherokee	S CULLOWHEE RET	S Cullowhee Ret 1203	67301203	2
Cherokee	S SYLVA RET	South Sylva Ret 1204	67531204	1
Cherokee	S SYLVA RET	South Sylva Ret 1205	67531205	1
Cherokee	S SYLVA RET	South Sylva Ret 1206	67531206	2
Cherokee	WEBSTER TIE	Webster Tie 1201	67471201	2
Cherokee	WEBSTER TIE	Webster Tie 1202	67471202	3
Cherokee	WEBSTER TIE	Webster Tie 1204	67471204	6
Elkin	BOONVILLE RET	Boonville Ret 1202	29021202	1
Elkin	CYCLE RET	Cycle Ret 1201	29041201	2
Elkin	CYCLE RET	Cycle Ret 1202	29041202	4
Elkin	ELK VALLEY RET	Elk Valley Ret 1203	29071203	1
Elkin	ELK VALLEY RET	Elk Valley Ret 1204	29071204	2
Elkin	ELK VALLEY RET	Elk Valley Ret 1205	29071205	2
Elkin	ELK VALLEY RET	Elk Valley Ret 1207	29071207	1
Elkin	ELKIN RET	Elkin Ret 1203	29011203	3
Elkin	FALL CREEK RET	Fall Creek Ret 1201	29051201	1
Elkin	RONDA RET	Ronda Ret 1201	29091201	1

Area	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Elkin	SHACKTOWN RET	Shacktown Ret 1201	29031201	3
Elkin	SMITHTOWN RET	Smithtown Ret 1201	29081201	4
Elkin	SURRY-YADKIN EMC DEL 8 PARKS RD	Surry-Yadkin EMC Parks Rd 1201	29101201	1
Elkin	YADKINVILLE RET	Yadkinville Ret 1205	29061205	1
Elkin	YADKINVILLE RET	Yadkinville Ret 1206	29061206	1
Elkin	YADKINVILLE RET	Yadkinville Ret 1207	29061207	2
Franklin	CASHIERS RET	Cashiers Ret 1201	67421201	3
Franklin	CASHIERS RET	Cashiers Ret 1202	67421202	2
Franklin	CASHIERS RET	Cashiers Ret 1203	67421203	1
Franklin	CASHIERS RET	Cashiers Ret 1204	67421204	6
Franklin	DEPOT ST RET	Depot St Ret 1202	67131202	1
Franklin	DEPOT ST RET	Depot St Ret 1204	67131204	2
Franklin	E FRANKLIN RET	E Franklin Ret 1201	67271201	1
Franklin	E FRANKLIN RET	E Franklin Ret 1202	67271202	4
Franklin	E FRANKLIN RET	E Franklin Ret 1203	67271203	1
Franklin	E FRANKLIN RET	E Franklin Ret 1204	67271204	4
Franklin	N FRANKLIN RET	N Franklin Ret 1201	67461201	3
Franklin	OTTO RET	Otto Ret 1203	67481203	2
Franklin	OTTO RET	Otto Ret 1204	67481204	3
Franklin	S FRANKLIN RET	S Franklin Ret 1201	67411201	1
Franklin	S FRANKLIN RET	S Franklin Ret 1203	67411203	11
Franklin	SAPPHIRE RET	Sapphire Ret 1202	67491202	2
Franklin	SHORTOFF RET	Shortoff Ret 1202	67381202	2
Franklin	SHORTOFF RET	Shortoff Ret 1203	67381203	1
Franklin	THORPE HYDRO	Thorpe Hydro 1202	67091202	1
Franklin	W FRANKLIN RET	W Franklin Ret 1202	67451202	2
Franklin	WESTS MILL TIE	Wests Mill Tie 1201	67361201	1
Franklin	WESTS MILL TIE	Wests Mill Tie 1202	67361202	3
Greensboro	COLFAX RET	Colfax Ret 2406	9502406	1
Greensboro	COLFAX RET	Colfax Ret 2410	9502410	1
Greensboro	DENNY RD RET	Denny Rd Ret 2409	9252409	1
Greensboro	E MARKET ST DIST	E Market St Dist 0401	9230401	1
Greensboro	FRIENDSHIP RET	Friendship Ret 2407	9092407	1
Greensboro	FRIENDSHIP RET	Friendship Ret 2409	9092409	1
Greensboro	GROOMTOWN RET	Groomtown Ret 1210	9121210	1
Greensboro	GROOMTOWN RET	Groomtown Ret 2403	9122403	1
Greensboro	JESSUPTOWN RET	Jessuptown Ret 2407	9072407	1

Area	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Greensboro	JESSUPTOWN RET	Jessuptown Ret 2408	9072408	3
Greensboro	KILDARE RET	Kildare Ret 2410	9082410	1
Greensboro	LAKE TOWNSEND RET	Lake Townsend Ret 2401	9302401	1
Greensboro	LORILLARD CORP	Lorillard Corp 1201	9321201	1
Greensboro	MERRITT DR RET	Merritt Dr Ret 2406	9242406	1
Greensboro	MONTICELLO RET	Monticello Ret 1201	9571201	1
Greensboro	MONTICELLO RET	Monticello Ret 1202	9571202	2
Greensboro	PLEASANT GARDEN RET	Pleasant Garden Ret 1202	9791202	2
Greensboro	RANDOLPH AVE RET	Randolph Ave Ret 2407	9042407	1
Greensboro	RANDOLPH AVE RET	Randolph Ave Ret 2412	9042412	1
Greensboro	RUDD RET	Rudd Ret 2404	9262404	1
Greensboro	RUDD RET	Rudd Ret 2408	9262408	1
Greensboro	SUMMERFIELD RET	Summerfield Ret 2405	9102405	2
Greensboro	SUMMERFIELD RET	Summerfield Ret 2406	9102406	1
Greensboro	SUMMERFIELD RET	Summerfield Ret 2410	9102410	1
Greensboro	TARRANT RD RET	Tarrant Rd Ret 2403	9202403	1
Greensboro	VANDALIA RET	Vandalia Ret 2410	9052410	1
Hendersonville	ASHEVILLE HWY RET	Asheville Hwy Ret 1201	65011201	3
Hendersonville	ASHEVILLE HWY RET	Asheville Hwy Ret 1204	65011204	1
Hendersonville	ASHEVILLE HWY RET	Asheville Hwy Ret 1205	65011205	1
Hendersonville	ASHEVILLE HWY RET	Asheville Hwy Ret 1206	65011206	3
Hendersonville	ASHEVILLE HWY RET	Asheville Hwy Ret 1207	65011207	3
Hendersonville	BALSAM RET	Balsam Ret 1203	65151203	1
Hendersonville	BALSAM RET	Balsam Ret 1204	65151204	3
Hendersonville	BIG WILLOW RET	Big Willow Ret 1201	65021201	2
Hendersonville	BIG WILLOW RET	Big Willow Ret 1202	65021202	1
Hendersonville	BLANTYRE RET	Blantyre Ret 1202	65341202	2
Hendersonville	BREVARD RET	Brevard Ret 1201	66101201	1
Hendersonville	BREVARD RET	Brevard Ret 1203	66101203	1
Hendersonville	DAVIDSON RIVER RET	Davidson River Ret 1203	66221203	1
Hendersonville	DAVIDSON RIVER RET	Davidson River Ret 1204	66221204	1
Hendersonville	EDNEYVILLE RET	Edneyville Ret 1202	65171202	2
Hendersonville	EDNEYVILLE RET	Edneyville Ret 1203	65171203	3
Hendersonville	EDNEYVILLE RET	Edneyville Ret 1204	65171204	2
Hendersonville	KANUGA RET	Kanuga Ret 1202	65181202	3
Hendersonville	KANUGA RET	Kanuga Ret 1203	65181203	2
Hendersonville	MILLS RIVER RET	Mills River Ret 1208	65121208	5
Hendersonville	NAPLES RET	Naples Ret 1204	65201204	1

Area	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Hendersonville	NAPLES RET	Naples Ret 1206	65201206	1
Hendersonville	RICH MOUNTAIN RET	Rich Mountain Ret 1201	66131201	1
Hendersonville	RICH MOUNTAIN RET	Rich Mountain Ret 1203	66131203	3
Hendersonville	RICH MOUNTAIN RET	Rich Mountain Ret 1204	66131204	1
Hendersonville	ROSMAN SS	Rosman SS 1201	66091201	1
Hendersonville	SALUDA RET	Saluda Ret 1201	65071201	4
Hendersonville	SALUDA RET	Saluda Ret 1202	65071202	1
Hendersonville	SPARTAN HEIGHTS RET	Spartan Heights Ret 1204	65031204	1
Hendersonville	TUCKERS CREEK RET	Tuckers Creek Ret 1203	66161203	2
Hendersonville	TUCKERS CREEK RET	Tuckers Creek Ret 1204	66161204	2
Hendersonville	TUXEDO RET	Tuxedo Ret 1201	65041201	2
Hendersonville	TUXEDO RET	Tuxedo Ret 1202	65041202	3
Hickory	BETHLEHEM SS	Bethlehem SS 1201	13361201	1
Hickory	BETHLEHEM SS	Bethlehem SS 1204	13361204	1
Hickory	BRIDGEPORT RET	Bridgeport Ret 1201	13011201	1
Hickory	BRIDGEPORT RET	Bridgeport Ret 1202	13011202	2
Hickory	CANOE CREEK RET	Canoe Creek Ret 1202	13021202	1
Hickory	CANOE CREEK RET	Canoe Creek Ret 1203	13021203	1
Hickory	CATAWBA RET	Catawba Ret 1202	13031202	2
Hickory	CATAWBA RET	Catawba Ret 1203	13031203	1
Hickory	CATAWBA RET	Catawba Ret 1204	13031204	1
Hickory	CATAWBA RET	Catawba Ret 1205	13031205	1
Hickory	CATFISH RET	Catfish Ret 1204	13341204	2
Hickory	CLAREMONT RET	Claremont Ret 1211	13121211	2
Hickory	COMMSCOPE SHERRILLS FORD T&D	CommScope Sherrills Ford T&D 1201	13611201	1
Hickory	CRUMP RD RET	Crump Rd Ret 1201	12181201	1
Hickory	CRUMP RD RET	Crump Rd Ret 1202	12181202	1
Hickory	CRUMP RD RET	Crump Rd Ret 1205	12181205	3
Hickory	DRAKA COMTEQ T&D	Draka Comteq T&D 2401	13662401	1
Hickory	E MAIDEN RET	East Maiden Ret 1201	13051201	1
Hickory	E MAIDEN RET	East Maiden Ret 1202	13051202	1
Hickory	GLEN ALPINE RET	Glen Alpine Ret 1201	13071201	2
Hickory	HIDDENITE RET	Hiddenite Ret 1201	13081201	1
Hickory	HIDDENITE RET	Hiddenite Ret 1202	13081202	2
Hickory	HIDDENITE RET	Hiddenite Ret 1203	13081203	2
Hickory	ICARD RET	Icard Ret 1203	13111203	1
Hickory	ISLAND FORD RD RET	Island Ford Rd Ret 1202	13291202	1

Area	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Hickory	ISLAND FORD RD RET	Island Ford Rd Ret 1203	13291203	3
Hickory	KINCAID RD RET	Kincaid Rd Ret 1203	12131203	1
Hickory	LONGVIEW RET	Longview Ret 1201	13351201	2
Hickory	LONGVIEW RET	Longview Ret 1202	13351202	1
Hickory	MACEDONIA RET	Macedonia Ret 1201	13411201	3
Hickory	MILLER HILL RET	Miller Hill Ret 1207	12141207	2
Hickory	MILLER HILL RET	Miller Hill Ret 1208	12141208	1
Hickory	MT OLIVE RET	Mt Olive Ret 1201	13151201	1
Hickory	MT OLIVE RET	Mt Olive Ret 1202	13151202	1
Hickory	MTN VIEW RET	Mtn View Ret 1206	13161206	1
Hickory	MTN VIEW RET	Mtn View Ret 1208	13161208	1
Hickory	N HICKORY RET	N Hickory Ret 1205	13171205	3
Hickory	N HICKORY RET	N Hickory Ret 1211	13171211	1
Hickory	OYAMA RET	Oyama Ret 1205	13181205	1
Hickory	OYAMA RET	Oyama Ret 1206	13181206	2
Hickory	PROPST RET	Propst Ret 1210	13131210	1
Hickory	RHODHISS RET	Rhodhiss Ret 1202	13191202	1
Hickory	RUTHERFORD COLLEGE RET	Rutherford College Ret 1202	13201202	1
Hickory	RUTHERFORD COLLEGE RET	Rutherford College Ret 1203	13201203	1
Hickory	SAWMILLS RET	Sawmills Ret 1202	12291202	1
Hickory	SAWMILLS RET	Sawmills Ret 1203	12291203	1
Hickory	SHERRILLS FORD SS	Sherrills Ford SS 1201	13301201	1
Hickory	ST STEPHENS RET	St Stephens Ret 1206	13281206	3
Hickory	ST STEPHENS RET	St Stephens Ret 1207	13281207	1
Hickory	ST STEPHENS RET	St Stephens Ret 1209	13281209	1
Hickory	STARTOWN RET	Startown Ret 1201	13101201	1
Hickory	STARTOWN RET	Startown Ret 1202	13101202	1
Hickory	STARTOWN RET	Startown Ret 1203	13101203	1
Hickory	SWEETWATER RET	Sweetwater Ret 1208	13371208	1
Hickory	TAYLORSVILLE TIE	Taylorsville Tie 1202	13391202	1
Hickory	THIRD AVE RET	Third Ave Ret 1205	13241205	1
Hickory	VALMEAD RET	Valmead Ret 1201	12261201	1
Hickory	VALMEAD RET	Valmead Ret 1203	12261203	1
Hickory	ZION CHURCH RD RET	Zion Church Rd Ret 1201	13261201	2
HighPoint	DENTON RET	Denton Ret 1211	10221211	3
HighPoint	E THOMASVILLE RET	E Thomasville Ret 1207	10151207	1
HighPoint	E THOMASVILLE RET	E Thomasville Ret 1211	10151211	1
HighPoint	FAIR GROVE RET	Fair Grove Ret 1203	10251203	1

Area	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
HighPoint	FAIR GROVE RET	Fair Grove Ret 1204	10251204	3
HighPoint	GLENOLA RET	Glenola Ret 1203	10231203	3
HighPoint	GLENOLA RET	Glenola Ret 1204	10231204	3
HighPoint	GLENOLA RET	Glenola Ret 1207	10231207	1
HighPoint	HOLLY HILL RET	Holly Hill Ret 1206	10161206	3
HighPoint	HOLLY HILL RET	Holly Hill Ret 1208	10161208	2
HighPoint	HOLLY HILL RET	Holly Hill Ret 1210	10161210	1
HighPoint	HOLLY HILL RET	Holly Hill Ret 1211	10161211	1
HighPoint	HOLLY HILL RET	Holly Hill Ret 1212	10161212	1
HighPoint	KIVETT DR RET	Kivett Dr Ret 1203	10091203	1
HighPoint	LINDEN ST SW STA	Linden St Sw Sta 2405	10042405	1
HighPoint	LINDEN ST SW STA	Linden St Sw Sta 2412	10042412	1
HighPoint	MILLIS RET	Millis Ret 2407	10172407	3
HighPoint	MILLIS RET	Millis Ret 2412	10172412	2
HighPoint	N GORDONTON RET	N Gordonton Ret 1201	10201201	1
HighPoint	N GORDONTON RET	N Gordonton Ret 1203	10201203	1
HighPoint	N MAIN ST DIST	N Main St Dist 1201	10081201	1
HighPoint	RAGSDALE RET	Ragsdale Ret 2408	10192408	3
HighPoint	RANDLEMAN RD RET	Randleman Rd Ret 1205	10121205	1
HighPoint	RANDLEMAN RD RET	Randleman Rd Ret 1206	10121206	1
HighPoint	RANDLEMAN RD RET	Randleman Rd Ret 1209	10121209	1
HighPoint	RANDLEMAN RD RET	Randleman Rd Ret 1210	10121210	2
HighPoint	TRIAD PARK RET	Triad Park Ret 1201	10211201	2
HighPoint	TRIAD PARK RET	Triad Park Ret 1202	10211202	1
HighPoint	WILLOW CREEK RET	Willow Creek Ret 1207	10181207	3
HighPoint	WILLOW CREEK RET	Willow Creek Ret 1208	10181208	1
HighPoint	WILLOW CREEK RET	Willow Creek Ret 1211	10181211	1
HighPoint	WILLOW CREEK RET	Willow Creek Ret 1212	10181212	2
Kannapolis	BRANTLEY RD RET	Brantley Rd Ret 1206	22271206	1
Kannapolis	BRANTLEY RD RET	Brantley Rd Ret 1209	22271209	2
Kannapolis	BRANTLEY RD RET	Brantley Rd Ret 1210	22271210	1
Kannapolis	ENOCHVILLE RET	Enochville Ret 1201	22251201	2
Kannapolis	ENOCHVILLE RET	Enochville Ret 1202	22251202	1
Kannapolis	ENOCHVILLE RET	Enochville Ret 1207	22251207	1
Kannapolis	MANCHESTER RET	Manchester Ret 1201	22311201	1
Kannapolis	MANCHESTER RET	Manchester Ret 1202	22311202	2
Kannapolis	MT PLEASANT RET	Mt Pleasant Ret 1201	22321201	1
Kannapolis	PITTS SCHOOL RET	Pitts School Ret 1202	22371202	1

Area	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Kannapolis	POPLAR TENT RET	Poplar Tent Ret 1201	22241201	1
Kannapolis	POPLAR TENT RET	Poplar Tent Ret 1206	22241206	1
Kannapolis	ROBERTA RD RET	Roberta Rd Ret 1203	22261203	1
Kannapolis	SPEEDWAY RET	Speedway Ret 1205	22281205	1
Kannapolis	WATERTOWER RET	Watertower Ret 1202	22291202	2
Kannapolis	WINECOFF RET	Winecoff Ret 1202	22231202	1
Kernersville	BECKERDITE TIE	Beckerdite Tie 1202	3021202	1
Kernersville	BECKERDITE TIE	Beckerdite Tie 1203	3021203	2
Kernersville	CASSELL ST SS	Cassell St SS 1203	3061203	2
Kernersville	CASSELL ST SS	Cassell St SS 1209	3061209	1
Kernersville	FIDDLERS CREEK RET	Fiddlers Creek Ret 1210	3101210	1
Kernersville	GUTHRIE RET	Guthrie Ret 1203	3131203	1
Kernersville	GUTHRIE RET	Guthrie Ret 1207	3131207	1
Kernersville	KernersvilleE RET	Kernersvillee Ret 1205	3171205	1
Kernersville	OAK RIDGE RET	Oak Ridge Ret 1203	3241203	1
Kernersville	OAK RIDGE RET	Oak Ridge Ret 1205	3241205	1
Kernersville	OAK RIDGE RET	Oak Ridge Ret 1206	3241206	1
Kernersville	SEDGE GARDEN RET	Sedge Garden Ret 1201	3291201	1
Kernersville	SEDGE GARDEN RET	Sedge Garden Ret 2404	3292404	1
Kernersville	TRIAD PARK RET	Triad Park Ret 1205	3331205	1
Kernersville	TRIAD PARK RET	Triad Park Ret 1206	3331206	1
Kernersville	WALKERTOWN RET	Walkertown Ret 1207	3361207	3
Kernersville	WALKERTOWN RET	Walkertown Ret 1208	3361208	1
Kernersville	WELCOME RET	Welcome Ret 1202	3391202	1
Lewisville	ADVANCE RET	Advance Ret 1202	3011202	2
Lewisville	ADVANCE RET	Advance Ret 1208	3011208	1
Lewisville	ADVANCE RET	Advance Ret 1209	3011209	3
Lewisville	CLEMMONS RET	Clemmons Ret 1206	3071206	1
Lewisville	CLEMMONS RET	Clemmons Ret 1209	3071209	1
Lewisville	ENERGYUNITED UNION GROVE	Union Grove 1201	3641201	2
Lewisville	GRIFFITH RD RET	Griffith Rd Ret 1208	3121208	2
Lewisville	HAGER RD RET	Hager Rd Ret 1202	3661202	1
Lewisville	HINSHAW RET	Hinshaw Ret 1211	3151211	1
Lewisville	LEWISVILLE RET	Lewisville Ret 1205	3201205	1
Lewisville	LEWISVILLE RET	Lewisville Ret 1207	3201207	1
Lewisville	LEWISVILLE RET	Lewisville Ret 1211	3201211	1
Lewisville	LEWISVILLE RET	Lewisville Ret 1212	3201212	1

Area	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Lewisville	MOCKSVILLE MN	Mocksville Main 2401	3552401	2
Lewisville	MOCKSVILLE MN	Mocksville Main 2402	3552402	1
Lewisville	MOCKSVILLE MN	Mocksville Main 2403	3552403	2
Lewisville	MT TABOR RET	Mt Tabor Ret 1208	3221208	1
Lewisville	PFAFFTOWN RET	Pfafftown Ret 1203	3271203	1
Lewisville	PPG IND FIBER GLASS LEX T&D	PPG Ind Fiber Glass T&D 1201	3621201	1
Lewisville	TURNERSBURG RET	Turnersburg Ret 1202	3651202	1
Lewisville	TURNERSBURG RET	Turnersburg Ret 1203	3651203	1
LittleRock	CHESTER MAIN	Chester Main 1201	6011201	1
LittleRock	CHESTER MAIN	Chester Main 1203	6011203	2
LittleRock	CHESTER MAIN	Chester Main 1204	6011204	4
LittleRock	E CHESTER RET	East Chester Ret 1205	6021205	1
LittleRock	E CHESTER RET	East Chester Ret 1206	6021206	1
LittleRock	E CHESTER RET	East Chester Ret 1208	6021208	4
LittleRock	KENILWORTH RET	Kenilworth Ret 1208	1281208	1
LittleRock	LAKEWOOD RET	Lakewood Ret 1205	1071205	1
LittleRock	LANDO RET	Lando Ret 1201	6031201	1
LittleRock	LANDO RET	Lando Ret 1202	6031202	1
LittleRock	LANDO RET	Lando Ret 1203	6031203	1
LittleRock	LANDO RET	Lando Ret 1204	6031204	1
LittleRock	LITTLE ROCK RET	Little Rock Ret 1206	1351206	1
LittleRock	MONTCLAIRE RET	Montclaire Ret 2405	1392405	1
LittleRock	OGDEN RET	Ogden Ret 1201	6041201	3
LittleRock	REMOUNT RD RET	Remount Rd Ret 1203	1191203	1
LittleRock	REMOUNT RD RET	Remount Rd Ret 1214	1191214	1
LittleRock	THRIFT RET	Thrift Ret 1206	1381206	1
MarionNC	CARSON RET	Carson Ret 1203	90391203	1
MarionNC	CARSON RET	Carson Ret 1204	90391204	1
MarionNC	GLENWOOD RET	Glenwood Ret 1206	90201206	1
MarionNC	MARION MN	Marion Main 1201	90401201	1
MarionNC	MARION MN	Marion Main 1202	90401202	1
MarionNC	NEBO RET	Nebo Ret 1203	90501203	1
MarionNC	OLD FORT RET	Old Fort Ret 1201	90301201	2
MarionNC	OLD FORT RET	Old Fort Ret 1202	90301202	2
Matthews	BEAVER DAM RET	Beaver Dam Ret 2414	72542414	3
Matthews	CARMEL RD RET	Carmel Rd Ret 1205	1261205	1
Matthews	CARMEL RD RET	Carmel Rd Ret 1206	1261206	1

Area	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Matthews	MARSHVILLE DIST	Marshville Dist 1201	72591201	1
Matthews	MATTHEWS RET	Matthews Ret 2407	1102407	3
Matthews	MONROE RD RET	Monroe Rd Ret 1207	1121207	1
Matthews	MONROE RD RET	Monroe Rd Ret 1208	1121208	1
Matthews	PARK RD RET	Park Rd Ret 1214	1161214	1
Matthews	STOUTS RET	Stouts Ret 2408	1412408	1
Matthews	WILGROVE RET	Wilgrove Ret 2409	1332409	1
Mt. Airy	DOBSON RET	Dobson Ret 1201	28051201	3
Mt. Airy	DOBSON RET	Dobson Ret 1202	28051202	1
Mt. Airy	FLAT SHOAL RET	Flat Shoal Ret 1201	28031201	1
Mt. Airy	KEY ST RET	Key St Ret 1201	28071201	2
Mt. Airy	LEVEL CROSS RET	Level Cross Ret 1201	28041201	5
Mt. Airy	MT AIRY RET	Mt Airy Ret 0404	28010404	1
Mt. Airy	MT AIRY RET	Mt Airy Ret 1211	28011211	1
Mt. Airy	MT AIRY RET	Mt Airy Ret 1212	28011212	1
Mt. Airy	PILOT MTN RET	Pilot Mtn Ret 0402	28020402	2
Mt. Airy	TOAST RET	Toast Ret 1210	28081210	1
Mt. Airy	WHITE PLAINS RET	White Plains Ret 1204	28091204	2
Newell	DERITA RET	Derita Ret 2407	1452407	1
Newell	FOUR SEASONS RET	Four Seasons Ret 2406	1402406	1
Newell	FURR RD RET	Furr Rd Ret 1202	1731202	1
Newell	MALLARD CREEK RET	Mallard Creek Ret 1205	1271205	1
Newell	NEWELL RET	Newell Ret 2412	1342412	1
Newell	SUNSET RET	Sunset Ret 1211	1321211	1
NorthWilkesboro	BROOK ST RET	Brook St Ret 1201	44021201	3
NorthWilkesboro	BROOK ST RET	Brook St Ret 1203	44021203	2
NorthWilkesboro	BROOK ST RET	Brook St Ret 1204	44021204	1
NorthWilkesboro	BROOK ST RET	Brook St Ret 1210	44021210	1
NorthWilkesboro	BROOK ST RET	Brook St Ret 1212	44021212	1
NorthWilkesboro	BROWNS FORD RET	Browns Ford Ret 1207	44061207	4
NorthWilkesboro	CAIRO RET	Cairo Ret 1202	44071202	2
NorthWilkesboro	FAIRPLAINS RET	Fairplains Ret 1206	44031206	2
NorthWilkesboro	FAIRPLAINS RET	Fairplains Ret 1208	44031208	1
NorthWilkesboro	FAIRPLAINS RET	Fairplains Ret 1210	44031210	2
NorthWilkesboro	HAYS RET	Hays Ret 1201	44051201	5
NorthWilkesboro	MILLERS CREEK RET	Millers Creek Ret 1205	44041205	5
NorthWilkesboro	MILLERS CREEK RET	Millers Creek Ret 1206	44041206	2
NorthWilkesboro	MILLERS CREEK RET	Millers Creek Ret 1207	44041207	1

Area	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
NorthWilkesboro	MILLERS CREEK RET	Millers Creek Ret 1209	44041209	3
NorthWilkesboro	MILLERS CREEK RET	Millers Creek Ret 1210	44041210	1
NorthWilkesboro	ROARING RIVER RET	Roaring River Ret 1201	44091201	1
RuralHall	BROOKWOOD RET	Brookwood Ret 1207	3031207	1
RuralHall	BUCK ISLAND DIST	Buck Island Dist 1201	3571201	1
RuralHall	DANBURY RET	Danbury Ret 2402	3382402	2
RuralHall	DANBURY RET	Danbury Ret 2403	3382403	1
RuralHall	KING RET	King Ret 1205	3191205	1
RuralHall	KING RET	King Ret 1206	3191206	2
RuralHall	KING RET	King Ret 1207	3191207	2
RuralHall	KING RET	King Ret 1209	3191209	1
RuralHall	KING RET	King Ret 1210	3191210	1
RuralHall	LUNSFORD RD RET	Lunsford Rd Ret 1204	3451204	3
RuralHall	MT TABOR RET	Mt Tabor Ret 1206	3221206	1
RuralHall	N WINSTON RET	N Winston Ret 1201	3231201	1
RuralHall	N WINSTON RET	N Winston Ret 1202	3231202	1
RuralHall	N WINSTON RET	N Winston Ret 1203	3231203	1
RuralHall	N WINSTON RET	N Winston Ret 1208	3231208	1
RuralHall	N WINSTON RET	N Winston Ret 1209	3231209	1
RuralHall	RURAL HALL RET	Rural Hall Ret 1203	3281203	1
RuralHall	RURAL HALL RET	Rural Hall Ret 1204	3281204	1
RuralHall	SEWARD RET	Seward Ret 2404	3312404	1
RuralHall	SHATTALON SW STA	Shattalon Sw Sta 1208	3301208	1
RuralHall	WALNUT COVE TIE	Walnut Cove Tie 2402	3372402	1
Salisbury	ALBEMARLE SW STA	Albemarle Sw Sta 2402	21302402	1
Salisbury	BARRIER RD RET	Barrier Rd Ret 1203	22441203	2
Salisbury	CHINA GROVE RET	China Grove Ret 1206	21481206	3
Salisbury	CLEVELAND RET	Cleveland Ret 1203	21081203	1
Salisbury	FAITH RET	Faith Ret 1207	21431207	3
Salisbury	LOCUST RET	Locust Ret 1205	21361205	1
Salisbury	LOCUST RET	Locust Ret 1206	21361206	1
Salisbury	LOCUST RET	Locust Ret 1207	21361207	1
Salisbury	LONG FERRY RET	Long Ferry Ret 1203	21091203	2
Salisbury	LONG FERRY RET	Long Ferry Ret 1204	21091204	1
Salisbury	LONG FERRY RET	Long Ferry Ret 1207	21091207	1
Salisbury	OAKBORO RET	Oakboro Ret 1208	21311208	1
Salisbury	ROCKWELL RET	Rockwell Ret 1201	21401201	2
Salisbury	ROCKWELL RET	Rockwell Ret 1202	21401202	3

Area	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Salisbury	ROCKWELL RET	Rockwell Ret 1211	21401211	2
Salisbury	ROCKWELL RET	Rockwell Ret 1212	21401212	2
Salisbury	STATESVILLE RD RET	Statesville Rd Ret 1204	21021204	2
Salisbury	STATESVILLE RD RET	Statesville Rd Ret 1205	21021205	1
Shelby	BELWOOD RET	Belwood Ret 1202	16651202	4
Shelby	BELWOOD RET	Belwood Ret 1203	16651203	2
Shelby	BETHWARE RET	Bethware Ret 1207	16061207	1
Shelby	BLANTON RET	Blanton Ret 1202	16701202	2
Shelby	BLANTON RET	Blanton Ret 1203	16701203	2
Shelby	BLANTON RET	Blanton Ret 1204	16701204	2
Shelby	BUFFALO CREEK RET	Buffalo Creek Ret 1203	16541203	1
Shelby	CHERRYVILLE RET	Cherryville Ret 1201	16041201	4
Shelby	CHRISTOPHER RD RET	Christopher Rd Ret 1202	16861202	2
Shelby	ELLIOTT RET	Elliott Ret 1204	16921204	1
Shelby	ELLIOTT RET	Elliott Ret 1207	16921207	1
Shelby	ELLIOTT RET	Elliott Ret 1208	16921208	3
Shelby	LAWNDALE RET	Lawndale Ret 1213	16201213	3
Shelby	LAWNDALE RET	Lawndale Ret 1214	16201214	1
Shelby	MOORESBORO RET	Mooresboro Ret 1204	16901204	4
Shelby	MOORESBORO RET	Mooresboro Ret 1205	16901205	1
Shelby	OAK GROVE RET	Oak Grove Ret 1201	16601201	1
Shelby	PARKWAY SS	Parkway SS 1209	16071209	1
Shelby	PARKWAY SS	Parkway SS 1212	16071212	3
Shelby	PATTERSON SPRINGS RET	Patterson Springs Ret 1205	16801205	1
Shelby	PATTERSON SPRINGS RET	Patterson Springs Ret 1209	16801209	1
Shelby	PATTERSON SPRINGS RET	Patterson Springs Ret 1211	16801211	1
Shelby	PATTERSON SPRINGS RET	Patterson Springs Ret 1212	16801212	2
Shelby	S SHELBY SS	S Shelby SS 1201	16301201	1
Spindale	AVONDALE RET	Avondale Ret 1202	15151202	1
Spindale	AVONDALE RET	Avondale Ret 1203	15151203	2
Spindale	CLEGHORN SS	Cleghorn SS 1203	15171203	2
Spindale	COLUMBUS RET	Columbus Ret 1203	15021203	2
Spindale	HUDLOW RET	Hudlow Ret 1205	15261205	1
Spindale	HUDLOW RET	Hudlow Ret 1206	15261206	5
Spindale	LAKE LURE RET	Lake Lure Ret 1202	15201202	2
Spindale	MOORESBORO RET	Mooresboro Ret 1202	15901202	2
Spindale	OAKLAND RD RET	Oakland Rd Ret 1203	15121203	1
Spindale	OAKLAND RD RET	Oakland Rd Ret 1210	15121210	1

Area	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Spindale	RIVERSTONE RET	Riverstone Ret 1202	15241202	2
Spindale	RIVERSTONE RET	Riverstone Ret 1203	15241203	1
Spindale	RUTHERFORDTON RET	Rutherfordton Ret 0401	15050401	1
Spindale	TANNER RET	Tanner Ret 1207	15131207	1
Spindale	TRYON RET	Tryon Ret 1202	15081202	3
Spindale	WASHBURN RET	Washburn Ret 1202	15951202	2
Spindale	WASHBURN RET	Washburn Ret 1203	15951203	2

Hydraulic Recloser

3-Phase Electric Recloser

2020-2022 DEP Candidate Locations *(Hydraulic to Electronic Recloser Replacement)*

Operations Center	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Asheboro	ASHEBORO EAST 115KV	HIGHWAY 64 23KV	T0960B11	1
Asheboro	ASHEBORO NORTH 115KV	WORTHVILLE 23KV	T0965B05	1
Asheboro	ASHEBORO WEST 115KV	UWHARRIE STREET 23KV	T0955B01	1
Asheboro	BISCOE 115KV	STAR NORTH 23KV	T0990B01	1
Asheboro	ROBBINS 115KV	CITY 23KV	T1230B01	5
Asheboro	SEAGROVE 115KV	POTTERS WAY 12 KV	T1520B02	1
Asheboro	TROY 115KV	M.T.I. 12KV	T1610B04	1
Asheville	BALDWIN 115KV	HOOPERS CREEK 23KV	T0350B03	2
Asheville	BEAVERDAM 115KV	PIEDMONT 23KV	T0371B02	1
Asheville	CANDLER 115KV	CANDLER 24KV	T0390B01	5
Asheville	CANDLER 115KV	CASE COVE 24KV	T0390B02	2
Asheville	ELK MOUNTAIN 115KV	LAKESHORE 24KV	T0510B13	2
Asheville	FAIRVIEW 115KV	GARREN CREEK 12KV	T0535B04	3
Asheville	FAIRVIEW 115KV	OLD FORT ROAD 12KV	T0535B03	1
Asheville	LEICESTER 115KV	JENKINS VALLEY 24KV	T0665B22	2
Asheville	LEICESTER 115KV	LEICESTER 24KV	T0665B11	2
Asheville	LEICESTER 115KV	MOUNT CARMEL 24KV	T0665B12	1

Operations Center	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Asheville	MARSHALL H. E. PLANT 115KV	HOT SPRINGS 23KV	T0670B01	2
Asheville	MONTE VISTA 115KV	ENKA 24KV	T0700B02	1
Asheville	MONTE VISTA 115KV	MONTE VISTA 24KV	T0700B04	1
Asheville	SKYLAND 115KV	MILLS GAP 23KV	T0781B01	1
Asheville	SWANNANOA 115KV	BLUE RIDGE ROAD 12KV	T0810B06	2
Asheville	WEAVERVILLE 115KV	HIGHLAND STREET 12KV	T0870B03	1
Asheville	WEAVERVILLE 115KV	WEAVER BOULEVARD 12KV	T0870B04	2
CapeFear	BEARD 115KV	EASTOVER 12KV	T1765B01	1
CapeFear	BENSON 230KV	HWY 50 23KV	T5480B03	2
CapeFear	BENSON 230KV	SOUTH JOHNSTON 23KV	T5480B01	1
CapeFear	BUIES CREEK 230KV	BUIES CREEK 23KV	T5504B01	1
CapeFear	BUIES CREEK 230KV	COATS 23KV	T5504B02	1
CapeFear	ERWIN 230KV	HWY 55 23KV	T5650B20	1
CapeFear	LILLINGTON 115KV	SHAWTOWN 24KV	T5860B01	1
Chatham	BYNUM 230KV	CHAPEL HILL 24KV	T1025B01	1
Chatham	PITTSBORO 230KV	NORTHWOOD 23KV	T2250B03	1
Chatham	SILER CITY 115KV	ROCKY RIVER 23KV	T1530B03	1
Chatham	SILER CITY 115KV	SILER CITY NORTH 23KV	T1530B01	3
Clinton	CLINTON FERRELL ST. 115KV	BOYKIN BRIDGE ROAD 23KV	T5580B05	1
Clinton	CLINTON FERRELL ST. 115KV	UNION SCHOOL 23KV	T5580B02	1
Clinton	CLINTON NORTH 115KV	KEENER 23KV	T5570B03	2
Clinton	CLINTON NORTH 115KV	McKOY STREET 23KV	T5570B01	1
Clinton	GARLAND 230KV	GARLAND 23KV	T6360B02	1
Clinton	NEWTON GROVE 230KV	HERRING SCHOOL 23KV	T5921B02	2
Clinton	NEWTON GROVE 230KV	NEWTON GROVE 23KV	T5921B01	2
Clinton	ROSEBORO 115KV	AUTRYVILLE 23KV	T5600B03	2
Fuquay	ANGIER 230KV	PEARIDGE 23KV	T5427B04	1
Fuquay	CLAYTON 115KV	AMELIA CHURCH 23KV	T5640B03	1
Fuquay	DUNCAN 230KV	WILBON 24KV	T4630B12	2
Fuquay	GARNER PANTHER BRANCH 230KV	BUFFALOE ROAD 23KV	T4725B01	1
Fuquay	GREEN LEVEL 230KV	GREEN LEVEL 24KV	T4603B11	1
Fuquay	NEW HILL 230KV	NEW HILL 23KV	T5911B01	2
Fuquay	WAKE TECH 230KV	MCCULLERS 24KV	T4426B12	1
Goldsboro	BELFAST 115KV	BELFAST 24KV	T5465B01	3
Goldsboro	BELFAST 115KV	BUCK SWAMP 24KV	T5465B05	1
Goldsboro	BELFAST 115KV	NAHUNTA 24KV	T5465B02	2
Goldsboro	GOLDSBORO LANGSTON 115KV	HOOD SWAMP 24KV	T5754B02	1
Goldsboro	GOLDSBORO LANGSTON 115KV	WAYNE MEMORIAL 24KV	T5754B03	3
Goldsboro	GRANTHAM 230KV	DUDLEY 23KV	T5770B03	1
Goldsboro	GRANTHAM 230KV	GRANTHAM 23KV	T5770B01	4
Goldsboro	LAGRANGE 115KV	BESTON ROAD 12KV	T5830B03	1
Goldsboro	MT. OLIVE WEST 115KV	CALYPSO 24KV	T5888B03	2

Operations Center	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Goldsboro	MT. OLIVE WEST 115KV	SMITH CHAPEL 24KV	T5888B01	1
Goldsboro	NEW HOPE 115KV	CHAPEL RD. 23KV	T5912B06	1
Goldsboro	NEW HOPE 115KV	NEW HOPE 23KV	T5912B01	2
Goldsboro	WARSAW 230KV	HWY 117 N 23KV	T6070B04	1
Goldsboro	WARSAW 230KV	KENANSVILLE 23KV	T6070B01	3
Goldsboro	WARSAW 230KV	WARSAW 23KV	T6070B03	3
Henderson	HENDERSON NORTH 115KV	WILLIAMSBORO 23KV	T4770B05	1
Henderson	LITTLETON 115KV	LITTLETON 23KV	T4915B01	3
Henderson	OXFORD NORTH 230KV	BEREA 23KV	T5090B04	2
Henderson	OXFORD NORTH 230KV	STOVALL 23KV	T5090B02	1
Henderson	OXFORD SOUTH 230KV	STEM 23KV	T5085B02	2
Henderson	WARRENTON 115KV	HWY 401 NORTH	T5360B01	5
Henderson	WARRENTON 115KV	NORLINA 23KV	T5360B03	3
Henderson	WARRENTON 115KV	WARRENTON 23KV	T5360B02	3
Henderson	YOUNGSVILLE 115KV	HARRIS CROSSROADS 24KV	T5401B01	1
Jacksonville	BEULAVILLE 115KV	BEULAVILLE 23KV	T5490B01	2
Jacksonville	CATHERINE LAKE 230KV	HWY 111 23 KV	T4108B03	1
Jacksonville	JACKSONVILLE BLUE CREEK 115KV	TAR LANDING 24KV	T6742B11	1
Jacksonville	SWANSBORO 230KV	HUBERT 23KV	T4360B03	1
Jacksonville	SWANSBORO 230KV	MAYSVILLE 23KV	T4360B01	2
Kinston	GRIFTON 115KV	GRAINGER 23KV	T4170B02	2
Kinston	GRIFTON 115KV	GRIFTON 23KV	T4170B01	1
Kinston	KINSTON 115KV	KINSTON INDUSTRIAL 24KV	T4230B01	1
Kinston	KINSTON 115KV	SEVEN SPRINGS 24KV	T4230B02	2
Kinston	KORNEGAY 115KV	PINK HILL 23KV	T4225B01	1
Kinston	SNOW HILL 115KV	JASON 24KV	T4320B02	1
Kinston	SNOW HILL 115KV	SNOW HILL 24KV	T4320B01	1
Maxton	FAIRMONT 115KV	FAIRMONT CENTRAL 23KV	T1980B01	1
Maxton	FAIRMONT 115KV	FAIRMONT NORTH 23KV	T1980B03	2
Maxton	LAURINBURG 230KV	COLLEGE 23KV	T2200B22	3
Maxton	LAURINBURG CITY 230KV	WESTWOOD 23KV	T2190B02	1
Maxton	MAXTON 115KV	MIDWAY 23KV	T2215B02	1
Maxton	MAXTON AIRPORT 115KV	CAMPBELL 23KV	T2217B02	1
Maxton	PEMBROKE 115KV	ODUM STREET 23 KV	T2247B03	2
Maxton	PEMBROKE 115KV	PEMBROKE CITY 23KV	T2247B01	1
Maxton	PEMBROKE 115KV	PEMBROKE COLLEGE 23KV	T2247B02	1
Maxton	RED SPRINGS 115KV	MILL 23KV	T2320B01	2
Maxton	RED SPRINGS 115KV	RED SPRINGS CITY 23KV	T2320B02	1
Maxton	SHANNON 115KV	LUMBER BRIDGE 23KV	T2475B02	3
Maxton	ST. PAULS 115KV	INDUSTRIAL 23KV	T2520B01	2
Maxton	WEATHERSPOON 230KV	RIVER ROUTE 23KV	T2631B01	1
Morehead City	NORTH RIVER 115KV	ATLANTIC 34.5KV	T4272B01	1
NewBern	NEW BERN WEST 230KV	SPRING GARDEN 23KV	T4255B01	2
NewBern	RHEMS 230KV	POLLOCKSVILLE 23KV	T4276B02	1

Operations Center	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Rockingham	ROCKINGHAM 230KV	ROCKINGHAM EAST 23KV	T1440B28	1
Rockingham	ROCKINGHAM WEST 115KV	CAS-WADE 23KV	T1430B06	1
Rockingham	ROCKINGHAM WEST 115KV	FIVE POINTS 23KV	T1430B04	2
Rockingham	WADESBORO 230KV	LILESVILLE 23KV	T1670B01	1
Rockingham	WADESBORO BOWMAN SCHOOL 230KV	POLKTON 23KV	T1672B02	5
Roxboro	PERSON 500KV	HYCO LAKE 24KV	T5095B13	1
Roxboro	ROXBORO SOUTH 230KV	BUSHY FORK 23KV	T5230B03	4
Roxboro	YANCEYVILLE 230KV	HANOVER MILLS 12KV	T5390B02	1
Roxboro	YANCEYVILLE 230KV	MILTON 12KV	T5390B04	2
Sanford	BEAR BRANCH 230KV	SEMINOLE 24KV	T2443B13	1
Sanford	JONESBORO 230KV	OLIVIA 23KV	T2141B01	1
Sanford	MONCURE 115KV	INDUSTRIAL 23KV	T2225B02	1
SouthernPines	ABERDEEN 115KV	PINEBLUFF 23KV	T0900B03	1
SouthernPines	CANDOR 115KV	BRUTONVILLE 23KV	T1850B02	3
SouthernPines	CANDOR 115KV	HWY 211 23KV	T1850B01	1
SouthernPines	CARTHAGE 115KV	CARTHAGE SOUTH 12KV	T1050B02	1
SouthernPines	CARTHAGE 115KV	COURTHOUSE 12KV	T1050B04	1
SouthernPines	LAKEVIEW 115KV	CAMERON 24KV	T1549B12	1
SouthernPines	LAKEVIEW 115KV	LAKEVIEW MOUNT PLEASANT 24KV	T1549B13	1
SouthernPines	RAEFORD 115KV	TIMBERLAND 12KV	T2280B05	1
SouthernPines	RAEFORD SOUTH 115KV	NC HWY #20 12 KV	T2282B02	1
SouthernPines	RAEFORD SOUTH 115KV	NC HWY. #211 12KV	T2282B01	1
SouthernPines	SOUTHERN PINES CENTER PARK 115KV	BENNETT STREET 23KV	T1548B02	1
SouthernPines	WEST END 230KV	WEST END 23KV	T1700B15	1
SprucePine	SPRUCE PINE 115KV	ESTATOE 23KV	T0791B04	5
SprucePine	SPRUCE PINE 115KV	LITTLE SWITZERLAND 23KV	T0791B03	2
SprucePine	SPRUCE PINE 115KV	SPRUCE PINE 23KV	T0791B01	5
Whiteville	ELIZABETHTOWN 115KV	DUBLIN 23KV	T6330B02	1
Whiteville	ELIZABETHTOWN 115KV	ELIZABETHTOWN 23KV	T6330B01	1
Whiteville	LAKE WACCAMAW 115KV	BOLTON 23KV	T4233B01	1
Whiteville	TABOR CITY 115KV	HIGHWAY 701 NORTH 23KV	T6630B02	2
WilmingtonN	DELCO 115KV	DELCO 24KV	T6250B02	1
WilmingtonN	EAGLE ISLAND 115KV	BELVILLE 24KV	T6310B26	1
WilmingtonN	EAGLE ISLAND 115KV	FLEMINGTON 24KV	T6310B20	1
WilmingtonN	LELAND INDUSTRIAL 115KV	MACO 24KV	T6446B23	1
WilmingtonN	VISTA 115KV	SLOOP POINT RD 24KV	T6386B11	1
WilmingtonS	SCOTTS HILL 230KV	EDGEWATER CLUB 24KV	T6387B21	1
Zebulon	ARCHER LODGE 230KV	THANKSGIVING FIRE ROAD 24KV	T4500B23	1
Zebulon	CASTALIA 230KV	MATTHEWS CROSSROADS 24KV	T6040B12	1
Zebulon	ELM CITY 115KV	ELM CITY 23KV	T5680B01	1
Zebulon	FOUR OAKS 230KV	HOLTS LAKE 24KV	T5732B01	1
Zebulon	ROLESVILLE 230KV	WATKINS ROAD 24KV	T5205B01	1
Zebulon	SELMA 230KV	BROGDEN 23KV	T5970B07	1

Operations Center	Substation Name	Circuit Name	Circuit ID	Approx. No. of Units
Zebulon	WILSON MILLS 230KV	WILSON MILLS 24KV	T5385B01	1
Zebulon	ZEBULON 115KV	ZEBULON EAST 23KV	T6090B06	1

SYSTEM INTELLIGENCE & MONITORING

Candidate Locations *(System Intelligence & Monitoring)*

Substation	Circuit	Year(s)
Marshall 115kV	T0670B01	2020-2021
Southport 230kV	T6561B03	2020
RANKIN AVE RET	Rankin Ave Ret 1208	2020-2021
New Hill 230kV	T5911B02	2020-2021
LaGrange 115kV	T5830B01	2021

Additional sites may be selected in 2022.

FUSE REPLACEMENT

The list of target sites for Fuse Replacement was developed through a detailed examination of every fuse in the DEC & DEP service territories. Data regarding circuit location, fuse size, and fuse zone of protection was sorted and filtered down to a list of potential candidate fuse replacement sites. These were then cross-referenced with historic outage data to ensure problem areas are the first to be targeted. By replacing fuses with small electronic reclosers at these problem sites we expect to provide our customers with a reduction in both sustained and momentary interruptions.

Fuse Replacement Reclosers Example

2020-2022 Proposed DEC Locations (Fuse Replacement)

Substation Name	Number of Circuits	Approx. No. Fuse Replacement Units
Fisher	1	6
Derita	4	37
Provol Ret	6	49
Wentworth Ret	2	11
Watertower Ret	1	9
Withers Ret	4	23
Lake Townsend Ret	4	34
Piper Glen Ret	5	33
Willow Creek Rt	3	22
Webbs Chapel Ret	4	10
Sunset Ret	7	58
S Shelby Ss	1	3
Glen Alpne Ret	2	11
Margrace Ss	2	3
Montclaire Ret	7	80
Four Seasons Ret	4	62

Reames Rd	6	45
Garrett Rd Ret	5	46
Stouts Ret	5	46
Cottonwood	3	16
Tryon Ret	2	9
Peace Haven Rd Ret	5	15
Springfield	4	73
Wests Mill Tie	1	2
Glenola	4	28
Wilgrove Ret	6	116
Blantyre Ret	3	16
Majolica	2	16
Mt Airy Ret	4	27
Monroe Mn	2	16
Propst Cross	2	3
Christopher Rd Ret	3	24
Steele Creek	5	38
Climax Ret	3	17
Hays Ret	2	5
Beatties Ford Ret	4	29
Mt Energy Dist	2	20
Longs Ferry	3	21
Kanuga Ret	3	25
Rockwell Tie	5	41
Camp Creek Rd Ret	3	20
Riverstone Ret	2	5
North Charlotte Ret	6	57
E Andrews Ret	1	1
Fairntosh Ret	3	29
Briar Creek Ret	4	77
Sumner Ret	4	18
Mallard Creek Ret	6	47
McAlpine Creek Ret	5	54
Shacktown Ret	1	3
Mt Tabor Ret	7	80
N Franklin Ret	2	3
Glenwood Ret	4	13
Triad Park Ret	2	15
Newell	5	71
Lake Lure Ret	2	4
Wallace Rd Ret	2	16
Research Triangle Ret	7	78
Elizabeth Ave Ret	8	73
Commonwealth Ret	9	121
Grey Ret	5	30
Kenilworth Ret	8	107
Peacock Tie	2	5

Friendship Ret	5	66
Beaver Dam	3	62
Parkwood Ret	2	32
Belmont Tie	4	44
Statesville Rd	5	58
Poplar Tent Ret	5	15
Hill St	2	46
Easy St	2	28
Hickory Grove Ret	9	108
Remount Rd Ret	8	111
Homestead Ret	4	29
Mine Shaft Ret	5	21
Lakewood Ret	5	55
Shattalon Sw Sta	5	60
Mar-Don Dr Ret	4	41
Sharon Ret	2	37
Hawthorne Rd Ret	7	80
Brantley Rd Ret	4	30
Canoe Creek Rt	1	20
Park Rd Ret	7	77
Tuckers Creek Ret	2	25
Mocksville Mn	3	58
Jessuptown Ret	6	87
Eastgate Ret	8	67
Lawndale Ret	2	7
Beckerdite Tie	4	45
China Grove	3	15
Montroyal Rd Ret	4	49
Pope Rd Ret	5	65
Hiddenite Ret	2	19
Claremont	3	12
Carmel Rd Ret	4	28
Ashe St Sw Sta	8	108
Walnut Cove Tie	2	25
Greensboro Mn	10	137
Monroe Rd Ret	9	135
E Thomasville Ret	6	40
Valmead Ret	3	25
Belwood Ret	2	13
Seward Ret	2	31
Island Ford Rd Ret	1	4
Goodwill Church Rd Ret	3	12
Randolph Ave Ret	8	328
Faith Ret	3	31
Valdese Ret	2	18
Speedway Ret	5	65
Coleman Ret	1	1

Matthews Ret	8	151
N Winston Ret	6	58
Cooleemee Ret	1	2
Denny Rd Ret	6	109
Turnersburg Ret	1	4
Frieden Ret	4	64
Ogburn Dist	2	2
Barrier Rd Ret	2	19
Winston Tie	4	54
Level Cross Ret	1	6
Ellerbee Ret	2	23
Rankin Ave Ret	7	82
Rozzelles Ret	5	26
Oxford Rd Ret	4	34
Davidson River Ret	1	4
Trollingwood Ret	4	45
Salisbury Mn	4	37
Brawley School Ret	8	60
Nix Rd Ret	3	11
Fairfax Rd Ret	8	126
Barbee Chapel Rd Ret	2	7
Thorpe Hydro	2	10
St Marks Ret	5	97
Robbinsville Ret	4	15
Catfish Ret	4	20
N Stanley Ret	4	45
Horton Rd Ret	7	58
Gateway Ret	2	3
White Plains Ret	2	8
N Hickory Ret	6	92
Crab Creek Ret	2	9
Tanner Ret	4	21
Kernersville Ret	5	88
Durham Mn	8	131
Woodlawn Ret	9	86
Cairo Ret	3	17
Webster Tie	3	24
Millers Creek Ret	5	32
Shortoff Ret	2	19
Rutherford College Ret	3	40
Sedge Garden Ret	5	46
Marble Tie	1	1
Mt Olive Ret	4	31
Toast Ret	5	62
Asheville Hwy Ret	7	85
Oak Grove Ret	2	17
Ruffin Ret	2	2

James St Ret	3	26
Kildare Ret	7	198
Cameron Ave Ret Ss	4	44
Brassfield Ret	6	49
Cullowhee Ret	1	5
Hinshaw Ret	7	93
Roberta Rd Ret	3	29
Blanton Ret	2	6
S Cullowhee Ret	2	5
Pfafftown Ret	2	16
Tysinger Rd Ret	2	33
Elmwood Ret	1	11
Bellhaven Ret	6	45
Mini Ranch Ret	2	16
Patterson Springs Ret	6	45
Jenkins Branch Ret	3	23
Cashiers Ret	4	43
Lewisville Ret	6	66
Broad St Ret	6	73
Bryant St Ret	2	12
Red Raider Ret	2	19
Merritt Dr Ret	6	125
Ball Park Ret	2	13
Highlands Ret	1	5
Stallings Rd Ret	4	37
Ossipee Dist	2	10
Ebert Rd Ret	2	11
Guthrie Ret	4	25
Butner Ret	4	74
Bannertown Tie	3	46
Morning Star Tie	6	95
Bancroft Ret	5	87
E Bryson Ret	2	26
Whitsett Ret	2	28
Rudd Ret	4	60
Holly Hill Ret	6	25
Buxton St Ret	5	61
Swaimtown Ret	5	65
Hope Valley Ret	8	83
Vandalia Ret	5	111
Thrift Ret	6	65
Monticello Ret	1	6
Fiddlers Creek Ret	5	57
Fairplains Ret	5	54
Southbound Ret	1	20
Ragsdale Ret	3	30
Elk Valley Ret	4	32

Pitts School Ret	3	3
Avondale Ret	3	19
Rhodhiss Ret	2	17
Hartford Ave Ret	4	40
E Sylva Ret	4	39
Burlington Mn	7	133
Mills River Ret	4	39
Lunsford Rd Ret	1	10
North Denver Ret	3	19
Linden St Sw Sta	5	64
Browns Ford Ret	4	20
Troutman Ret	2	23
Summerfield Ret	4	77
Eno Ret	3	83
Oak Ridge Ret	5	30
Murdock Rd Ret	2	13
S Franklin Ret	3	14
Otto Ret	2	8
Taylorsville	3	56
Depot St Ret	3	26
Gilbreath Ret	6	112
Big Willow Ret	2	4
Glen Raven Mn	6	123
King Ret	6	75
Griffith Rd Ret	5	45
East Maiden Ret	1	2
Advance Ret	4	26
Oakwood St Ret	4	33
Zion Church Rd Ret	2	9
Randleman Rd Ret	3	27
Startown Ret	3	24
Colfax Ret	4	31
Crest St Ret	4	49
Millis Ret	3	67
Cherokee Reservation Ret	5	20
Oyama Ret	4	38
Lincolnton Tie	7	77
S Hickory Ret	4	19
Bridgeport Ret	2	13

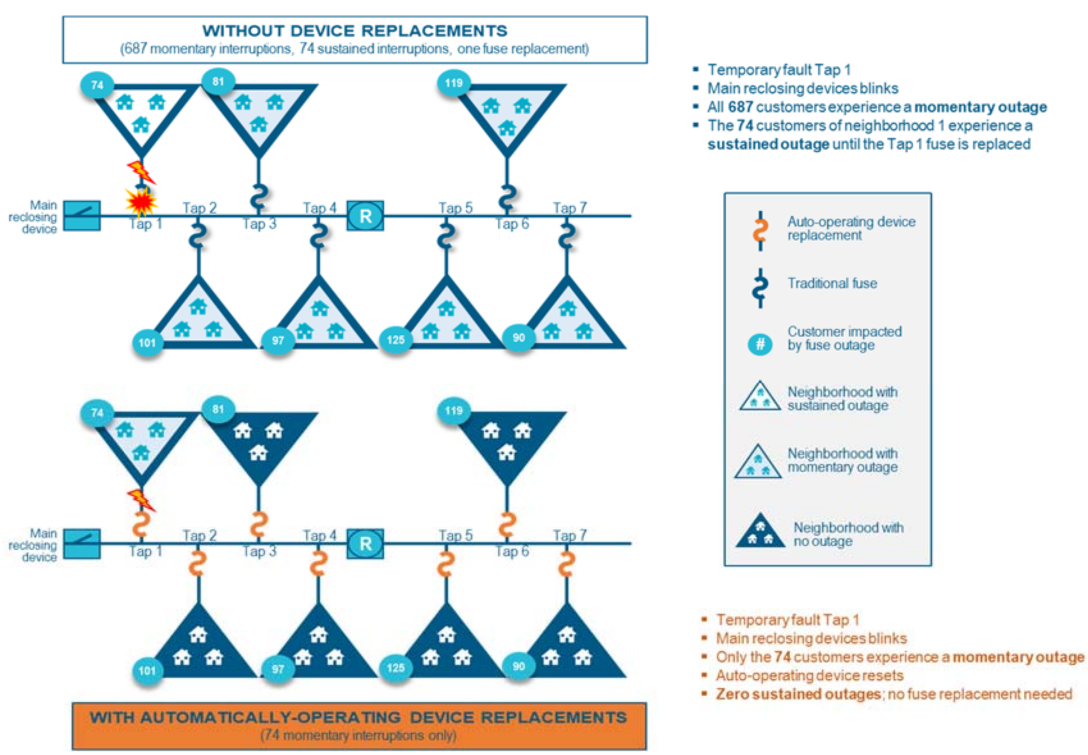
2020-2022 Proposed DEP Locations (Fuse Replacement)

Substation Name	Number of Circuits	Approx. No. Fuse Replacement Units
CARY REGENCY PARK 230KV	4	2
SAMARIA 115KV	2	24
DUNCAN 230KV	3	34
RALEIGH HONEYCUTT 230KV	3	21
WEATHERSPOON 230KV	4	36
MILBURNIE 230KV	5	13
GARNER WHITE OAK 230KV	3	30
CLAYTON 115KV	5	43
RED SPRINGS 115KV	2	7
ASHEBORO WEST 115KV	3	69
GARNER PANTHER BRANCH 230KV	5	41
RALEIGH FOXCROFT 230KV	3	25
LUMBERTON 115KV	2	18
ELK MOUNTAIN 115KV	5	91
RALEIGH HARRINGTON STREET 115KV	1	3
GREEN LEVEL 115KV	2	19
RALEIGH OAKDALE 230KV	5	79
RALEIGH WORTHDALE 230KV	4	75
SKYLAND 115KV	5	71
FUQUAY 230KV	5	90
KNIGHTDALE SQUARE D 230KV	3	38
SANFORD HORNER BLVD. 230KV	5	129
WAKE TECH 230KV	3	43
RALEIGH LEESVILLE ROAD 230KV	8	24
CARALEIGH 230KV	5	61
CARY PINEY PLAINS 230KV	7	18
CARY 230KV	5	69
SANFORD GARDEN STREET	5	127
FUQUAY BELLS LAKE 230KV	5	46
BILTMORE 115KV	8	109
PINE LAKE 230KV	7	13
MT. GILEAD 115KV	3	48
NEW SALEM 115KV	4	73
RALEIGH SOUTH 115KV	5	74
HOLLY SPRINGS INDUSTRIAL 230KV	2	13
RALEIGH NORTHSIDE 115KV	9	125
GARNER TRYON HILLS 115KV	3	45
AVERY CREEK 115KV	3	20
GARNER 115KV	5	107
ROLESVILLE 230KV	5	56
MORDECAI 115KV	4	44

APEX 230KV	4	18
BEAVERDAM 115KV	3	95
WENDELL 230KV	3	80
AUBURN 230KV	2	17
ANGIER 230KV	4	63
LIBERTY 115KV	2	62
SWANNANOA 115KV	7	135
CARY EVANS ROAD 230KV	6	5
ARDEN 115KV	4	80
RALEIGH SIX FORKS 230KV	5	11
ABERDEEN 115KV	5	106
BALDWIN 115KV	3	27
FOUR OAKS 230KV	3	59
ELM CITY 115KV	1	16
OTEEN 115KV	7	124
WEAVERVILLE 115KV	4	91
KNIGHTDALE 115KV	4	34
RALEIGH YONKERS ROAD 115KV	2	45
BARNARDSVILLE 115KV	2	24
WEST ASHEVILLE 115KV	8	90
ASHEVILLE ROCK HILL 115KV	3	62
CANDLER 115KV	2	47
WEST END 230KV	5	50
BLACK MOUNTAIN 115KV	3	63
BYNUM 230KV	4	45
SILER CITY 115KV	5	103
REYNOLDS 115KV	2	25
GARNER I-40 230KV	3	21
AMBERLY 230KV	5	13
STALLINGS CROSSROADS 115KV	3	48
LEESVILLE WOOD VALLEY 230KV	6	36
CASTALIA 230KV	2	25
MARSHALL 115KV	1	2
ROBBINS 115KV	1	30
SPRING HOPE 115KV	3	56
RALEIGH PRISON FARM 230KV	5	32
TROY 115KV	4	29
METHOD 230KV	8	119
MONCURE 115KV	2	23
HAMLET 230KV	4	37
ARCHER LODGE 230KV	5	32
RALEIGH BLUE RIDGE 230KV	5	24
ZEBULON 115KV	5	55
HOLLY SPRINGS 230KV	6	45
CARY TRENTON ROAD 230KV	3	3
EMMA 115KV	3	65
CARY TRIANGLE FOREST 230KV	5	7

HENDERSON 230KV	6	116
BAILEY 230KV	3	47
LAKESTONE 115KV	7	63
RAEFORD 115KV	5	66
FALLS 230KV	3	7
JONESBORO 230KV	7	68
ROCKINGHAM-ABERDEEN ROAD	2	55
LAURINBURG CITY 230KV	1	29
LAUREL HILL 230KV	2	31
SOUTHERN PINES CENTER PARK 115KV	5	129
SELMA 230KV	6	79
MONTE VISTA 115KV	5	139
CARTHAGE 115KV	3	45
NASHVILLE 115KV	5	85
ASHEBORO SOUTH 115KV	5	107
PEMBROKE 115KV	3	45
PRINCETON 115KV	3	67
ROWLAND 230KV	2	28
RAMSEUR 115KV	3	72
ROCKY MOUNT 230KV	3	31
RALEIGH HOMESTEAD 230KV	5	26
MAXTON 115KV	2	52
MAGGIE VALLEY 115KV	2	43
CANTON 115KV	5	118
ROXBORO BOWMANTOWN ROAD 230KV	2	11
PITTSBORO 230KV	3	86
ASHEBORO NORTH 115KV	5	71
LAKE JUNALUSKA 115KV	3	93
WADESBORO-BOWMAN SCH.	3	72
OXFORD NORTH 230KV	5	79
ASHEVILLE BENT CREEK 115KV	3	34
SANFORD DEEP RIVER 230KV	3	18
HAZELWOOD 115KV	4	104
ROCKINGHAM 230KV	5	99
CANDOR 115KV	2	36
BAHAMA 230KV	1	25
ROCKINGHAM WEST 115KV	5	83
SOUTHERN PINES 115KV	5	100
SPRUCE PINE 115KV	5	110
WILSON MILLS 230KV	4	50
FAIRMONT 115KV	4	88
ELLERBE 230KV	1	20
FAIRVIEW 115KV	4	80
VANDERBILT 115KV	6	118
HENDERSON NORTH 115KV	5	40
ASHEBORO EAST 115KV	3	64

LAURINBURG 230KV	4	14
NEW HILL 230KV	2	17
CHESTNUT HILLS 115KV	10	77
BISCOE 115KV	3	68
ROXBORO 115KV	6	104
HENDERSON EAST 230KV	5	76
OXFORD SOUTH 230KV	4	46
SHANNON 115KV	2	20
RALEIGH 115KV	6	29
RALEIGH EAST STREET 230KV	7	59
LEICESTER 115KV	4	91
WARRENTON 115KV	4	52
NEUSE 115KV	5	15
SEAGROVE 115KV	2	20
YANCEYVILLE 230KV	4	43
RALEIGH DURHAM AIRPORT 230KV	5	28
ROXBORO SOUTH 230KV	3	36
WADESBORO 230KV	4	53
LITTLETON 115KV	1	19
ST. PAULS 115KV	2	71
MICAVILLE 138KV	1	9
TROY BURNETTE STREET 115KV	2	44
FRANKLINTON 115KV	2	44
RALEIGH TIMBERLAKE 115KV	6	52



UNDERGROUND (UG) SYSTEM AUTOMATION

DEC Locations *(Underground System Automation)*

Year	Location	# Vaults/Pads Implemented	Project Scope	Communications Method
2020	Charlotte A&I	6	Automation & Comm Deployment	Fiber and Cellular
2020	Charlotte Redesign	Phase 1	Infrastructure (circuit ext., duct back)	N/A
2021	Charlotte A&I	6	Automation & Comm Deployment	Fiber and Cellular
2021	Charlotte Redesign	Phase 2.1.1-4	Infrastructure (circuit ext., duct back)	N/A
2022	Hickory	2	Automation & Comm Deployment	Fiber
2022	Salisbury	2	Automation & Comm Deployment	Cellular
2022	Charlotte A&I	11	Automation & Comm Deployment	Fiber and Cellular
2022	Charlotte Redesign	Phase 2.1.5-6	Infrastructure (circuit ext., duct back)	N/A

DEP Locations *(Underground System Automation)*

Year	Location	# Vaults/Pads Implemented	Project Scope	Communications Method
2020	Raleigh DT	2	Automation & Comm Deployment	Fiber
2021	Raleigh DT	4	Automation & Comm Deployment	Fiber
2021	RDU Airport	1	Automation & Comm Deployment	Fiber
2021	Asheville	2	Automation & Comm Deployment	Cellular
2022	Raleigh DT	4	Automation & Comm Deployment	Fiber
2022	RDU Airport	2	Automation & Comm Deployment	Fiber
2022	Asheville	2	Automation & Comm Deployment	Cellular


Pad-Mount Automatic Throw Over Switchgear


Vacuum Operated Self-Healing Loop Switchgear

XIV. Enterprise Applications

This portfolio effort enables enterprise wide application and system performance enhancements and optimizations. Within this enterprise wide portfolio, there are sub-portfolios responsible for the delivery of enterprise technology solutions that support transmission, distribution, and other critical lines of business: (1) Enterprise Systems and (2) Grid Analytics.

Enterprise Systems focuses on delivering transformative, cross-functional technical solutions to the enterprise in non-disruptive ways. An element within this portfolio includes the IoT Platform Assessment POC, which will pave the way for future Distributed Intelligence activities.

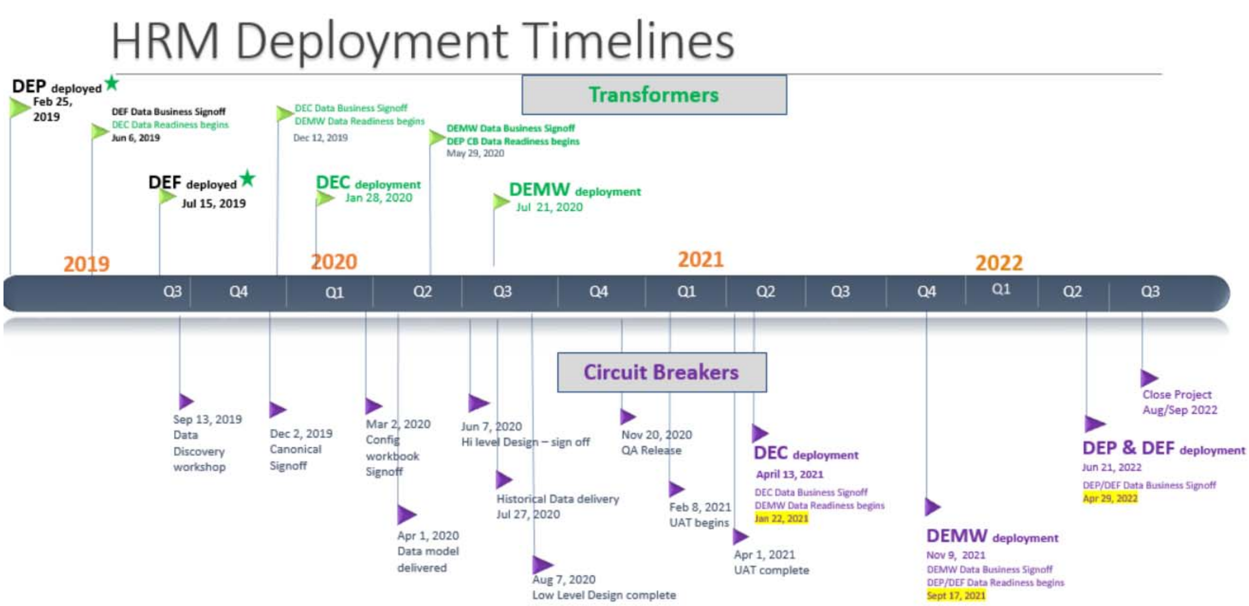
Grid Analytics optimizes the electric system health and performance through the deployment of the Health Risk Management (HRM) tool; helping to prevent equipment failures and improve asset performance on our transmission systems. There are also investments made through GIS Data Cleanup activities that will assist in optimizing IVVC and SOG.

3-Year Scope *(Enterprise Applications)*

The NC specific detailed implementation plan for 2020 – 2022 is as follows.

	Duke Energy Carolinas			Duke Energy Progress		
Enterprise Applications	2020	2021	2022	2020	2021	2022
TOTAL	$4,348,263	$3,139,778	$9,554,856	$1,360,755	$3,211,415	$6,232,132
Enterprise Applications	$4,348,263	$3,139,778	$9,554,856	$1,360,755	$3,211,415	$6,232,132

3-Year Scope *(Transmission Health & Risk Management)*



XV. Integrated System Operations Planning (ISOP)

Requirements for modern electric utility systems are evolving rapidly with the advent of emerging new energy technologies, changes in policy, and rapid advancements in information exchange and customer needs. Integrated System Operations Planning (ISOP) focuses on the integration of utility planning disciplines for generation, transmission, distribution and customer programs to improve the valuation and optimization of energy resources across all segments of the utility system to best serve electric customers.

The ISOP process addresses key operational and economic considerations across all segments of the system through integration and refinement of existing system planning tools and, in some cases, development of new analytical tools to assess characteristics that have not historically been captured or considered in long-term planning. For example, the ISOP process would include developing the methodology to determine the combined ("stacked") value that the Distributed Energy Resources (including utility energy storage) and Customer programs can provide by addressing multiple use cases, e.g., combining the benefit of deferring or avoiding local traditional "wires" investments while also helping to meet bulk generation needs such as regulating reserves, balancing reserves, and capacity reserves.

ISOP is a multi-year development program to build and integrate the tools, and related processes needed to accommodate an increasingly integrated approach that will be required to optimize planning and operation of the electric utility system of the future. One example is the Morecast circuit level load forecasting tool, which is necessary to enable the Advanced Distribution Planning (ADP) tool. While the ADP project is being led by the Grid Solutions group, the two efforts are complementary and with both efforts being developed in an Agile, coordinated fashion.

3-Year Scope *(Integrated System Operations Planning)*

The North Carolina plan for 2020 – 2022 is as follows.

	Duke Energy Carolinas			Duke Energy Progress		
ISOP	2020	2021	2022	2020	2021	2022
TOTAL	$3,027,886	$378,609	$748,720	$1,829,939	$233,062	$430,513
Adv Dist Planning (ADP)Tool	$3,027,886	$378,609	$748,720	$1,829,939	$233,062	$430,513

Project Schedule

XVI. DER Dispatch Enterprise Tool

This Distributed Energy Resources (DER) Dispatch Enterprise tool will coordinate with the Distribution Management System (DMS) and Energy Management System (EMS) to improve the way DERs are integrated in the energy supply mix, both at the Distribution and the bulk power level.

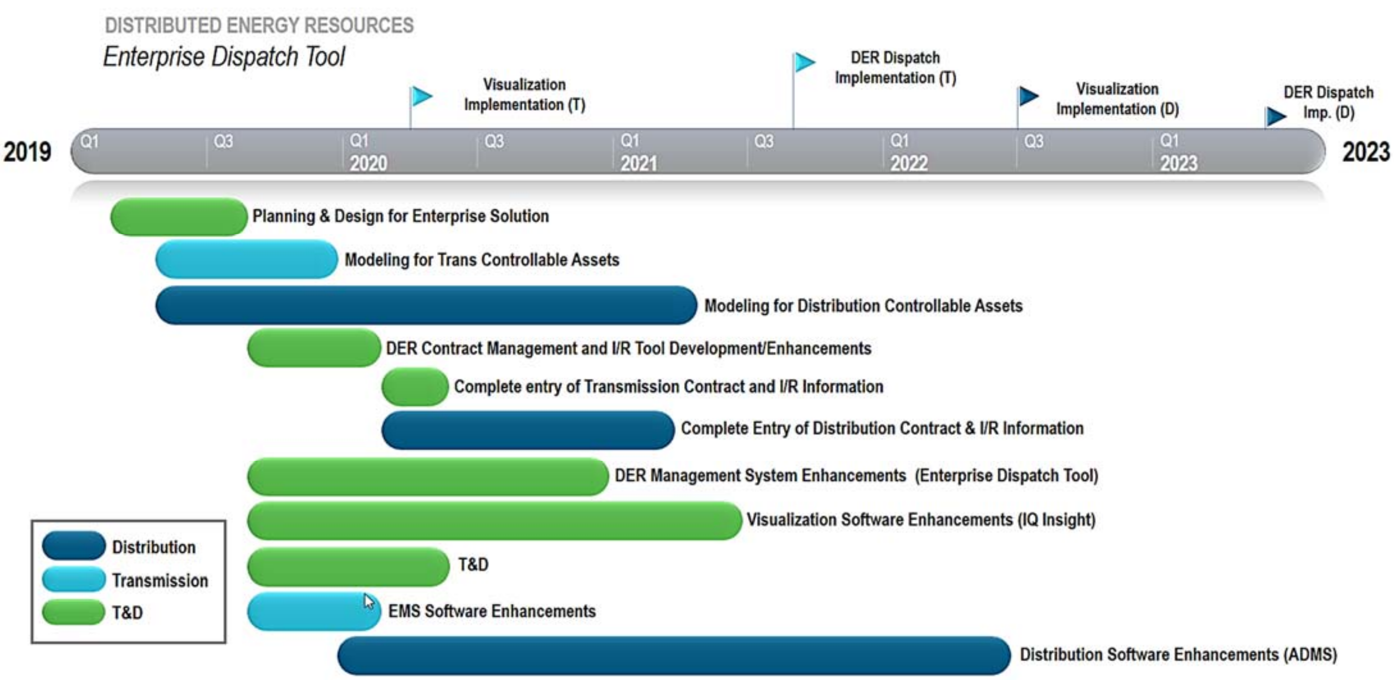
By providing system-wide visualization and control of large-scale DERs, the DER Dispatch Tool will enable system operators to model, forecast, and dispatch a portfolio of distributed energy resources, like solar generation, biofuel generation and energy storage, based on system conditions and real-time customer demand. This tool will help meet the need to match energy demand with supply, especially in emergency conditions.

Current processes and tools provide system operators with a rudimentary ability to quickly shed large blocks of solar generation in emergency conditions to meet standards for real power control (BAL-001-2). The proposed solution will provide operators with a more automated and refined toolset to optimize management of both utility and customer owned DERs to meet system stability requirements.

This system will replace an existing tool in DEP that is used to dispatch distribution connected solar in 50 MW increments

3-Year Scope *(DER Dispatch Enterprise Tool)*

	Duke Energy Carolinas			Duke Energy Progress		
DER Dispatch Tool	2020	2021	2022	2020	2021	2022
Costs	$1,737,899	$2,031,895	$761,961	$1,118,237	$1,307,406	$490,277



XVII. Electric Transportation

The NC Electric Transportation Pilot will deploy infrastructure starting in 2019 for a period of three years to facilitate adoption of electric transportation technologies. The main goals of the Pilot are:

- Install a foundational level of fast charging infrastructure across North Carolina.
- Study the effects of charging multiple types of electric vehicles.
- Develop procedures to ensure cost-effective integration of vehicle charging by actively managing charging loads.
- Support public transit electrification and associated cost savings to public agencies.
- Ensure electrification projects benefit all customers, including those in disadvantaged communities and those who do not own electric vehicles.
- Provide cost share to VW Settlement Mitigation Trust funding and other transportation electrification funds to reduce the upfront capital premium of electric transit and school bus deployments.

The Pilot is designed to determine best practices for realizing the significant potential benefits of increased electric transportation adoption including:

- Ratepayer benefits from increasing electric system utilization.
- Economic benefits from retaining fuel cost savings in state, improving the state energy trade balance, and deploying cutting-edge vehicle technology.
- Environmental benefits of improving local air quality by eliminating harmful vehicle emissions.

The company will report operational data and results to the NCUC on an annual basis and at the conclusion of the three-year term will prepare a final report outlining a proposed permanent program, or explain why a permanent program is not warranted.

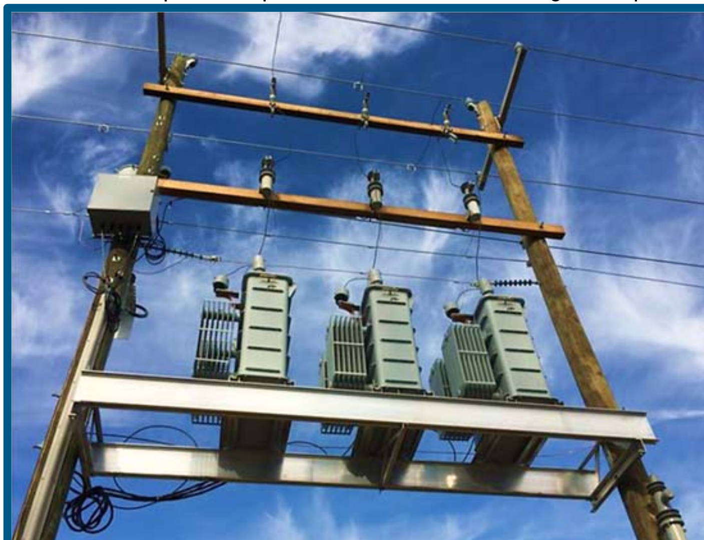
The limited scope and duration of the Pilot works to protect both customers and the EV market by laying a foundation for EV market growth in the state without future impeding mandates.

	Duke Energy Carolinas			Duke Energy Progress		
Electric Transportation	2020	2021	2022	2020	2021	2022
Electric Transportation	$19,117	$19,117	$0	$12,623	$12,623	$0

XVIII. Power Electronics for Volt/VAR

As the adoption of distributed energy resources (DER) (e.g., customer-owned solar and energy storage) reaches critical levels and microgrid technology matures, protective device technology must also advance to appropriately detect and respond to rapid voltage and power fluctuations that often accompany non-dispatchable resources such as solar.

As clouds move across the daytime sky and momentarily block sunlight from reaching solar panels, solar generation immediately ceases. As sunlight peaks through openings in the cloud cover, the solar panels begin generating, creating power spikes and voltage instability on the circuit. These intermittent power impacts occur and then change at rapid rates (in some cases sub-second) and frequently faster than the legacy electro-mechanical voltage management equipment like regulators and capacitors can handle.


Medium Voltage Stat Comm Device

Integrating advanced solid-state technologies like power electronics (i.e., static VAR compensators and other solid-state voltage support equipment), better equips the distribution system to manage power quality issues associated with increasing DER penetration.

The Power Electronics for Volt/VAR program is a limited-scale deployment focused on to validation of capabilities and benefits.

3-Year Scope *(Power Electronics)*

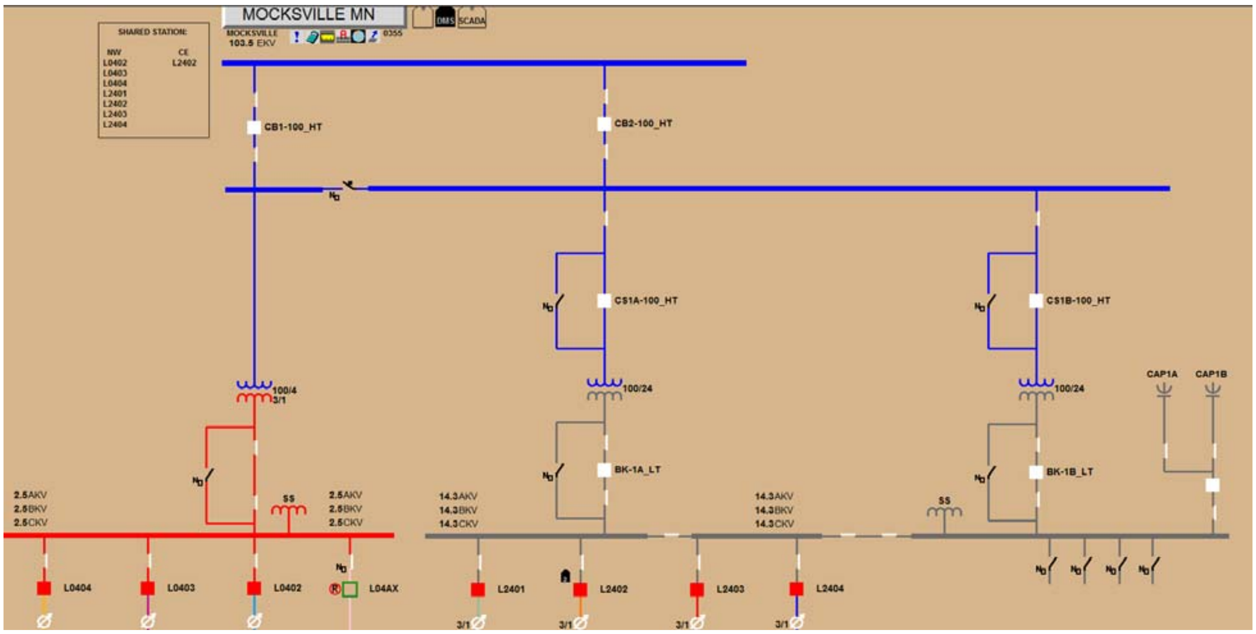
	Duke Energy Carolinas			Duke Energy Progress		
Power Electronics	2020	2021	2022	2020	2021	2022
Costs	-	$347,000	$347,000	$36,000	$532,000	$532,000

Secondary Voltage Support Equipment

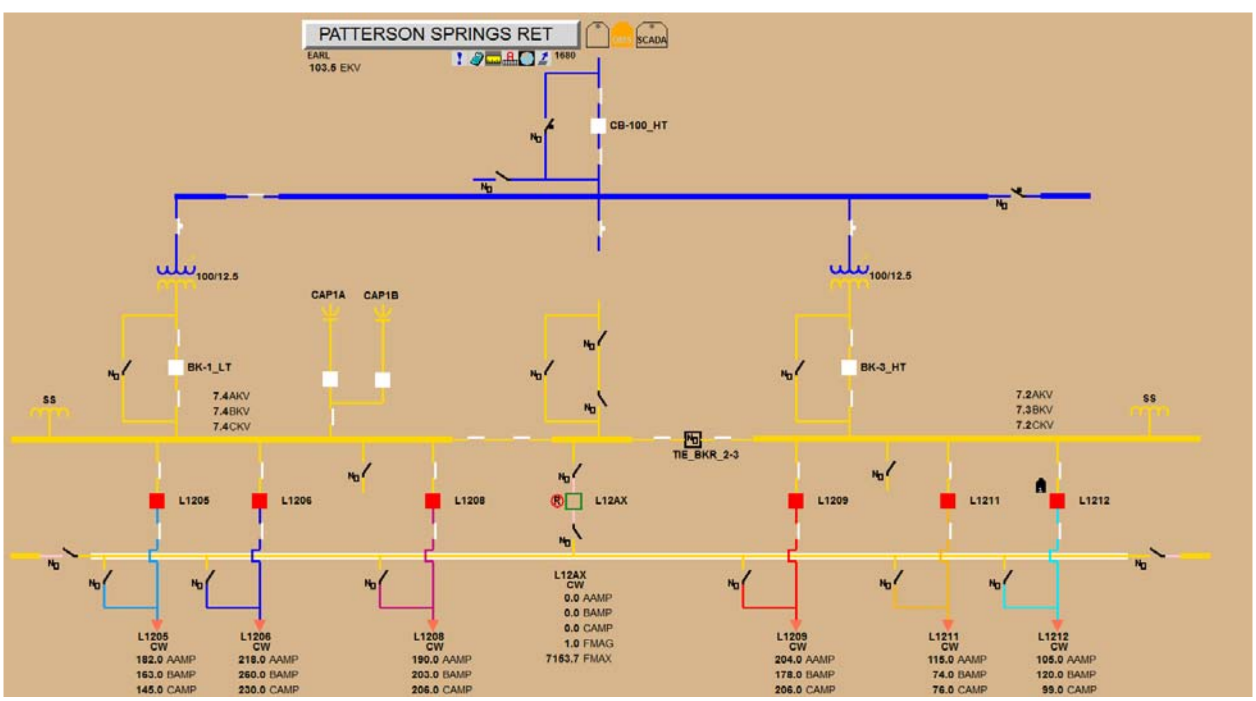

Locations *(Power Electronics for Volt/VAR)*

Year	Location	Jurisdiction
2021	Mocksville	DEC
2021	Oxford North	DEP
2021-2022	Henderson North	DEP
2022	Patterson Springs	DEC
2022	Grantham	DEP

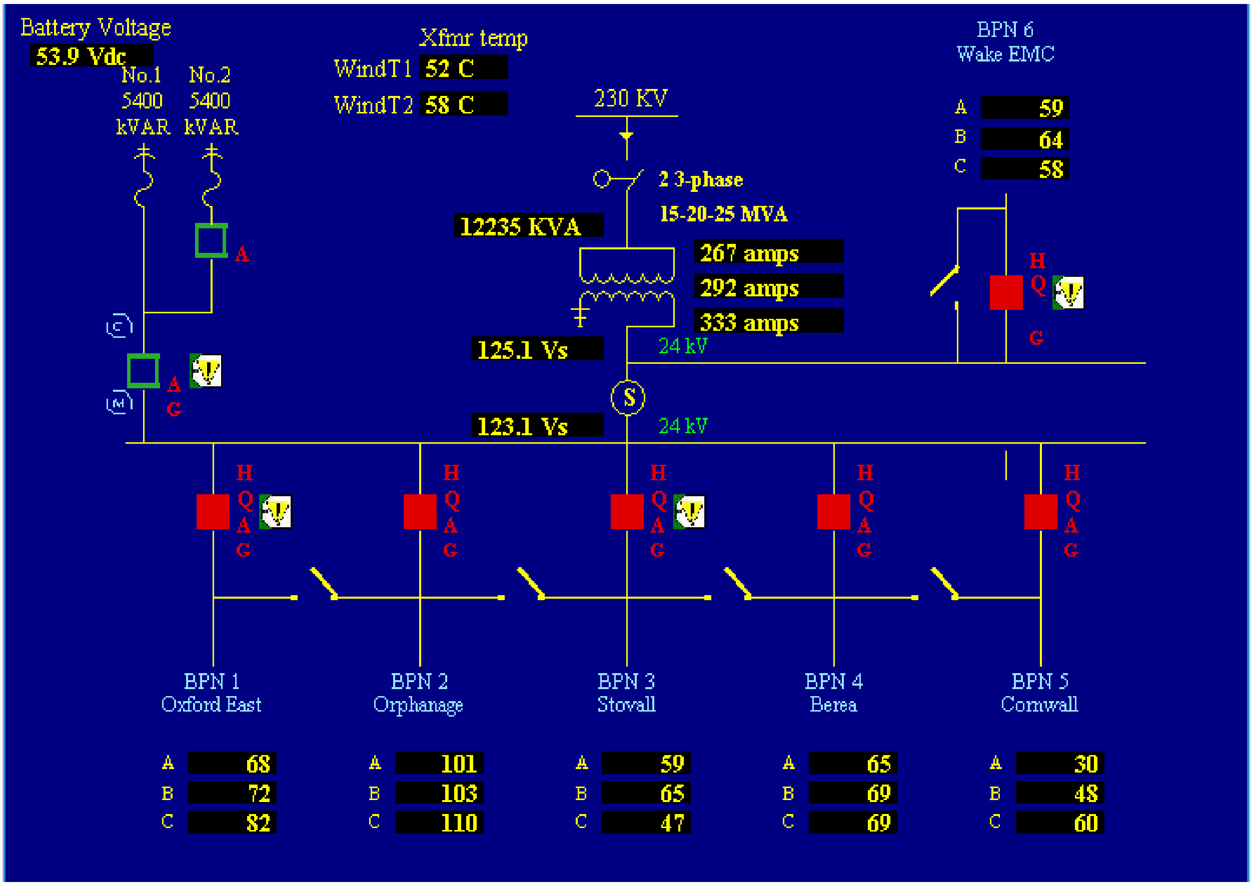
DEC: Mocksville Mn One Line Diagram



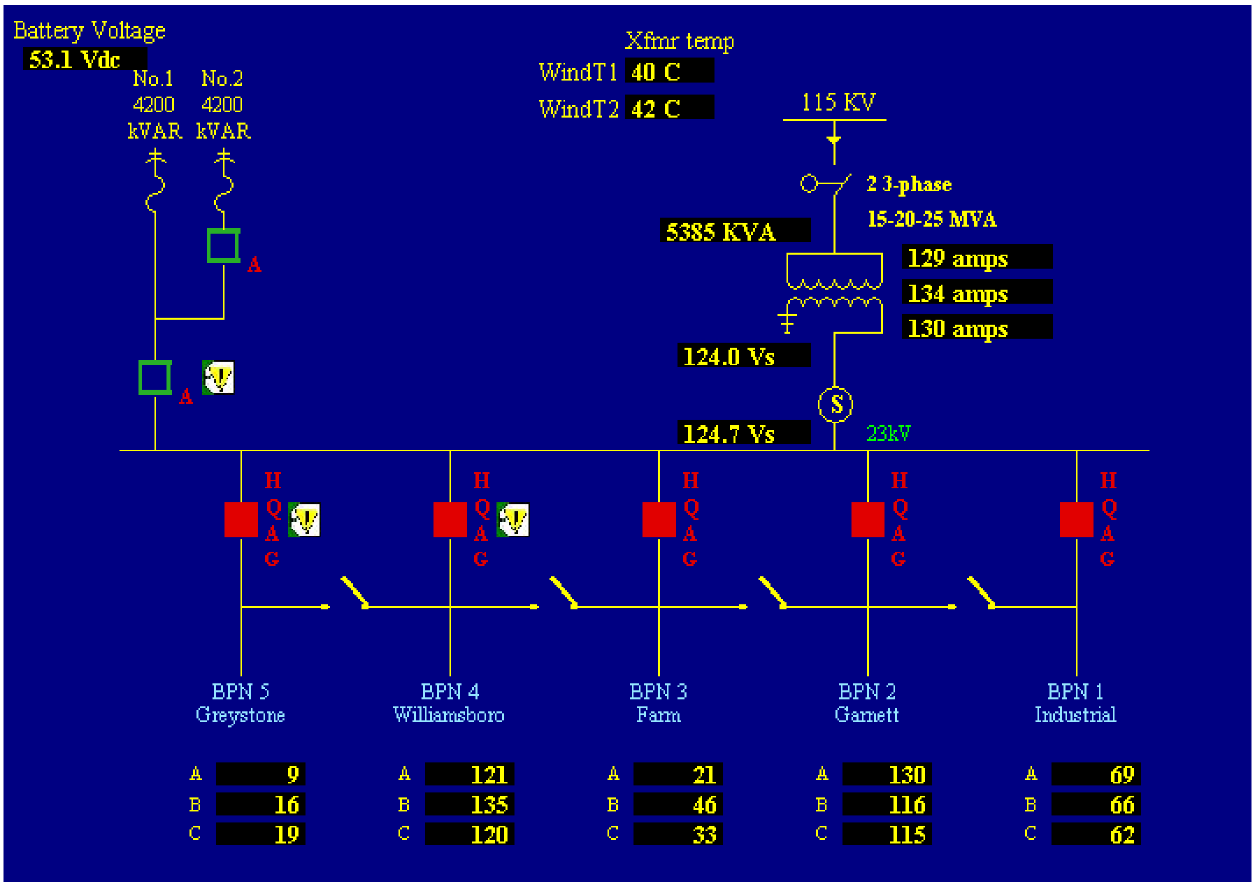
DEC: Patterson Springs Ret One Line Diagram



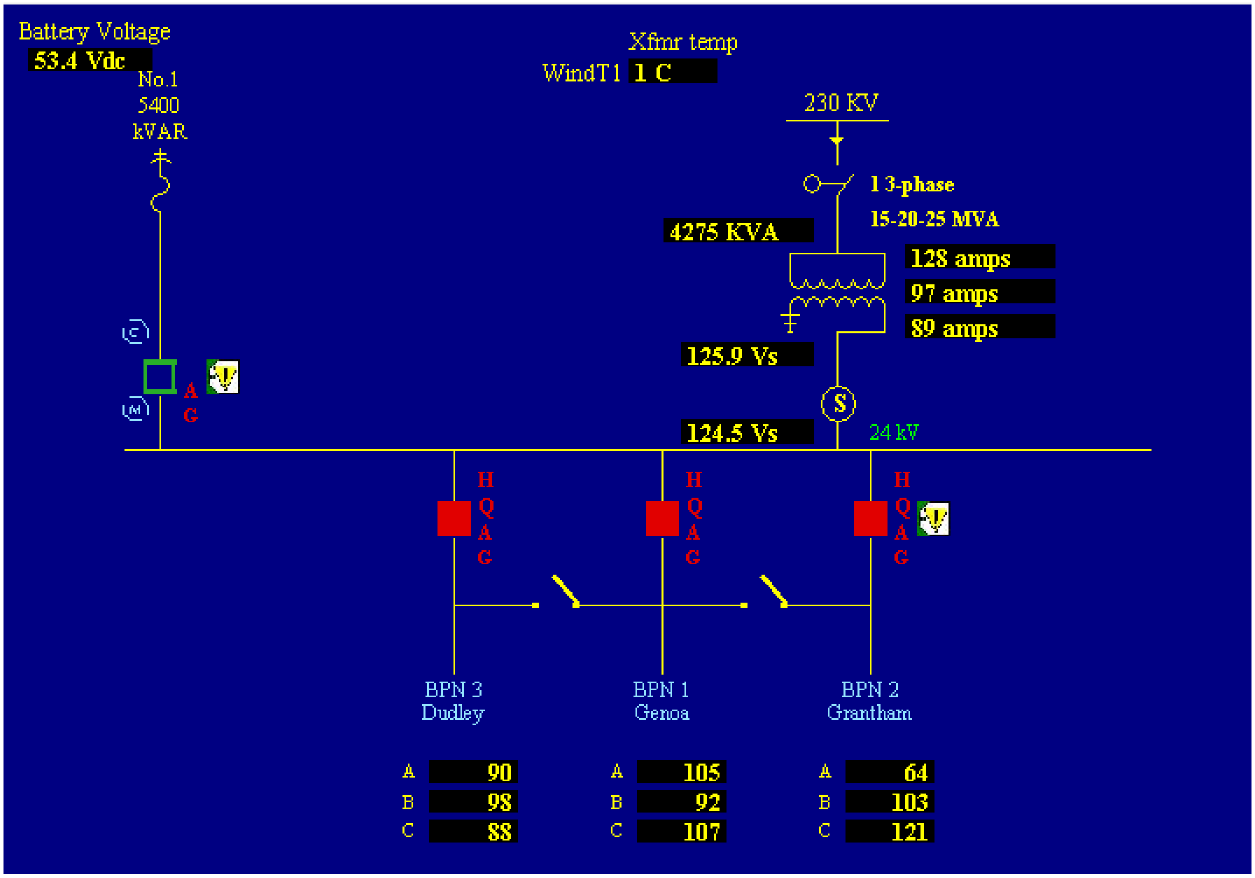
DEP: Oxford North 230KV
One Line Diagram



DEP: Henderson North 115KV One Line Diagram



DEP: Grantham 230KV
One Line Diagram



XIX. Physical and Cyber Security

The program focuses on hardening above the standard compliance requirements the overall security of the grid including identification of threats (current and evolving) along with the installation of measures to detect, defend, and mitigate these threats, as well as implement rapid recovery should an event occur. Transmission elements of the program include:

- Transmission Substation Physical Security
- Windows-based Change Outs to address cyber security standards for older Windows-based relays
- Cyber Security Enhancements
- Electromagnetic Pulse and Intentional Electromagnetic Interference (EMP/IEMI) Protection

At the distribution system level, much of the focus involves securing and improving risk mitigation of remotely controlled field equipment. An example is enabling door alarms and entry notifications. Programs include:

- Device Entry Alert System (DEAS)
- Distribution Line Device Cyber Protection
- Secure Access Device Management (SADM) - a single tool to remotely and securely perform device management activities and event record retrieval on the entire transmission and distribution device inventory

3-Year Scope *(Physical and Cyber Security)*

	Duke Energy Carolinas			*Duke Energy Progress*		
Phys & Cyber Security	2020	2021	2022	2020	2021	2022
TOTAL	$51,911,337	$10,872,865	$2,301,782	$13,683,052	$23,964,865	$31,024,227
Substation Physical Security*	$47,117,700	$7,254,630	-	$7,742,475	$20,170,140	$28,428,780
Windows Based Unit Change outs*	$822,690	-	-	-	-	-
Device Entry Alert System	$1,197,327	$745,237	-	$770,410	$479,416	-
Secure Access Device Mgmt	$1,728,621	$1,512,999	$1,021,782	$1,112,267	$973,527	$657,458
Line Device Protection**	$1,045,000	$1,360,000	$1,280,000	$4,057,900	$2,341,682	$1,937,989

* Actual costs will be captured on a per-site basis. This approach allows the Company to bundle multiple programs at the same site for better cost efficiency. The state dollars represented are based on an allocation methodology as Transmission's work is recorded on a system basis and not a state specific basis.

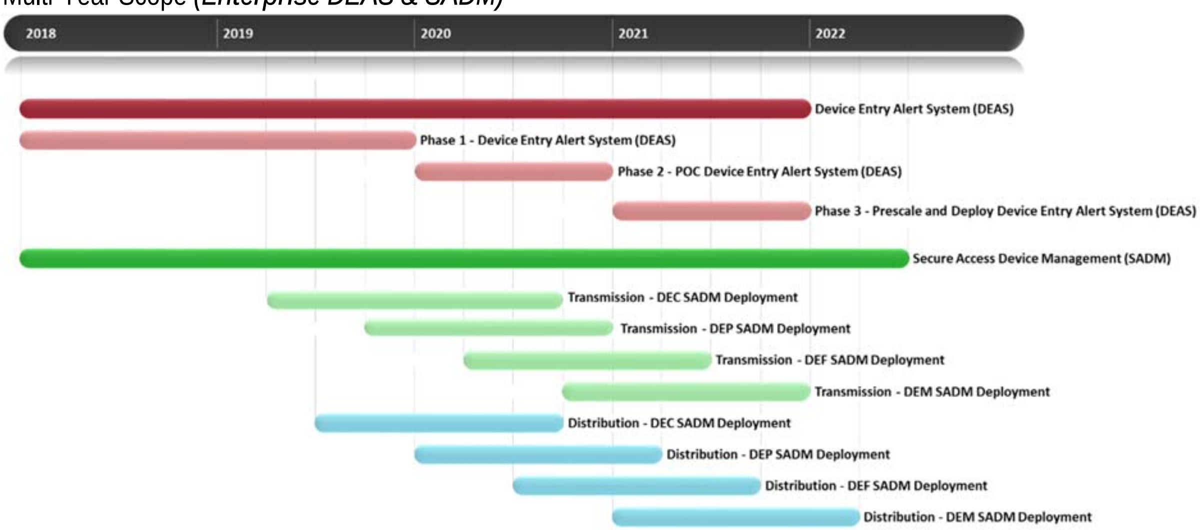
** The Capacitor Bank Control replacements associated with DSDR assets will not be recovered through GIP but instead will be separately evaluated and recovered under the DSDR rider.

Entry alarm being installed in legacy controls

Device with integrated entry alarm capabilities

Transmission Substation Physical Security – High Security Perimeter Fencing

Multi-Year Scope *(Enterprise DEAS & SADM)*



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June 26, 2018

VIA ELECTRONIC FILING

M. Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Report of NC Power/Forward Technical Workshop Docket Nos. E-2, Sub 1142 and E-7, Sub 1146

Dear Ms. Jarvis:

Pursuant to the Commission's February 23, 2018 *Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase* in the Duke Energy Progress, LLC ("DEP") general rate case in Docket No. E-2, Sub 1142, and as also discussed in the Duke Energy Carolinas, LLC general rate case in Docket No. E-7, Sub 1146, the stipulation included a requirement for DEP to report to the Commission the results of its NC Power/Forward Technical Workshop, which was held May 17, 2018. I enclose the report prepared by Rocky Mountain Institute, the independent organization that facilitated the workshop.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,

Lawrence B. Somers

Enclosure

cc: Parties of Record

Power/Forward Carolinas Technical Workshop Report

June 25, 2018

Prepared by Rocky Mountain Institute

Contact: Mark Dyson, mdyson@rmi.org

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Executive summary

In the settlement agreement approved by the North Carolina Utilities Commission (NCUC) on February 23, 2018, in Docket No. E-2, Sub 1142 for the Duke Energy Progress, LLC (DEP) general rate case, DEP agreed to "host a technical workshop during the second quarter of 2018 regarding the Company's NC Power/Forward grid investments to explain the need for and ongoing benefits of grid investments, and to hear feedback from stakeholders in attendance."[1]

The workshop was held on May 17, 2018. Acting as a neutral facilitator, a team from Rocky Mountain Institute (RMI) convened 65 participants (inclusive of 18 Duke Energy and five RMI staff) for a day-long workshop that included content presentations, structured feedback sessions, and facilitated small group breakout sessions. RMI captured detailed notes for all small group and plenary discussions, and conducted an anonymous post-event survey among non-Duke, non-RMI attendees to gather stakeholder feedback.

This document provides a record of the day's activities and outcomes, as well as a summary of survey results. This document contains an anonymized synthesis of what was shared by participants, and does not attribute specific comments to specific parties, in order to respect the ground rules agreed to by participants at the beginning of the meeting. Specifically, participants agreed that what was discussed at the workshop could be shared publicly, but specific comments could not be attributed to individuals without their permission.

Workshop objectives

The workshop was organized around three objectives, listed below. RMI defined these objectives in consultation with Duke Energy and other participants interviewed in advance of the event.

- **Objective 1:** *Develop stakeholder understanding of the needs for and benefits of the Power/Forward Carolinas (P/FC) proposal*.
- **Objective 2:** *Listen to and explore stakeholder feedback*.
- **Objective 3:** *Lay the groundwork for a collaborative process moving forward*.

Key workshop outcomes and takeaways

Five high-level themes emerged from the conversations during the workshop and in the post-event surveys as key outcomes and takeaways for future action. They are described below, with supporting detail in the subsequent sections of this report.

1. **Participants generally viewed the workshop as a valuable step in building toward a future collaborative process around Power/Forward Carolinas**. A majority of survey respondents indicated that they were satisfied with the

[1] North Carolina Utilities Commission order issued on February 23, 2018, in Docket No. E-2, Sub 1142, page 25; http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=d2b2a1a0-dae1-45de-af9c-c987d4aeddc8

opportunity to provide feedback on the proposed grid investments and engage in dialogue with Duke staff in a neutral, facilitated setting. A majority of participants also reported that the workshop helped them build a better understanding of both the proposed investments and other stakeholders' points of view, and in doing so helped lay a foundation for a future collaborative process.

2. **Participants were divided over the degree to which the workshop was effective in addressing near-term issues around the Power/Forward Carolinas proposal.** While most participants indicated that the workshop improved their understanding of Duke Energy's proposed grid investments, a significant number of attendees felt that the information presented during the workshop was repetitive of what was covered in rate case proceedings. The former group expressed optimism that the workshop would lead to a collaborative process moving forward, while the latter group expressed uncertainty over whether Duke Energy is willing to make meaningful changes to the proposed investments or the process used to define them. Participants also raised concerns that the timing of the workshop, in between the DEP Order and the Duke Energy Carolinas, LLC (DEC) rate case hearings and the subsequent Commission ruling, could limit its effectiveness.

3. **Participants shared feedback that better metrics are needed to characterize the performance expectations, costs, and benefits of Duke Energy's proposed investments.** Participants expressed dissatisfaction with the process used to date by Duke Energy in developing and sharing information about Power/Forward Carolinas, and discussed the need for clear, concise metrics to prioritize grid modernization outcomes, measure the success of proposed programs, and determine the need for revisiting programs post-implementation. Participants also requested that Duke Energy make available breakdowns of expected costs and benefits across different customer classes, and for each proposed workstream within the broader Power/Forward Carolinas proposal.

4. **Participants expressed a wide and diverging range of views on grid investment priorities, and investments needed to address them.** In comments shared during plenary discussions and breakout sessions, attendees expressed differing priorities for grid modernization-related investments in North Carolina, including environmental benefits, incorporation of distributed energy resources (DERs), service quality and reliability, and minimizing rate impacts. Participants also disagreed on the extent to which current system performance (e.g., outage duration and frequency) was inadequate and needed to be addressed through incremental investment. Related to this, many participants voiced their concerns with the proposal to recover incremental investment costs through a rider, versus through the existing rate case mechanism.

5. **A majority of attendees expressed support for an ongoing collaborative process to shape the future of Power/Forward Carolinas.** Both during the event and in the post-event survey, participants indicated significant interest in continuing to engage with Duke Energy on refining the Power/Forward Carolinas proposal. Participants offered many forms of support for this process, including

data and analysis around topics where they had expertise or national context to bring to bear, and made specific recommendations and requests of both Duke Energy and other stakeholders to support the success of any such process. The following section of this Executive Summary includes a list of commonly expressed criteria for a successful process going forward.

Criteria for an effective collaborative process going forward

Workshop participants discussed a wide range of options for how to continue a collaborative process going forward, and offered related recommendations for how Duke Energy and other attendees could support an effective process. These recommendations do not necessarily represent the views of RMI, Duke Energy, or any specific attendees. Rather, we include them as a representation of common themes that arose in multiple conversations during the workshop, and thus could be considered by Duke Energy and other stakeholders as they design a process moving forward.

- **Continue direct engagement between Duke Energy and stakeholders to gain further understanding of perspectives surfaced in the workshop**. Duke Energy should develop and execute a plan for future stakeholder engagement activities, including one-on-one meetings and facilitated workshops on a regular basis. This process should be inclusive, allowing all relevant stakeholders to contribute. Duke Energy should plan future engagements to precede formal regulatory processes, in order to avoid the issues identified by workshop participants that may arise if open dialogue is precluded by ongoing negotiations or adversarial proceedings.

- **Duke Energy should continue developing metrics and analysis to support an ongoing dialogue around the costs and benefits of the proposed investments**. To the extent possible, this information should be tailored to specific stakeholder groups to address their gaps in understanding, and shared early in the planning process to allow for useful stakeholder input, including around goals for and prioritization of proposed investments. Duke Energy should consider offers from participants to help structure analysis processes and metrics, and share the results in a way that is at the appropriate level of detail to build stakeholder understanding and prompt input that can be incorporated into a collaborative planning process.

- **Duke Energy should consider integrating the Power/Forward Carolinas planning process with other processes to support related activities**. Workshop participants identified the potential value of integrating grid modernization planning with integrated resource planning, integrated distribution system planning, and the Smart Grid Technology Plan. Duke Energy should scope a collaborative process to encompass a wide range of planning processes that, together, fully capture all sources of value from Duke Energy’s proposed grid investments.

Workshop activities and attendee list

RMI consulted with both Duke Energy and other participants in pre-workshop meetings and heeded calls to refine the objectives and design the workshop agenda to best meet the objectives. The workshop agenda as executed is included below in Table 1.

Table 1: May 17 Technical Workshop Agenda

Time	Activity	Objectives addressed
9:30	Welcome remarks	
10:10	Check-in and introductions	
10:25	Activity: “Cynics and believers”	#2, #3
10:40	Presentation (RMI): National grid modernization context	#1
11:10	Presentation (Duke Energy): Understanding the Power/Forward Carolinas proposal, and Q&A	#1, #2
12:20	Lunch	
1:20	Activity: Stakeholder priorities for process going forward	#2, #3
2:25	Activity: Breakout group discussions	#1, #2, #3
4:00	Plenary discussion: Breakout group reports	#2, #3
4:20	Checkout	#3
4:25	Closing remarks and adjournment	

A total of 65 participants attended the technical workshop, including 18 participants from Duke Energy and five from RMI. A full list of attendees is included below in Table 2.

Table 2: May 17 Technical Workshop Attendees

Last Name	First Name	Organization
Adair	Sarah	Duke Energy
Ayers	Chris	Public Staff NC Utilities Commission
Bowen	Lauren	Southern Environmental Law Center
Bowman	Kendal	Duke Energy
Brooks	Jeff	Duke Energy
Brown	Justin	Duke Energy
Brown	Mary Jo	Duke Energy
Burnett	John	Duke Energy
Chan	Coreina	Rocky Mountain Institute
Collins	Sarah	NC League of Municipalities
Culley	Thad	Vote Solar
Cummings	Layla	Public Staff NC Utilities Commission
Dalley	Bryce	Facebook
Delli-Gatti	Dionne	Environmental Defense Fund
Dodge	Tim	Public Staff NC Utilities Commission
Dory	Jacqueline	Facebook
Dyson	Mark	Rocky Mountain Institute
Edge	Chris	Duke Energy
Estes	Rachael	NC Conservation Network
Finnigan	John	Environmental Defense Fund
Floyd	Jack	Public Staff NC Utilities Commission
Fountain	David	Duke Energy
Geib	John	Duke Energy
Golin	Caroline	Vote Solar
Harrod	Jennifer	NC Department of Justice
Hawkins	Kathy	Duke Energy
Hicks	Warren	Bailey & Dixon - CIGFUR
Hipp	Dawn	SC Office of Regulatory Staff
Holder	Nathan	Advanced Energy
Josey	Robert	Public Staff NC Utilities Commission
Kalland	Steve	NC Clean Energy Tech Center
Kruse	Susan	Duke Energy
Ledford	Peter	NC Sustainable Energy Association
Li	Becky	Rocky Mountain Institute
Maurer	Christine	Advanced Energy
McIntire	Mark	Duke Energy
McLawhorn	James	Public Staff NC Utilities Commission
Miller	Sharon	Carolina Utility Customer Association
Mundt	Jennifer	NC Dept of Environmental Quality
Neal	David	Southern Environmental Law Center
Newcomb	James	Rocky Mountain Institute
O'Donnell	Kevin	Carolina Utility Customer Association
Ohms	Cindy	Carolina Utility Customer Association
Oliver	Jay	Duke Energy
Palmer	Miko	Duke Energy
Peedin	Darlene	Public Staff NC Utilities Commission
Ragsdale	Lee	NC Electric Cooperatives
Ralph	Karen	Duke Energy
Ripley	Al	NC Justice Center
Rogers	David	Sierra Club NC Beyond Coal Campaign
Ross	Deborah	NC League of Municipalities
Sides	Jim	United States Marine Corps
Simpson	Bobby	Duke Energy

Sipes	Robert	Duke Energy
Smith	Benjamin	NC Sustainable Energy Association
Stone	Greg	Duke Energy
Tarr	Jeremy	NC Dept of Environmental Quality
Thomas	Jeff	Public Staff NC Utilities Commission
Thompson	Gudrun	Southern Environmental Law Center
Trathen	Marcus	Brooks Pierce
Waller	Jeff	Rocky Mountain Institute
Weiss	Jennifer	Nicholas Institute for Environmental Policy
Williamson	Tommy	Public Staff NC Utilities Commission
Williamson	David	Public Staff NC Utilities Commission
Youth	Michael	NC Electric Cooperatives

Workshop outcomes

The following sections outline the workshop activities, common themes of discussion, and outcomes associated with each of the three technical workshop objectives. RMI developed these summaries based on notes taken during the workshop as well as on the results of the anonymous survey distributed to participants (excluding Duke Energy and RMI staff) afterwards. There was a 68% response rate to the survey.

Objective 1: Develop understanding of proposed investments

Activities

RMI designed several sections of the agenda to allow for explanation of the costs and benefits of grid modernization investment, including the context of grid modernization nationwide as well as the specifics of Duke Energy's Power/Forward Carolinas proposal.

A presentation from RMI (see Attachment 2) reviewed grid modernization trends across the nation, to place the proposed Power/Forward investments in context. The presentation outlined both the content of proposals across the country (e.g., specific investment, regulatory, and operational approaches to grid modernization) as well as processes used by utilities, regulators, and other stakeholders to reach alignment.

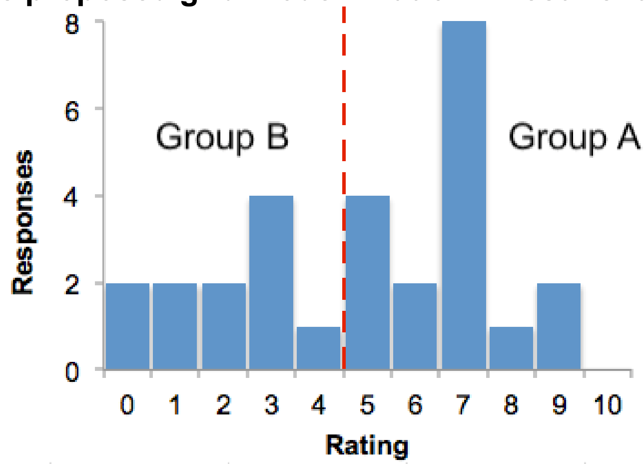
Following the discussion on national context, a presentation from Duke Energy (see Attachment 3) covered the unique factors in North Carolina that form the basis for Duke's proposed grid modernization efforts. After the presentation, participants had a chance to ask clarifying questions that were answered in real time by Duke Energy representatives (see Appendix 3).

In addition to the plenary discussions, where Duke Energy shared details on its proposed investments, the discussion in breakout group 1 also covered technical information. In particular, representatives from Duke Energy shared additional details on the expected reliability benefits of proposed investments—including targeted undergrounding—to customers during major events (e.g., hurricanes, ice storms, severe thunderstorm events, and other events that exceed the IEEE Major Event Day [MED] threshold) and to customers connected to currently underperforming feeders.

Outcomes

Most participants indicated that the workshop improved their understanding of Duke Energy's proposed grid investments, but a significant number indicated that the workshop did not present substantial new information.

Figure 1: Survey responses: "How well did this workshop enhance your understanding of the proposed grid modernization investments?"



The post-event survey asked participants "How well did this workshop enhance your understanding of the proposed grid modernization investments?" Participant answers are shown above in Figure 1. On a scale of one to 10, 57% of respondents answered with a score of five or higher. In comments, participants who awarded these high scores suggested that the presentations were useful in providing insight into both the content of the proposal as well as the priorities Duke Energy held in designing the portfolio. Responses along these lines included "Great overview" and "Helpful to understand Duke's priorities."

On the other hand, a significant number of respondents (43%) responded with a score of four or lower, indicating that the information presented at the workshop did not improve their understanding of the proposed investments. In comments, respondents indicated that the presented information was not substantially different from what had been shared previously, in particular during the DEC rate case hearings. Responses in this vein included "[Duke] presented no new information in the workshop," and "Repetitive with rate case."

The divergence in responses to the survey question around Objective 1 is reflected in Figure 1. For later reference, this document refers to respondents who answered the question with a five or higher Group A (those who felt the workshop significantly improved their understanding of Power/Forward), and those that responded with a four or lower Group B (those who felt the workshop did not provide significantly new information to them). As discussed below in the section related to Objective 3, these groups tended to respond differently to other survey questions, as well. Overall, individuals in Group A expressed satisfaction with the open dialogue and diversity of stakeholders present, and look forward to substantive discussions in the future. On the other hand, Group B generally sought more details on work plans and investments than what was presented at the workshop, and expressed more uncertainty regarding whether this collaborative process would continue.

Objective 2: Hear and explore stakeholder feedback

Activities
Most activities within the agenda allowed for open discussion of participant feedback. Following the Power/Forward presentation, participants asked coaching questions that were not answered directly, but were recorded and served to guide the discussion in subsequent activities. This activity allowed participants to offer suggestions in the form of a question, in order to phrase the feedback in a forward-looking way rather than purely as a critique of past actions.

In addition to the opportunity to share feedback in plenary discussions, all five breakout sessions provided extensive opportunities for stakeholders to share feedback on the proposed grid investments. Specific discussions hosted in each breakout session, outlined below, allowed participants to raise points of feedback:

- Group 1: Participants discussed the question “how do costs and benefits of the proposed investments transfer to different customer groups?,” and shared feedback on specific items (e.g., targeted undergrounding) as well as the process used to arrive at and communicate the proposed investments.
- Group 2: Participants provided their reactions to an underlying premise of Power/Forward that “the time is now and the need is clear” for grid modernization, and discussed ways to more clearly communicate the needs for the proposed investments.
- Group 3: Participants discussed the regulatory changes required to advance grid modernization, and reflected on the relationship between Power/Forward and other activities in North Carolina. Participants suggested integrating grid modernization planning into other related processes to capture the full value of grid investments.
- Group 4: Participants reflected on the question “what are the next collaborative steps for a successful stakeholder process,” and shared feedback on the timing and level of detail of information sharing from Duke regarding the proposed investments.
- Group 5: Participants reflected on what a successful grid modernization program should look like, and discussed metrics for measuring program success. Participants also provided feedback on the impacts of P/FC on low-income groups.

Common Themes
Key points of feedback from participants centered around information sharing, planning processes, and the scope and pace of Duke Energy’s proposed investments.

Information sharing
Most participants agreed that additional information regarding the proposed investments should be shared among stakeholders. Some participants voiced desire to understand the costs and benefits of P/FC versus maintaining the grid under current practices.

Participants also asked whether Duke Energy had evaluated “the cost of doing nothing” in terms of expected reliability degradation, and compared it to costs of the proposed investments.

Many participants requested specific cost and benefit analysis for proposed investments. In particular, several participants requested that Duke make available specific breakdowns of costs and benefits across different customer classes (e.g., transmission-connected industrial, residential) as well as across different customer types within customer classes (e.g., rural versus urban residential). Participants acknowledged that the full suite of benefits from the proposed investments is difficult to quantify and communicate effectively. In particular, participants acknowledged that, while benefits related to average system reliability are straightforward to quantify using existing metrics (e.g., SAIDI and SAIFI),[2] there are no straightforward means to quantify many other benefits of the proposed investments (e.g., increased ability to integrate renewable energy).

Planning and communication process
Participants raised concerns with the way Power/Forward Carolinas was developed and initially shared. Many participants agreed that a more transparent, collaborative process would have been preferable to the way that Duke Energy was perceived to have arrived at the original Power/Forward proposal; i.e., through an entirely utility-driven process. Participants recommended that arriving at shared priorities and goals for grid modernization with stakeholders in advance of assessing solutions in a full proposal would have been preferable.

Participants also commented that Duke’s initial messaging around Power/Forward Carolinas discussed the expected costs without clarifying the full range of benefits. Participants acknowledged that the full stack of benefits is difficult to quantify (as noted above), but recommended that Duke should have led with messaging around the benefits of investment proposals, rather than focusing on the costs and expected investment magnitude.

Objectives, scope, and pace of investments
Participants voiced diverging perspectives on the necessity and prioritization of individual P/FC investments, and expressed differing perspectives on priorities of grid modernization investments including environmental benefits, integration of distributed energy resources, power quality and reliability, and rate stability. Some stakeholders questioned whether the need for reliability is strong enough to justify the investments, with several participants sharing a view that reliability for the customer groups they were representing was adequate, and improvements were not necessarily worth the anticipated rate impacts of the proposed investments.

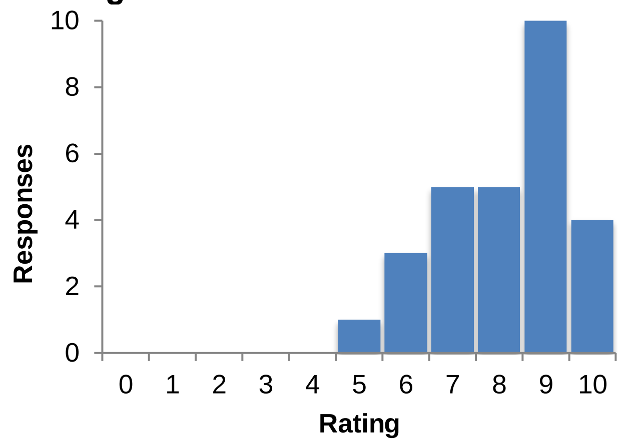
Participants also proposed giving priority to certain projects for earlier completion, based on their ability to address reliability or other goals and prove the case for further investment. For example, participants discussed the potential value of prioritized

[2] System Average Interruption Duration Index and System Average Interruption Frequency Index

investment in integrated volt/VAR control (IVVC) to arrive at near-term energy savings and peak demand savings, or specific targeted undergrounding (TUG) pilots to demonstrate the value proposition. More broadly, participants voiced concern around whether targeted undergrounding should be included within the P/FC proposal at all, and whether additional cost/benefit analysis on TUG is needed.

Outcomes
A majority of participants indicated they were satisfied with the opportunity to provide feedback and engage in dialogue with Duke Energy staff and other participants.

Figure 2: Survey responses: "How satisfied are you with the opportunity to provide feedback and dialogue with Duke?"



The post-event survey asked participants, "how satisfied are you with the opportunity to provide feedback and dialogue with Duke?" The average score given was 8.1 out of 10, as shown in Figure 2. Quotes from survey respondents indicate a broad appreciation of the opportunity to provide feedback to and discuss with Duke Energy:

- "Open dialogue with a broad group of stakeholders"
- "Ability to share different perspectives in a safe space"
- "Great representation from Duke. Executives were present and engaged."

Objective 3: Support a collaborative process going forward

Activities
Several activities within the agenda focused on considerations for setting up a collaborative process moving forward. The workshop started with a "cynics and believers" activity (see Appendix 2), where participants in pairs discussed arguments for why the collaborative workshop might be a failure or success. In an activity following a Duke Energy-led discussion on next steps, participants were asked to break into nine groups to discuss the top grid modernization issues that require stakeholder input to address effectively (see Appendix 2).

Outside of plenary discussions, each breakout group also discussed a possible set of next steps to guide a more collaborative planning process moving forward, with summaries below:

- Group 1: Participants discussed ways that stakeholders could contribute data and analysis to inform updated grid modernization plans.

- Group 2: Participants discussed the importance of maintaining ongoing and frequent communication with stakeholders, and tailoring information to individual groups.
- Group 3: Participants suggested adopting an integrated planning process better suited to assessing the value of grid modernization investments such as DERs.
- Group 4: Participants developed proposals for mid-term and long-term plans to engage stakeholders in various stages of planning for specific P/FC investments.
- Group 5: Participants suggested a process to revisit investments and make necessary adjustments through future stakeholder engagements.

Common Themes

Workshop participants proposed several objectives and criteria for future collaborative processes, with common themes including a recommendation for regular facilitated workshops, early sharing of additional analysis, and an integrated process across multiple planning domains.

Regular facilitated workshops

Many participants recommended continuing stakeholder engagement in a workshop format with third-party facilitators on a regular basis. Participants suggested that a comprehensive list of stakeholders should be involved in the conversations early, to ensure an inclusive process.

Participants recommended that Duke Energy's next steps be made transparent and openly discussed with the stakeholder group in attendance. However, some participants also questioned the usefulness of a stakeholder engagement process focused narrowly on the existing Power/Forward Carolinas proposal, given the NCUC's pending decision in the DEC rate case, and suggested a collaborative process would be most applicable if held in advance of formal regulatory proceedings.

Early and tailored sharing of analysis results

Participants recommended that Duke Energy perform additional analysis around proposed investments, and share with stakeholders early in the planning process. In particular, participants requested that Duke Energy provide more clarity on the costs and benefits of individual P/FC investments, especially the values delivered outside of reliability (as noted above around Objective 2). Attendees recommended that Duke Energy work with individual stakeholder groups to identify group-specific gaps in understanding that require more education, and suggested that Duke could tailor communication and analysis to be most useful for different stakeholders.

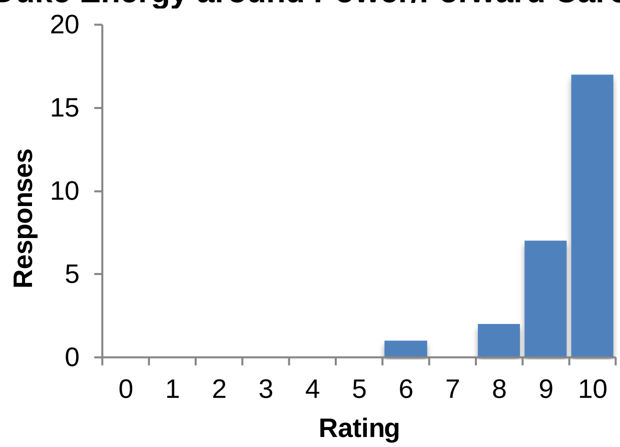
Participants also recommended that Duke Energy provide technical information in a way that is more digestible and useful for stakeholders than currently available work plans, which participants perceived to be too detailed and technical to generate useful understanding of the proposed investments. Participants emphasized that sharing digestible information early in the planning process, before final proposals had been crafted, could allow for useful stakeholder input that could be used to shape and generate alignment around a final proposal that reflected input from a broad group.

Relation to other activities
Attendees discussed the potential value of developing a planning process better suited to understanding and testing the value of grid modernization investments in the context of other, related activities. Specifically, participants discussed the potential to integrate P/FC planning into other planning processes (e.g., integrated resource planning, integrated distribution system planning, and the Smart Grid Technology Plan) to fully capture all sources of value from the proposed grid investments.

Participants acknowledged a need to identify and reconcile gaps between existing planning processes, in order to effectively bridge them in the future. Participants also prioritized creating corrective mechanisms that could revisit different components of the plan and allow for adjustment with ongoing learning from previous investments.

Outcomes
Participants overwhelmingly indicated interest in continuing to engage with Duke Energy on grid modernization planning, and a majority stated that the workshop provided an effective foundation for future collaboration.

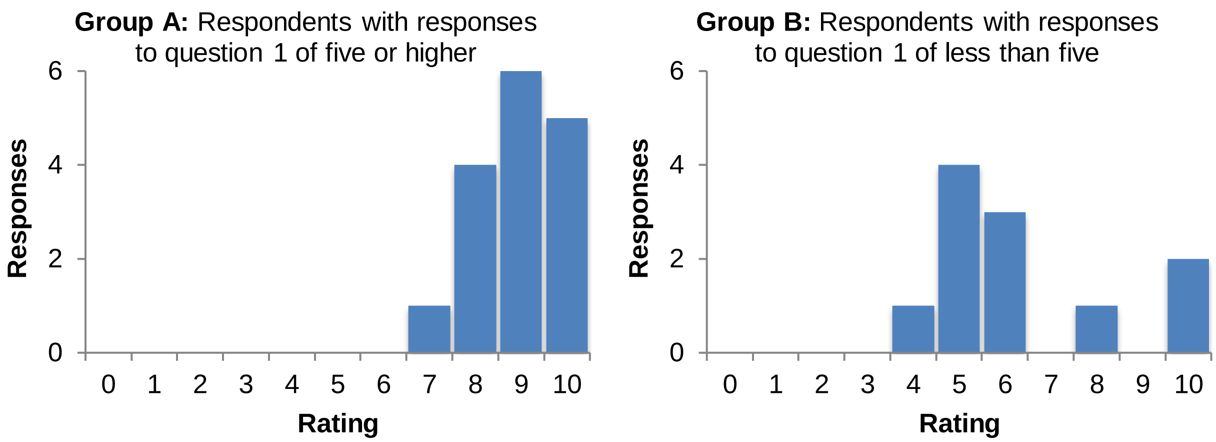
Figure 3: Survey responses: "How willing are you to engage in future follow-up conversations with Duke Energy around Power/Forward Carolinas?"



The post-event survey asked "How willing are you to engage in future follow-up conversations with Duke Energy around Power/Forward Carolinas?" Participants responded with an average score of 9.3 out of 10, indicating significant interest in continuing to engage; see Figure 3 above.

In addition, in response to the question "How effective was this workshop in providing a foundation for new kinds of conversation and collaboration going forward?", respondents gave an average score of 7.9 out of 10. However, individual responses depended heavily on whether participants felt the workshop had enhanced their understanding of the Power/Forward proposal; the more participants felt that the workshop enhanced their understanding of proposed investments, the more they felt that it also laid a foundation for future collaboration. Respondents in Group A (i.e., those who felt the workshop significantly improved their understanding of Power/Forward) gave an average score of 8.9, while respondents in Group B (i.e., those who felt the workshop did not provide new information) gave an average score of 6.4.

Figure 4: Survey responses: "How effective was this workshop in providing a foundation for new kinds of conversation and collaboration going forward?"



In survey comments, Group A generally expressed optimism that the workshop would lead to a collaborative process moving forward, with example responses including "[This workshop helped] build relationships. Business is done through relationships" and "We have some great ideas for future discussions. We need to keep the momentum going!"

However, Group B expressed uncertainty as to whether Duke is actually willing to make changes to the proposed investments. Example responses indicated that participants' willingness to engage going forward "depends on if Duke will listen to what was said today" and "depends entirely on whether I see results from this process."

Appendix 1: Breakout discussion notes

This appendix provides detailed notes from the five breakout discussions, including a synthesis of common points of discussion and potential next steps. The summaries of common themes for each breakout session were not necessarily endorsed by every participant within the group, nor are they necessarily the recommendations of RMI or Duke Energy.

Description of breakout sessions:
RMI selected four breakout topics based on the most common areas of interest/concern that surfaced during the stakeholder interviews RMI conducted prior to the workshop. The fifth breakout topic was sourced from the participants at the event after the morning plenary discussions. Participants chose their preferred topic of discussion, which was facilitated by RMI. Following the breakout group discussions, each group reported the answers to the following questions out to the plenary:

1. What did we learn?
2. Were there any areas of convergence or divergence?
3. What can be taken forward?

List of breakout topics:

Breakout Topic 1

> How do costs/benefits of proposed investments transfer to different customer groups, and what changes to the investments would you like to see in P/FC?

Breakout Topic 2

> P/FC is built on the premise that "the time is now and the need is clear." Does that resonate with you? Why, why not?

Breakout Topic 3

> What changes (e.g., policy, regulatory, technology, customer adoption) need to happen in North Carolina for grid modernization to advance?

Breakout Topic 4

> This is a 10-year process—what are the criteria for a successful stakeholder process going forward? What are the next collaborative steps that need to happen?

Breakout Topic 5

> What does a successful grid modernization program look like?

Activity detail: Breakout Topic 1

Prompt: How do costs/benefits of proposed investments transfer to different customer groups, and what changes to the investments would you like to see in P/FC?

Summary of key points discussed:

1. Breakout participants generally agreed that there is a need to quantify the benefits of P/FC, but that doing so outside of standard reliability metrics (e.g., SAIDI, SAIFI) is difficult, especially by different customer class.
    a. The group identified three kinds of cost shifts: time/intergenerational, retail vs wholesale, and shift between retail customer classes. Participants suggested that, while such costs shifts may be possible to quantify for small programs, the cost shifts for a large grid modernization program such as P/FC are difficult to quantify.
    b. Participants suggested that it is difficult to quantify all benefits/values of distributed energy resources without an organized wholesale market in Duke Energy territory with transparent price signals. While the operational cost savings to Duke Energy may be concrete, other value streams (e.g., mitigating customer load loss) are not as clear.
2. There was disagreement around the role and value of targeted undergrounding programs within P/FC.
    a. The group voiced concern about TUG investments becoming stranded assets, should other investments in distributed energy resources obviate the value provided by undergrounding.
    b. Participants voiced concern with large and near-term investment in TUG while overhead lines still have long useful life.
    c. Participants discussed the argument that, without TUG, customers without DERs at the ends of distribution lines will be harmed (i.e., suffer from extended outages during major events).
    d. The group raised the question of whether there could be a reliability guarantee from Duke Energy associated with the $5 billion investments on TUG.

What can be taken forward?

1. Some participants proposed that Duke pursue an alternative, bottom-up approach of a stakeholder process before continuing the P/FC investments.
2. Participants suggested that stakeholders could assist Duke Energy in defining the priorities of grid modernization investments in advance of a formal proposal, and structuring the cost/benefit analysis of specific components of Power/Forward Carolinas.

Activity detail: Breakout Topic 2

Prompt: P/FC is built on the premise that “the time is now and the need is clear.” Does that resonate with you? Why, why not?

Summary of key points discussed:

1. Not everyone in the breakout group agreed with both “the time is now” and “the need is clear.” There was a sense that the message came across as too dire and urgent.
2. “The time is now” didn’t resonate with some who pointed to the need for Duke to ensure that the grid is continuously well-maintained (i.e., we should not have gotten to a point where major upgrades need to happen). One participant raised the argument that “now is always now,” i.e., Duke always has a responsibility to invest prudently in a reliable and cost-effective system.
3. Others pointed out that, when the grid was originally engineered, renewable energy integration did not exist and storm resilience was not as significant a factor, so a major transformation is needed given recent and expected trends.
4. The sheer breadth of P/FC makes it harder for some to grasp the overall need. Participants wanted more clarity around certain aspects of the P/FC proposal to better understand the needs being addressed. Some suggested that Duke disaggregate the needs and run cost/benefit analyses for different aspects of the work.

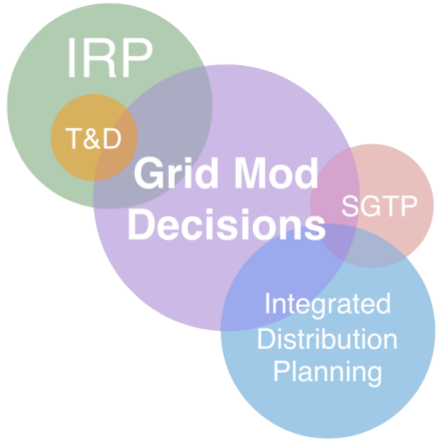
What can be taken forward?
Participants suggested several actions that Duke Energy could take to better explain and generate alignment with stakeholders around the motivation for P/FC:
- Maintain ongoing and frequent communication with stakeholders, rather than providing an overwhelming amount of information at one time.
- Surface different stakeholder perspectives and tailor communication and analysis that is relevant to the individual groups, e.g., provide cost/benefit analyses for specific aspects of the P/FC work.
- Highlight the economic benefits of P/FC because they resonate with certain populations.
- Be more transparent—especially around rate impact and cost recovery—so no one is caught off guard.
- Consider changing the slogan to something that sounds less decisive and dire; rather, it should be more forward looking and aspirational.

Activity detail: Breakout Topic 3

Prompt: What changes (e.g., policy, regulatory, technology, customer adoption) need to happen in North Carolina for grid modernization to advance?

Summary of key points discussed:
- Participants discussed ways in which grid modernization planning can be better integrated with other planning processes (e.g., IRP, integrated distribution planning, and the Smart Grid Technology Plan) to fully encompass the types of the investments that grid modernization represents. The overlapping nature of these planning processes is reflected in Figure 5, below.
    - Current regulatory structure does not support investment in assets such as storage that can provide multiple benefits across different planning and operational domains. Integrated distribution planning would allow investments to be evaluated on a level playing field.

Figure 5: Grid modernization decisions overlap with existing planning processes



- Customers may be able to provide grid services in the future, but participants disagreed on how reliably these services can be procured. Further, questions remain about how these services can be fairly compensated.
  - What are the performance risks, and how can they be properly managed?
  - How to align utility incentives with growing customer adoption of DERs?
- Several other questions remained:
  - Unclear whether NC is a proactive or reactive policy state, and whether Duke is a proactive or reactive investor. Should the customers and market dictate this relationship?
  - How would the business model need to shift to evaluate grid modernization using a least-cost paradigm?

What can be taken forward?
Participants suggested several actions that Duke Energy could take to better integrate P/FC with other processes:

- Develop a planning process better suited to assessing the value of grid modernization investments, including the deployment and grid integration of DERs.
- Reconcile gaps between existing planning processes.
- Characterize the values and risks associated with third-party services, to better understand the role of third-party providers in a modernized grid.

Participants also discussed the potential for the NCUC to adopt a regulatory incentive structure that supports a more simple, transparent, holistic process toward grid modernization.

Activity detail: Breakout Topic 4

Prompt: This is a 10-year process—what are the criteria for a successful stakeholder process going forward? What are the next collaborative steps that need to happen?

Summary of key points discussed:
Participants discussed both near- and long-term process criteria for ongoing stakeholder collaboration.

Near-term proposal
The next stakeholder meeting should be held within a few months, with one representative from each major stakeholder organization. The following objectives were proposed:

1. All stakeholders: Identify whether there is any definitive common ground and/or low-hanging fruit to implement.
2. Duke: Answer detailed questions that remain regarding the seven elements of P/FC.
3. Duke: Identify benefits for each proposed project.
4. Duke: Identify gaps where others can offer input, data, or analysis.

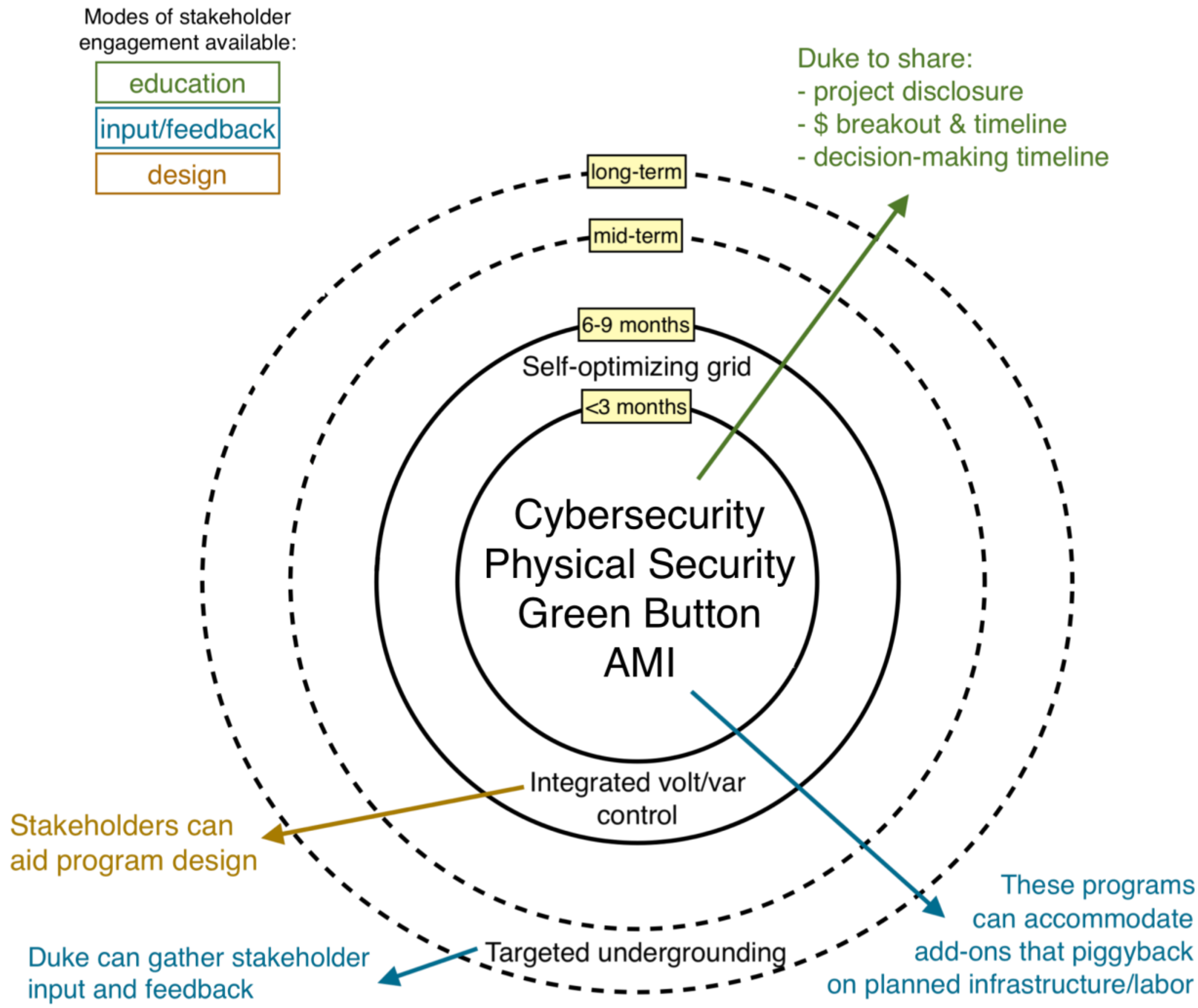
Long-term proposal
After identifying gaps that show the need for more education, gather stakeholder input on specific projects through ongoing meetings. As shown in Figure 6, below, P/FC projects can be grouped into buckets based on their proposed start dates, which dictate the types of stakeholder engagement that could be used to inform each project's planning and deployment:

1. Certain projects are already underway or slated to start within the next three months: **cybersecurity & physical security measures, AMI, and Green Button.**[3] Due to their imminence, these projects are already mostly finalized, but Duke is open to suggestions for *adding on* additional functionality to these workstreams.
2. Mid-term projects to be implemented within six to nine months, such as a **self-optimizing grid and integrated volt/VAR control**, can accommodate more stakeholder involvement in the *design process*.
3. Long-term projects, such as **targeted undergrounding,** can accommodate extensive stakeholder *input, design recommendations, and feedback*.

What can be taken forward?
Participants suggest that, for future decisions, Duke can provide certain information as early as possible in the planning process: a disclosure of proposed plans, a dollar breakdown, and decision-making timelines. This would create a common understanding among all stakeholders and consumers to allow them to participate more actively in the planning process.

[3] Green Button Connect and integrated volt/VAR control were not included in the original Power/Forward proposal, but were raised by the breakout group as potential programs for stakeholder engagement in the future.

Figure 6: Visual representation of the long-term proposal for stakeholder collaboration



Activity detail: Breakout Topic 5

Prompt: What does a successful grid modernization program look like?

Summary of key points discussed:

1. The team discussed the metrics that should be included to measure the success of a grid modernization program, listed below:

   Include clear metrics of the following characteristics:
   - Power quality
   - Reliability
   - Peak load needs
   - Flexibility

   Include the key components, such as:
   - Energy efficiency programs
   - Demand-side management programs
   - Data access

   Include quantified measurement of:
   - Cost
   - Cost avoided
   - Health benefits
   - CO_2 emission reduction
   - Enabled deployment of renewables

   Include practical consideration of:
   - Programs deployment
   - Customer acceptance (willingness to pay)

2. The team also proposed other key characteristics that successful grid modernization programs should have. They identified the following needs:
   a. Duke should identify and remove barriers that low-income groups are facing before implementing grid modernization programs.
   b. Grid modernization should ultimately reduce the customer rates. If there's a rate increase, it should provide enough offsetting value and still give choices to customers.
   c. Need to have trusted sources to provide customers with access to information and truly identify both sides of the program impact.
   d. Need to have a life-cycle view of cost, especially for low-income groups.
   e. Need to include behind-the-meter into the scope of grid modernization (e.g., heat pumps, EV, storage, solar, etc).

What can be taken forward?

Participants suggested several actions that Duke Energy could take to better define and measure the value of proposed grid investments:

1. Revisit different components of the plan and establish correcting mechanisms that allow for adjustment.
2. Initiate the next stakeholder engagement and continue having credible third-party facilitation.
3. Get aligned internally around the motivations, messages and work plans.

The participants also saw a role for Duke Energy to work closely with stakeholders to integrate different pieces that are not currently in the scope of grid modernization.

Appendix 2: Plenary activity notes

This appendix provides detailed notes from the two plenary sessions where significant information was shared by participants with the broader group: the "cynics and believers" exercise, and the stakeholder input needs discussion. The summaries of common themes for each session were not necessarily endorsed by every participant within the group, nor are they necessarily the recommendations of RMI or Duke Energy.

Activity detail: "Cynics and believers"

Description of process: Participants were assigned randomly to one of two groups: "cynics" or "believers." Each participant was asked to pair with someone from the other group to discuss why the workshop was bound to either fail (for cynics) or succeed (for believers). In the plenary session, a few participants from each group shared what they had heard from the opposing group that resonated with them.

Summary of key points discussed:

1. Participants designated as cynics were asked to consider, "why is this workshop, at this time, in this location, with this group of people, bound to be a failure?
    a. After pairing with participants from the believers group, cynics shared the following reflections from the believers that resonated with them:
        i. "There are a lot of smart people in this room. Everyone putting their head together can come up with solutions."
        ii. "We have things that we can agree on, we should find those common things."
        iii. "Resilience is a huge issue. It would be of huge benefit for NC customers."
2. Participants designated as believers were asked to consider, "why is this workshop, at this time, in this location, with this group of people, bound to be a success?"
    a. After pairing with participants from the cynics group, believers shared the following reflections from the cynics that resonated with them:
        i. "There is high level of skepticism and lack of trust with the intent and purpose of P/FC."
        ii. "It's a little late to have a collaborative process now."
        iii. "This might not be the best forum. People here might not truly represent the customers."
        iv. "Diverging priorities from different attendees might create barriers."

Activity detail: Stakeholder input priorities

Description of process: Following a Duke Energy-led discussion that reflected on the process for creating the Power/Forward proposal to date and potential next steps, participants were asked to break into nine groups to discuss, “What are the top two or three grid modernization issues that require stakeholder input to address effectively?” Each group reported back to plenary the two or three most important issues that surfaced in their discussions, in order to guide a collaborative process moving forward.

Summary of most-common issues:
Three issues arose across a majority of the nine table groups, and are summarized here:

1. Scope and planning process for Power/Forward
    a. How to distinguish grid modernization projects from customary spend and maintenance?
    b. Define the *need* for grid modernization, and the vision or approach for solving that need.
    c. Clearly define the *goals* for grid modernization, then compare potential solutions to identify the best candidates for addressing those goals.
        i. The primary goal of P/FC is improving reliability. But what about meeting other goals, such as integrating renewables and planning for a new energy future?
        ii. What is an acceptable reliability goal?
2. Costs and benefits of proposed investments
    a. Identify the most cost-effective way to solve each problem or achieve each goal.
    b. Quantify the benefits to customers, broken down by class: industrial, commercial, and residential (including vulnerable communities and rural vs. urban customers)
        i. Will P/FC provide equal benefits to each class? If not, how to ensure each class pays in proportion to the benefits they receive?
    c. Since P/FC is predicated on improving reliability, how much are customers willing to pay for improved reliability?
3. Prioritization of project completion
    a. How to prioritize the deployment of the seven elements/towers of P/FC? What is the appropriate timing of project implementation?
    b. What metrics are available to gauge the performance/success of grid modernization efforts?

Other common issues raised:
Two other common topics emerged at several tables:

1. Enabling customer choice and engagement
    a. How to align Duke’s financial incentives with customer priorities for grid modernization outcomes?
    b. What rate options and incentives can be offered to customers?
    c. What tools can Duke provide customers to manage and control their energy use?
    d. What data access system provides the most customer benefits?

2. Utility regulation and business models
    a. Who should be responsible for the grid of the future? What will be the method of recovery?
    b. What is the correct regulatory structure for vetting & recovering grid investments? A rate case, a rider?

Appendix 3: Plenary record

This appendix presents a full, transcribed record of questions asked following Duke's presentation on Power/Forward Carolinas, as well as the full notes from the plenary discussion of stakeholder input priorities.

List of Elements of this Appendix:

Full notes: Clarifying questions and answers following Duke's P/FC presentation

> A presentation from Duke Energy covered the unique factors in North Carolina that form the basis for Duke's proposed grid modernization efforts. After the presentation, participants had a chance to ask clarifying questions that were answered in real time by Duke Energy representatives. This provides a full record of the questions raised and answers provided in this session.

Full notes: Coaching questions following Duke's P/FC presentation

> Following the Power/Forward presentation, participants asked coaching questions that were not answered directly, but were recorded and that served to guide the discussion in subsequent activities. This activity allowed participants to offer feedback in the form of a question, in order to phrase the feedback in a forward-looking way rather than purely as a critique of past actions. This provides a full record of the coaching questions raised in this session.

Full notes: Stakeholder input needs

> Participants were asked to break into nine groups to discuss, "What are the top two or three grid modernization issues that require stakeholder input to address effectively?" Every participant wrote down two or three issues on sticky notes, which were then sorted into categories and discussed within each group. This provides a full record of all the sticky notes generated from each group.

Full notes: Clarifying questions and answers following Duke's P/FC presentation

Description of process: A presentation from Duke Energy covered the unique factors in North Carolina that form the basis for Duke's proposed grid modernization efforts. After the presentation, participants had a chance to ask clarifying questions that were answered in real-time by Duke Energy representatives. This provides a full record of the questions raised and answers provided in this session.

- [Question from participant] There was a chart from Ohio showing the incidence above ground line, cost associated of maintaining the line, cost of undergrounding. What's missing is what's the saving of undergrounding. If we can show the saving for putting those lines underground in NC, we can then make the case for the customers. Those are the things that are missing. Working with low-income communities, we never get a call that complains the power shuts down for 45 minutes. The calls are about "I can't afford the bill".
    - [Response from Duke Energy] OH is overhead, not Ohio. That cost is for NC.
- In that academic study, what's the 95% level?
    - It's the level of confidence that the trend will not change.
- The statistical analysis spoke about responsive action you have determined to act. Have you looked at any preventive measures to change the ongoing path, as well as reactive measures?
    - The hardening is a preventive measure.
- Will the transformation take place at the end of lifespan of an asset?
    - It will take place along the way throughout the 10-year period.
- Causation link of weather and reliability. What perspective of weather? Thunderstorms, high winds?
    - Convective weather event. Heavy precipitation, severe thunderstorm. Specific event drivers were not in the statistical analysis, but there are academic articles on it. We didn't do the breakout because weather tends to be a multiplier.
- Improvement or decline around SAIFI, SAIDI—what's the context?
    - It refers to what percentage did SAIDI increase in the past certain amount of years. If you look at SAIDI number, Duke ranked number 12 in Southeastern utilities a couple years ago, and now ranked number 20.
- What are some examples the companies are considering about non-wire solutions? What's the decision-making process of adopting that instead of T&D infrastructure?
    - The most common one is microgrid for communities that have long duration of outages, e.g., Hot Springs in North Carolina. It's a rural community. When the power goes out, it takes eight to 12 hours to get back. The solution is looking at cost/benefit analysis of building a microgrid (solar plus storage) that could carry a reliability benefit, and sometimes peak shaving benefit.
- What type of DER future you are planning for? Do you take into account likely shift to smaller (solar) systems, closer to customer loads? There's a trend of

moving away from 5 MW systems and getting to rooftop—is it influencing proposed investments?
    - Yes, it's factored in. Good utility practice is a sustaining system while rooftop solar adoption increases.
- You showed 50% reduction in SAIDI and SAIFI. What's the cost of maintaining the current grid to keep the same numbers? Did you price out a P/FC initiative that would keep SAIDI and SAIFI where it is but keep same type of investments?
    - The investment to maintain SAIDI and SAIFI would be the same for integrating more renewables. We didn't do the calculation for what the cost would be for maintaining the current grid.
- Customer expectation. What has changed in the expectation? Who has voiced? What's the cost they are willing to pay for the changes?
    - The thing I'm most familiar with is the desire for more options and control.
- Following the previous question: Do you mean options and control over how they're using energy in their own domain, or over what resources they are using?
    - I was speaking specifically to smart meters. How can they be more personally involved? How can they save money?
- What are the drivers and determinants to scale up and down the current P/FC investment proposal?
    - Drivers include non-wires alternatives, if price points come down.
- What would be the driver from the cost sensitivity perspective to scale back on those projects? Is there a threshold or benchmark of cost sensitivity to customers?
    - Have a healthy respect for cost, taking that seriously of the concerns.
- Have you done the cost/benefit analysis for P/FC scenario vs. maintenance scenario?
    - Customary investment is not improving the performance. P/FC is incremental investment.
- What would rates look like in 10 years if you didn't do P/FC?
    - We did the forecast. Reliability forecasts show a worsening trend and would be causing customer disruption. We are willing to share that forecast.

Full notes: Coaching questions following Duke's P/FC presentation

Description of process: Following the Power/Forward presentation, participants asked coaching questions that were not answered directly, but were recorded and served to guide the discussion in subsequent activities. This activity allowed participants to offer feedback in the form of a question, in order to phrase the feedback in a forward-looking way rather than purely as a critique of past actions. This provides a full record of the coaching questions raised in this session.

- Is it possible to articulate the difference between modernization and maintenance?
- Is it possible to quantify how much more solar we are able to integrate with P/FC?
- Can we quantify financial benefit as a consequence of improved resiliency? What's the saving of building the system for hurricane?
- Is it possible to rethink P/FC without the emphasis on reliability, but instead, on energy transition and modernization?
- Can we consider priorities beyond reliability? Cost, transparency? How do they relate to each other?
- Is it possible to quantify cost and benefit for targeted undergrounding using Duke data?
- Given the lack of transparency (people controlling energy usage) and renewable goals, what is the process for getting buy-in from stakeholders in those areas given there hasn't been a lot progress in those areas? Don't sell if you are not going to do it. How are you going to do it?
- Would you consider integrated volt/VAR Control (IVVC)? There was a discussion in the DEC hearing. Studies show IVVC represents 40% of the benefit of the smart grid (DOE had ARRA grant for IVVC). No P/FC money is allocated for IVVC. How can P/FC be designed to account for IVVC?
- Would you consider doing IVVC, self-optimizing grid, and distribution automation at the same time? Would that capture labor efficiency (mobilize labor crews) as well as equipment efficiency? (RTUs, communication nodes)
- Would you consider taking a more flexible and marginal investment strategy?
- How can we test and document customer expectation across different customer groups and class?
- How can we design a plan that takes into account low-income needs at the outset?
- How can we disclose to the customer the cost of stranded asset? (understand the benefit and inherent cost)?
- How would Duke test cost and benefit, and make sure the benefit goes to the customers that are willing to pay the cost?
- Given that some info about critical energy infrastructure is protected for national security reasons, what are the company's plans for ensuring transparency and vetting of investments in geographies targeted?
- Would you reconsider cost/benefit analysis for P/FC to incorporate consumer benefits? In the filing it only shows operational benefits. If consumer benefit is not measured or identified, there's no way stakeholders can assure those are achieved.

- Can we consider a rate program that not only reflects the increase of the cost but also the benefit in the same rider mechanism as is being done in other states? This is the area RMI expertise can be helpful (e.g., RMI helped NY to conduct transparent cost/benefit analysis). [RMI rephrasing as a question: How do we ensure in ratemaking process that costs/benefits are equitably shared among customer classes?]
- Is there a way to insulate ratepayers from the risk of programs that don't work?
- Can we bring expertise from outside IOUs (academic, etc.) to ensure not falling prey to insular thinking? To ensure taking best ideas from all possible angles to be forward looking?
- What kind of guarantee do we have going forward? For service reliability. For consumer regulation of their energy usage and cost savings. A quicker interconnection queue for renewable energy resources.
- Can utility share if they have done any calculation on whether this will reduce the need for future capital investment? Plans for that?
- National standard on access to data from the program (e.g., Green Button Connect)? Would like to see it fully considered before it's applied. Concerned that Duke is heading down a path with the proprietary system that only the company can use, not third parties.
- Appreciate the company is considering non-wire solutions. Is there any detailed process of implementation? Can you share cost/benefit for non-wire solutions?
- What guarantees do we get for consumer regulation of cost savings? What guarantees for quicker interconnection queue?
- North Carolina is under a least-cost paradigm for generation investment. Would it be the same for P/FC?

Full notes: Stakeholder input priorities

Description of process: Participants were asked to break into nine groups to discuss, "What are the top two or three grid modernization issues that require stakeholder input to address effectively?" Every participant wrote down two or three issues on sticky notes, which were then sorted into categories and discussed within each group.

This provides a full record of all the sticky notes generated from each group and used to build up the summary presented in Appendix 2. The notes are structured in the following way:

[Group # 1–9]
- [Sorted categories of common notes at each table]
    - [Individual sticky notes]

Group 1:
- Biggest one is rate impact, cost impact.
    - Rate impacts
    - TUG program & costs
    - Is modernization worth the cost, if so, who decided?
    - Rate design: investments may not fall into traditional [part?] of cost causation
    - Cost-effective implementation
- The other player in the room that's impacting the grid: renewables, storage, etc.
    - Renewable integration
    - Energy storage applications
    - Deployment of self-optimizing grid
    - Non-wire solutions (microgrids, etc.)
- What's the future benefit of the modernization?
- Prioritizing the work that needs to be done. How quickly it gets done?
    - Prioritizing benefits & expectations:
        - More than just grid reliability
        - Order of grid modernization
        - Outage mitigation
        - Data
    - Order of program deployment
- Data and customer access? If you make revenue neutral for me, why bother?
    - Data access & transparency
    - Customer data
- Business model; who's going to take ownership of the grid?
    - Who will/should be responsible for the grid of the future?
    - Method of recovery

Group 2:
- Rate design:
    - Customer information and billing options. The incentives of the customers.

- What's the cost split coming in? Industrial, residential, commercial. Who gets the benefit, how to balance the cost?
- Need to take the lessons we learn on the generation side, IRP to the distribution level.
    - Determining integrated distribution planning parameters
    - What is the role of customer-owned DERs in future grid planning/operations?
    - Expansion of renewables: who/what is driving?
    - What is the acceptable reliability goal?
    - Technology and investment solutions assessed to provide grid management services

<u>Group 3:</u>

- Define modernization
    - Identify what problems we are trying to solve
    - What should grid modernization include?
- Cost/benefit analysis
    - Demonstrate cost savings through cost/benefit analysis on components of grid modernization
    - Identify the most cost-effective ways to solve a problem
    - Quantify benefits
- Prioritization
    - What elements of grid modernization should be given priority?
    - What projects will maximize positive impacts in the greatest number of ratepayers/people?
    - More renewables at what cost?
- Customer options
    - What customer-facing information and rate options can be offered?

<u>Group 4:</u>

- Balancing cost and benefit
    - Valuation of benefits without clear market signals (e.g., ancillary services)
        - Individual value gain vs system value gain
    - Impacts on ratepayers; equity concerns
        - Should the utility strive to provide the same level of service to everyone?
        - Who pays?
    - How much money should be spent over what time period?
- Players, process, priority
    - Timing of implementation of projects/proposals on the ground
    - Priority of program deployment
    - Balance of investments across the "towers"—need flexibility across towers
    - Role of third parties in construction, ownership, and operation of assets
- Parameters for moving forward
    - Customer impact: residential, commercial/industrial, vulnerable communities
        - Cost breakdown per class
    - Build framework consistently across jurisdictions

- Definition of “grid modernization”
  - Promote renewables?
  - Now is the time to plan for new technology
- Country goals vs. North Carolina needs/goals

<u>Group 5:</u>

- Cost/benefit
  - Prioritization of four elements (and many subelements) of P/FC
  - Framework (goals/values) for evaluating investments and measuring success
  - Are we choosing the “right” focus areas to accomplish our objectives?
  - What is the full detail of “customer choice”
  - How much are customers willing to pay for those additional benefits grid modernization is designed to provide?
- How do you measure success? (metrics)
  - What is the accountability like (reporting, other)?
  - What are the appropriate metrics to gauge the performance/success of grid modernization efforts?
- How do you pay for it? (recovery mechanisms, customer classes?)
  - Price and mechanism of cost recovery
  - Customary spend: maintenance vs upgrades
  - The cost of doing “nothing” vs the P/FC cost
  - TUG: is it grid modernization? To what extent is it needed?
  - How to ensure that customers who benefit from grid modernization pay for it on a proportional basis to benefits received?

<u>Group 6:</u>

- What is grid modernization vs. maintenance?
- Long-term planning/reform
  - What type of energy future is best for North Carolina?
  - Long-term technology evolution/changing needs
  - Stakeholder process could be used to rethink the utility model and create a process for more integrated planning across all areas
- How do you define and account for [grid modernization]? (defining process and objective)
  - How to define what is grid modernization vs normal course of action
  - How can we focus Duke’s grid modernization efforts on energy transition and not on reliability?
  - Defining the objectives for the program
  - What opportunity do stakeholders have to give input? so far, it’s just asking questions, suggesting topics
- Stakeholder process, transparency
  - Establish separate docket for further detailed discussion prior to moving forward with any grid modernization project
  - Communicate plan to stakeholders, policy makers, etc.
  - Assuming there is a rider, how will the benefits/savings be reflected in rates—during each annual rider update or when next rate case occurs?

- Benefits to customers and communities. How do you determine the benefit? (cost/consumer benefits)
    - Value of the improvement to various customer groups
    - Honest and transparent accounting of ratepayer impacts vs material benefits to Duke's customers (by customer class)
    - How much are customers willing to pay for reliability?
    - What tools do customers want/need to manage and control their energy use?
    - Has TUG been compared to other reliability mechanisms in terms of customer costs?
    - Assistance to identify risks and benefits
    - What types of investments should be made?
    - The evaluation of data access and what system provides the most customer benefits?
    - What will Duke do to ensure that all available cost-effective consumer benefits are achieved, even if this results in revenue erosion?

<u>Group 7:</u>
- Goal, overall vision, and methods
    - Agreement on how to define the need for grid investment ("why?") and the vision/approach for solving the need
    - What are the goals that the utility is trying to achieve?
    - How does grid modernization advance state policy goals (economic development, etc.)
    - Agreement on a method for defining desired benefits and assigning value
    - What is grid modernization vs general maintenance?
    - What is the relative weight/priority that customers assign to different values that grid modernization can deliver?
- DER integration
    - Effectively integrating DERs: solar, energy storage [x2]
- Rate impact and cost implication
    - What are the rate impacts on ratepayers, by class? [x2]
- Cost/benefit analysis, how it applies to non-wire solutions
    - Long-term and near-term cost/benefit analysis. What is acceptable?
    - Agreement on cost/benefit parameters for non-wires alternatives
- Regulatory incentives for investment priorities
    - Cost recovery (rider?)
    - How can financial incentives for Duke be aligned with customer priorities for grid modernization outcomes?
    - What is the correct regulatory structure for vetting & recovering grid investments?

<u>Group 8:</u>
- Value, cost/benefit, prioritization of delivery
    - Quantifying and timing customer benefits
    - From their perspective, what is the most important and what is it worth?
    - Investment prioritization: reliability improvements, DER enabling, storm hardening/resiliency, carbon reduction

    - What is our common understanding of "cost-effectiveness" for different programs?
- Cost and benefit of equity. How to address low-income [customer groups]
    - Equity across customer base (rural/urban)
    - How to reconcile grid modernization with financial limitations of customers
    - How do we pay for these programs without overburdening customers?
- Transparency via data to customers and their ability to use it
    - Timing and structures of time-of-use and critical-peak pricing
- There's not a shared vision of what the grid of the future is going to look like. What that vision is worth to the citizens.

Group 9:

- Planning and transparency with stakeholders
    - Prioritization of grid modernization impacts: when do you pull the trigger?
    - End of useful life/when to invest
    - Distribution planning process
    - How do we time investments in technology given the accelerating development of new functionality
    - Goals/visions for grid modernization
    - Clarity on what grid modernization investments cover
- Data and customer focus. Data access to customers
    - Integration of customer programs and data access with technology deployment
    - Data access [x2]
    - Data about customer needs/desires/expectations
    - Assessment of customer expectations/needs/wants
- Integration
    - Integrating DERs while maintaining grid stiffness, protection, reliability, and efficiency
    - Technologies that can integrate with evolving technologies
- Costs and benefits
    - Impact on ratepayers
    - Cost/benefit of TUG
    - Role of Duke and third parties in installing and operating
- Are there any game changers?

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Progress, LLC's Report of NC Power/Forward Technical Workshop, in Docket No. E-2, Sub 1142, has been served by hand delivery, depositing a copy in the United States Mail, first class postage prepaid, or by electronic mail, properly addressed to the following parties of record:

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DUKE ENERGY

NORTH CAROLINA GRID IMPROVEMENT PLAN

PRE-READ PACKET

FOR STAKEHOLDER WORKSHOP

11/08/18

INTRODUCTION TO THIS PRE-READ DOCUMENT AND ROCKY MOUNTAIN INSTITUTE'S ROLE AS WORKSHOP FACILITATOR

ABOUT THIS DOCUMENT

- This read-ahead packet includes information about the November 8 workshop, including:
  - Workshop objectives, agenda, and list of attendees.
  - Duke Energy's draft grid improvement portfolio and detailed information on how it was created.
- Please familiarize yourself with these materials so that you are prepared for the workshop and ready with any questions.

ROCKY MOUNTAIN INSTITUTE'S ROLE

- Rocky Mountain Institute (RMI) has been contracted by Duke Energy to act as a neutral facilitator for the this workshop.
- RMI is an independent, nonprofit organization with 35 years of experience in analysis and partnerships around electricity grid investment and regulatory innovation across the United States and globally.
- RMI's role in this workshop includes:
  - Pre-event interviews with many stakeholders
  - Agenda design & facilitation of the workshop
  - Preparation of a post-event summary report

We look forward to seeing you on November 8 !

DUKE ENERGY

WORKSHOP OBJECTIVES, AGENDA & PARTICIPANTS

North Carolina University Club. 4200 Hillsborough Street, Raleigh, North Carolina 27606

WORKSHOP OBJECTIVES:

- Obtain stakeholder input to Duke Energy's outlook on seven megatrends shaping grid improvement decisions.
- Describe and get feedback on how Duke Energy has used stakeholder input, the impact of megatrends on grid needs, and a prioritization methodology to develop a grid improvement portfolio.
- Describe the benefits and risks of the draft program portfolio, and hear from stakeholders what changes they propose and why.

8:30am	Sign In
9am	PROMPT START and Welcome Objectives, Agenda, Ground Rules Introductions Overview of Analysis Megatrends
11:40am	LUNCH
12:25pm	Portfolio Prioritization Methodology Input on Grid Modernization Discussion and Next Steps Check-Out
4:00pm	ADJOURN

*coffee, tea, lunch and afternoon snacks provided

PARTICIPATING ORGANIZATIONS INCLUDE:

- Advanced Energy
- Brooks Pierce Tech Customers
- Carolina Utility Customers Association
- Clean Air Carolina
- Clean Energy
- Corning Incorporated
- DOJ – Consumer Protection
- Environmental Defense Fund
- ElectriCities of North Carolina
- Energy NC
- Evergreen Packaging
- Nekins at Law
- NC Interfaith Power & Light
- NC Justice
- NC Sustainable Energy Association
- NC WARN
- NC Manufacturers Alliance
- NC State University (School of Public Affairs)
- Nicholas Institute for Environmental Policy Solutions
- North Carolina Department of Environmental Quality
- North Carolina League of Conservation Voters
- Nutrien
- Public Staff - NC Utilities Commission
- Sierra Club
- Southern Environmental Law Center
- US Marine Corp (Government and External Affairs)
- US Marine Corp (Regional Energy Programs)
- Varentec
- Vote Solar
- Warren Hicks, Bailey & Dixon, LLP

THIS WORKSHOP IS PART OF A BROADER STAKEHOLDER ENGAGEMENT PROCESS AROUND DUKE ENERGY'S GRID IMPROVEMENT PLAN IN NORTH CAROLINA

- Stakeholder perspectives are necessary to ensure Duke Energy is making the best decisions possible for North Carolina customers.
- In this workshop, Duke Energy wishes to inform stakeholders of the status of its revised draft Grid Improvement Plan and get critical feedback that could inform the final Grid Improvement Plan for North Carolina.
- Stakeholder input has already shaped the revised draft Grid Improvement Plan and will continue to do so.

TABLE OF CONTENTS

NORTH CAROLINA GRID IMPROVEMENT PLAN

MEGATRENDS IMPACTING NORTH CAROLINA

FOR STAKEHOLDER WORKSHOP

11/08/18

TRENDS IN OUR SERVICE TERRITORY

DUKE ENERGY.

In the context of the emerging distributed electric system, Duke Energy has recognized multiple trends and facts that warrant recognition and analysis.

I Threats to grid infrastructure

II Technology advancements – Renewables and DER

III Lower carbon future and other environmental trends

IV Impact of weather events

V Grid improvement

VI Concentrated population growth

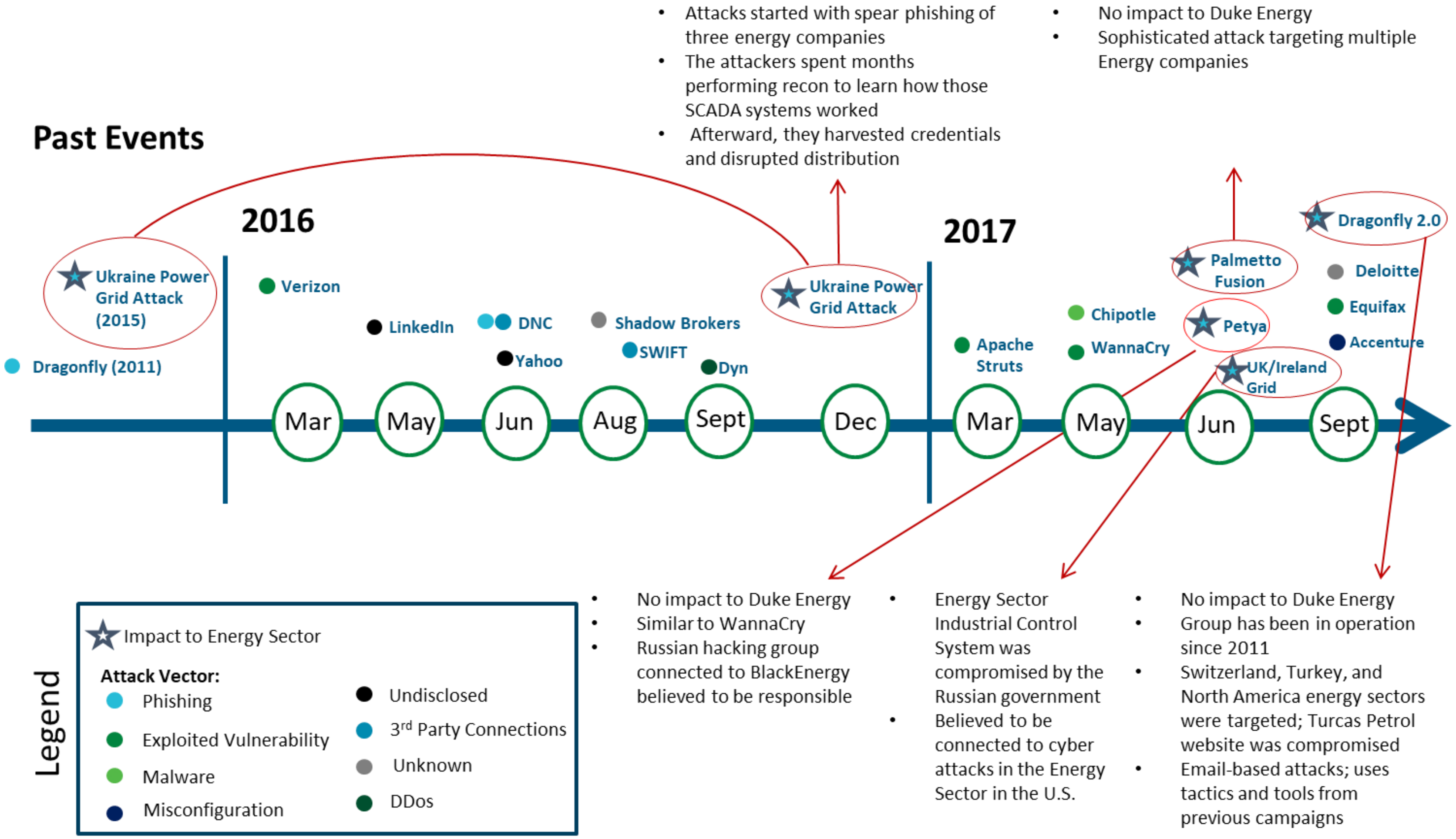
VII Customer expectations

I. THREATS TO GRID INFRASTRUCTURE

DUKE ENERGY

What is happening?

- Purposeful threats, both physical and cyber, to the electric grid are on the rise worldwide

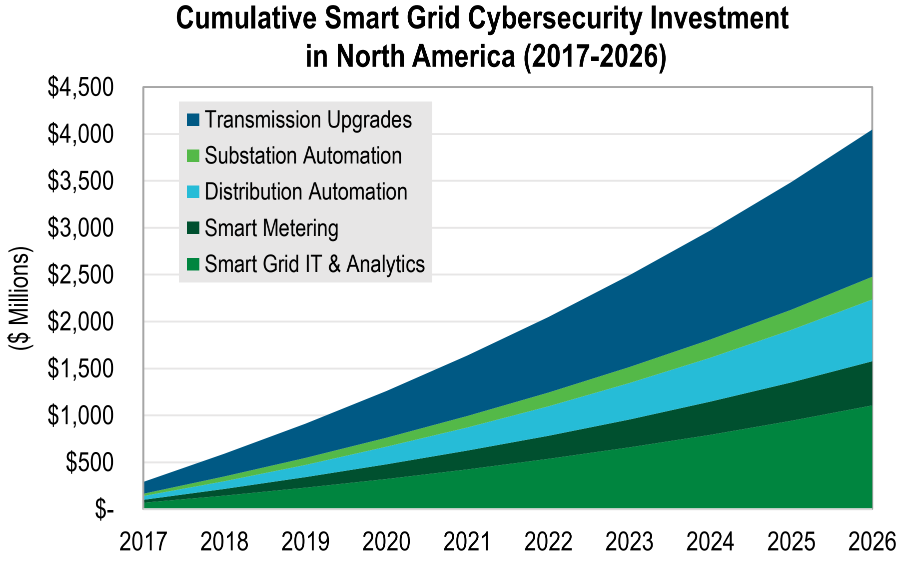


Source: Duke Energy[1]

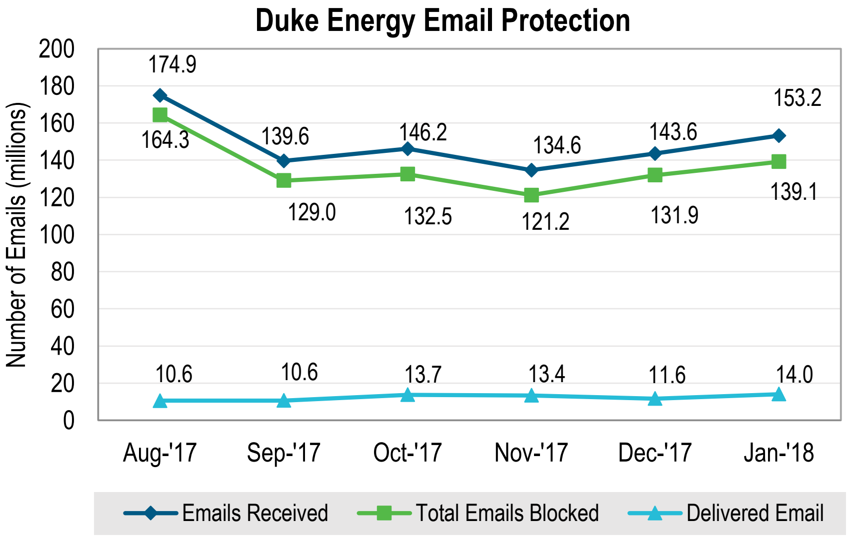
I. THREATS TO GRID INFRASTRUCTURE

What is happening?

- Grid cybersecurity investment expected to grow from $300 million in 2017 to $4 billion by 2026[2]
- Increasing points of entry: as of November 2017, an estimated 378 million Internet of Things (IoT) devices were vulnerable to hacking[3]
- Ukrainian power grid attacks in 2015 and 2016 and more recent ransomware attacks driving utilities to expand beyond compliance-based management practices[4]
    - Industrial Control Systems Cyber Emergency Response Team estimates a similar incident in the US would result in damages totaling between $243 billion and $1 trillion[5]
- Cyber attacks impacting Southeast municipalities and utilities
    - Ransomware attacks in Mecklenburg County (Charlotte) and Atlanta impacted key government services including bill payments[6]
    - North Carolina fuel distribution company experienced $800,000 cyber heist[7]
    - Duke Energy protection solutions currently blocking +90% of incoming emails[8]



Source: Navigant Research Cybersecurity for the Digital Utility[9]



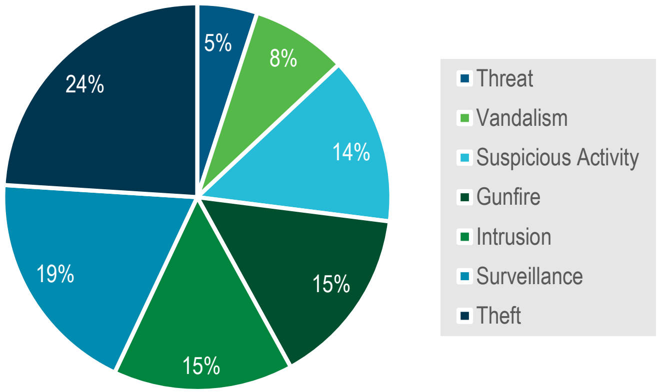
Source: Duke Energy[10]

I. THREATS TO GRID INFRASTRUCTURE

What is happening?

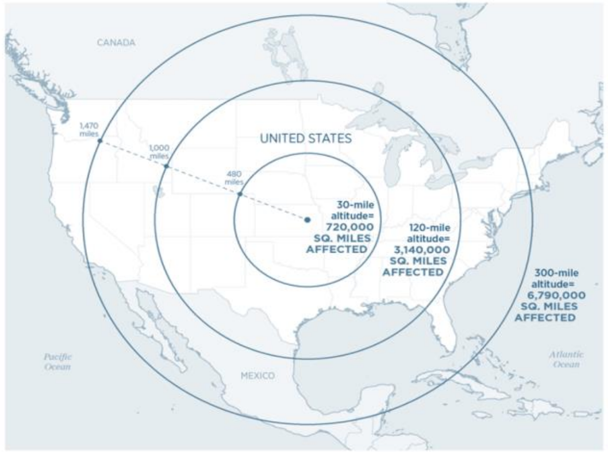
- Electricity Information Sharing and Analysis Center (E-ISAC) assesses that there will be an increase in theft, especially in areas more negatively impacted by socio-economic issues[11]
    - Theft was the top physical threat to the grid in 2017[12]
- The number of terrorist attacks is increasing
    - Physical/sniper attack on PG&E transmission station damaged 17 substation transformers, caused $15 million in damages, and led to $100 million in physical security investments[13]
- Electromagnetic Pulse (EMP) generated at an altitude of 30 miles above the earth can severely damage electronics within an area of about 720,000 square miles[14]
    - Currently there is limited protective equipment installed to address consequences of EMP-like events[15]
    - Have potential to cause wide-scale long-term losses with economic costs[16]
    - Cost of damage from the most extreme solar event is estimated to cost $1 trillion-$2 trillion with recovery time of 4-10 years[17]

Breakdown of Physical Security Incidents for 2017



Source: NERC[18]

Potential Magnitude of EMP Events



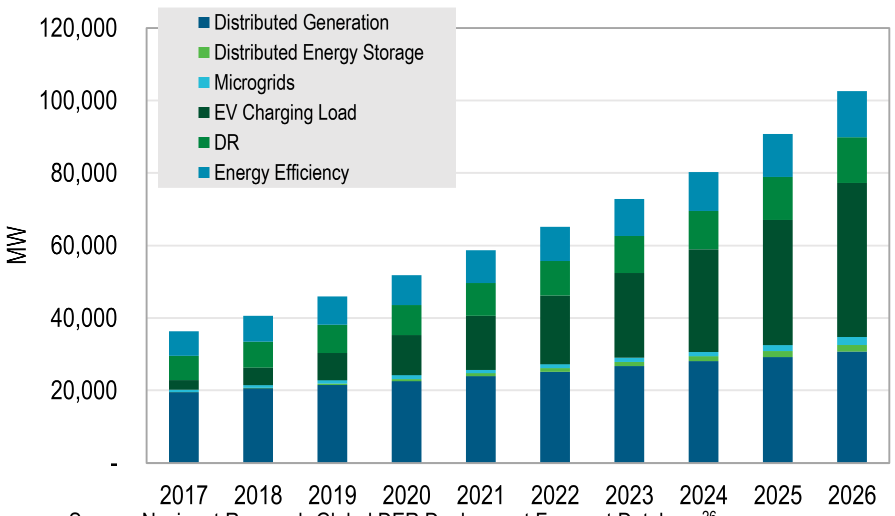
Source: The Heritage Foundation[19]

II. TECHNOLOGY ADVANCEMENTS – RENEWABLES AND DER

What is happening?

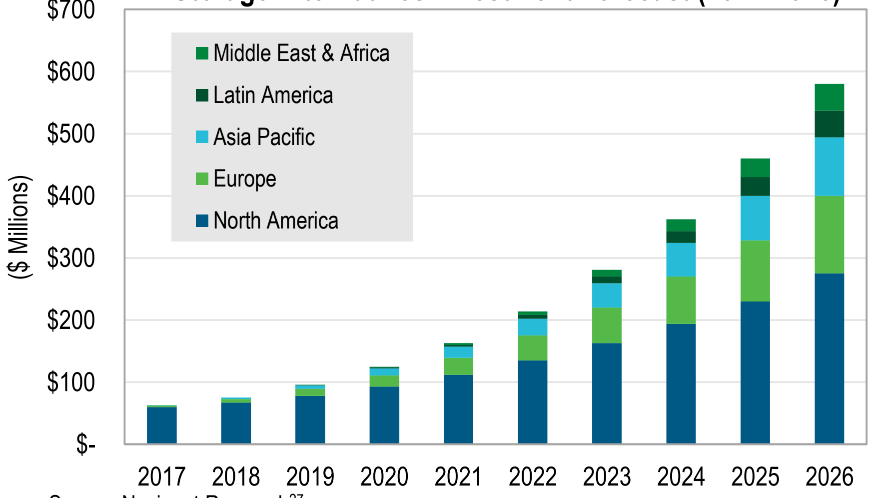
- Distributed energy resources (DER) expected to grow eight times faster than net new centralized generation in the next 10 years globally[20]
  - Distributed generation, including solar PV, remains a dominant contributor to this forecast
  - EVs and EV charging are the fastest growing segments
- Spending on energy storage solutions and alternatives is forecasted to increase at an annual rate of 18% over the next 10 years in North America[21]
- Renewables and DER becoming significant capacity resource for Duke Energy in North Carolina
  - Recent North Carolina Integrated Resource Plan (IRP) includes capacity from renewable resources, energy efficiency, and demand-side management, increasing from 8% in 2019 to 16% in 2033 (Duke Energy Carolinas (DEC)) and 18% in 2019 to 22% in 2033 (Duke Energy Progress (DEP))[22]
  - Duke Energy customer-sited solar programs totalling 10 MW in DEC and DEP approved in May 2018[23]
    - The customer-scale solar programs for both residential and commercial customers in both DEC and DEP reached the 10 MW cap for 2018 within three weeks[24]
  - The Duke Energy North Carolina interconnection queue for DEC and DEP combined represents approximately 12 GW[25]

Global DER Capacity Forecast (2017-2026)



Source: Navigant Research Global DER Deployment Forecast Database[26]

Storage Alternatives Investment Forecast (2017-2026)



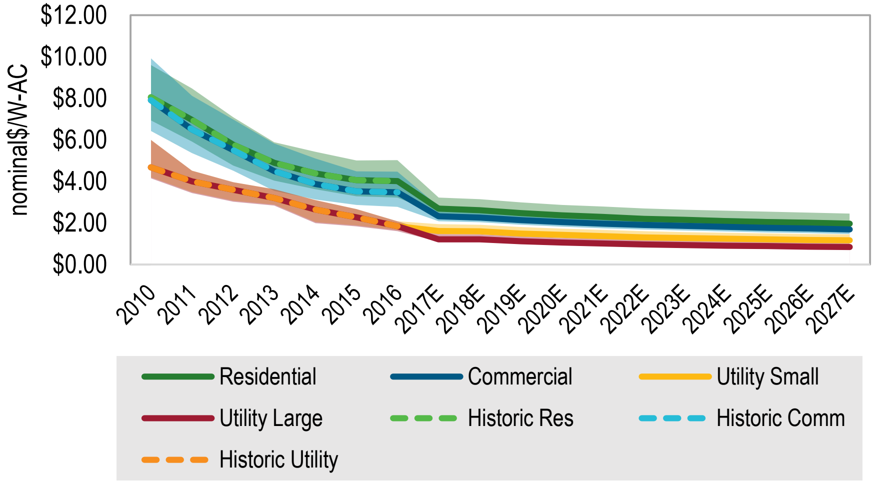
Source: Navigant Research[27]

II. TECHNOLOGY ADVANCEMENTS – SOLAR PV

What is happening?

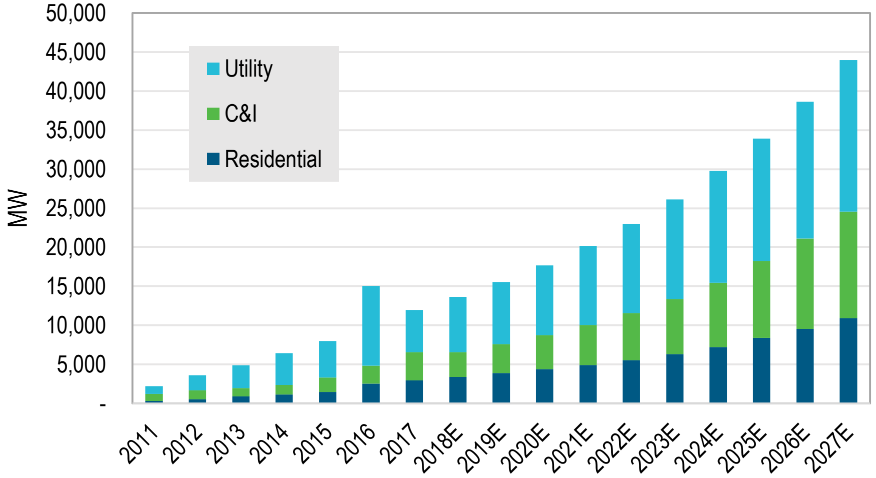
- Solar PV is becoming increasingly competitive[28]
  - Cost of utility-scale solar has dropped 66% since 2010 and is projected to decline by 3.6% per year in the next 10 years[29]
  - Cost of distributed solar has dropped 67% since 2010 and is projected to decline by 3.1% per year in the next 10 years[30]
- Solar PV efficiency has increased which lowers overall installed cost by minimizing the number of panels needed to achieve the same output
- Module efficiency has increased 2% annually since 2007[31]
  - Manufacturing is shifting to higher efficiency monocrystalline panels
- Distributed solar PV installations are projected to continue increasing in North Carolina
  - North Carolina ranked 2nd in the nation for the highest solar generation capacity[32]
  - Over 4,400 MW of solar currently installed in North Carolina[33]
  - Installed capacity in North Carolina is projected to increase 7% per year 2017-2026[34]

Solar PV Cost Declines (2010-2027)



Source: Navigant, NREL[35]

Historical and Forecasted Annual Solar PV Installed Capacity in US (2011-2027)



Source: Navigant Research Market Data: Global Distributed Solar PV[36]

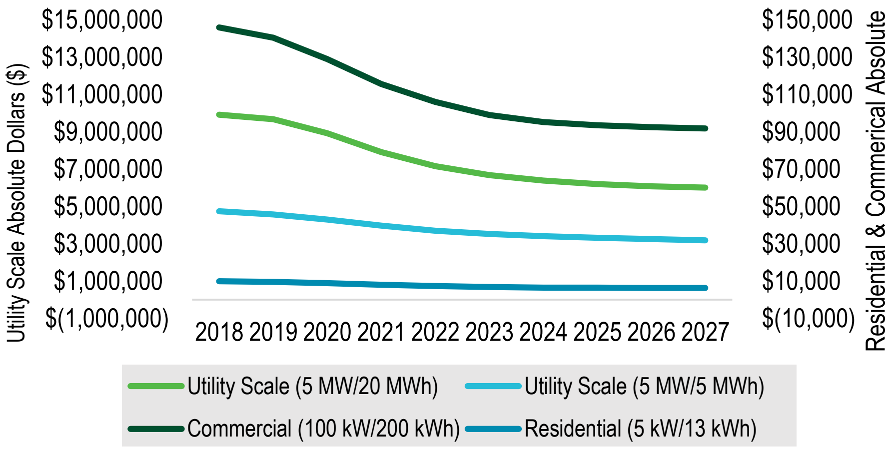
II. TECHNOLOGY ADVANCEMENTS – BATTERY STORAGE

DUKE ENERGY

What is happening?

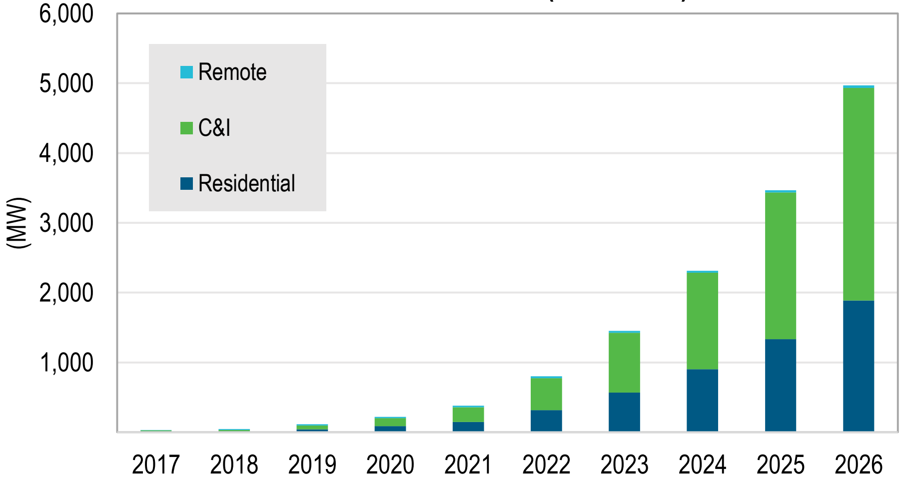
- Battery storage costs expected to decline over the next 10 years in the US
  - Cost of utility-scale storage is projected to decline by 5.4% per year, and utility investment in storage is likely to increase to provide more grid flexibility[37]
  - Cost of distributed storage projected to decline by 5% per year[38]
- Storage installations are projected to increase 2018-2027 in North America:
  - 35% per year for utility-scale[39]
  - 25% per year for distributed storage[40]
- Storage is increasingly installed co-located with renewable energy. Installed capacity of solar plus storage is projected to increase in North America:
  - 57% per year 2018-2026 for utility-scale[41]
  - 76% per year for distributed storage[42]
- Duke Energy's 15-year forecast includes 300 MW of battery energy for the Carolinas storage to improve reliability and grid support[43]

Li-Ion Battery Storage System Capital Cost Forecast (2018-2027)



Source: Navigant Research Large Commercial and Industrial Energy Storage [44]

Annual Solar PV + Storage Power Capacity and Revenue in North America (2017-2026)

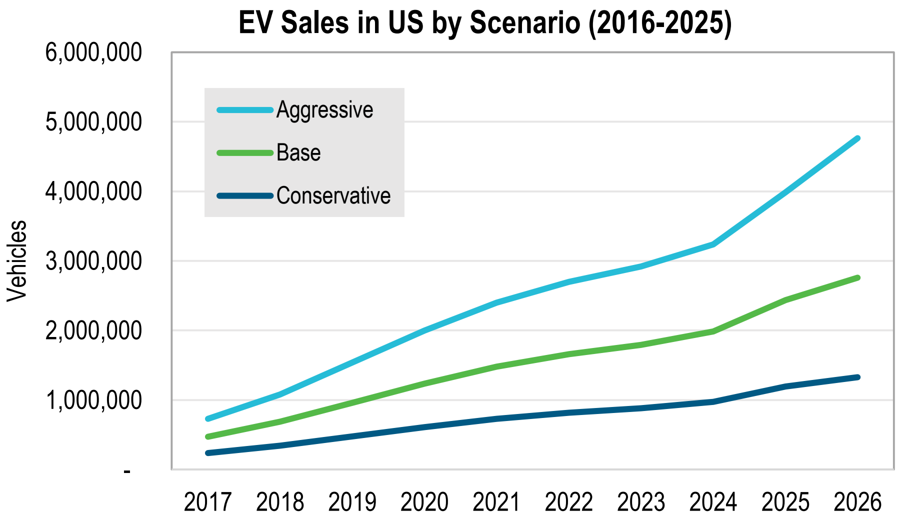


Note: Remote, off-grid solar plus storage typically serves loads of 5 kW or less in remote areas without grid access

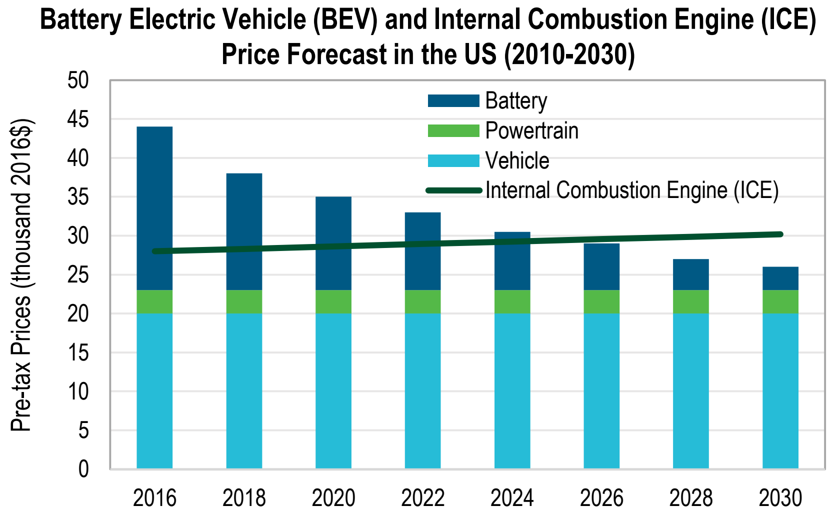
Source: Navigant Research Distributed Solar PV plus Energy Storage Systems[45]

What is happening?

- Cost of EVs has decreased by 80% since 2010[46]
- EVs expected to be competitive with internal combustion engine (ICE) vehicles by 2030[47]
- General Motors announced all-electric, zero emissions future with 20 fully electric models by 2023[48]
  - "General Motors believes electric, self-driving, connected vehicles and shared mobility services will transform how we get around, and we are drawing the blueprint to advance our vision of a world of zero crashes, zero emissions, and zero congestion." – General Motors
- EV adoption is projected to increase
  - By 2027, there will be near 58M PEVs[49]
  - By end of 2018, over 5M PEVs will be on roads globally[50]
  - The number of US residential charging locations is estimated to reach ~6 million by 2025[51]
  - The global market of EVs should see continued sales growth at around 38% through 2020[52]
- EVs in North Carolina are projected to increase 42% annually[53]
  - ~8,500 PEVs are on North Carolina's roads today[54]
  - North Carolina Energy Policy Council recognizes that "the greatest impact of increased EV adoption will be on the distribution system, so whether there is high or low penetration, a modern grid will be required to support it."[55]



Source: Navigant Research EV Geographic Forecasts[56]



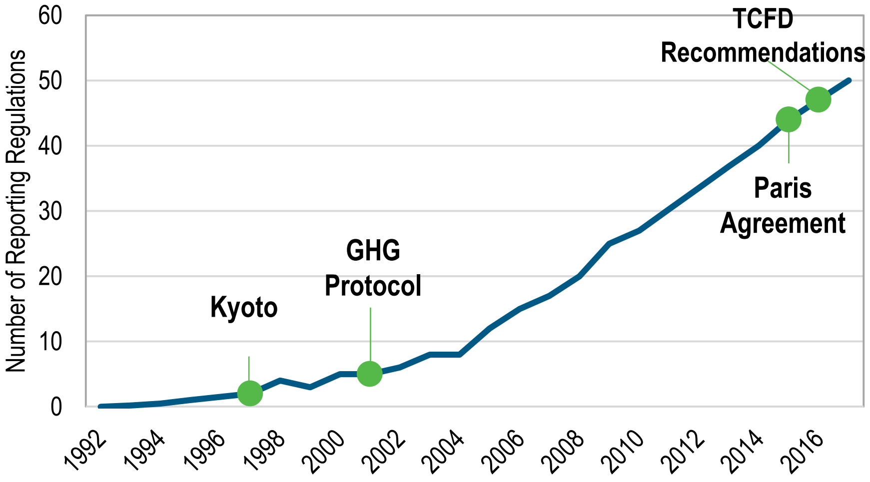
Note: Vehicle prices based on medium segment price

Source: Bloomberg New Energy Finance[57]

What is happening?

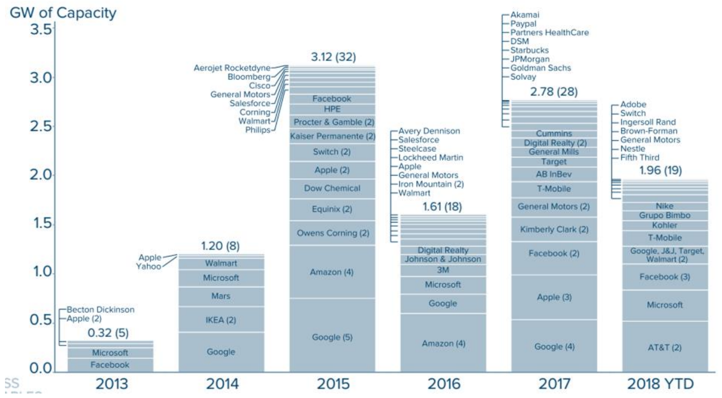
- Broad international commitment and pressure to reduce carbon emissions
- Cyclical federal environmental policy commitments (COP 21, CPP) but implementation of federal energy efficiency standards (transportation, lighting, etc.) underway
- Corporations making commitments and demanding renewable options
  - ~48% of Fortune 500 companies have sustainability and renewable energy commitments[58]
  - Leading NC corporations have set sustainability goals, including Bank of America, Lowe's, Owens Corning, Reynolds American, VF Corporation, Walmart, and Wells Fargo
  - 488 companies taking science-based climate action and 133 have approved targets[59]
  - 75 companies have committed to Corporate Renewable Energy Buyers' Principles with goal to "work with utilities and regulators to expand choices for buying renewable energy"[60]
- States and cities setting goals for renewables, low carbon transportation, and energy efficiency
  - Fifty percent of states are currently examining one or more of the following topics: (1) smart grid and advanced metering infrastructure (Smart Meters), (2) utility business model reform, (3) regulatory reform, (4) utility rate reform, (5) energy storage, (6) microgrids, and (7) demand response[61]
  - Electric utilities in North Carolina established a 40% carbon reduction goal from 2005 levels by 2030 with approximately 60% of electricity coming from carbon-free energy sources[62]
  - NC set renewable energy and energy efficiency portfolio standard (REPS) of 12.5% of 2021 sales[63]
  - Smart city initiatives being carried out in many NC cities, such as Charlotte and Cary
    - Envision Charlotte and Town of Cary Simulated Smart City projects are integrating energy efficient practices[64]

Growth in Reporting Related to Greenhouse Gas Emissions (1992-2017)



Source: World Business Council for Sustainable Development[65]

Contracted Capacity of Corporate Power Purchase Agreements, Green Tariffs, and Outright Project Ownership



Source: Business Renewables Center[66]

IV. IMPACT OF WEATHER EVENTS

What is happening?

- North Carolina has faced major weather events, with Hurricanes Matthew (2016) and Florence (2018), and most recently Michael (2018) illustrating the magnitude of the challenge the grid faces today from weather
  - Approximately 715,000 outages in North Carolina during Hurricane Matthew[67]
  - Approximately 1.8 million total Duke Energy customer outages restored across the Carolinas during Hurricane Florence, ~1.6 million of which were Duke Energy customers in North Carolina[68]
    - ~ 45 transmission lines out, 185 miles of distribution lines down, and 10 substations flooded at peak of storm[69]
  - Approximately 1 million total Duke Energy customer outages restored across the Carolinas during Hurricane Michael[70]
- "I know North Carolina can rebuild, we have to rebuild in a smart way. We have to understand when you have two so called 500 year floods within 22 months of each other, not sure you're talking about a 500 year flood anymore. We've got something else on our hands."

  - NC Governor Roy Cooper[71]

Hurricane Michael Impacts (2018)

Source: Citizen Times[72]

Hurricane Florence Impacts (2018)

Source: T&D World[73]

Hurricane Matthew Impacts (2016)

Source: Chicago Tribune[74]

IV. IMPACT OF WEATHER EVENTS

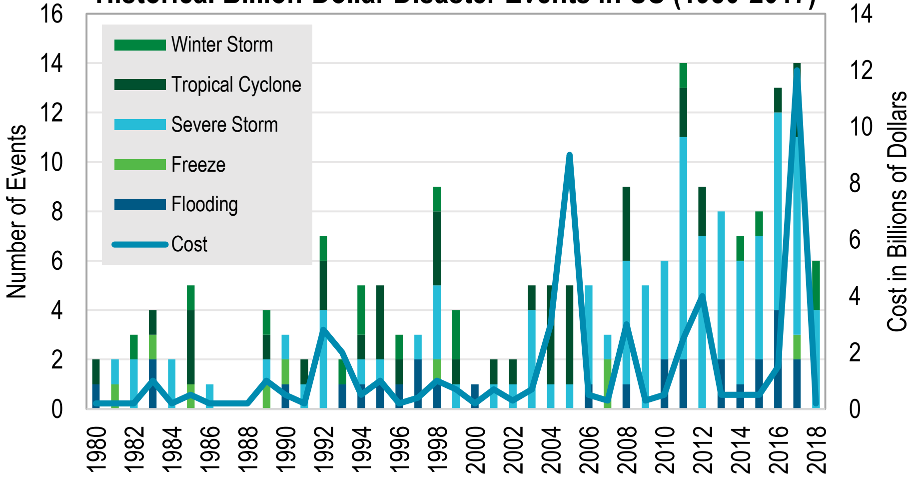
What is happening?

- North Carolina experienced over 300 bulk electric system outages related to weather events (2009-2017) and is part of a larger region that sees the most major storms[75]
- The number of customers impacted by weather events is increasing due to population growth in regions most affected by weather
- The average outage duration for each Duke customer served (SAIDI) in North Carolina increased by 20% (2012-2017)[76]
- Number of major event days (MEDs) have increased by 2% per year over the past 25 years[77]
- Number of Duke Energy NC customer outage events increased by 18% since 2012[78]

Temporary Flood Mitigation at 6 Carolinas East Station

Source: Duke Energy[79]

Historical Billion-Dollar Disaster Events in US (1980-2017)



Note: Costs are adjusted for Consumer Price index (inflation)

Source: NOAA[80]

What is happening?

- Grid improvement technology has advanced over the last decade, and has given utilities alternatives to traditional grid infrastructure options.
  - Grid improvement got a boost from $4 billion in Smart Grid Investment Grants under the American Recovery and Reinvestment Act of 2009 (the Stimulus Act) which, combined with industry spending, led to nearly $8 billion in related projects[81]
  - "Smart" grids are expected to increase the grids' efficiencies by 9% by 2030. This is equivalent to saving more than 400 billion kilowatt-hours each year[82]
  - Grid improvement deployments reduce peak demands by 13% to 24%[83]
  - Savings between $46 billion and $117 billion are expected over the next 20 years[84]
  - Smart meters are expected to save more than $150 billion/year by 2020 by reducing the cost of power interruptions by more than 75%[85]
- The global market for smart grid IT and analytics for software and services is expected to grow from approximately $12.8 billion in 2017 to more than $21.4 billion in 2026[86]

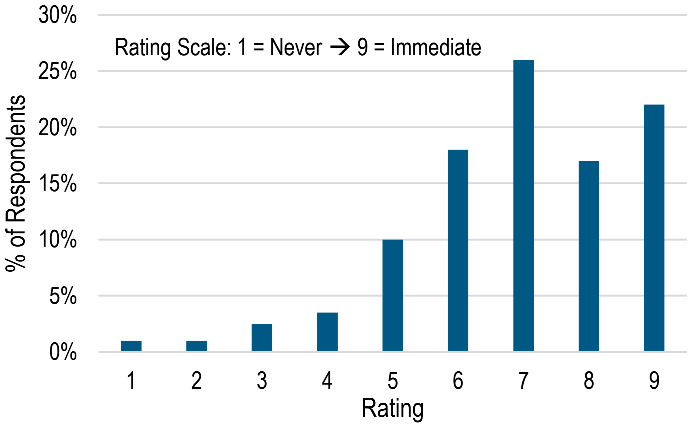
Rapidly Advancing Smart Grid Technologies

Intelligent Devices	Information Technology
• High speed communication networks (fixed and wireless) • Smart Meters • Distribution Automation including intelligent switches, capacitors, and remote fault identification	• Advanced Distribution Management Systems (ADMSs) • Integrated Volt/Volt-ampere reactive Control (IVVC) • Fault, location, isolation, and service restoration (FLISR) • Asset Management Systems (AMSs) • Customer Information Systems (CISs) • Demand Response Management Systems (DRMSs) • Distributed Energy Resources Management Systems (DERMSs) • Energy Management Systems (EMSs) • Geographic Information Systems (GISs) • Meter Data Management Systems (MDMSs) • Advanced Analytics (Asset, Grid Operation, Demand-side, Customer)

Source: Navigant[87]

"Pulse of Power" Survey of Readers

How soon should the power industry adapt to a clean, intelligent, mobile, and distributed grid?



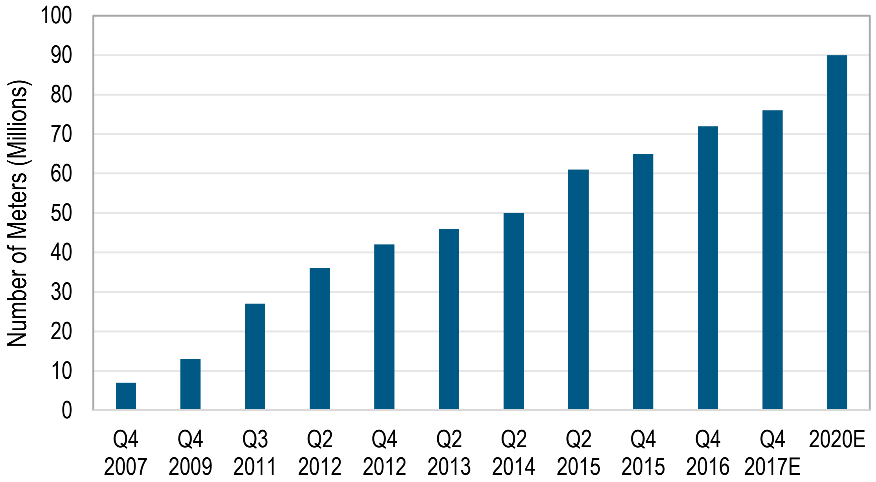
Source: Public Utilities Fortnightly[88]

V. GRID IMPROVEMENT – SMART METER DEPLOYMENT

What is happening?

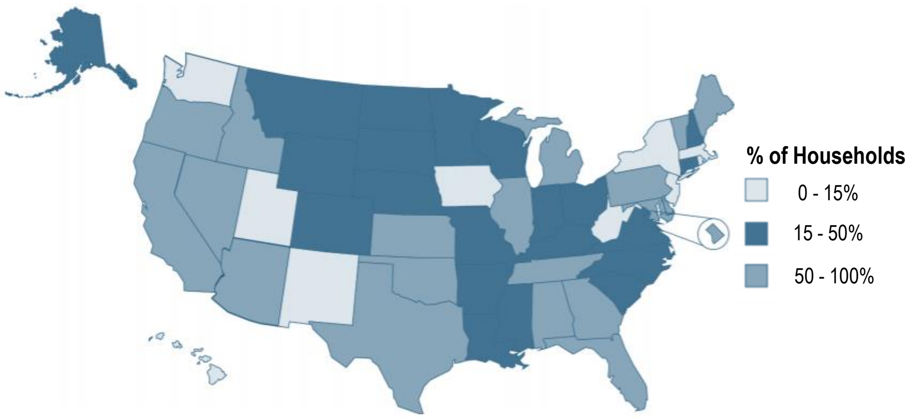
- Deployment of Smart Meters is an indicator of grid modernization adoption by utilities
  - Two-way Smart Meters allow utilities and customers to interact to support smart consumption applications using real-time or near real-time electricity data
  - Smart Meters support demand response and distributed generation, improve reliability, and provide information that consumers use to save money by managing their use of electricity
  - Smart Meter data provides utilities with detailed outage information in the event of a storm or other system disruption, helping utilities restore service to customers more quickly and reducing the overall length of electric system outages
- National Smart Meter installations are approaching 76 million and is projected to reach 90 million by 2020[89]
  - Currently, ~2 million North Carolina Duke Energy customers have Smart Meters installed (~1.8 million in DEC and ~0.16 million in DEP)[90]

US Smart Meter Installations (2007-2020)



Source: The Edison Foundation[91]

Residential Smart Meter Adoption Rates by State (2016)

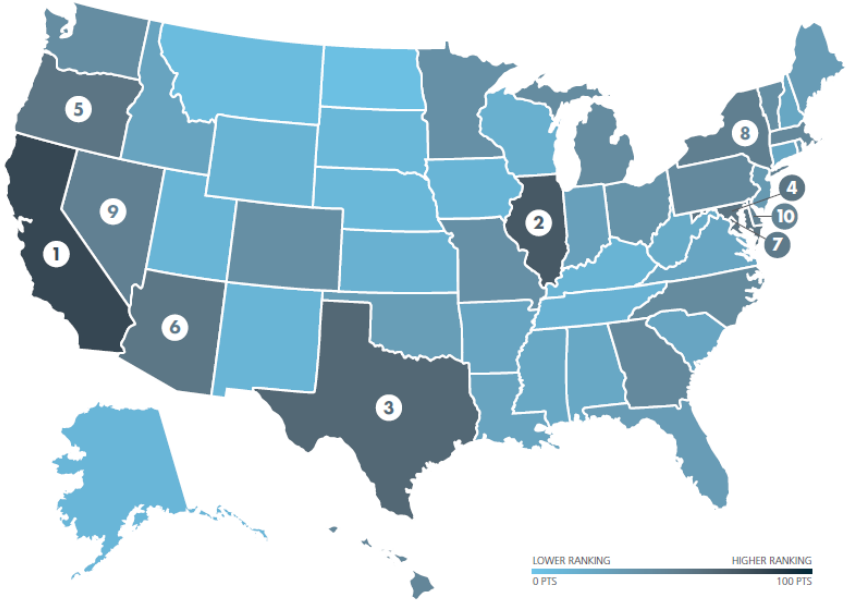


Source: The Edison Foundation[92]

What is happening?

- NC Energy Policy Council states that "utility grid modernization is a solution to address the increased complexity and demands from operating a changing electric grid. Due to the transient nature and potential imbalances of intermittent distributed renewable generation, modernizing the grid can address these issues more effectively than legacy devices in substations and distribution feeders today"[93]
- In Q1 2018, 37 US states and the District of Columbia took grid modernization actions involving regulations and legislature. Most of these actions involved Smart Meters, energy storage, and utility business model reforms[94]
- North Carolina was ranked 15th in the nation on the GridWise Alliance's 2017 Grid Modernization Index, which evaluates the leading states using a three-part score based on state support, customer engagement, and grid operations[95]

Grid Modernization Index Across the US



Source: GridWise Alliance[96]

Sample of Targeted Cost Recovery Mechanisms for Grid Modernization Investment

State	Type of Investment
California	Research and technology development
Massachusetts	Grid modernization
Minnesota	Grid modernization
New Jersey	Hardening infrastructure modernization
Ohio	Grid modernization
Pennsylvania	Advanced metering

Source: Navigant[97]

V. GRID IMPROVEMENT – UTILITY BENCHMARKING

What is happening?

- Utilities are adopting grid technology to support increasing DER penetration
- There are varying types of grid modernization technology, many of which are listed in the table below

Benchmarking of Utility Grid Modernization

Smart Grid Investment	Utility 1	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6	Utility 7
DER Penetration*	5%	25%	32%	55%	4%	<1%	<1%
Smart Meters		●	○	N/A**	○	●	●
Demand Response	○	●	●	◐	◐		◐
Distribution Automation	●	◐	○	●		●	●
Substation Automation	◐	◐	○	◐	◐	●	●
Advanced Communications	●	◐	◐	◐	◐	●	○
Energy Storage	○	◐	◐	◐	○		◐
Electric Vehicle Charging	◐	◐	○	◐	○	○	◐
Volt VAR Optimization	○	○	○		○	◐	◐
Time-of-use Pricing		◐	○	N/A**	◐		●
DERMS/ADMS	○	○	○	○	○	○	○
Microgrids			◐	○			◐
Undergrounding of Circuits	◐		◐	●			◐
Recovery Mechanism	●	●	●	◐	●	●	●

Source: Navigant[98]

*As percentage of peak demand. Note that utilities may define DER resources somewhat differently.
**Utility 4 market structure does not allow them to deploy Smart Meters or TOU rates

● **Large Scale**: utility has deployed technology in majority of its jurisdiction, and has begun evaluating the impacts on its system.

◐ **Pilot/Small Scale**: utility has deployed technology in one to a few locations, and has not been implemented long enough to evaluate its impact.

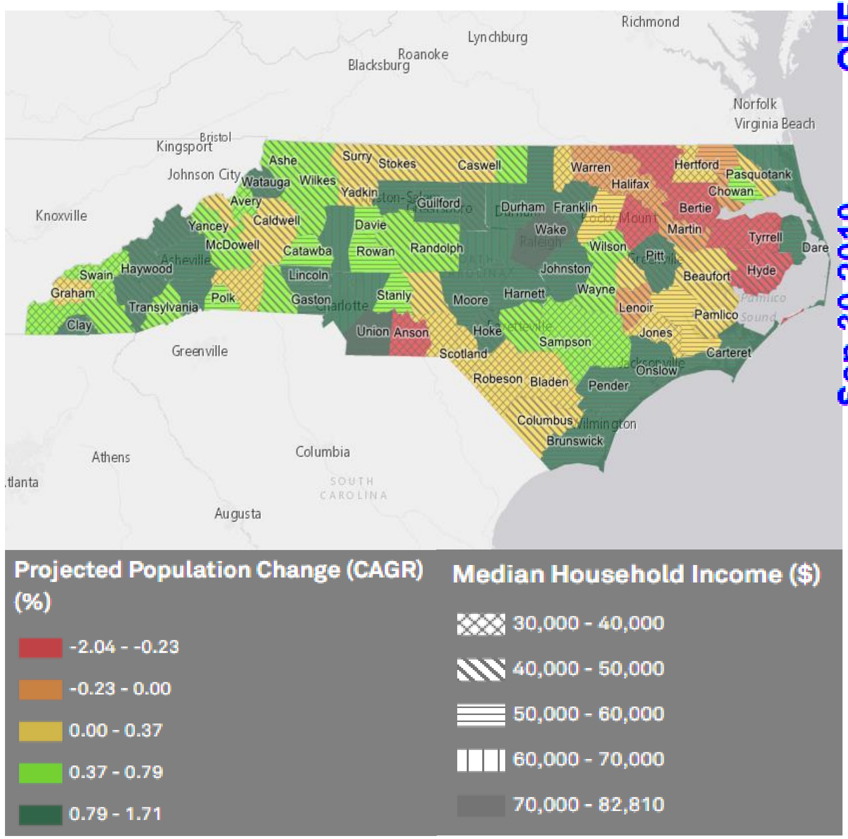
○ **Planned**: utility has not deployed the technology yet, but has plans for implementation in their most recent smart grid filing.

VI. CONCENTRATED POPULATION GROWTH

What is happening?

- People, wealth, and jobs continue to concentrate in urban and suburban areas
  - Movement is being driven by shifting demographics and changing lifestyle preferences
  - Many suburban areas getting an urban makeover with mixed-use development, thoughtful public spaces, transit options, and community-focused street-level development
  - Businesses, industry, and construction are following suit to take advantage of increased population density and connectivity
- North Carolina's population is expected to grow by ~6% (2017-2026)[99]
  - Wake and Mecklenburg counties experienced high population growth of 19% and 17%, respectively (2010-2017)[100]
    - These two counties expect ~24% population growth through 2028[101]
  - Charlotte and Raleigh, the largest cities in North Carolina, accounted ~67% of NC's growth since 2010[102]
  - Even outside of economic development efforts so prevalent in North Carolina, a significant number of rural counties project stagnant or declining population
- Load is growing with population requiring new infrastructure
  - Load in Raleigh and Charlotte growing 3% and 6% per year, respectively[103]
  - There are challenges and costs siting new infrastructure in constrained areas

NC Projected Population and Income Demographics

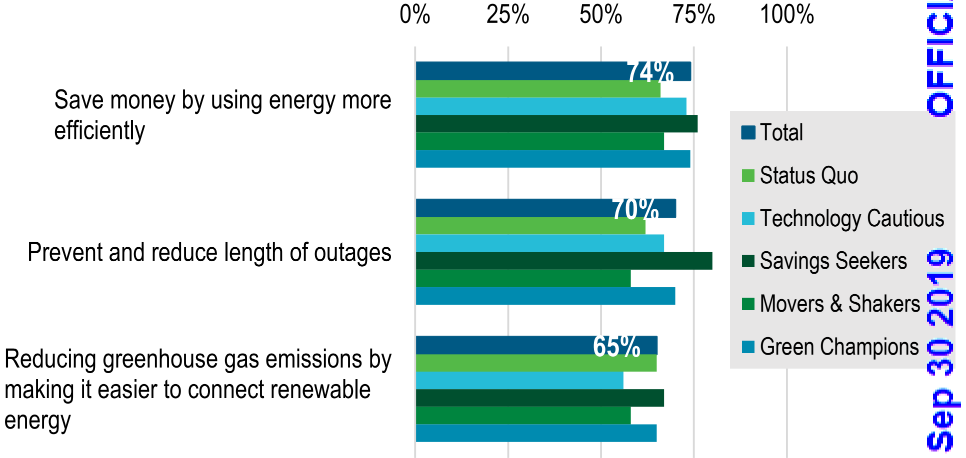


Source: S&P Global[104]

What is happening?

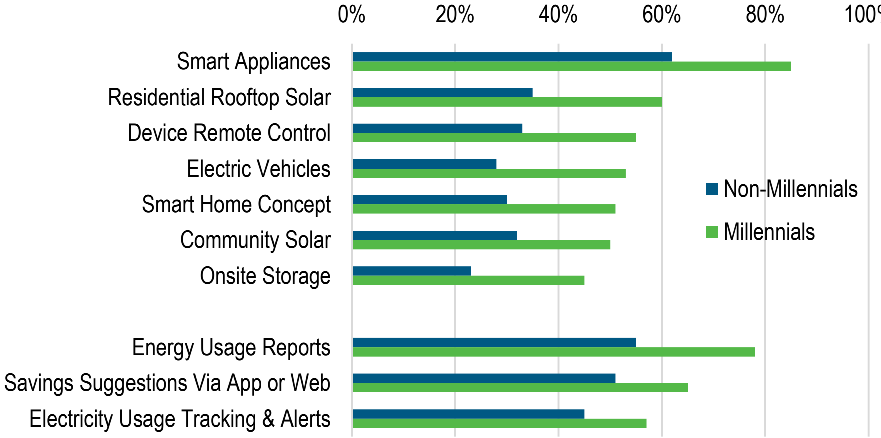
- Customers want to save money and reasonably reduce outages and greenhouse gas emissions[105]
  - Relative importance of these three may vary across customer personas, but they remain consistently the top factors
  - Customers want smart grid investments to reflect these needs
- To address these needs, customers are interested in new technology and increased control over their usage, including (1) smart appliances, (2) rooftop solar, and (3) device remote control[106]
- Millennials are far more interested in energy-related topics than non-millennials[107]
- Duke Energy's high growth business segments (advanced manufacturing, biotechnology, data centers, healthcare) requiring substantial mission-critical electrical infrastructure and cost-effective energy management services
- NC Energy Policy Council recognizes that "as the electric grid in North Carolina ages, it must keep pace with emerging technologies and customer expectations"[108]

Factors customer perceive as important for utility supply



Note: These are the top 3 choices for all types of respondents
Source: Smart Energy Consumer Collaborative[110]

Interest in Energy-related Concepts



Source: Smart Energy Consumer Collaborative[111]

VII. CUSTOMER EXPECTATIONS

What is happening?

Today, in North Carolina:[112]

- Customers want their power to be on all the time as much as this is reasonably possible
- Customers want their power to be safe
- Customers do not want their power company to harm the environment
- Customers want their power to be as cheap as reasonably possible
- Customers want their interactions with the power company to be as easy and user-friendly as possible
- Customers want increases to their power bills to be minimal, infrequent, and predictable as possible
- Customers want to be informed of problems and issues in advance where possible and want to be updated with status reports as problems are being resolved
- Customers know and accept that there are things beyond our control that will cause power outages no matter what actions we take to prevent them
- Customers are more accepting of power outages when they know what caused the outage and how long it will take to restore power
- The frequency of outages and power quality issues are generally more important to customers than the duration of outages and events
- Most non-residential customers have built the effects of outages and power quality issues in to their business costs and are not willing to pay significantly more to prevent them
- Only some highly power-dependent customers (mostly complex businesses) have taken or are willing to take extraordinary measures to ensure a virtually uninterrupted supply of power

NORTH CAROLINA GRID IMPROVEMENT PLAN

IMPLICATIONS

FOR STAKEHOLDER WORKSHOP

11/08/18

IMPLICATIONS TO OUR CUSTOMERS FROM THE MEGATRENDS

Our customers are impacted by the megatrends, and, under business as usual (BAU), our customers' expectations will not be met and we will miss the opportunity to optimally use advanced technology.

I	Increased costs
II	Reduced reliability and resiliency
III	Reduced ability to manage and integrate distributed energy resources (DER)
IV	Reduced ability to meet customer expectations and commitments
V	Reduced economic competitiveness for North Carolina
VI	Increased geographic and demographic disparity

I. INCREASED COSTS

Under business as usual, costs to customers may increase as compared to emerging alternatives.

Megatrend	BAU Threat	Opportunity
Concentrated Growth	Costs to build BAU infrastructure in urban and suburban areas with concentrated growth are increasing, and do not provide enhanced capabilities to meet expected future grid needs. These costs will be borne by all customers, including those in rural areas that are unaffected.	Advanced system controls, intelligence, planning, and automation would improve overall system efficiency using existing and new assets and thus lower costs for all customers from what they would otherwise be. Additionally, grid capacity needs and the need for two-way power flow can be addressed proactively.
Technology Advancements – Renewables and DER	Because DER is becoming more cost competitive, customers are installing DER and EVs, which, in turn, require improvements to the grid beyond BAU which increases costs if not done in a proactive and planned manner. The reduced load from DER can also lead to higher bills.	Advanced tools and technologies will enable greater application of DER on the grid. Effectively planning for and optimizing the installation of DER on the grid will lower costs for all customers from what they would otherwise be while maintaining safe and reliable operation of the grid.
Grid Modernization	"Like for like" replacement of technology will not lower costs beyond what it is today because capital and operating cost will be unchanged. Further, as the grid is impacted by other trends, existing grid technology may require more rapid replacement, thus increasing costs.	Using advanced grid technologies, system and operational efficiency are increased which lower costs to customers from what they would otherwise be.
Customer Expectations	Customers want to save money and under business as usual, costs will not decline and may go up. As the grid increasingly interconnects DER, interconnection costs of an individual project increase, making it cost prohibitive for customers to have more DER options.	With appropriate grid capabilities, such as ability to manage two-way power flow and intermittent resources, customers will have options that help them manage their costs better, including DER and usage management tools.
Environmental Commitments	Corporations and governments will not be able to meet their environmental goals and commitments if it becomes cost prohibitive to do so. And, in the case where interconnection costs are not incurred, such as with EV, costs to meet these goals and commitments are borne by all customers.	Advanced tools and technologies will enable greater application of DER on the grid, including renewable energy resources. Effectively planning for and optimizing the installation of DER on the grid will lower costs for all customers from what they would otherwise be while maintaining safe and reliable operation of the grid.
Impact of Weather Events	Absent resiliency and reliability improvements, customers will see increased costs from outages as they increase in number and severity. These costs include those incurred by the utility and by customers.	Proactively hardening the system and building advanced monitoring, smart control and grid intelligence can reduce the occurrence and duration of outages, saving customers money compared to business as usual.
Threats to Grid Infrastructure	Absent adequate protection against modern threats, costs to customers will increase due to increased attacks. These costs include those incurred by the utility and by customers.	By building cyber and physical protections that go beyond current compliance requirements to anticipate threats of the future, occurrence and duration of outages can be reduced saving customers money compared to business as usual.

When will implication occur under BAU? 2018 — 2028

Level of severity of implication: = Manageable = Some issues = Many issues

II. REDUCED RELIABILITY AND RESILIENCY

DUKE ENERGY

Under business as usual, reliability will not improve and may decrease.

Megatrend	BAU Threat	Opportunity
Concentrated Growth	In concentrated growth areas, reliability will decrease if improvements to the grid don't keep pace with concentrated load increases and DER penetration. Reliability will decrease in rural areas where flat load growth does not support traditional grid strategies.	Advanced system controls, intelligence, planning, and automation can improve overall system efficiency using existing and new assets and thus can improve reliability for all customers. .Additionally, grid capacity needs and the need for two-way power flow can be addressed proactively, which can improve reliability.
Technology Advancements – Renewables and DER	Because DER is becoming more cost competitive, customers are installing DER and EV at an increasing rate, which may decrease reliability due to voltage fluctuation and capacity limitations on the distribution system.	Using rapidly advancing technology and systems, the utility can provide active monitoring and control power flow and improved voltage fluctuation issues using "grid-edge" decision making. Non-traditional applications are also an opportunity to improve reliability.
Grid Modernization	"Like for like" replacement of existing grid infrastructure will not improve reliability beyond what it is today because functionality will not have improved. In particular, the number of customers that experience multiple interruption per year will increase (CEMI-6).	Rapidly advancing grid technologies are available to improve grid reliability, including improving visibility to a more granular level of where outages are occurring and enable grid-edge decision making and control.
Customer Expectations	Customer satisfaction will decrease with increased outages, and reduced power quality, as customers are inconvenienced or unable to work. These outages may be caused from voltage or power flow issues from DER, traditional infrastructure, or major events such as weather or cyber attack	Customers expectations of reduced outages (either short- or long-term) and better power quality would be addressed with the use of rapidly advancing grid technology and systems.
Environmental Commitments	Customers with environmental commitments will interconnect DER which could cause voltage and power flow issues on the grid resulting in reduced reliability. Conversely, if DER is curtailed to address the reliability issues, customers will be prevented from meeting their commitments.	Using advanced grid technologies and systems helps customers meet their environmental commitments without sacrificing reliability or resiliency.
Impact of Weather Events	The BAU approach of reacting to damage when storms occur will not improve resiliency. In particular, in concentrated areas, when storms damage equipment, it affects more customers.	Using advanced grid technologies and systems will reduce frequency of short-term outages and reduce time to recover from major storm-induced outages. Undergrounding or hardening the most outage prone lines reduces costs and major event duration for all customers from what they would otherwise be.
Threats to Grid Infrastructure	Cyber and physical threats to grid infrastructure are increasing rapidly. Failure to keep pace with these threats will result in compromised reliability and resiliency of the electric grid.	Aggressive development and implementation of advanced system protections and protocols will help the electric grid remain protected from the ever increasing number and variety of threats it faces every day. Also, in the event that a threat is successful, these measures will help minimize damage/disruption that could impact customers.

When will implication occur under BAU? 2018 — 2028

Level of severity of implication: = Manageable = Some issues = Many issues

III. REDUCED ABILITY TO MANAGE AND INTEGRATE DER

DUKE ENERGY

Business as usual limits the ability to manage and integrate DER, resulting in the need to curtail or issue moratoriums on customer-owned interconnection.

Megatrend	BAU Threat	Opportunity
Concentrated Growth	The existing constrained grid in urban areas limits the ability to interconnect DER for customers who are interested in renewable energy, storage and electric vehicles.	Advanced tools and technologies that enable two-way power flows will allow for increased application of DER on the grid. Effectively planning for and optimizing the installation of DER's on the grid will lower costs for all customers beyond what they would otherwise be while maintaining safe and reliable operation of the grid.
Technology Advancements – Renewables and DER	As more DER is connected to the grid, hosting capacity available for additional DER diminishes, causing customer interconnection costs to increase for future installations.	If the grid is able to handle two-way power flow by building capacity and using advanced monitoring and automation to manage DER, then DER can become a "tool in the toolbox" for grid operators.
Grid modernization	Current technology on the grid does not enable two-way power flow or voltage and power flow optimization needed to handle customer-sited, intermittent generation. This limits the ability for the grid to handle increasing capacity of DER.	With the use of advanced grid technologies (e.g. microprocessor based equipment), the grid could become a platform to connect and proactively use customer DER.
Customer Expectations	Customer satisfaction will decrease if customers are not given the option to connect DER, particularly renewables or EVs. If DER is not integrated properly, voltage fluctuations will cause DER to be curtailed.	If DER could be integrated, customers will have more energy options and be able to meet their individual needs such as to reduce greenhouse gases and reduce costs from what they would otherwise be.
Environmental Commitments	If customers, particularly corporations and governments, cannot interconnect renewable DER they will not meet their environmental goals.	By allowing customers to interconnect renewable generation, North Carolina will continue to be attractive to businesses with environmental commitments—this includes fast-growing sectors such as data centers, healthcare, and advanced manufacturing.
Impact of Weather Events	Grid-connected microgrids and other DER options for resiliency would not be able to be interconnected and used during severe weather events.	Customers will be able to leverage customer-owned resources in outages to improve resiliency by providing power in an outage at a local level.
Threats to Grid Infrastructure	Without proper protections, new "points of entry" that pose new cyber attack threat points, i.e. hacking a third-party resource, could impact the grid.	Duke Energy can work proactively with customers to build in protections upfront and over time as needs evolve.

When will implication occur under BAU? 2018 — 2028

Level of severity of implication: = Manageable = Some issues = Many issues

IV. REDUCED ABILITY TO MEET CUSTOMER EXPECTATIONS AND COMMITMENTS

DUKE ENERGY

Business as usual will limit customer options, resulting in higher costs and lower reliability.

Megatrend	BAU Threat	Opportunity
Concentrated Growth	As the demographics of customers in urban and suburban load growth areas evolve they place a higher priority on uninterrupted and personalized energy service. Strained traditional systems in these areas will not be able to meet customer expectations.	Advanced system controls, intelligence, planning, and automation would improve overall system efficiency using existing and new assets and thus improve reliability for all customers. Building capacity for two-way power flow enables options and grid resiliency.
Technology Advancements – Renewables and DER	Under business as usual costs of customer interconnection will increase and curtailment and/or moratoriums will eventually be required which will not meet customer expectations for renewables and DER.	Advanced technologies such as advanced monitoring and controls and solutions that increase hosting capacity will reduce need for curtailment or moratoriums and decrease the cost of interconnection from what they would otherwise be.
Grid Modernization	"Like for like" replacement of technology will not lower costs or improve reliability beyond what it is today because capabilities will be unchanged. Further, lack of visibility and control to customer-sited assets and outages will increase cost and reduce reliability.	Distribution automation, grid intelligence and other advanced technologies will minimize outages, accelerate power restoration, and open the opportunity to use DER.
Customer Expectations	Customers will be unhappy if expectations for affordability, reliability, and options are not met.	Access to new capabilities and offerings, as enabled by enhanced grid capabilities, enable customers to meet their expectations, encourage their participation in energy decisions and gives them more control over their energy use.
Environmental Commitments	The grid will increasingly have less ability to integrate DER and renewables which will cause customers to miss meeting their environmental commitments.	With enhanced grid capabilities, such as increased hosting capacity and the ability to integrate two-way power flow and intermittent resources (such as renewables), customers can meet their commitments with DER including solar, storage and EVs.
Impact of Weather Events	Absent resiliency and reliability improvements, customers will see increased costs and outages as storms and major weather events increase in number and severity. Increasing frequency of outages and increased costs lead to lower customer satisfaction.	By proactively hardening the system, undergrounding or hardening the most outage prone lines, and building advanced monitoring, control and grid intelligence, occurrence and duration of outages and associated costs can be reduced from what they would otherwise be.
Threats to Grid Infrastructure	Absent adequate protection against modern threats, customers will see increased costs and outages due to increased attacks. Increasing frequency of outages and increased costs lead to lower customer satisfaction.	By building cyber and physical protections that go beyond current compliance requirements to anticipate threats of the future, customers will be better protected from disruptions and costs of attack.

When will implication occur under BAU? 2018 — 2028

Level of severity of implication: = Manageable = Some issues = Many issues

V. REDUCED ECONOMIC COMPETITIVENESS FOR NORTH CAROLINA

DUKE ENERGY.

Business as usual makes North Carolina less attractive for businesses and residents.

Megatrend	BAU Threat	Opportunity
Concentrated Growth	Growth will not be absorbed cost-effectively, thus increasing costs to all customers which drives North Carolina to be a less attractive place to live or do business. Additionally, businesses will be deterred from locating in urban areas (where employees are located) due to reliability issues.	Advanced grid technologies and grid capacity deployed in concentrated growth areas and throughout the system will help to maintain affordability across all customers and encourage business development and relocation to the State.
Technology Advancements – Renewables and DER	Due to the inability of the grid to handle increasing amounts of DER, options will be limited for businesses to deploy renewables and/or DER which will make the State less attractive for businesses that desire these options.	Advanced technologies such as advanced monitoring and controls and solutions that increase hosting capacity will allow more DER and renewables making it an attractive market for certain companies.
Grid Modernization	Businesses will not be attracted to do business in North Carolina if the electric grid is not reliable or energy costs are less affordable due to existing equipment and operations. Further, prospective businesses may perceive North Carolina as not embracing rapidly advancing technologies.	A more resilient, reliable and intelligent grid will represent a modern, competitive energy system to current and prospective employers and their employees.
Customer Expectations	Customer satisfaction will decrease if expectations of affordability, reliability and options are not met, which could lead to residents and businesses choosing not to locate in the State.	Programs to protect, modernize and optimize the grid will provide reliable operation and offer customers the options they seek.
Environmental Commitments	The inability to utilize DER to meet environmental goals could inhibit commercial and industrial growth in North Carolina, particularly from large corporations with high renewable energy goals and environmental commitments.	Advanced grid technologies that increase hosting capacity and help to manage intermittency of renewable energy will make it possible for customers to pursue their environmental and sustainability commitments and be interested in North Carolina.
Impact of Weather Events	Absent resiliency and reliability improvements, customers will see increased costs and outages as storms and major weather events increase in number and severity resulting in decreased business and consumer confidence in the ability to stay open during storms.	By proactively hardening the system; undergrounding or hardening the most outage prone lines; and building advanced monitoring, control and grid intelligence; the occurrence and duration of outages and associated costs can be reduced helping customers be confident they can do business in an areas subject to storms.
Threats to Grid Infrastructure	Absent adequate protection against modern threats, customers will see increased costs and potential outages due to increased attacks resulting in decreased business and consumer confidence.	By building cyber and physical protections that go beyond current compliance requirements to anticipate threats of the future, customers will be better protected from disruptions and costs of attack helping customers be confident they can do business despite threats.

When will implication occur under BAU? 2018 — 2028

Level of severity of implication: = Manageable = Some issues = Many issues

Business as usual will not adequately meet the needs of rural customers in the future.

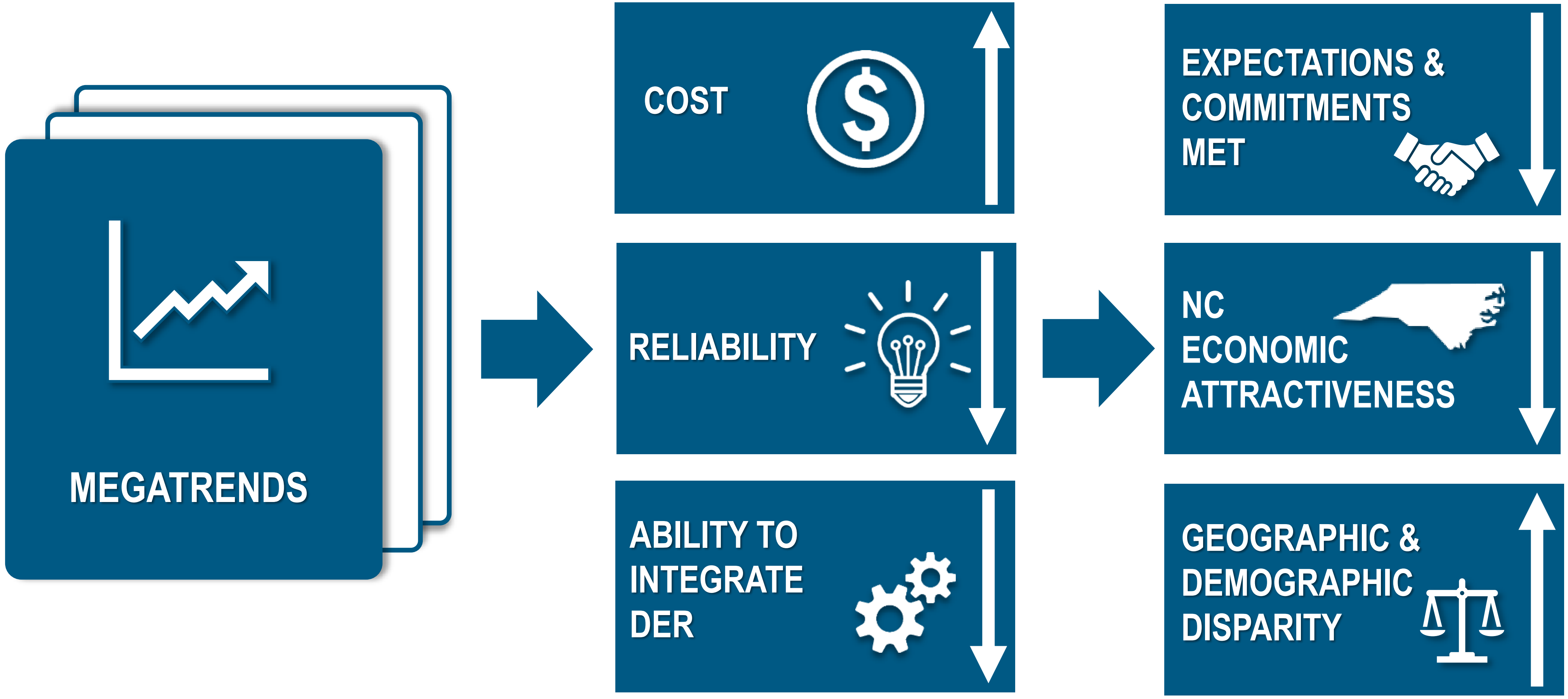
Megatrend	BAU Threat	Opportunity
Concentrated Growth	Capital demands to meet system expansion in high growth areas can undermine investment in rural areas of the state causing disparity between customer demographics and geography.	Advanced system controls, intelligence, planning, and automation would improve overall system efficiency using existing and new assets and thus improve reliability for all customers. Building grid capacity and the ability for two-way power flow enables options and grid resiliency.
Technology Advancements – Renewables and DER	Growth and demographic trends suggest that DER will predominate in urban and suburban centers that have an increasingly younger and higher-wealth demographic, leading to a lesser participation from and cost shifting to lower income or rural customers.	Advanced tools and technologies will enable greater application of DER on the grid. Effectively planning for and optimizing the installation of DER on the grid will lower costs for all customers from what they would otherwise be while maintaining safe and reliable operation of the grid.
Grid Modernization	Under business as usual, capital allocated for traditional system improvements necessarily goes to areas where there is highest load and customer count. As a result, rural areas see less timely improvements to the grid under legacy practice using traditional technology.	By optimally implementing new capabilities that reduce costs of improvements and operations in constrained urban areas, additional focus can be given to improvements in rural areas. In addition, grid automation will enhance ability to serve remote areas of the system.
Customer Expectations	Business as usual will not allow all customer classes to equally address their expectations for affordability, reliability and options.	Additional capabilities and programs can be used to proactively address the needs of all customer classes and open new opportunities for all customers.
Environmental Commitments	Under business as usual, only certain customers and businesses will be able to deploy DER or renewables needed to meet their commitments.	Advanced grid technologies that increase hosting capacity and help to manage intermittency of renewable energy will make it possible for all customer to have access to more DER or renewables.
Impact of Weather Events	Absent resiliency and reliability improvements, customers will see increased costs and outages as storms and major weather events increase. This is particularly challenging in rural areas where cost and times for repairs are higher due to longer radials and distance for crews to cover.	By proactively hardening the system, undergrounding or hardening the most outage prone lines, and building advanced monitoring, control and grid intelligence, the occurrence and duration of outages and associated costs can be reduced, particularly in hard-hit rural areas.
Threats to Grid Infrastructure	Absent adequate protection against modern threats, customers may see increased costs and outages due to increased attacks. In particularly, physical attacks will be more detrimental in radial systems, particularly in rural areas, due to singular failure points.	By building cyber and physical protections that go beyond current compliance requirements to anticipate threats of the future, customers will be better protected from disruptions and costs of attack in rural areas.

When will implication occur under BAU?

Level of severity of implication: = Manageable = Some issues = Many issues

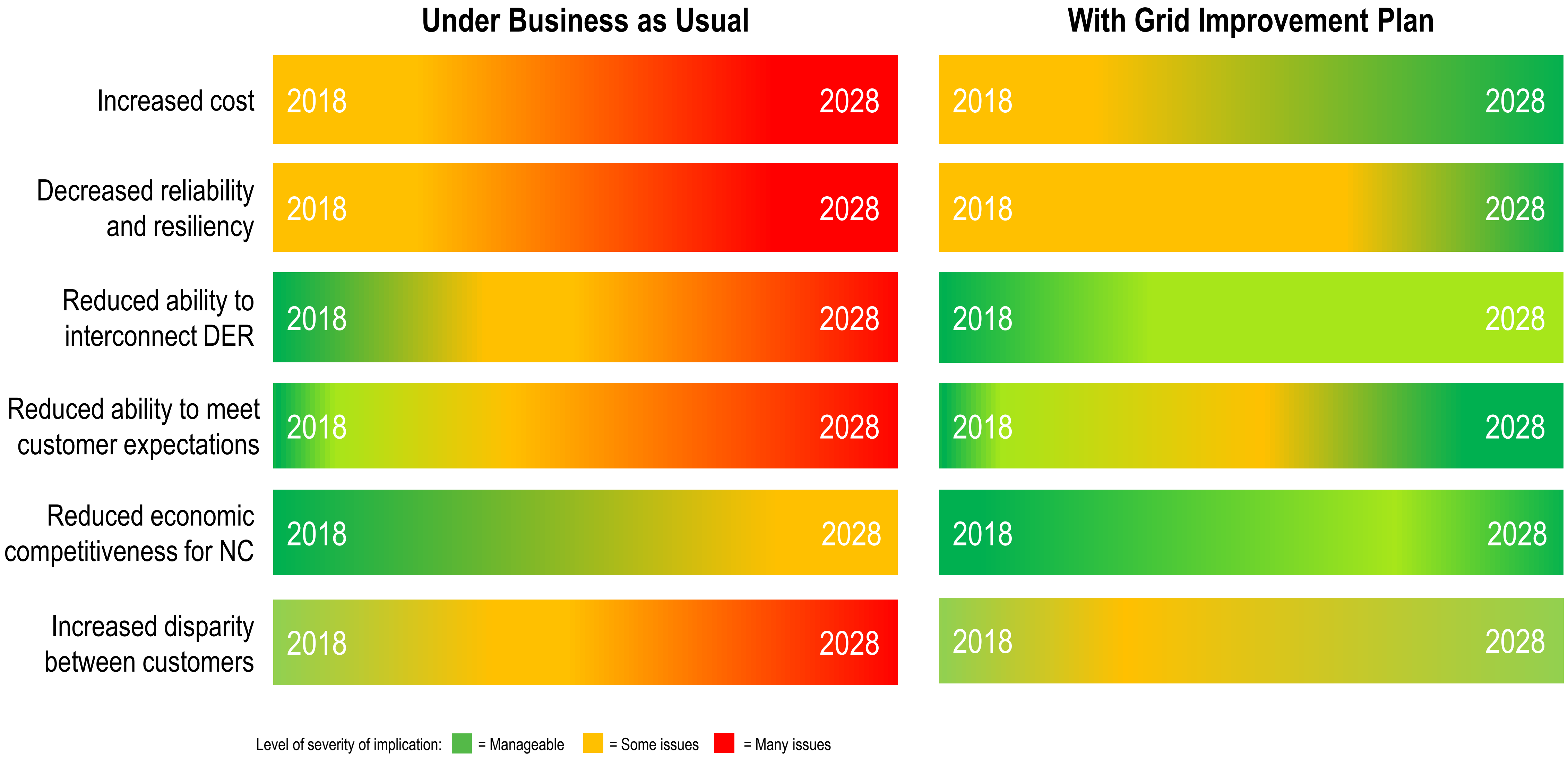
IMPLICATIONS OF MEGATRENDS

In summary, evolving megatrends will have implications on our **customers and the State.**



IMPACT OF GRID IMPROVEMENT PLAN ON IMPLICATIONS

Over time, the Grid Improvement Plan will reduce the degree of severity of the implications experienced under business as usual.

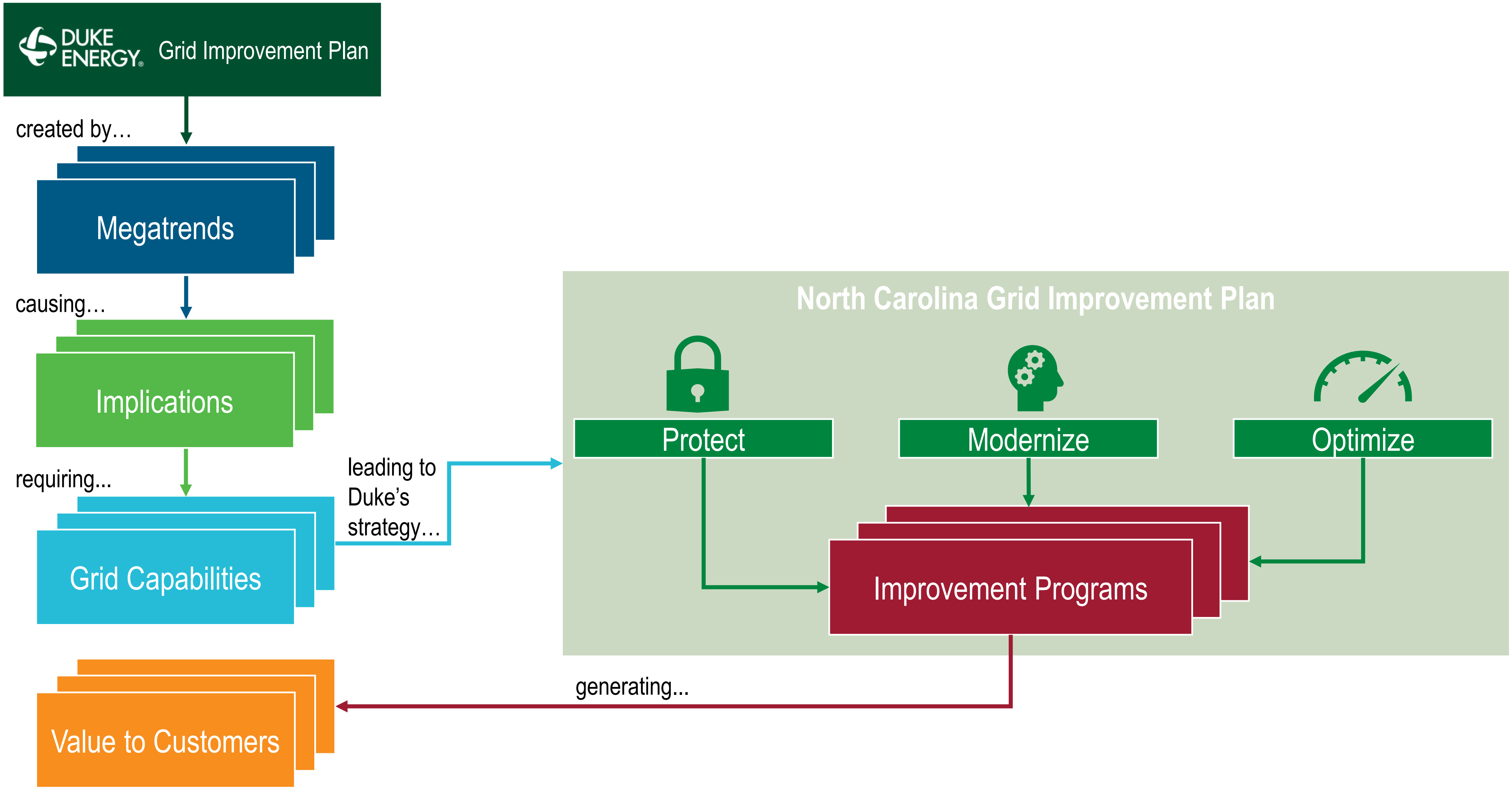


NORTH CAROLINA GRID IMPROVEMENT PLAN

PORTFOLIO PRIORITIZATION METHODOLOGY

FOR STAKEHOLDER WORKSHOP

11/08/18



DUKE ENERGY. Grid Improvement Plan
created by…
Megatrends
causing…
Implications
requiring...
Grid Capabilities
leading to Duke's strategy…
North Carolina Grid Improvement Plan
Protect
Modernize
Optimize
Improvement Programs
generating...
Value to Customers

DUKE ENERGY'S NC GRID IMPROVEMENT PLAN FRAMEWORK

OPTIMIZE

Optimize the total customer experience

MODERNIZE

Leverage enterprise systems and technology advancements

PROTECT

Reduce threats to the grid

MAINTAIN[1]

Serve customers in a manner that meets industry safety, reliability and environmental standards

(1) *Maintain* base work not included in NC Grid Improvement Plan

DUKE ENERGY'S NC GRID IMPROVEMENT PLAN FRAMEWORK

OPTIMIZE

Optimize the total customer experience

Energy Storage	EV Charging	Hardening and Resiliency [T]	Hardening and Resiliency [D]	Integrated Volt-Var Control	Long Duration Interruptions

Oil Breaker Replacement	Self-Optimizing Grid	Targeted Undergrounding	Transformer Retrofit	Transformer Bank Replacement

MODERNIZE

Leverage enterprise systems and technology advancements

Advanced Metering	DER Dispatch Tool	Distribution Automation	Enterprise Applications	Enterprise Communications

Customer Data Access	Integrated System Operations Planning	Power Electronics	Transmission System Intelligence

PROTECT

Reduce threats to the grid

Physical & Cyber Security

MAINTAIN[1]

Serve customers in a manner that meets industry safety, reliability and environmental standards

Line Extensions	Capacity Expansions	Substation Additions	Outage Follow-up	Pole Replacements

Vegetation Management	End-of-life Asset Replacement	Equipment Inspection & Maintenance	General System Protection

(1) *Maintain* base work not included in NC Grid Improvement Plan

DUKE ENERGY

DEFINITIONS FOR JUSTIFICATION METHODOLOGIES

Cost-Benefit and Cost-Effectiveness Justified (Optimize)

Programs and projects in this category provide customers more net benefits than net costs and solve for one or more external "megatrends."

Rapid Technology Advancement-Cost Effectiveness Justified (Modernize)

Equipment, software, hardware, operating systems, and/or accepted system operating practice has advanced at an atypical pace in this category causing the need for rapid and sometimes frequent changes within the utility at a system deployment level. Work in this category is usually related to system communication, automation, and intelligence and must be executed at a deliberate pace while ensuring not to deploy new technology before it has reached operational and price point maturity. While not technically compliance work, work in this category is essential for modern system operations.

Compliance-Cost Effectiveness Justified (Protect)

i. An external law, rule, or regulation applicable to the company requires the work;

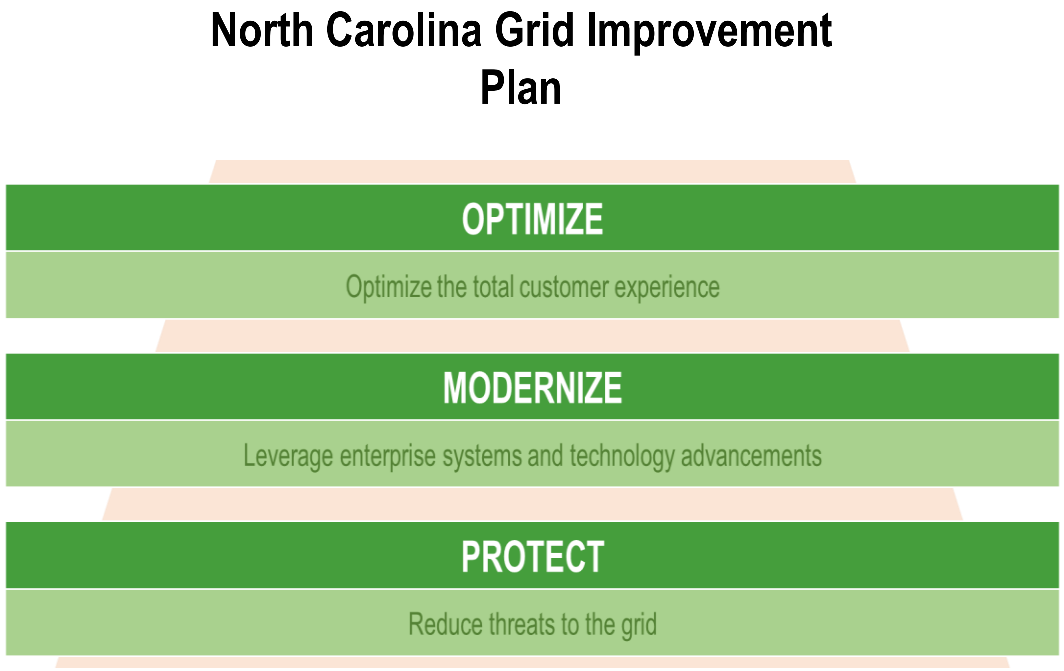
ii. A binding legal obligation such as a contract, agency order, or other legal document compels the work; or

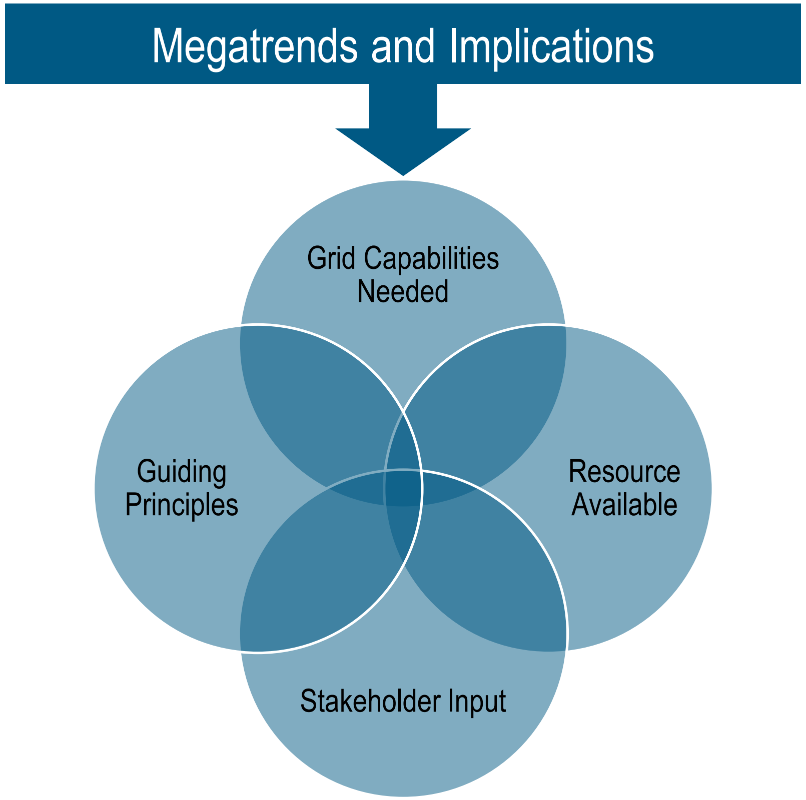
iii. The Operations Council has approved the work as being critical and imperative to the Company's operations

Maintain Base (Maintain)

Programs and investments to serve customers in a manner that meets industry safety, reliability, and environmental standards.

The programs in our portfolio were selected based on alignment with our framework and prioritization criteria.





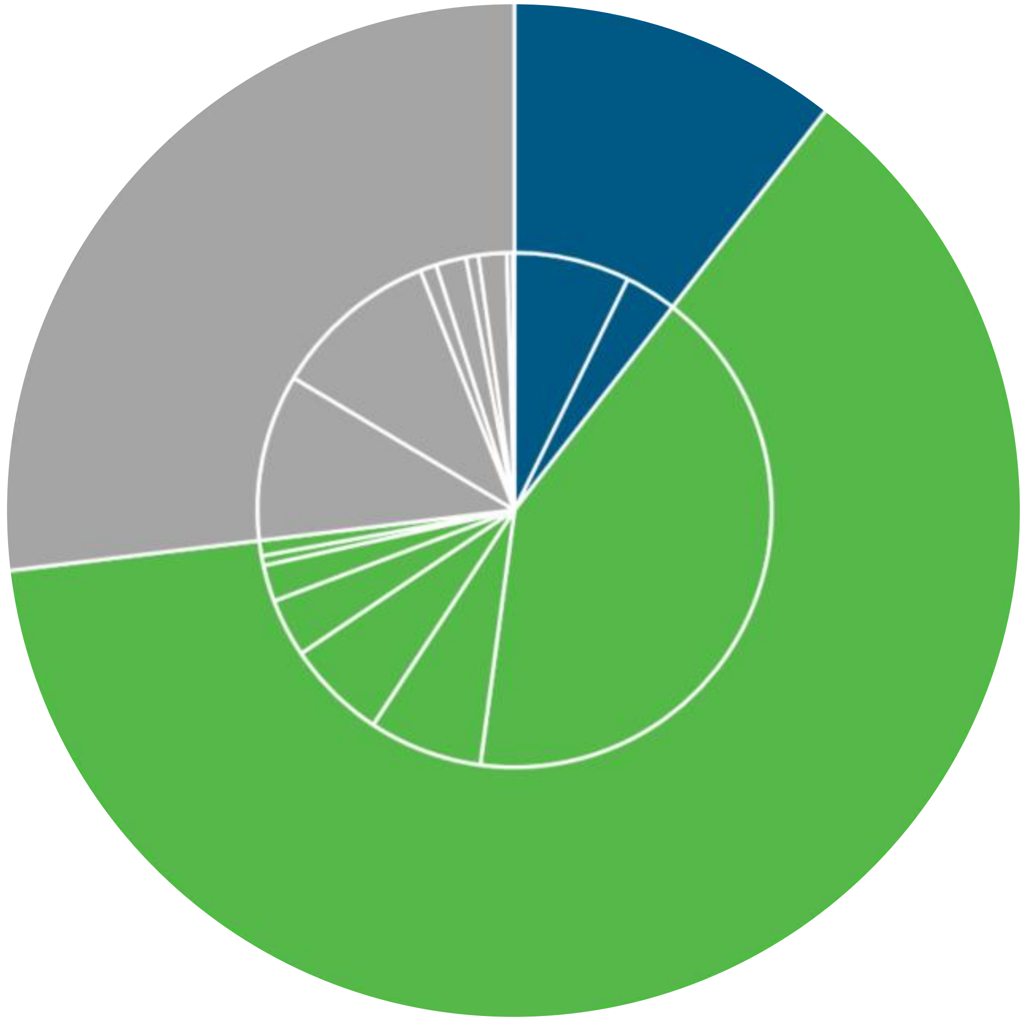
Programs are considered based on fit with framework and justification methodology:

- **Protect**: required for compliance
- **Modernize**: technology has rapidly advanced and is now mature
- **Optimize**: program provides attractive benefits

Customer-Focused Programs are selected and funded based on:

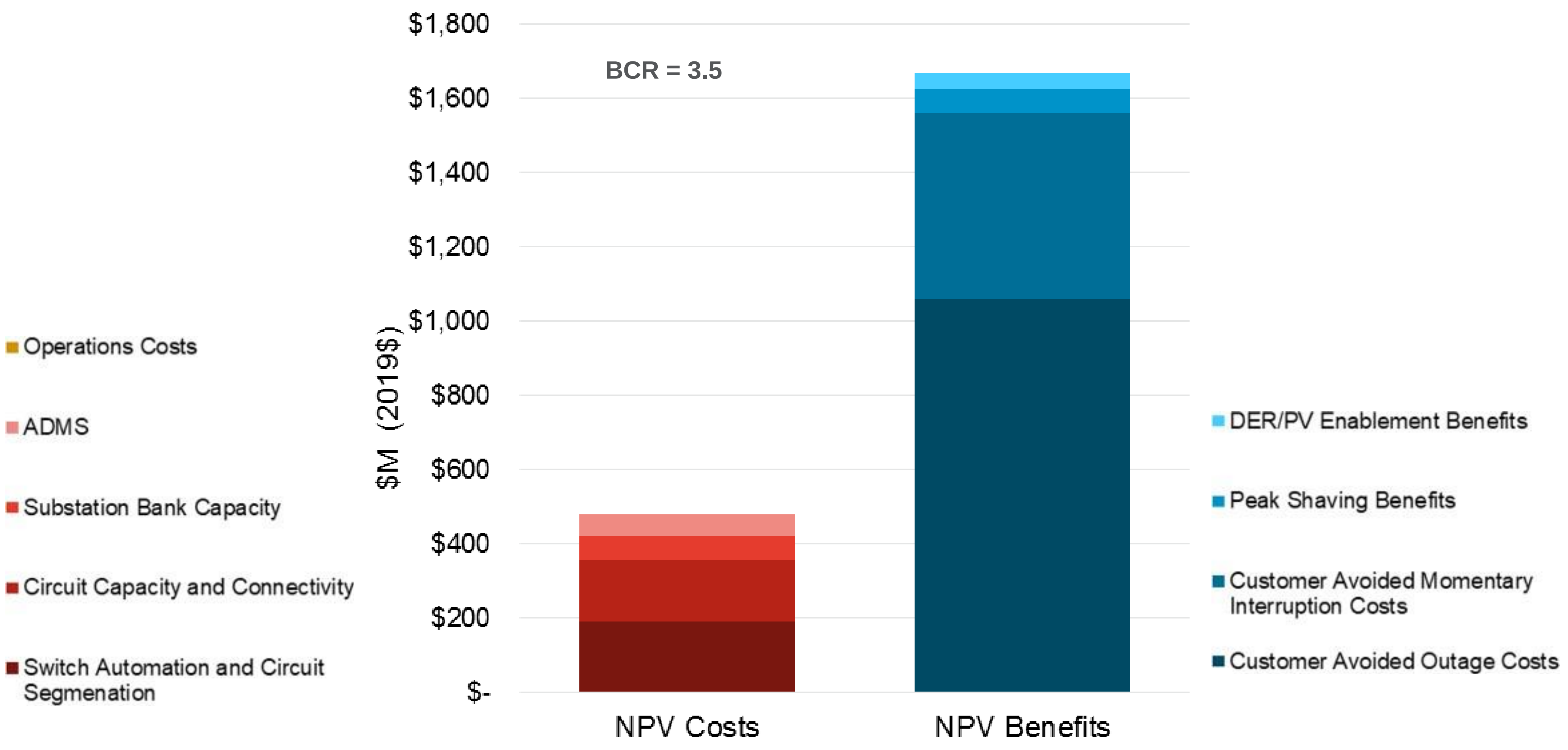
- **Grid capabilities** that are needed to address megatrends
- Scope and budgets right-sized to **available resources**
- **Stakeholder input**
- Alignment with **guiding principles**

PROGRAM PORTFOLIO

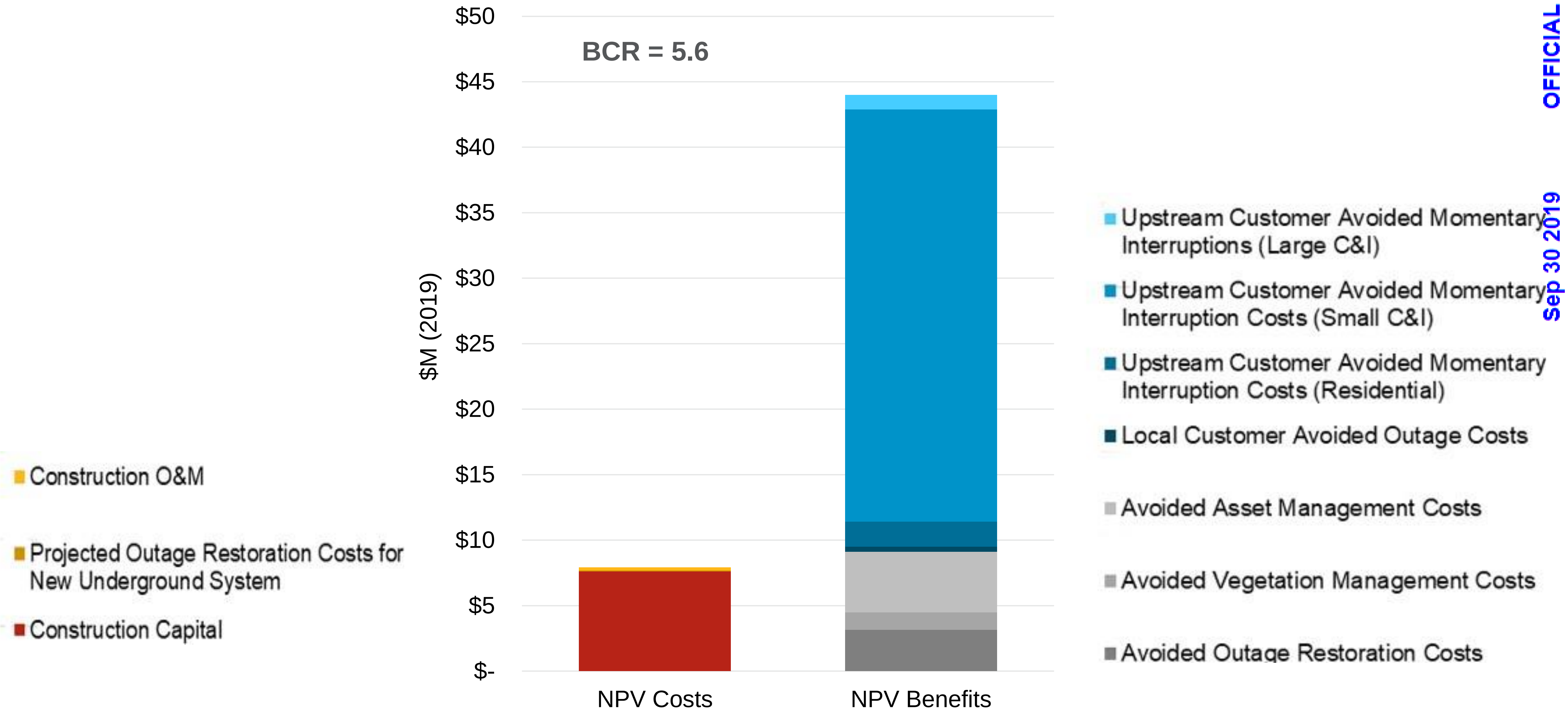


Program
Compliance: Cost Effectiveness Justified
Physical Security
Cyber Security
Cost Benefit & Cost Effectiveness Justified
SOG
Distribution H&R
IVVC DEC
Transmission H&R
TUG
Energy Storage
Transmission Bank Replacement
D-OIL Breaker Replacements
T-OIL Breaker Replacements
DSDR peak shaving to CVR in DEP
Rapid Technology Advancement: Cost-Effectiveness Justified
T&D Communications
Distribution System Automation
Transmission System Automtation
T&D Enterprise Systems
ISOP
DER Dispatch Tool
Electric Vehicle Charging
Power Electronics for volt/var control
Customer Data Access

SOG 3-YEAR DEPLOYMENT – NPV OF BENEFITS AND COSTS



TUG WINDSOR PARK DEPLOYMENT – NPV OF BENEFITS AND COSTS



DUKE ENERGY

NORTH CAROLINA GRID IMPROVEMENT PLAN

PROGRAM SUMMARIES

FOR STAKEHOLDER WORKSHOP

11/08/18

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PROGRAM: INTEGRATED VOLT/VAR CONTROL (IVVC)

The IVVC program establishes control of distribution equipment in substations and on distribution lines to optimize delivery voltages to customers and power factors on the distribution grid.

DESCRIPTION

IVVC allows the distribution system to optimize voltage and reactive power needs. The program employs remotely operated substation and distribution line devices such as voltage regulators and capacitors. The settings for thousands of these controllable field devices are optimized and dispatched via a distribution management system.

IVVC capabilities enable a grid operator to lower voltage as a way of reducing peak demand (peak shaving), thereby reducing the need to generate or purchase additional power at peak prices, or protecting the system from exceeding its load limitations. The current DEP **Distribution System Demand Response (DSDR)** program uses the peak shaving mode of IVVC to support emergency load reduction.

Another operational mode enabled by IVVC capabilities on the distribution system is **Conservation Voltage Reduction (CVR)**. CVR uses IVVC during periods of more typical electricity demand to reduce overall energy consumption and system losses.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

MORE ABOUT THE PROGRAM

The Distribution Management System (DMS), which manages the dispatch of IVVC functionality, can be designed to manage distribution circuits such that any impacts to customers with large motors sensitive to voltage control can be reduced. To maximize operational flexibility and value, the IVVC system can also have peak shaving capability and emergency modes of operation. Advanced DMS software upgrades will enable IVVC to operate in various modes to provide further customer benefit in the future.

DSDR to CVR in DEP

In 2014, Duke Energy implemented DSDR in DEP, achieving peak shaving voltage reduction of approximately 3.6% across the DEP distribution system. The DMS in DEP is capable of optimized modes (i.e., DSDR) or non-optimized (i.e., emergency) modes. When in emergency mode, the system can quickly provide a temporary voltage reduction capability of up to 5.0%.

DEP's initial implementation of DSDR also included a significant amount of circuit conditioning to optimize the system for DSDR mode (i.e., the installation of voltage regulating devices and capacitors, balancing of load on distribution circuits, and reconductoring of some distribution lines to larger wire sizes).

Because the substation, distribution, telecommunications, and IT infrastructure were put in place as part of the original DSDR implementation, this sub-program focuses on the deployment of the few additional device installations as well as the DMS upgrades required to support various operational modes, including the current DSDR mode and CVR mode, as well as Self Optimizing Grid and other distribution automation capabilities.

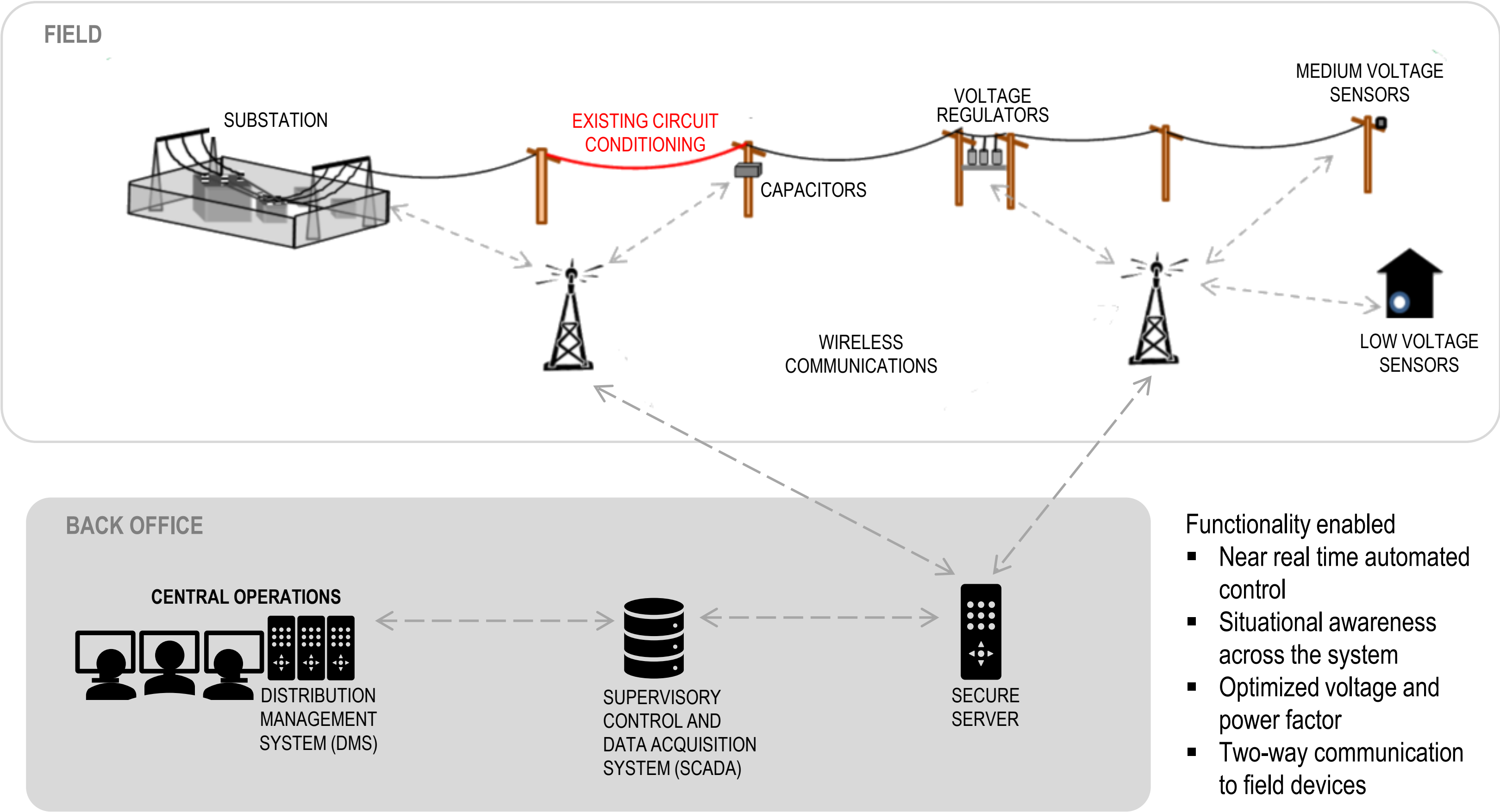
Through this sub-program, Duke Energy will enable 2% voltage reduction for energy conservation (an average of roughly 1.4% load reduction).

IVVC Project in DEC

The DEC IVVC pre-scale deployment project used real-time field conditions on a small scale to demonstrate the use of IVVC on the DEC system, and validate benefits in advance of its full-scale rollout. The small-scale demonstration validated voltage reductions of approximately 2% are possible with appropriate transmission and distribution system upgrades.

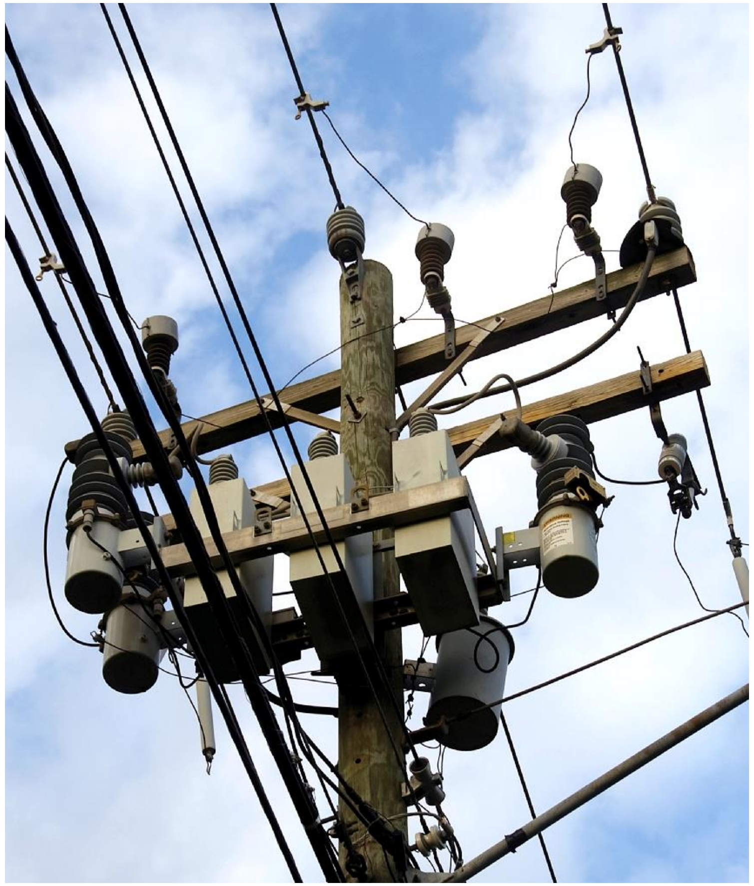
The DEC IVVC project will install communications and voltage control infrastructure at substations and associated distribution lines. The project will also leverage overlaps with efforts like Self Optimized Grid projects that deploy some of the infrastructure and capabilities necessary to enable IVVC.

PROGRAM: INTEGRATED VOLT/VAR CONTROL (IVVC)



Functionality enabled
- Near real time automated control
- Situational awareness across the system
- Optimized voltage and power factor
- Two-way communication to field devices

SMART CAPACITOR BANK



PROGRAM: SELF-OPTIMIZING GRID (SOG)

The self-optimizing grid program, also known as the smart-thinking grid, redesigns key portions of the distribution system and transforms it into a dynamic self-healing network.

DESCRIPTION

The current grid has limited ability to reroute or rapidly restore power and limited ability to optimize for the growing penetrations of distributed energy resources (DER). The SOG program is established to address both of these issues.

The SOG program consists of three (3) major components: grid capacity, grid connectivity, and automation and intelligence. The SOG program redesigns key portions of the distribution system and transforms it into a dynamic smart-thinking, self-healing grid. The grid will have the ability to automatically reroute power around trouble areas, like a tree on a power line, to quickly restore power to the maximum number of customers and rapidly dispatch line crews directly to the source of the outage. Self-healing technologies can reduce outage impacts by as much as 75 percent.

The **SOG Capacity projects** focus on expanding substation and distribution line capacity to allow for two-way power flow. **SOG Connectivity projects** create tie points between circuits. **SOG Automation projects** provide intelligence and control for the Self Optimizing Grid. Automation projects enable the grid to dynamically reconfigure around trouble and better mange local DER.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ IMPROVE RELIABILITY
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

PROGRAM: SELF-OPTIMIZING GRID (SOG)

MORE ABOUT THE PROGRAM

The SOG program, also known as the smart-thinking or self-healing gird, implements distribution system design guidelines that improve grid reliability and resiliency. SOG circuits will have automated switches to divide the circuit into switchable segments. Each segment is designed to consist of approximately 400 customers, three miles in circuit segment length, or serve 2MW of peak load. This design ensures that any issues on the system can be isolated, and customer impacts are limited. The long term vision is to serve 80% of customers by the Self-Optimizing Grid.

Advanced Distribution Management System (ADMS)

The ADMS subprogram is an enterprise-wide program to deploy a common distribution management system. Consolidating to a single platform for DMS and SCADA systems enables operational efficiency and the ability to integrate future solutions needed as demands on the distribution system evolve. The three main projects are: (1) **SCADA upgrade project** which upgrades the supervisory control and data acquisition system; (2) **DMS common platform project** which deploys a common version of DMS across DEC and DEP; and (3) **Closed loop FLISR project** which deploys DMS functionality that minimizes the area impacted by the resulting outage.

SOG Segmentation & Automation

This subprogram focuses on segmenting circuits in accordance with SOG design guidelines (segments should serve approximately 400 customers, are three miles in length or serve 2 MW of peak load) and equipping those segments with automated switching devices. The purpose is to limit the exposure of customers to power outages associated with faults on a line (e.g., a tree falling or vehicle-power pole collision). This is accomplished by sectionalizing a circuit by adding and/or re-configuring a number of protective devices on tap lines.

Circuit Capacity and Connectivity

This subprogram focuses on upgrading selected circuit feeders and tying them together to meet the SOG design philosophy. The circuit capacity activities involve upgrading the feeder conductor and voltage control devices to enable a circuit to carry its own customer load as well as portions of adjacent circuit customer load, as needed.

Substation Bank Capacity

This subprogram focuses on upgrading selected substations to meet the SOG design philosophy. The substation bank capacity activities involve upgrading existing substation transformers and other associated equipment to allow for a substation to service its normal customer load as well as any additional load it may pick up during a SOG isolation/reconfiguration event.

PROGRAM: POWER ELECTRONICS FOR VOLT/VAR

The Power Electronics program integrates protection and control technology, helps reduce power quality issues associated with high DER penetration, and ultimately improves reliability to customers.

DESCRIPTION

As the adoption of distributed energy resources (DER) (e.g., customer-owned solar and energy storage) reaches critical levels and microgrid technology matures, protective device technology must also advance to appropriately detect and respond to rapid voltage and power fluctuations that often accompany non-dispatchable resources such as solar.

As clouds move across the daytime sky and momentarily block sunlight from reaching solar panels, solar generation immediately ceases. As sunlight peaks through openings in the cloud cover, the solar panels begin generating, creating power spikes and voltage instability on the circuit. These intermittent power impacts occur and then change at rapid rates (in some cases sub-second) and frequently faster than the legacy electro-mechanical voltage management equipment like regulators and capacitors can handle.

Integrating advanced solid-state technologies like power electronics (i.e., static VAR compensators and other solid-state voltage support equipment), better equips the distribution system to manage power quality issues associated with increasing DER penetration.

The program is still in its early stages and current plans are small pre-scale deployments to validate capabilities and benefits.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

PROGRAM: POWER ELECTRONICS FOR VOLT/VAR

FIRST INSTALLATION OF MINIDVAR IN DEP TERRITORY

COST-EFFECTIVE UPGRADE FOR FEEDERS WITH HIGH SOLAR PV OR DG GROWTH

PROGRAM: DISTRIBUTION SYSTEM AUTOMATION (DA)

The DA program improves how the distribution system protects the public and itself from unsafe voltage and current levels and significantly reduces the impact experienced by customers due to grid issues.

DESCRIPTION

The capabilities offered through DA can transform what may have been an hour-long power outage for hundreds or even thousands of homes and businesses into a momentary outage – or potentially help avoid an outage altogether.

The DA consists of several complementary efforts that work in concert to support dynamic and growing distribution system loads in a more sustainable way while minimizing power quality issues that often accompany a large-scale transition to solar power. One of these projects, **Urban Underground System Automation,** modernizes the protection and control of underground power systems that serve critical high-density areas, such as urban business districts and airports.

The **Fuse Replacement** project focuses on replacing one-time use fuses with automatic operating devices capable of intelligently resetting themselves for reuse, thus eliminating unnecessary use of resources (inventory, time, gasoline, etc.). The **Hydraulic to Electronic Recloser** program replaces obsolete oil-filled (hydraulic) devices with modern, remotely operated reclosing devices that support continuous system health monitoring.

Such digital device upgrades offer further value through efforts like the **System Intelligence and Monitoring** pilot, which develops advanced diagnostic tools that help engineers and technicians address electrical disturbances on the distribution system and improve customer experience.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ IMPROVE RELIABILITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

PROGRAM: DISTRIBUTION SYSTEM AUTOMATION (DA)

DUKE ENERGY.

MORE ABOUT THE PROGRAM

Through its suite of complementary efforts, the DA Program offers a way to deliver electricity to customers while avoiding preventable service interruption for thousands of customers.

Hydraulic to Electronic Recloser

Phases out existing hydraulic (oil-filled) reclosers to reduce the oil footprint and eliminate maintenance activities. The sub-program has two phases: (1) target all hydraulic reclosers rated 140 amps or greater and replace with electronic, solid-dielectric interrupter devices; and (2) focus on smaller hydraulic reclosers (those rated less than 100 amps) and replace them with similar electronic, solid-dielectric, reclosing devices as this technology becomes mature enough for full scale deployment.

System Intelligence and Monitoring Pre-Scale Effort

Leverages data from digital devices deployed as part of the Self-Optimizing Grid, Smart Meter, and other programs to build a database and system model that monitors electrical disturbances across the distribution system. While each grid device may only monitor a portion of a circuit, advanced analytics creates a larger picture of system activity and an end-to-end blended view of customer experience. When completed, this subprogram will create a new system diagnostic tool for troubleshooting problem areas and mitigating emerging issues as they occur, as well as for managing the integration of DER.

Fuse Replacements with Electronic Reclosers

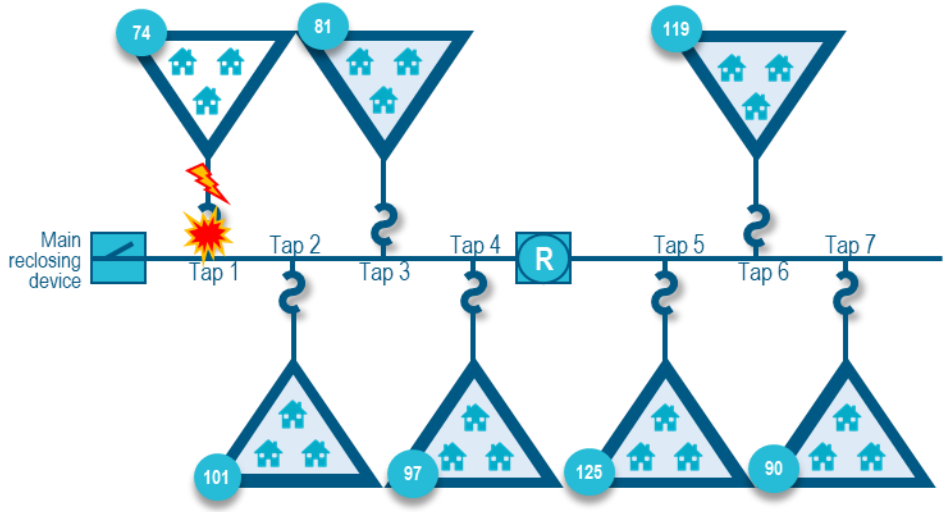
Replaces protective tap line fuses with small electronic sectionalizing devices on segments that can eliminate the most interruptions for customers. The small electronic reclosers serve to prevent customer outages by allowing temporary faults time to clear power lines before operating and initiating sustained outages. A protective fuse in this same tap line configuration is designed to actuate and initiate a sustained line outage at the first sign of a line fault; it must then be replaced before service can be restored. The fuse replacement with electronic recloser eliminates the mainline breaker from operating at all, eliminating unnecessary momentary interruptions and sustained outages.

Underground (UG) System Automation

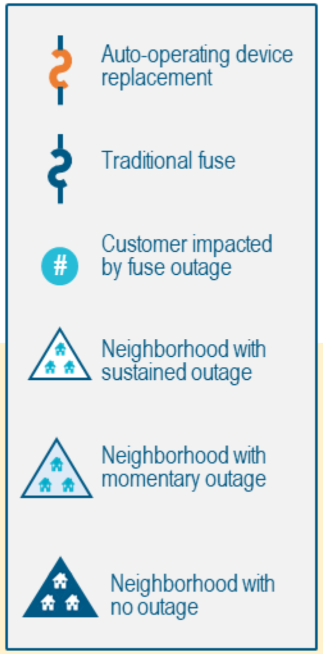
Replaces manually operated underground switchgear with remotely operated automated switchgear and deploys advanced automation schemes in urban downtown areas and other places with high density public use, such as airports and public entertainment areas. UG Automation enables automatic reconfiguration of underground systems for connecting to a new feeder or for isolating downstream system faults to minimize customer outages and impacts to the public. When completed, what might have been hours of service interruption can be reduced down to seconds.

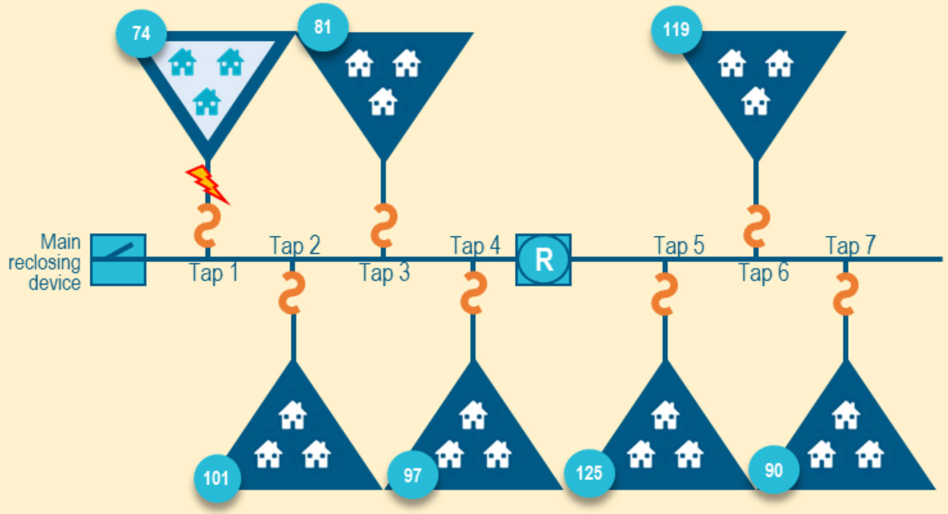
PROGRAM: DISTRIBUTION SYSTEM AUTOMATION (DA)

WITHOUT DEVICE REPLACEMENTS
(687 momentary interruptions, 74 sustained interruptions, one fuse replacement)



- Temporary fault Tap 1
- Main reclosing devices blinks
- All **687** customers experience a **momentary outage**
- The **74** customers of neighborhood 1 experience a **sustained outage** until the Tap 1 fuse is replaced





WITH AUTOMATICALLY-OPERATING DEVICE REPLACEMENTS
(74 momentary interruptions only)

- Temporary fault Tap 1
- Main reclosing devices blinks
- Only the **74** customers experience a **momentary outage**
- Auto-operating device resets
- **Zero sustained outages**; no fuse replacement needed

PROGRAM: ENERGY STORAGE

DUKE ENERGY

The Energy Storage program implements battery storage and other related non-traditional measures to defer, mitigate, or eliminate the need for traditional utility investments, such as line capacity upgrades.

DESCRIPTION

The program supports customer and utility initiatives through smart investments in storage for applications that deliver value to customers and the company. These applications include microgrid projects for preventing planned and unplanned outages, as well as long-duration outage projects for providing redundant power sources for vulnerable (rural and remote) communities, and circuit and bank capacity projects using substation-tied energy storage.

Given the multiple applications energy storage technology supports, projects within the Energy Storage program are designed and assessed on a case-by-case basis for the specific challenge being addressed (e.g., long duration outage support, microgrid or emergency power support, auxiliary service needs, etc.).

The Energy Storage program also includes the development and deployment of an energy storage control system to manage the fleet of energy storage resources.

GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY (DER Enablement)
- ✓ MODERNIZE GRID OPERATIONS & PLANNING
- ✓ EXPAND CUSTOMER OPTIONS AND CONTROL

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

MORE ABOUT THE PROGRAM

Energy storage provides several different forms of value when applied to the distribution grid. It can be used as a tool to improve reliability to remote communities and it can help increase the how much DER in the form of solar energy can be connected to the grid. It can also be used as a way to delay or mitigate the need to invest in more traditional resources to address transmission and distribution capacity needs.

Energy Storage Control System (ESCS)

By enabling grid operators to dispatch batteries, and batteries plus solar, as part of a diverse generation portfolio, the ESCS project creates the means for distributed energy resources to provide a more cost-effective, energy storage solutions for enhancing grid efficiency and reliability, along with bulk power operations effectiveness. The primary ESCS applications include: (1) Frequency regulation services, (2) Energy arbitrage (i.e., shifting to charge off-peak, discharge-on peak), and (3) Microgrid islanding for outage support and peak shaving.

Interrelation with Integrated System Ops Planning (ISOP)

Energy storage is a technology that offers the ability to support many valued requirements across the generation, transmission and distribution systems. The Integrated System Operation Planning (ISOP) effort will enable storage and microgrid projects to be deployed more effectively.

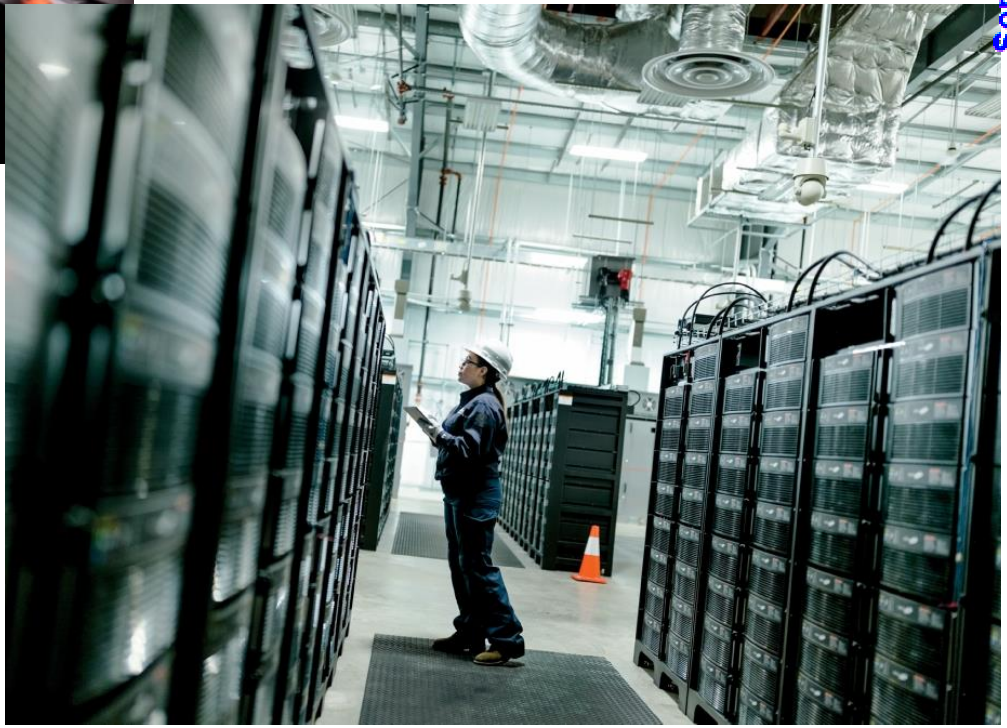
Example: Mt. Sterling Microgrid

The Mt. Sterling Microgrid project was developed to provide electric service to a remote customer in a reliable but more cost-effective way than via a traditional distribution feeder. The microgrid option meets customer needs through use of distributed energy resources, while enhancing both safety and productivity for utility workers by mitigating line maintenance activity in a high-risk, labor-intensive environment. With the maturity of energy storage technology, a microgrid with solar and storage components sized to support customer load for seven consecutive days (without solar generation) was designed, assessed, and determined to be a more reliable and cost effective option for meeting the customer's need for service. The solution, a 10-kW solar PV array, a 95-kWh battery energy storage system and remote monitoring system, offers availability 99.95% of time, with 25-year asset life.

PROGRAM: ENERGY STORAGE

MCALPINE MICROGRID BATTERY SYSTEM

NOTREES BATTERY STORAGE FACILITY



COMMUNITY BATTERY BACKUP SYSTEM

PROGRAM: LONG DURATION INTERRUPTION / HIGH IMPACT SITES (LDI/HIS)

The LDI/HIS program is designed to improve the reliability for parts of the grid with high potential for long duration outages as well as for high-impact customers like airports and hospitals.

DESCRIPTION

The LDI/HIS program is designed to improve the reliability in parts of the grid where the duration of potential outages is expected to be much higher than average. Focus areas for this program are radial feeds to entire communities or large groups of customers as well as inaccessible line segments (i.e. off road, swamps, mountain gorges, extreme terrain, etc.).

Many of the areas served by these long, rural, single-sourced feeders can experience significant impacts to the local economy and to quality of life when the entire town loses power. Further, operational and repair costs are generally higher than average in these areas due to the special equipment required.

While some sites may include extreme hardening, circuit relocations, new circuit ties and undergrounding, energy storage solutions may offer more cost-effective solutions for improving reliability and managing costs.

The LDS/HIS program is designed to improve the reliability of high- impact customers like airports and hospitals, and high-density areas that could require a variety of infrastructure solutions to improve power quality and reliability. Typical projects include substation upgrades, circuit ties, voltage conversions, and reconductoring.

GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ HARDEN FOR RESILIENCY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

PROGRAM: LONG DURATION INTERRUPTION / HIGH IMPACT SITES (LDI/HIS)


POWERING REMOTE COMMUNITIES


DOWNTOWN RALEIGH, NC


HILLY TERRAIN


UPTOWN CHARLOTTE, NC

PROGRAM: INTEGRATED SYSTEM OPERATIONS PLANNING (ISOP)

The ISOP program integrates utility planning for generation, transmission, distribution, and customer programs to improve the valuation and optimization of energy resources across the system.

DESCRIPTION

Requirements for modern electric utility systems are evolving rapidly with the advent of emerging new energy technologies, changes in policy, and rapid advancements in information exchange and customer needs. Integrated System Operations Planning (ISOP) focuses on the integration of utility planning disciplines for generation, transmission, distribution and customer programs to improve the valuation and optimization of energy resources across all segments of the utility system to best serve electric customers.

The ISOP process addresses key operational and economic considerations across all segments of the system through integration and refinement of existing system planning tools and, in some cases, development of new analytical tools to assess characteristics that have not historically been captured or considered in long-term planning. Some examples include locational values for distributed resources, system ancillaries and reserves needed to support future operations, and energy resource flexibility to support new dynamic operational demands on the system.

ISOP is a multi-year development program to build the tools and processes needed to accommodate an increasingly integrated approach that will be required to optimize planning and operation of the electric utility system of the future.

GRID CAPABILITIES ENABLED

- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ IMPROVE RELIABILITY
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

The TUG program strategically identifies Duke Energy's most outage prone overhead power line sections and relocates them underground to reduce the number of outages experienced by customers.

DESCRIPTION

Overhead power line segments with a history of unusually high numbers of outages drive a disproportionate amount of momentary interruptions and outages that affect Duke Energy's customers. When these segments of lines fail, they cause problems for Duke Energy's customers directly served by them as well as customers upstream. Lines targeted to be moved underground are typically the most resource-intensive parts of the grid to repair after a major storm. Equipment on these line segments can experience shortened equipment life and additional equipment-related service interruptions.

The goal of the TUG program is to maximize the number of outage events eliminated. Converting outage prone parts of the system enables Duke Energy to restore service more quickly and cost effectively for all customers. Addressing areas with outlier outage performance improves service while lowering maintenance and restoration costs for all customers.

Criteria for consideration in the selection of targeted communities include:

- Performance of overhead lines
- Age of assets
- Service location (e.g., lines located in backyard where accessibility is limited)
- Vegetation impacts (e.g., heavily vegetated and often costly and difficult to trim)

GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ HARDEN FOR RESILIENCY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

PROGRAM: TARGETED UNDERGROUNDING (TUG)

DOWNED POWER POLES

DAMAGE FROM HURRICANE MATTHEW

LINEMAN IN RAIN

IN AREAS INACCESSIBLE BY BUCKET TRUCK, LINEMEN HAVE TO CLIMB POLES TO MAKE REPAIR

PROGRAM: DISTRIBUTION TRANSFORMER RETROFIT

The Distribution Transformer Retrofit program converts existing overhead distribution transformers to deliver the same reliability benefits as a modern transformer installed today.

DESCRIPTION

Like the Self-Optimizing Grid program, the new sectionalization capability of a retrofitted transformer works to minimize the number of customers impacted by fault or failure on the power line. In addition, similar to the Targeted Undergrounding program, the new protective features that mitigate equipment vulnerabilities work to significantly lower the risk of an outage occurring at the transformer all together.

The core activities of the transformer retrofit program include the installation of a fuse disconnect device on the high-voltage side of every overhead transformer to protect upstream customers from a fault at or downstream of the transformer. In addition, through protective device coordination, the local fused disconnect can be set to prevent any upstream operations of reclosing devices (the source of momentary outages for customers not served by the retrofitted transformer.)

Consistent with modern transformer standards, the program also retrofits transformers with additional protective elements to reduce the risk of external factors such as lightning strikes and animal interference.

GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

PROGRAM: DISTRIBUTION TRANSFORMER RETROFIT

UN-RETROFITTED CSP TRANSFORMER

RETROFITTED TRANSFORMER

FUSED CUTOUT, ANIMAL GUARDS,
COVERED LEAD WIRE, NEW ARRESTER.

PROGRAM: DISTRIBUTION HARDENING & RESILIENCY – FLOOD HARDENING

The Distribution H&R – Flood Hardening program will be targeted to areas where an overlay of actual outage events from Hurricanes Matthew and Florence intersect with the 100-year flood plan.

DESCRIPTION

In hurricane events like Hurricane Floyd and more recently Hurricanes Matthew and Florence, significant flooding was a major factor impacting restoration. Smart, targeted investments can mitigate the scale of impacts on communities and customers adjacent to these areas prone to extreme flooding. Hardening lines and structures is a balanced approach that can keep power and critical services available to some portion of a community and prevent a widespread outage in an area until flooding recedes.

This program includes the following:

- Alternate power feeds for substations in flood-prone areas, and for radial power lines that cross into and through flood-prone areas
- Hardened river crossings where power lines are vulnerable to elevated water levels during extreme flooding
- Improved guying for at-risk structures within flood zones

GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ HARDEN FOR RESILIENCY
- ✓ IMPROVE PHYSICAL SECURITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

MORE ABOUT THE PROGRAM

Data analytics and geo-spatial analysis will assist Duke Energy in identifying patterns of repeat flood impact issues and allow a targeted basis for assessing hardening investments with a cost benefit analysis approach that delivers savings to Duke Energy customers and, at the same time, enhanced reliability for these flood-prone areas.

For a three-year window, this program will focus on hardest hit flood-prone areas from Hurricanes Matthew and Florence, defining opportunities to accomplish the following:

- Event elimination where hardening can demonstrably eliminate future outages events and repair work
- Resiliency options to re-route power and keep many people supplied with power while repairs to damaged facilities are made.

This program will be coordinated with other programs to ensure work scopes do not overlap.

PROGRAM: DISTRIBUTION HARDENING & RESILIENCY – FLOOD HARDENING

GOLDSBORO FLOODING DURING HURRICANE MATTHEW

FLOODING OF A SUBSTATION IN GOLDSBORO FOLLOWING HURRICANE MATTHEW (2016)

PROGRAM: SMART METERING INFRASTRUCTURE

The Smart Meter program is a metering solution (meters, communication devices and networks, and back office systems) used to create two-way communications between customer meters and the utility.

DESCRIPTION

Smart meters are digital electricity meters that have advanced features and capabilities beyond traditional electricity meters. Some of the advanced features include the capability for two-way communications, interval usage measurement, tamper detection, voltage and reactive power measurement, and net metering capability.

Duke Energy's standard smart meter system utilizes a radio frequency ("RF") mesh architecture, which is flexible in that the meters within the mesh network establish an optimized RF communication path to a collection point either through other meters, through network range extenders, or via a direct cellular connection.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ EXPAND CUSTOMER OPTIONS AND CONTROL

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

PROGRAM: SMART METERING INFRASTRUCTURE

PROGRAM: ELECTRIC TRANSPORTATION

The Electric Transportation effort is a proposed pilot program for North Carolina that will focus on advancing adoption of electric transportation in the State.

DESCRIPTION

The North Carolina program will establish a foundational level of public fast-charging infrastructure to advance electric vehicle adoption and inform best practices for cost-effective integration of various electric vehicle types with the electric system.

The ET pilot program will consist of five components: (1) Residential EV Charging Rebates, (2) Commercial Customer Charging Rebate, (3) Electric School Bus Infrastructure Investments, (4) Electric Transit Bus Infrastructure Investments, (5) DC Fast Charging Infrastructure. The bus components of the program will serve to financially support deployments of electric school and transit buses in conjunction with the Volkswagen Settlement.

The program will allow system planners to assess the impacts of different electric vehicle types, as well as various electric vehicle charging configurations. In addition to evaluating grid impacts, the pilot program will assess how all utility customers can benefit from increasing adoption of electric transportation through operational cost savings, enabled grid capabilities, improved air quality, and reduced transportation emissions.

GRID CAPABILITIES ENABLED

- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING
- ✓ EXPAND CUSTOMER OPTIONS AND CONTROL

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

MORE ABOUT THE PROGRAM

In 2011, Duke Energy conducted a plug-in electric vehicle charging station pilot in DEC. This pilot provided charging stations and up to $1,000 credit toward installation for customers who bought or leased a plug-in electric vehicle. Duke Energy analyzed the distribution impact and ways to mitigate those impacts as electric vehicles come into its service territory; the technical capabilities that the charging stations can offer to help mitigate those potential impacts; and when, where, how long, and how often a customer charges their electric vehicle.

Fast Charging Deployment Needed for Market Growth

Electric vehicles are coming to North Carolina as sales growth through the end of 2017 continued with a compound annual growth rate of 62% since 2011. Lack of charging stations is commonly cited as a barrier to purchasing an EV. The program estimates that approximately 1,000 public direct-current fast charging ("DCFC") plugs will be necessary by 2025 to support current forecasts of EV market growth. Currently, there are only 64 open-standard, publicly available DCFC plugs in North Carolina.

Volkswagen Environmental Mitigation Trust

In 2016, Volkswagen agreed to spend up to $14.7 billion to settle allegations of cheating emissions standards. Of that amount, $2.9 billion was used to establish an Environmental Mitigation Trust, which states and U.S. territories may use to invest in transportation projects that will reduce NOx emissions. Of that amount, $92 million was allocated to North Carolina as a beneficiary under the Settlement Trust. In August 2018, the NCDEQ released the final draft of the state's Beneficiary Mitigation Plan ("BMP"). Eligible mitigation actions under the BMP include replacing or repowering diesel school buses, transit buses, and heavy-duty on-road and off-road vehicles. In addition, beneficiaries may utilize up to 15% of their total allocation on costs relating to light duty, zero-emission vehicle supply equipment.

Other States Are Embracing Electric Vehicles

The Florida PSC approved an EV Infrastructure Pilot proposed by DEF, including public Level 2 and DC Fast Charging; in New York, ConEdison is supporting the deployment of electric school and transit buses, planned fast charging networks, and residential customer charging research. In Orlando, Florida, the Orlando Utilities Commission has deployed one of the largest municipal EV infrastructure programs in the country. Other examples of states that have embraced EVs in a pilot or otherwise include Maryland, Massachusetts, Oregon, Kentucky, Ohio, and California. Georgia Power has installed 25 public fast charging stations, facilitating EV adoption across the state of Georgia. By installing DC Fast Charging stations in the Carolinas, the ET Pilot would build on neighboring networks and allow EV drivers to seamlessly traverse along the crucial interstate corridors.

PROGRAM: ELECTRIC TRANSPORTATION

PROGRAM: CUSTOMER DATA ACCESS

The Customer Data Access program focuses on preparing key data systems for sharing data in a manner that aligns with prevailing data access protocols such as the Green Button standard.

DESCRIPTION

Currently, the Company offers a method for customers to download their trailing energy usage data into an XML format. The Customer Data Access program will incorporate modern data access protocols such as the current "**Green Button-Download My Data**" functionality.

"**Green Button-Connect My Data** (CMD)" is a regular automatic transfer of a customer's interval usage data to a third party upon authorization by the customer. The Customer Data Access program will evaluate deployment of CMD or functionality like CMD based on several factors and requirements relevant to North Carolina customers and stakeholders.

GRID CAPABILITIES ENABLED

- ✓ EXPAND CUSTOMER OPTIONS AND CONTROL

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

PROGRAM: CUSTOMER DATA ACCESS

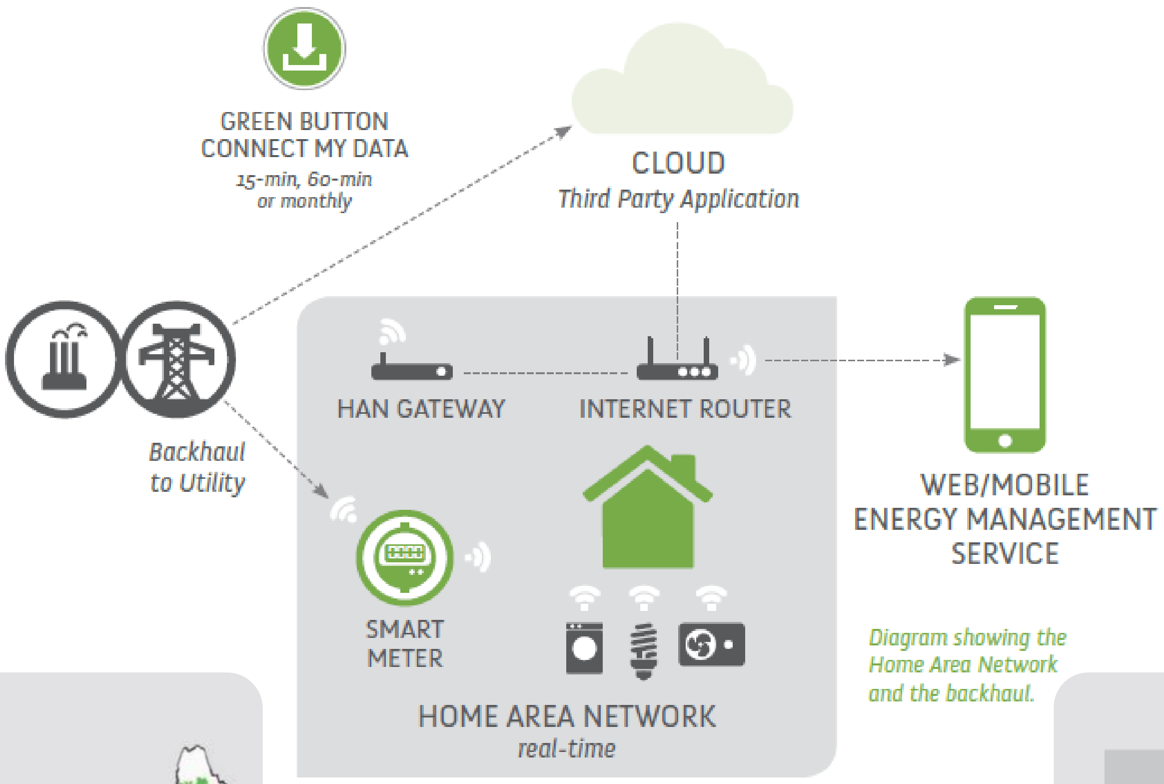
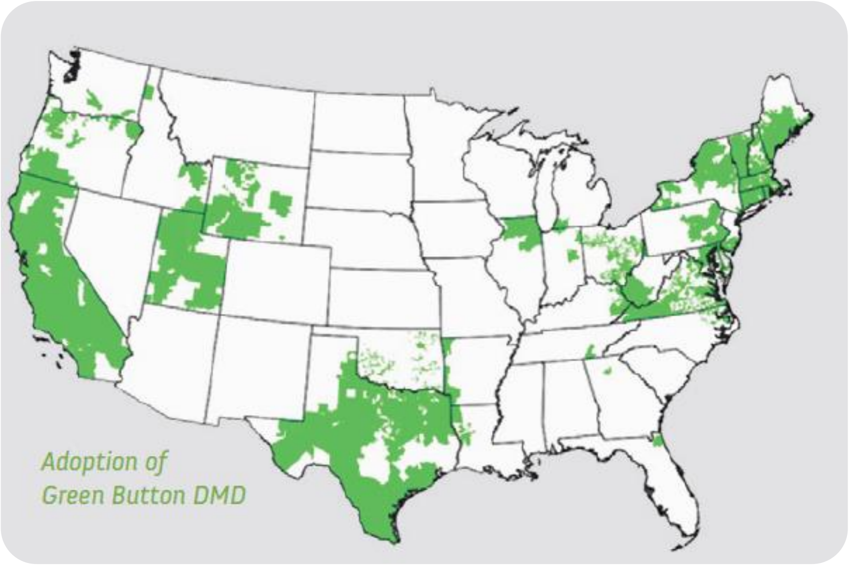
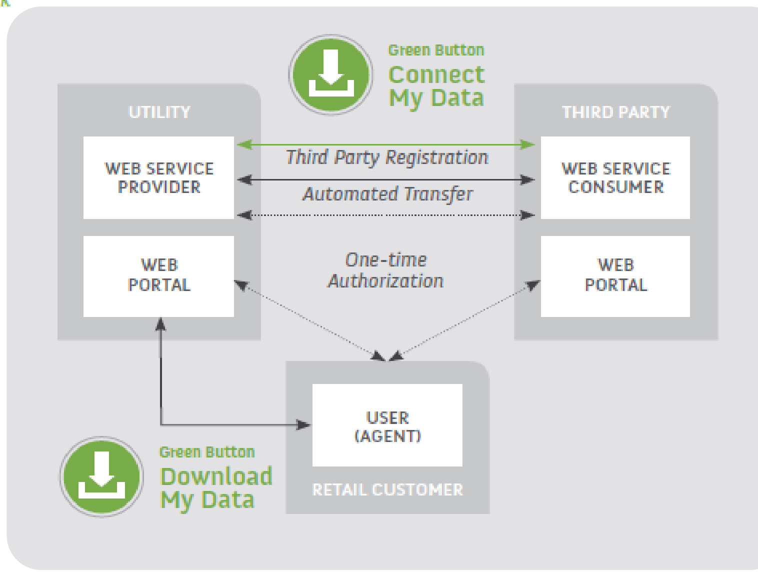


Diagram showing the Home Area Network and the backhaul.



Adoption of Green Button DMD



Source: Murry, M. and Hawley, J., Got Data? The Value of Energy Data Access to Consumers. More Than Smart. January 2016. <Retrieved from http://www.missiondata.org/s/Got-Data-value-of-energy-data-access-to-consumers.pdf>

PROGRAM: TRANSMISSION SYSTEM INTELLIGENCE

The Transmission System Intelligence program deploys transformational system monitoring and control equipment to enable faster response to outages and more intelligent analysis of issues on the grid.

DESCRIPTION

Transmission grid automation improvements will reduce the duration and impacts associated with transmission system issues.

Improvements in transmission system device communication capabilities enable better protection and monitoring of system equipment. The data collected from intelligent communication equipment helps better assess and optimize transmission asset health.

The Transmission System Intelligence program includes 1) the **replacement of electromechanical relays** with remotely operated digital relays, 2) the implementation of **intelligence and monitoring technology** capable of providing asset health data and driving predictive maintenance programs, and 3) the deployment of **remote monitoring and control** functionality for substation devices, and rapid service restoration.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

MORE ABOUT THE PROGRAM

System Intelligence and Monitoring

This subprogram focuses on a machine-learning platform that can determine when equipment maintenance or repair is needed. Health and Risk Monitoring (HRM) of the transmission system allows asset managers to proactively address equipment issues before catastrophic equipment failures occur. The HRM platform utilizes Condition Based Monitoring (CBM) – the continuous remote monitoring of asset health data which is used to extend asset life or execute mitigating activities to prevent equipment failures. HRM supplements CBM data with information from Digital Fault Recorders (DFR), which record the details of transmission system faults to support the types of post-fault event analysis that drives future system performance improvements.

Electromechanical to Digital Relays

This subprogram replaces noncommunicating electromechanical and solid state relays with digital relays. Modern relay design with communications capabilities and microprocessor technology enables quicker recovery from events than the design of the existing electromechanical relays. One digital relay is capable of replacing a variety of legacy single-function electromechanical relays. Two-way communications and event recording capabilities allow them to provide device performance information following a system event to support continuous system design and operational improvements. Additionally, they identify line fault locations, which is the ability to use device data to calculate the distance down a line to a line fault, rather than manually assessing and patrolling transmission lines.

Remote Substation Monitoring

This subprogram enables operators to remotely monitor and control substations. This includes the installation or upgrade of supervisory control and data acquisition system (SCADA) interfaces for substation devices, called remote terminal units (RTUs), and upgrades to associated data communication channels. This subprogram is a critical enabler for programs like Integrated Volt/Var Control and Distribution Automation. This subprogram also upgrades serial communication to IP communication for existing RTUs to collect more data and support more devices.

Remote Control Switches

This subprogram replaces non-communicating switches with modern switches enabled with SCADA communication and remote control capabilities. Transmission line switches are currently manually operated in most substations and cannot be remotely monitored or controlled. Switching, a grid operation often used to section off portions of the transmission system in order to perform equipment maintenance or isolate trouble spots to minimize impacts to customers, has historically required a technician to go to a substation and manually operate one or more line switches. This subprogram increases the number of remote controlled switches to support faster isolation of trouble spots on the transmission system and more rapid restoration following line faults.

PROGRAM: TRANSMISSION HARDENING & RESILIENCY (H&R)

The Transmission (H&R) program works to create a stronger and more resilient transmission grid capable of withstanding or quickly recovering from extreme external events, natural or man-made.

DESCRIPTION

Each Transmission H&R sub-program works to address unique challenges in ways that harden the system, and not only minimize impacts to customers, but enhance their electric service experience. The **44-kV System Upgrade** subprogram both protects the 44-kV system from extreme weather, but also paves the way for more DER interconnections by creating additional capacity on the system to transport generation from large scale solar sites. Similarly, the **Targeted Line Rebuild for Extreme Weather** subprogram protects some of the higher voltage transmission lines from extreme weather by addressing vulnerable wooden structures.

The **Networking Radially Served Substations** subprogram builds in more resiliency to the transmission system by creating alternative ways to provide customers with reliable electricity supply in the case of an issue with the primary transmission feed; and, the **Substation Flood Mitigation** subprogram builds in protection for substations most vulnerable to flood damage. Altogether, these H&R efforts not only enhance the functionality of individual assets, but substantially improve the overall functionality of the system, particularly under extreme weather conditions. The long-term plan for hardening and resiliency is to relocate or strengthen at-risk assets or other solutions such as raising the flood plane at that site.

GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ HARDEN FOR RESILIENCY
- ✓ IMPROVE PHYSICAL SECURITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

MORE ABOUT THE PROGRAM

44kV System Upgrades

Rebuilds and upgrades targeted portions of the 44-kV system to both harden the system against extreme weather, position the system to support DER, and make the overall system more resilient. This will be accomplished in three phases:

- PHASE I (infrastructure upgrades): structurally rebuilds the system, replacing wood structures with taller/stronger steel or concrete structures to better withstand damage in extreme weather conditions. Rebuilding 44-kV lines to 100-kV standards improves performance due to greater elevation and clearance from vegetation. The increased conductor spacing between each of the phases and the addition of basic insulation decreases impacts of lightning events.
- PHASE II (voltage conversions): converts specific circuits of the 44-kV system to 100-kV, making them more capable of supporting large scale solar, storage and other DER. These conversions also require converting the substations served by these lines, which generally involves installing high rated equipment such as transformers and breakers. Portions of the 44-kV system, particularly in rural areas that are prime locations for utility scale solar development, are capacity constrained and unable to support additional interconnections.
- PHASE III (circuit looping): builds in circuit ties between upgraded and converted circuits. This creates a looped circuit design capable of feeding power to these circuits from other sources, as needed, to provide additional system resiliency.

Networking Radially Served Substations

Increases resiliency of radially served substations where outage duration is higher than average, including~~:~~ networked lines sectionalized into separate radial lines, and lines designed as radial feeders. Networked radial lines can be re-networked by replacing the conductor with higher ampacity and by upgrading the protective relaying. Lines designed as radial feeders will be networked to existing lines into another substation. Substations served by networked transmission lines can be served from either end of the line and the line can be sectionalized to isolate an interruption and restore the majority, if not all, of customers before the full line is restored.

MORE ABOUT THE PROGRAM

Substation Flood Mitigation

Systematically reviewing and prioritizing substations at risk of flooding to determine the proper mitigation solution, which may include elevating or modifying equipment in substations or relocating substations altogether.

Targeted Line Rebuilds for Extreme Weather Events

Specific transmission lines require rebuilding to withstand extreme weather (including wind and ice) and mitigate the risk of unplanned outages. Lines are targeted based on risk-advised decisions along with selection criteria including: tower height, tower condition, and age of asset. Proactive replacement of wooden poles to steel poles that comply with the National Electrical Safety Code (NESC) achieve benefits such as protecting extreme weather and reducing O&M costs.

TRANSMISSION POLE REPLACEMENTS

69 KV WOOD POLE CONSTRUCTION

NEW 69 KV STEEL POLE CONSTRUCTION

PROGRAM: TRANSFORMER BANK REPLACEMENT

The Transformer Bank Replacement program leverages new system intelligence capabilities to target transformers before they fail.

DESCRIPTION

Predictive and proactive replacement programs like Transformer Bank Replacement significantly reduce the impacts and costs of replacement when compared to performing the same work following a catastrophic failure.

The objective of this program is to anticipate future transformer failures and replace those transformers in an orderly fashion, avoiding the cost and customer outage minutes associated with these failures. Catastrophic failures often result in significant oil spills, requiring expensive cleanup and other mitigation. Proactive replacement also reduces contingent material inventory needed, since replacements have a 12-24 month manufacturing lead time.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

The Oil Breaker Replacement program identifies and replaces oil-filled circuit breakers on the transmission and distribution systems with modern technology.

DESCRIPTION

The purpose of this program is to replace these legacy assets with breaker technology capable of two-way communications and remote operations.

Transmission level oil breakers will be replaced with the modern sulfur hexafluoride gas (SF_6) circuit breaker technology. The medium voltage distribution level oil-filled breakers will be replaced with modern vacuum circuit breaker technology.

The new communication and control capabilities of this modern technology better positions the transmission and distribution systems to work with grid automation systems to better respond to electric grid events. Looking forward, these fast-response gas and vacuum breakers are better suited for protecting circuits with higher solar and other variable energy resource penetration.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

OPTIMIZE the total customer experience

PROGRAM: PHYSICAL & CYBER SECURITY

The Physical and Cyber Security program protects against the potential risks and impacts of attacks on the electric grid.

DESCRIPTION

The program focuses on hardening above the standard compliance requirements. Transmission elements of the program include:

- **Transmission substation physical security**
- **Windows-based change outs** to address cyber security standards for older Windows-based relays.
- **Cyber security enhancements for non-bulk electric system substations**
- **Electromagnetic Pulse and Intentional Electromagnetic Interference (EMP/IEMI) Protection**

At the distribution system level, much of the focus involves securing and improving risk mitigation of remotely controlled field equipment. An example is enabling door alarms and entry notifications. Programs include:

- **Device Entry Alert System** (DEAS)
- **Distribution Line Device Cyber Protection**
- **Secure Access Device Management** (SADM) - a single tool to remotely and securely perform device management activities and event record retrieval on the entire transmission and distribution device inventory.

GRID CAPABILITIES ENABLED

- ✓ HARDEN FOR RESILIENCY
- ✓ IMPROVE CYBER SECURITY
- ✓ IMPROVE PHYSICAL SECURITY
- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

PROTECT to reduce threats to the grid

PROGRAM: PHYSICAL & CYBER SECURITY

MORE ABOUT THE PROGRAM

Transmission Substation Physical Security

This subprogram enhances the grid resiliency as part of the overall Transmission Security program. Tier 1 site enhancements include high security perimeter fencing and lighting, intrusion detection technology, new security enclosure buildings, hardening of existing control houses, security cameras, and access control. Tier 2 site enhancements include high security perimeter fencing and lighting.

Windows-based Unit Change Outs

The Windows-based Unit Change Outs effort replaces older Windows-based relays that cannot be upgraded due to technology constraints (such as insufficient memory or relay condition). Following these upgrades, the new devices will operate in a Linux environment and be compliant with standards.

Cyber Security Enhancements for non-BES

Cyber Security Enhancements for non-bulk electric system (BES) substations implements protective measures against possible cyber-attacks at those non-BES substations that have Internet-Protocol (IP) routable devices. Such measures include the installation of firewalls and the replacement of vulnerable devices.

EMP/IEMI Protection

Electromagnetic pulses (EMP) and Intentional Electromagnetic Interference (IEMI) can create disruptions for electronic equipment. The measures taken to protect against them focus on hardening and protecting targeted equipment. The electric industry is engaged in significant research, led by the Electric Power Research Institute (EPRI), focused on improving cost-effective and feasible mitigation against EMP/IEMI. This subprogram will focus on pre-scaled implementation of industry research findings.

MORE ABOUT THE PROGRAM

Device Entry Alert System (DEAS)

The Device Entry Alert System (DEAS) project will install an entry door alarm head-end system and deliver processes to enhance physical and cyber security on the distribution systems' intelligent electronic devices (IEDs). This tool will ensure that all physical access of IEDs and related infrastructure in the field are being tracked and monitored.

Secure Access and Device Management (SADM)

SADM provides a tool to remotely and securely perform device management activities and event record retrieval on our entire device inventory in transmission and distribution. The goal of the project is to improve the security of field devices and increase compliance with North American Electric Reliability Corporation critical infrastructure protection (NERC CIP) and other security requirements.

SADM also provides process and labor efficiencies associated with device management, and improves post-event resolution. Within this program, we will standardize systems and processes for secure remote access to field devices, implement device management tasks (including password management, firmware management, configuration management), manage post-fault and other operational event records, and implement a common solution and support model across all jurisdictions within transmission and distribution.

Distribution Line Device Cyber Protection

The Distribution Line Device Cyber Protection projects address physical and cyber security risks for thousands of SCADA-controlled line devices (e.g., regulators, capacitors, reclosers, etc.). The focus of the projects in this workstream is targeted replacement of legacy control equipment with Enterprise Security and Advanced Distribution Management System compliant equipment. The newer installed equipment meets or exceeds Duke Energy Industrial Control System (ICS) enterprise security requirements and also provides a platform for future asset management enhancements, such as remote firmware and device settings management, reducing the need to travel physically to a site to perform a system upgrade. Examples of equipment being replaced include capacitor and distribution (recloser) control devices.

PROGRAM: PHYSICAL & CYBER SECURITY

DUKE ENERGY

COCHRANE FENCE & MAIN ENTRANCE CRASH GATE

PROGRAM: ENTERPRISE COMMUNICATIONS ADVANCED SYSTEMS

The Enterprise Communications program modernizes and secures the critical communications between intelligent grid management systems, data and controls systems, and sensing and control devices.

DESCRIPTION

The program addresses technology obsolesce, secures vulnerabilities, and provides new workforce-enabling capabilities. This program includes improvement and expansion of the entire communications network from the high-speed, high-capacity backbone fiber optic and microwave networks to the wireless connections at the edge of the grid. These upgrades help build the secure communications required for the increasing number of smart components, sensors, and remotely activated devices on the transmission and distribution systems.

Key communication efforts are: (1) **Mission Critical Transport** which strategically upgrades the infrastructure required for high-speed, reliable, sustainable, interoperable communications for grid devices and personnel; (2) **Grid Wide Area Network (Grid WAN)** which improves network reliability, performance and security for current grid management/control applications; (3) **Mission Critical Voice** which replaces current Land Mobile Radio systems with enhanced, reliable, sustainable, interoperable communications across all service territories; and (4) **Next Generation Cellular** which replaces obsolete 2G/3G cellular technology with the more reliable and secure 4G/5G technology required for modern grid devices in the field.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ IMPROVE CYBER SECURITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

MORE ABOUT THE PROGRAM

Mission Critical Transport

Implements the strategic advancements to the backbone of the communication network to ensure reliable, sustainable, interoperable communications for grid devices and personnel. Replaces end-of-life fiber cable, optical systems, and microwave systems; strategically expands high-capacity fiber to new, targeted routes; and investigates alternatives for faster or more cost-effective fiber deployments.

Business Wide Area Network

Updates data network architecture to improve reliability and performance of the core business. Assesses capacity and redundancy requirements and evaluates network options for the core business network and associates area network structures. Supports growing demands for workforce mobility, real-time video capture, data transport needs, and mitigating communication network congestion.

Grid-wide Area Network (Grid WAN)

Improves network reliability, performance and security for grid control, O&M applications by replacing end-of-life data network hardware and converting substations to an IP network architecture. Employs a network redesign, providing capacity and resiliency, and positioning the network to support Field Area Network (FAN) and Neighborhood Area Network (NAN) needed for enabling a smart cities future.

Mission Critical Voice

Strategic replacement and improvement of mission-critical voice (radio) communications to provide reliable, sustainable, interoperable communications for all jurisdictions and businesses. The new radio system will provide increased functionality and interoperability between regions, allowing field workers to use the same radio system to help another region during major storms.

Next Generation Cellular

Addresses the need to migrate 2G/3G communication networks (to be decommissioned by cellular service providers) to updated 4G/5G. Replaces existing network devices located on distribution line devices. In addition to supporting communication continuity through network decommissioning, these upgrades provide greater network bandwidth, lower data latency, and better cybersecurity protection.

PROGRAM: ENTERPRISE COMMUNICATIONS ADVANCED SYSTEMS

COMMUNICATION TOWER (LEFT) &
POLE-MOUNTED COMMUNICATION NODE

PROGRAM: ENTERPRISE APPLICATIONS

The Enterprise Applications program deploys the systems and upgrades needed to monitor the health and security of the grid and analyze data to enable grid automation and optimization technologies.

DESCRIPTION

Upgrades to existing enterprise applications enable system optimization and overall better system performance. Within the program, there are two main components responsible for the delivery of enterprise technology solutions that support transmission, distribution, and other critical lines of business: (1) **Enterprise Systems** and (2) **Grid Analytics**.

This effort focuses on delivering transformative, cross-functional technical solutions to the enterprise in non-disruptive ways. Elements within the portfolio include the Integrated Tools for Outage Applications (iTOA), which works to drive standardization and coordination of grid control center tools and the Targeted Undergrounding (TUG) System, which facilitates efficient workflows via asset management and mapping system upgrades.

Grid Analytics optimizes the electric system health and performance through the deployment of the Health Risk Management (HRM) tool and Enterprise Distribution System Health (EDSH) tool. These tools help to prevent equipment failures and improve asset performance on the transmission and distribution systems, respectively.

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ IMPROVE RELIABILITY
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ IMPROVE PHYSICAL SECURITY

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

PROGRAM: ENTERPRISE APPLICATIONS

DUKE ENERGY

MORE ABOUT THE PROGRAM

Integrated Tools for Operations Application (ITOA)

ITOA is a new platform that optimizes current processes and drives standardization regarding system functionality, work processes, and configuration. This project also upgrades and consolidates outage coordination as well as planned switching and logging applications for transmission and distribution control centers.

Targeted Undergrounding (TUG) System

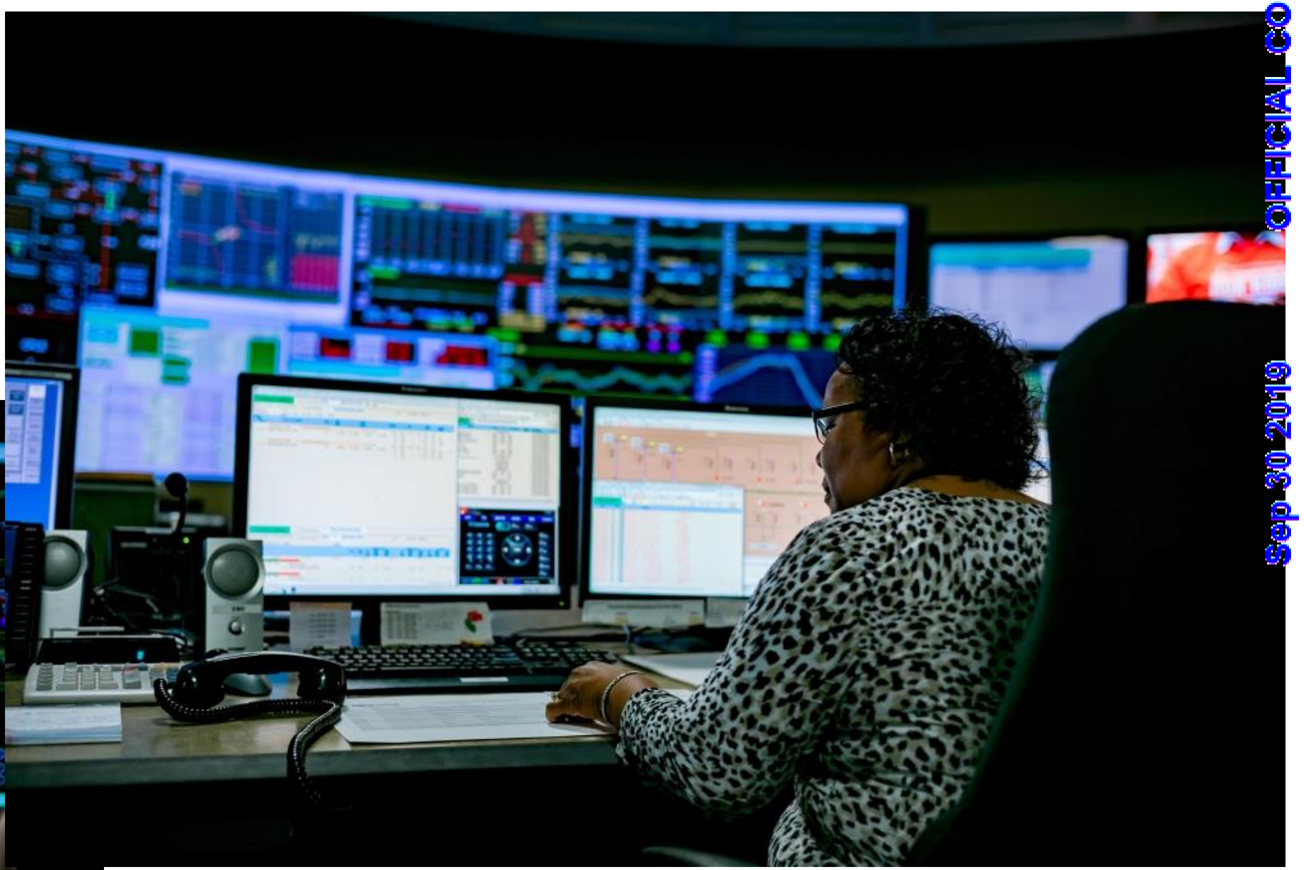
The TUG System automates manual processes and facilitates faster and more efficient workflow by integrating asset management systems. The product enhances the existing enterprise systems for tracking TUG work and creates new mapping capabilities. The mapping enables visualization of the ongoing targeted underground work and consistency in reporting.

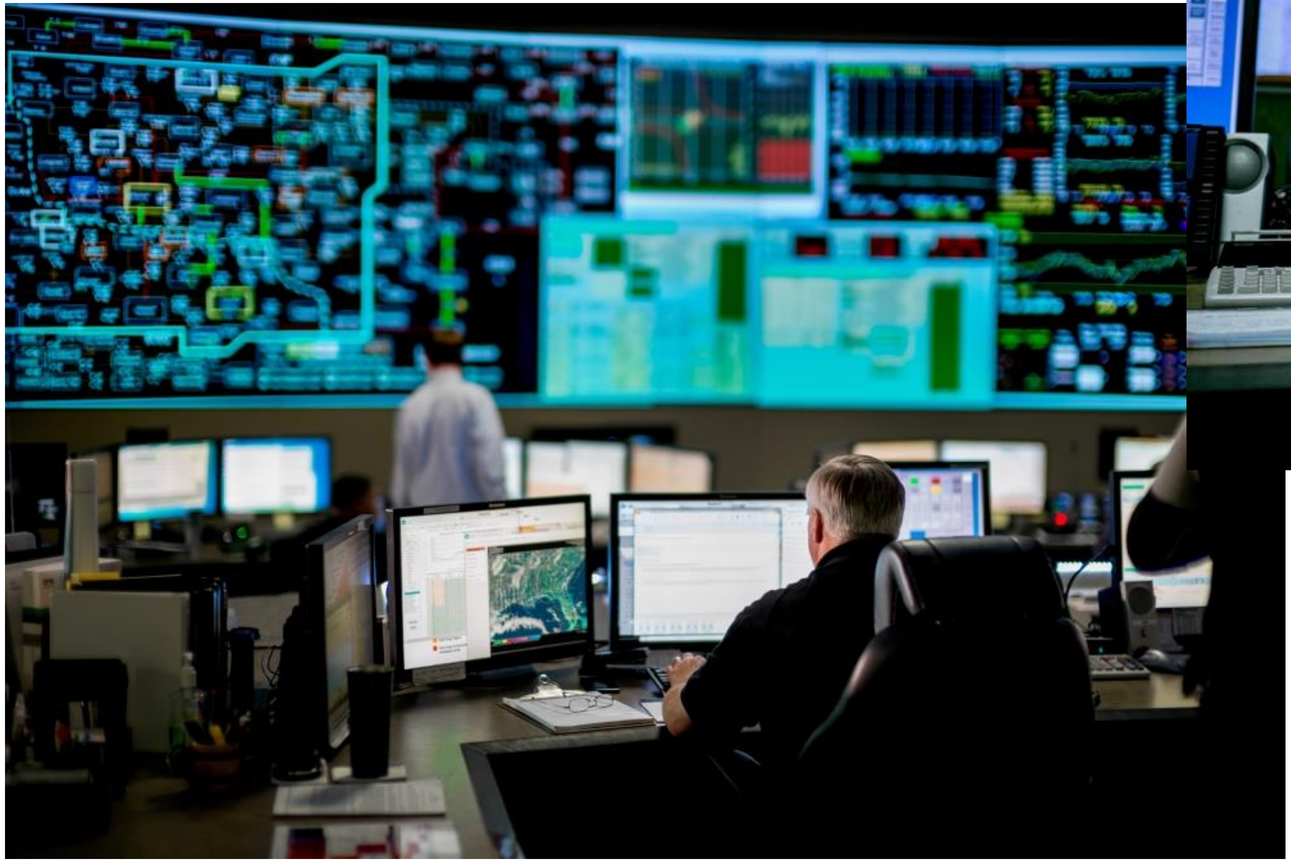
Health and Risk Management (HRM)

HRM will provide a new platform for collecting data and applying analytics optimization for managing transmission system assets. This sub-program will collect and analyze data to improve the management of assets by using predictive and prescriptive analytics and take proactive steps to prevent or mitigate disruptive events..

Enterprise Distribution System Health (EDSH)

EDSH provides a platform that enables PQR&I Planning, Governance, and Customer Delivery to improve reliability and customer satisfaction. It will enable customer-centric reliability planning and provide a basis for optimizing investments using predictive and prescriptive analytics and allow Duke Energy to take proactive steps to prevent or mitigate disruptive events.





PROGRAM: DER DISPATCH ENTERPRISE TOOL

The DER Dispatch Enterprise Tool is a software-based solution that provides operators with the ability to monitor and manage both transmission and distribution connected DERs.

DESCRIPTION

This tool will coordinate with the Distribution Management System (DMS) and Energy Management System (EMS) to improve the way DERs are integrated in the energy supply mix, both at the Distribution and the bulk power level.

By providing system-wide visualization and control of large-scale DERs, the DER Dispatch Tool will enable system operators to model, forecast, and dispatch a portfolio of distributed energy resources, like solar generation, biofuel generation and energy storage, based on system conditions and real-time customer demand. This tool will help meet the need to match energy demand with supply, especially in emergency conditions.

Current processes and tools provide system operators with a rudimentary ability to quickly shed large blocks of solar generation in emergency conditions to meet standards for real power control (BAL-001-2). The proposed solution will provide operators with a more automated and refined toolset to optimize management of both utility and customer owned DERs to meet system stability requirements.

This system will replace an existing tool in DEP that is used to dispatch distribution connected solar in 50 MW increments

GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ EXPAND CUSTOMER OPTIONS AND CONTROL

VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

WHERE IT FITS IN OUR PLAN

MODERNIZE by leveraging enterprise systems and technology advancements

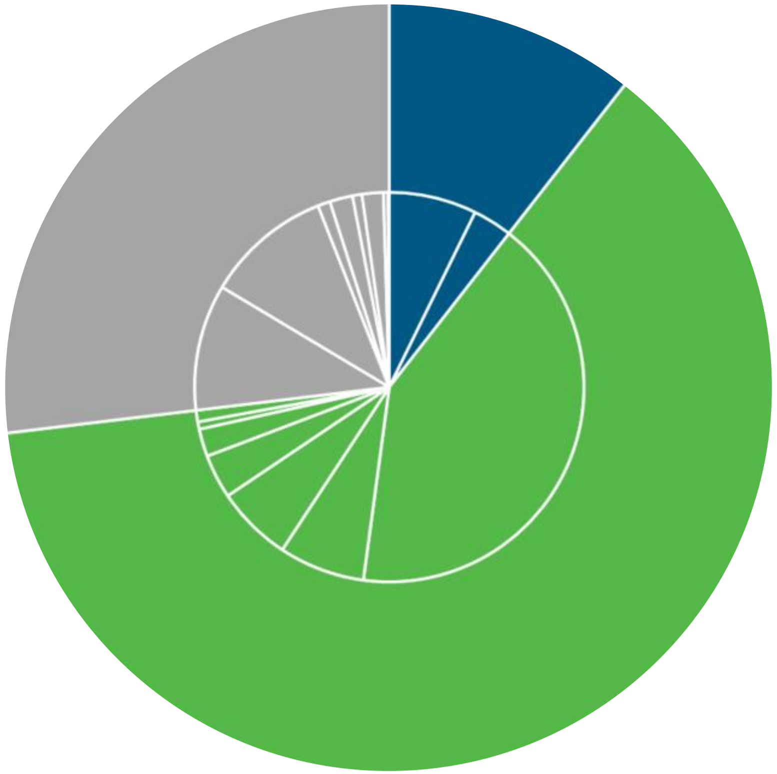
NORTH CAROLINA GRID IMPROVEMENT PLAN

PORTFOLIO SUMMARY

FOR STAKEHOLDER WORKSHOP

11/08/18

NC GRID IMPROVEMENT PLAN PORTFOLIO SUMMARY



Program	3 Year Range
Compliance: Cost Effectiveness Justified	**$164 - 266M**
Physical Security	$113 - 184M
Cyber Security	$51 - 83M
Cost Benefit & Cost Effectiveness Justified	**$973 - 1580M**
SOG	$412 - 670M
Distribution H&R	$111 - 180M
IVVC DEC	$123 - 200M
Transmission H&R	$98 - 159M
TUG	$57 - 93M
Energy Storage	$103 - 167M
Transmission Bank Replacement	$36 - 58M
D-OIL Breaker Replacements	$10 - 15M
T-OIL Breaker Replacements	$15 - 24M
DSDR peak shaving to CVR in DEP	$8 - 13M
Rapid Technology Advancement: Cost-Effectiveness Justified	**$418 - 680M**
T&D Communications	$163 - 264M
Distribution System Automation	$92 - 150M
Transmission System Automtation	$71 - 115M
T&D Enterprise Systems	$16 - 26M
ISOP	$30 - 48M
DER Dispatch Tool	$12 - 20M
Electric Vehicle Charging	$27 - 45M
Power Electronics for volt/var control	$6 - 10M
Customer Data Access	$2 - 3M
Total	**$1,600 - 2,500M**

- **Cost-Benefit and Cost-Effectiveness Justified (Optimize)**

Programs and projects in this category provide customers more net benefits than net costs and solve for one or more external "megatrends."

- **Rapid Technology Advancement-Cost Effectiveness Justified (Modernize)**

Equipment, software, hardware, operating systems, and/or accepted system operating practice has advanced at an atypical pace in this category causing the need for rapid and sometimes frequent changes within the utility at a system deployment level. Work in this category is usually related to system communication, automation, and intelligence and must be executed at a deliberate pace while ensuring not to deploy new technology before it has reached operational and price point maturity. While not technically compliance work, work in this category is essential for modern system operations.

- **Compliance-Cost Effectiveness Justified (Protect)**

i. An external law, rule, or regulation applicable to the company requires the work;
ii. A binding legal obligation such as a contract, agency order, or other legal document compels the work; or
iii. The Operations Counsel has approved the work as being critical and imperative to the Company's operations.

NORTH CAROLINA GRID IMPROVEMENT PLAN

APPENDIX

FOR STAKEHOLDER WORKSHOP

11/08/18

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NORTH CAROLINA GRID IMPROVEMENT PLAN

DUKE ENERGY

Megatrends
- Concentrated Growth
- Technology Advancements
- Grid Modernization
- Customer Expectations
- Environmental Commitments
- Impact of Weather Events
- Threats to Grid Infrastructure

Implications
- Increased Cost
- Decreased Reliability
- Inability to Interconnect DER
- Decreased Customer Satisfaction
- Decreased Economic Attractiveness for North Carolina
- Decreased Demographic Fairness

Grid Capabilities
- Increase monitoring and visibility
- Increase automation
- Increase distributed intelligence
- Improve reliability
- Harden for resiliency
- Enable voltage control
- Accommodate two-way power flows
- Modernize grid operations
- Improve cyber security
- Improve physical security
- Expand customer options and capabilities
- Increase hosting capacity

Plan
- Protect
- Modernize
- Optimize

Programs
- IVVC
- SOG
- TUG
- Power Electronics
- Energy Storage
- Distribution Automation
- Transformer Retrofit
- LDI/HI
- EV Charging
- ISOP
- Customer Data Access
- Transmission System Intelligence
- Transmission H&R
- Transformer Bank Replacement
- Physical & Cyber Security
- Oil Breaker Replacement
- Enterprise Communications Improvement
- Enterprise Apps
- DER Dispatch Tool
- Advanced Metering
- Distribution H&R

Value to Customers
- Maintain reasonable rates
- Improve reliability, safety, resiliency
- Meet or exceed customer expectations

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January 9, 2019

VIA ELECTRONIC FILING

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RE: Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Report of Second NC Grid Improvement Technical Workshop Docket Nos. E-2, Sub 1142 and E-7, Sub 1146

Dear Ms. Jarvis:

Duke Energy Progress, LLC and Duke Energy Carolinas, LLC held a follow-up Technical Workshop regarding Grid Improvement on November 8, 2018. I enclose the report prepared by Rocky Mountain Institute, the independent organization that facilitated the workshop.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,

Lawrence B. Somers

Enclosure

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's Report of Second NC Grid Improvement Technical Workshop, in Docket No. E-7, Sub 1146, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the following parties:

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I certify that a copy of Duke Energy Progress, LLC's Report of Second NC Grid Improvement Technical Workshop, in Docket No. E-2, Sub 1142, has been served by hand delivery, depositing a copy in the United States Mail, first class postage prepaid, or by electronic mail, properly addressed to the following parties of record:

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Summary Report of Duke Energy North Carolina Grid Improvement Workshop

Table of Contents

Prepared by Rocky Mountain Institute
Contact at Rocky Mountain Institute: Coreina Chan, cchan@rmi.org

Executive Summary

Duke Energy hosted a workshop with North Carolina stakeholders on November 8, 2018 to share the company's current thinking and plans for grid improvement and to solicit feedback. Duke Energy contracted Rocky Mountain Institute (RMI) as a 3rd party to conduct needs assessments with stakeholders, design the agenda and facilitate the workshop itself.

The workshop convened 78 stakeholders on November 8, 2018 at the North Carolina State University Club in Raleigh, inclusive of 4 RMI staff and 19 Duke Energy staff. At the workshop, stakeholders heard presentations from Duke Energy, participated in live polling, held discussions at individual tables of 4-6 participants, had questions answered by Duke Energy staff and provided written and verbal feedback to Duke Energy.

In this report, Rocky Mountain Institute summarizes the day's discussions, survey results and outcomes. The report's synthesis does not attribute specific comments to specific parties, to respect the ground rules agreed to by participants at the beginning of the meeting. Specifically, participants agreed that what was discussed at the workshop could be shared publicly, but specific comments could not be attributed to individuals without their permission.

Before the workshop, Duke Energy prepared and sent stakeholders a 103-page pre-read document that contained the company's analysis and current grid improvement plans. The workshop presentations summarized the pre-read material, leaving time to hear stakeholder feedback.

Workshop objectives

The workshop was organized around three objectives, listed below. RMI defined these objectives in consultation with Duke Energy and other participants interviewed in advance of the event.

1. Obtain stakeholder input to Duke Energy's outlook on seven megatrends shaping grid improvement decisions.
2. Describe and get feedback on how Duke Energy has used stakeholder input, the impact of megatrends on grid needs, and a prioritization methodology to develop a grid improvement portfolio.
3. Describe the benefits and risks of the draft program portfolio and hear from stakeholders what changes they propose, and why.

Key Workshop Takeaways

1. **Online polling, plenary question and answer sessions, and table discussions all indicated that stakeholders ranged widely in their support for Duke Energy's draft grid improvement plan.** In online polling explicitly asking for the extent that stakeholders supported the plan (Figure 1 below):
   - Stakeholders indicated a wide range of level of support from ~0% to ~80%
   - 14 stakeholders indicated support well below 50%; 13 stakeholders were near 50%; and 8 stakeholders were well above 50%.
2. The following major perspectives were expressed by stakeholders throughout the day. These perspectives do not represent consensus of the entire stakeholder group:
   - Many stakeholders **requested further details on how Duke's conducted its analysis.** Specifically, stakeholders asked for the underlying assumptions, data, and formulas used to assess 1) the costs and benefits and 2) how the plan would increase in the amount of distributed energy resources (DER) that could be added to the grid. These requests were made in several sessions and was detailed in the 'Sharing Data' portion of the workshop's final session.
   - Many of the stakeholders were supportive of aspects of the grid improvement plan but were hesitant to provide official support until they understood **the specifics of cost recovery and rate changes.**
   - Several stakeholders asked Duke Energy to **explicitly include Climate Change in its megatrends** and show how the plan would help reduce emissions.
   - Stakeholders wanted to know how much DER the grid could support today and **how much additional DER the grid could support with the plan's improvements**.
   - Industrial or 'transmission line' customers wanted to understand **how the plan would improve transmission service** and whether their rates would fairly reflect those benefits (or lack thereof).

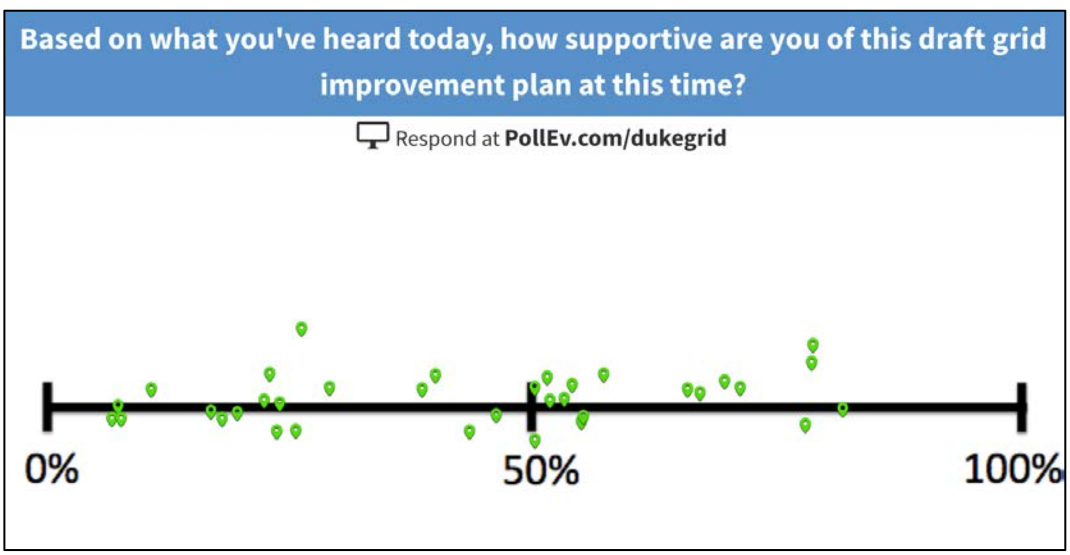

Figure 1. Online polling showed a wide distribution of support for the plan, varying from ~0% to ~80%.

- A number of stakeholders wanted to consider grid improvement together with other Duke Energy activities including resource planning, cost recovery and implementation plans.

3. Stakeholders generally acknowledged and appreciated Duke Energy's improved preparation and transparency (both in the pre-read and in the presentations), as compared to information provided in the original Power/Forward plan and previous grid improvement workshop.
4. Stakeholders generally appreciated the chance to provide feedback to Duke Energy on the grid improvement plans and felt the workshop provided an effective platform to provide that feedback. In the end-of-workshop survey question asking whether the workshop was an effective forum for giving Duke Energy feedback, most stakeholders respond with a 7 or higher (out of 10). The vast majority of stakeholders expressed a willingness to continue grid improvement conversations with Duke Energy. In the end-of-workshop survey question asking whether they would like to continue working with Duke Energy on grid improvement, most stakeholders responded with a 9 or higher (out of 10).

This Report

This report documents the feedback that stakeholders provided throughout the workshop in the form of online polling, table discussions and plenary question and answer sessions. We also summarize common themes that emerged in the workshop conversations, table conversations and the post-event survey. The Appendix documents detailed notes from all of the workshop conversations.

Workshop Agenda and Attendee List

The Workshop agenda was designed by RMI, in consultation with Duke Energy, to meet the workshop objectives. The agenda included dedicated sessions to discuss the megatrends and their implications (Objective #1), Duke Energy's portfolio prioritization method (Objective #2) and Duke Energy's current grid improvement plan (Objective #3). At the end of the workshop, stakeholders were invited to provide additional input to Duke on topics related to Grid Improvement.

Table 1: Workshop Agenda

Time	Activity	Objectives addressed
9:00	Welcome, Safety Briefing, Agenda and Ground Rules	
9:15	Introductions and Check-in	
9:35	Overview of Duke Energy's Grid Improvement Analysis	#1, #2, #3
9:50	Activity: Polling, Feedback and Questions	#1, #2, #3
10:30	Presentation on Megatrends and Implications	#1
10:40	Activity: Questions, Polling and Feedback	#1
11:40	Lunch	
12:25	Presentation on Portfolio Prioritization Method	#2
12:40	Activity: Discussion, Questions	#2
1:15	Presentation: Current Draft Grid Improvement Plan	#3
1:30	Activity: Questions, Polling and Discussions	#3
2:35	Activity: Coaching Questions, Data Dump, and Q&A	#1, #2, #3
3:30	Closing Remarks and Adjournment	#1, #2, #3

Table 2: Attendee List

Last Name	First Name	Organization Name
Adair	Sarah	Duke Energy
Ayala	Jacquie	NC Justice
Barrett	Emily	Town of Cary
Bowman	Kendal	Duke Energy
Bragg	Scott	Evergreen Packaging
Brooks	Jeff	Duke Energy
Brookshire	Daniel	NC Sustainable Energy Association
Brown	Justin	Duke Energy
Burnett	John	Duke Energy
Chan	Coreina	Rocky Mountain Institute
Cherry	Troy	Varentec
Coppola	Barbara	Duke Energy
Culley	Thad	Vote Solar
Cummings	Layla	Public Staff - NC Utilities Commission
Delli-Gatti	Dionne	Environmental Defense Fund
DeMay	Stephen	Duke Energy
Downey	Diana	Public Staff - NC Utilities Commission
Doyle	Ned	Energy Innovation Task Force - Asheville
Dyson	Mark	Rocky Mountain Institute
Edge	Chris	Duke Energy
Edmondson	Lucy	Public Staff - NC Utilities Commission
Faucette	Walker	Nutrien
Finnigan	John	Environmental Defense Fund
Floyd	Jack	Public Staff - NC Utilities Commission
Fondacci	Luis	North Carolina Electric Membership Corporation
Glenn	Alex	Duke Energy
Hartman	Beth	Rocky Mountain Institute
Hicks	Warren	Bailey & Dixon, LLP
Holder	Nathan	Advanced Energy
Howard	Preston	North Carolina Manufacturers Alliance
Hughes	Mike	Duke Energy
Jacob	Bryan	Southern Alliance for Clean Energy
Jenkins	Alan	Jenkins at Law
Kalland	Stephen	NCSU - NC Clean Energy Technology Center
Klein	PJ	Corning Incorporated
Kruse	Susan	Duke Energy
Ledford	Peter	NC Sustainable Energy Association
Maley	Dan	Duke Energy
Masemore	Sushma	North Carolina Department of Environmental Quality
McIlmoil	Rory	Appalachian Voices
McLawhorn	James	Public Staff - NC Utilities Commission
Miller	Sharon	Carolina Utility Customers Association

Musilek	Jim	North Carolina Electric Cooperatives
Neal	David	Southern Environmental Law Center
Ohms	Cindy	Carolina Utility Customers Association
Oliver	Jay	Duke Energy
Palmer	Miko	Duke Energy
Parkhurst	Daniel	Clean Air Carolina
Powell	Claudia	Advanced Energy
Quinn	Matthew	NC WARN
Ralph	Karen	Duke Energy
Ripley	Al	NC Justice Center
Rogers	David	Sierra Club
Rountree	Grace Trilling	Duke Energy
Rouse	Jay	North Carolina Electric Cooperatives
Scheier	Eric	NC Interfaith Power & Light
Schull	Matthew	ElectriCities of North Carolina
Sides	James	United States Marine Corps - Regional Energy Program
Simpson	Bobby	Duke Energy
Sipes	Robert	Duke Energy
Smith	Ben	NC Sustainable Energy Association
Teplin	Chaz	Rocky Mountain Institute
Trathen	Marcus	Brooks Pierce - Tech Customers
Urlaub	Ivan	NC Sustainable Energy Association
Waters	Mike	ChargePoint
Weiss	Jennifer	Nicholas Institute for Environmental Policy Solutions
Williamson	David	Public Staff - NC Utilities Commission
Wills	Kristen	NC WARN

Workshop Outcomes

Objective 1

Obtain stakeholder input to Duke Energy's outlook on seven megatrends shaping grid improvement decisions.

Supporting Activities

The following activities allowed stakeholders to provide input to Duke Energy on the seven megatrends:

- Pre-Read: In the pre-read sent to participants, Duke Energy identified seven megatrends shaping near and long-term grid improvement needs, and the potential implications of these megatrends on customer service under a business-as-usual scenario (no grid improvement). Duke Energy compared the outlook for grid performance under business-as-usual vs. grid improvement plan scenarios, using the following qualitative summary slide:
- Workshop presentations and discussions: A presentation by Duke Energy staff summarized the megatrends and how they shaped the company's approach to grid improvement. Following the presentation, several feedback activities collected input from stakeholders including: a Q&A session, table discussions, online polling, and additional discussion at the end of the day. Please see Appendix 2, for detailed notes from the Q&A, table discussions, and plenary comments.

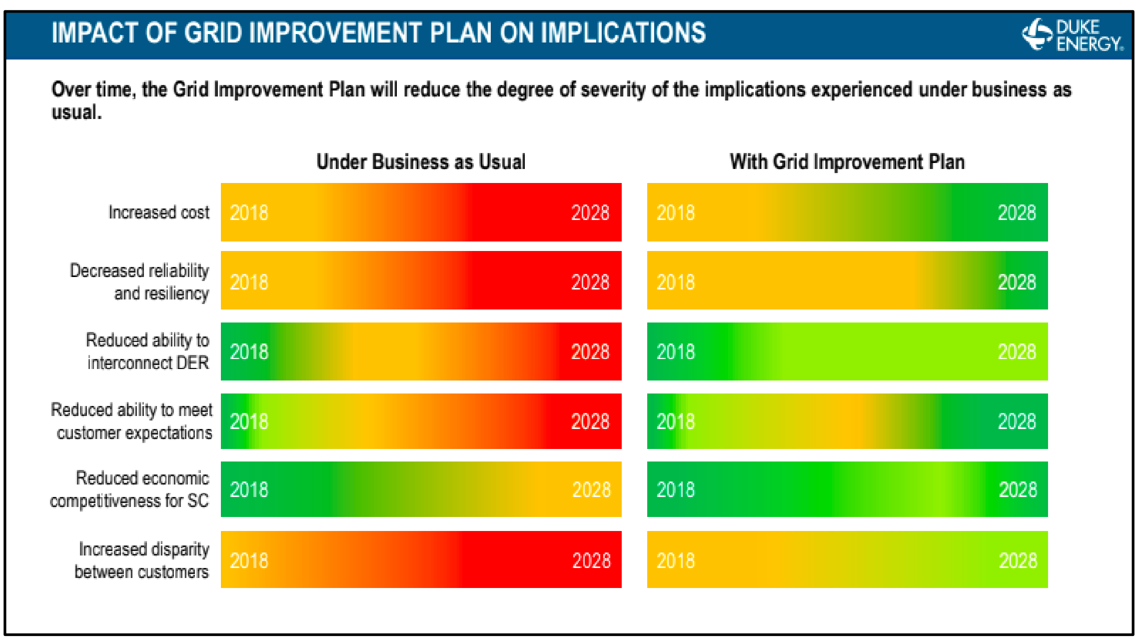

Figure 2. This heat map from the workshop pre-read summarized the Duke's analysis of the implications of the seven megatrends.

Summary of stakeholder feedback on the Megatrends

- Quantitative analysis: Many stakeholders requested more quantitative analysis, better descriptions of the methodology, and the underlying data and details on the assumptions used. In particular, stakeholders wanted to better understand quantitatively how Duke Energy formulated the implications resulting from the trends.
- Impact of clean and renewable technologies: Many stakeholders shared their belief that distributed energy resources (DERs) represent an opportunity to lower costs, in contrast to Duke Energy's heat map. Similarly, many stakeholders said that the analysis should have increased its emphasis of the lowering cost and increasing competitiveness of new, clean energy technologies.
- Climate change: A number of stakeholders said that climate change and sustainability needed to be addressed explicitly in the megatrends and their implications.
- Evolving utility business model: Many stakeholders said that changing utility business models was missing from the megatrend list.
- Underserved and at-risk communities: A number of stakeholders were concerned that the needs of low income and rural customers were not adequately accounted for in the trends.
- Changing customer expectations: Some stakeholders found the description of 'changing customer expectations' confusing and asked Duke Energy how interpreted these changes and what could reasonably be done in response.
- Outlook on load growth: A number of stakeholders questioned how load growth was addressed in Duke Energy's analysis. They shared their perspective that load growth is fairly flat today across the nation but could increase with increased electrification and electric vehicles.

Gauging stakeholder alignment on the Megatrends

Real-time polling indicated that stakeholders had mixed reactions to Duke Energy's megatrends and implications analysis. When asked "How aligned are you with how Duke Energy views these 7 megatrends?" (see Figure 3 below), stakeholder responses were fairly evenly distributed from 0% alignment to ~80% alignment.

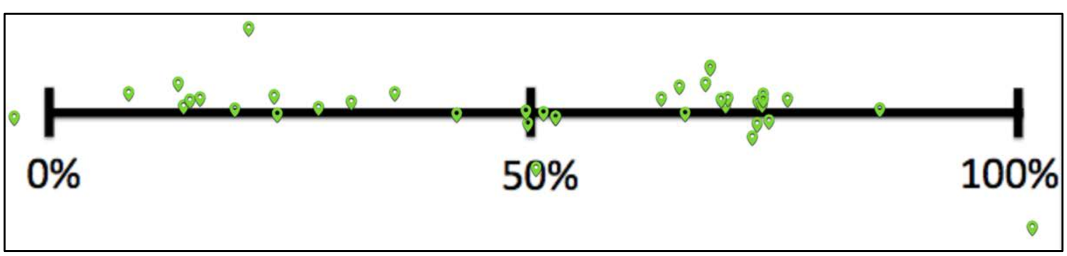

Figure 3. Results of online polling to the question: How aligned are you with how Duke Energy views these megatrends and implications?"

Objective 2

Describe and get feedback on how Duke has used stakeholder input, the impact of megatrends on grid needs, and a prioritization methodology to develop a grid improvement portfolio.

Supporting Activities

The following activities supported the second objective:

- Workshop pre-read: Duke Energy described the cost-benefit and cost-effectiveness analysis that they used to create the draft grid improvement plan. The key graphic describing Duke Energy's process in shown in Figure 4 below.
- Dedicated workshop session on Duke Energy's Methodology: Duke Energy summarized the process they used to create the draft grid improvement plan. After the presentation, stakeholders were given the chance to ask questions in plenary. This Q&A is documented in Appendix 3.
- **Question and Answer Summary**

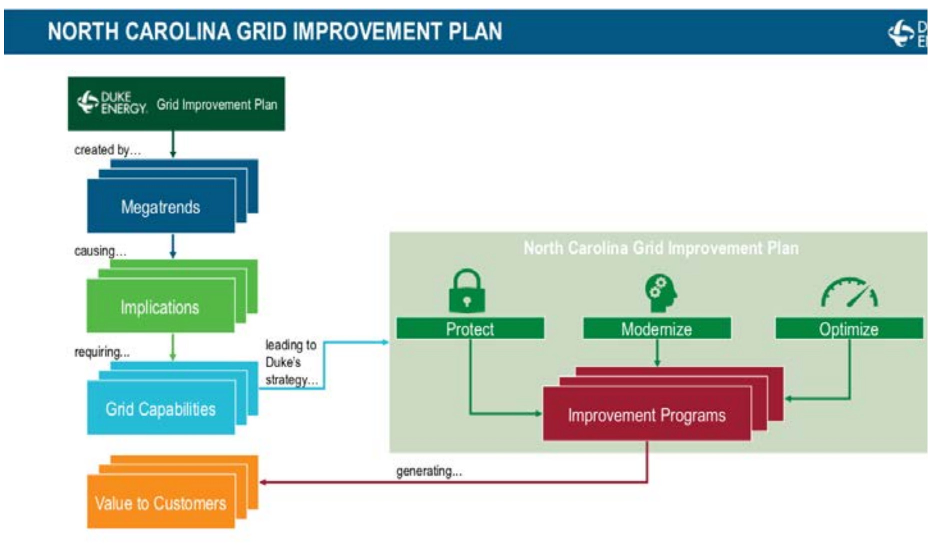

Figure 4. Duke's methodology for creating the draft grid improvement plan, reproduced from the workshop pre-read.

During the Q&A and subsequent sessions, stakeholders provided feedback that included the following recurring concerns:

- Cost and benefit balance among customers: Stakeholders asked how each customer and income class would benefit from the plan's programs and whether cost recovery would reflect that balance. Duke Energy described benefits for low income and industrial (transmission-level) customers, explained how service interruptions were monetized, and gave their rationale for including a number of programs in the draft grid improvement plan.

- Technical clarifications: Duke Energy staff explained the workings of the "ICE" model that was used to monetize interruptions, described undergrounding benefits for transmission customers, and detailed how line losses were taken into account.

Objective 3

Describe the benefits and risks of the draft program portfolio and hear from stakeholders what changes they propose and why.

Supporting Activities

Workshop Pre-Read: Duke Energy's workshop pre-read detailed the draft grid improvement plan budget (Figure 5). The pre-read also contained detailed descriptions of each program in the plan.

Workshop Presentations and Q&A: During the workshop, a dedicated Duke Energy presentation summarized the plan and its benefits for customers. After the presentation, Duke Energy answered stakeholder questions in plenary.

Online Polling: Following the Q&A, stakeholders responded to an anonymous online poll to assess their support of the plan (Figure 6). In plenary, some stakeholders indicated why they responded the way that they did.

Program	3 Year Range
Compliance: Cost Effectiveness Justified	**$164 - 266M**
Physical Security	$113 - 184M
Cyber Security	$51 - 83M
Cost Benefit & Cost Effectiveness Justified	**$973 - 1580M**
SOG	$412 - 670M
Distribution H&R	$111 - 180M
IVVC DEC	$123 - 200M
Transmission H&R	$98 - 159M
TUG	$57 - 93M
Energy Storage	$103 - 167M
Transmission Bank Replacement	$36 - 58M
D-OIL Breaker Replacements	$10 - 15M
T-OIL Breaker Replacements	$15 - 24M
DSDR peak shaving to CVR in DEP	$8 - 13M
Rapid Technology Advancement: Cost-Effectiveness Justified	**$418 - 680M**
T&D Communications	$163 - 264M
Distribution System Automation	$92 - 150M
Transmission System Automtation	$71 - 115M
T&D Enterprise Systems	$16 - 26M
ISOP	$30 - 48M
DER Dispatch Tool	$12 - 20M
Electric Vehicle Charging	$27 - 45M
Power Electronics for volt/var control	$6 - 10M
Customer Data Access	$2 - 3M
Total	**$1,600 - 2,500M**

Figure 5. The draft grid improvement plan budget, as communicated to stakeholders in the Workshop pre-read.

Table Discussions on the Plan's Strengths and Changes Stakeholders Would Like to See: After the poll, at their tables, participants discussed 'What are the strengths of the plan' and 'What changes would you like to see to this plan?' Duke Energy staff documented stakeholder answers on post-it notes. In plenary, Duke Energy representatives summarized the discussions at each table.

In Appendix 4, we include detailed notes of the Q&A, table summaries and post-it note comments.

Summary of stakeholder feedback and common discussion themes

Below, we summarize common stakeholder feedback and themes from the Q&A, table discussions and post-it note comments.

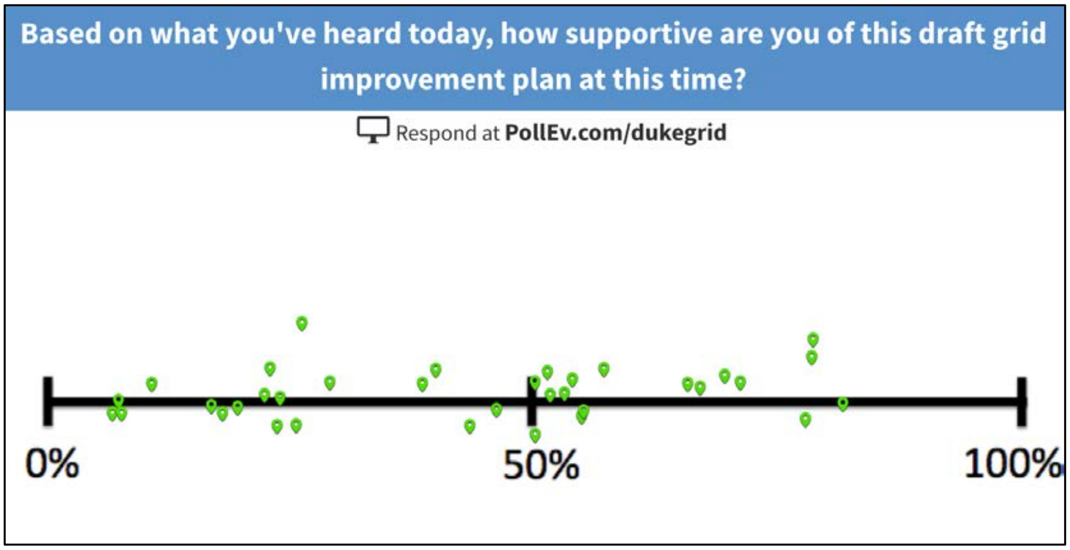

Figure 6. Online polling showed a wide distribution of support for the plan, varying from ~0% to ~80%.

- Improved transparency: Many stakeholders appreciated the additional details and transparency that Duke Energy provided in the pre-read and at the workshop, especially in comparison to previous grid mod plan descriptions from Duke Energy.
- Incorporation of feedback: Many stakeholders appreciated how the plan has been pared down and changed in response to stakeholder feedback to the original Power/Forward plan.
- Cost recovery details: Many stakeholders were unwilling to support the plan without cost recovery details. Additionally, stakeholders wanted to know whether the plan's costs would be distributed equitably among customers.
- Business model reform: Many stakeholders felt that it was difficult to assess the plan without also addressing the issue of utility business model reform and how it would affect Duke Energy and North Carolina.
- Quantify DER improvements: Stakeholders repeatedly asked for a quantitative assessment of how much additional distributed energy resources (DER) could be accommodated with the help of the draft grid improvement plan.
- Supporting data for costs and benefits: Stakeholders repeatedly asked for additional details regarding the assumptions and data used to calculate the benefits and cost of the plan.
- Plans for implementation: A number of stakeholders wanted to know if Duke Energy had plans or commitments to deploy customer programs that would take advantage of the technology improvements in the plan.
- Program cost-benefit choice: Some stakeholders wanted to know the justification for why some programs were put in the 'cost-effectiveness' category and not the 'cost-benefit' category.
- More DER support: Many stakeholders wanted to see more aggressive support for renewable energy and DER in the grid improvement plan.

Gauging stakeholder understanding and support of the draft grid improvement plan

In online polling after the Q&A session (Figure 6), there was a large variation in stakeholder support of the draft grid improvement plan, from being largely unsupportive (13 responses at 25% or lower) to mixed support (19 responses between 25% and 75%) to supportive (4 responses at about 75% supportive).

Participants also had the chance to indicate how well the workshop enhanced their understanding of the plan and provide feedback in the end-of-workshop survey questions. As shown in Figure 7, **most stakeholders indicated that the workshop enhanced their understanding of the plan**, scoring the first end-of-survey question 7 or higher. In their comments to this question, stakeholders indicated they would like to have seen more supporting details and justification for the cost-benefit analysis.

In the second end-of-workshop survey question (Figure 8), **stakeholders indicated overwhelming that they had a satisfactory ability to provide feedback** to Duke Energy. All but one respondent scored this question a 7 or higher.

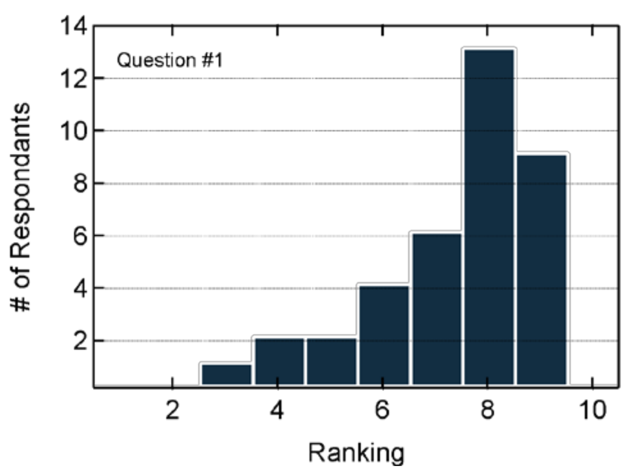

Figure 7: Responses to Survey Question #1: “On a scale of 1-10, how well did this workshop enhance your understanding of the draft grid improvement plan?”

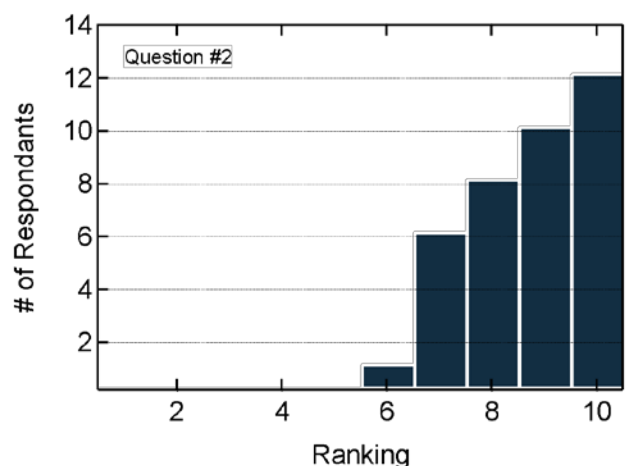

Figure 8. Responses to survey questions #2: “On a scale of 1-10, how satisfied are you with the opportunity to provide feedback to Duke Energy at this workshop?”

Additional Feedback to Duke Energy

The workshop's final session was organized into three sessions:

1. Coaching questions: Stakeholders were asked to provide input in the form of 'coaching questions' to Duke Energy staff, to help identify additional opportunities and issues important to stakeholders.
2. Requests for Duke Energy to share more underlying data and assumptions: Stakeholders were asked to provide specific requests for information and data from Duke Energy.
3. Final Q&A: Stakeholders were given a final opportunity to ask Duke Energy any questions relevant to Grid Improvement.

Coaching Questions for Duke

The following coaching questions were posed to Duke Energy.

- Is it possible for Duke Energy to elevate/advance the ISOP ahead of some of the other parts of the plan?
- Is it possible that Duke Energy could coordinate with the five or so other groups that are also creating visions of North Carolina's energy future?
- Can Duke Energy staff envision a completely different paradigm of how the energy business can be run in the future? (Changes to the utility business model could be a part of that.)
- If not directly addressing climate change, can Duke Energy consider the social cost of carbon?
- Is it possible for Duke Energy to show how their projections with the IRP match up with the new grid capabilities in this plan?
- How can the social cost of carbon be considered in the plan?
- Could Duke Energy consider exchanging more assurance for future cost recovery with a lower rate of return?
- Can Duke Energy explain the regulatory cost recovery options that NC needs, and that SC and some other states already have?
- Would Duke Energy consider rolling out the parts of this plan that pencil out as cost-effective without a requirement for additional cost recovery?
- Would Duke consider working with Co-op groups to get their perspective on what is needed for grid improvement?
- Can Duke Energy indicate how this plan will impact opportunities for Muni's and Co-ops to do their own grid improvement projects? For example, will those utilities be able to add their own storage?
- Will this plan improve interconnection speed?
- Can Duke Energy work with the municipalities with 100% clean energy plans to develop a plan that would help them meet their goals?
- Is it possible for Duke Energy to draft documents that address stakeholder questions about DERs, customer control, customer choice, and reliability?
- Can Duke Energy maximize the number of NC businesses it uses as vendors?

Sharing Data

In this session, stakeholders asked Duke Energy to provide further information about the data they used to create the plan and to conduct cost-benefit analysis. Stakeholders asked for:

- Underlying data to be provided in machine readable format (not as a PDF). When Duke noted that this is a very large amount of data, stakeholders indicated their understanding, and remained very interested.
- In places where specific assumptions had to be made, indicate the model's sensitivity to those assumptions and ranges for the outputs
- Include all calculation formulas so others can repeat the calculations
- Please clearly indicate alternative pathways for accomplishing the same goals, and why the current plan is the preferred option.
- Please provide the climate assessments that were used to create the plan, and the risks/uncertainties of that data
- More specific rate impact data — explain how costs and benefits are allocated to each rate classes.
- Indicate whether costs will be integrated into fixed and/or volumetric charges.

Final, Open Q&A with Duke Energy Staff

The following summary highlights the final Q&A. A detailed transcript is in Appendix 5.

- When asked about the amount of renewable energy the draft grid improvement plan would enable at the distribution grid, Duke Energy described how IVVC and SOG will help support behind-the-meter DERs and electric vehicles. Duke has not yet quantified how much DER capacity will be enabled by IVVC and SOG.
- When asked about Duke Energy's plans for customer programs that will fully leverage the capabilities of the technologies in the draft grid improvement plan, Duke Energy said that it has already started developing plans and working with 3rd parties.
- When asked about whether they will go to the General Assembly with this grid mod plan, Duke Energy said that they much preferred to first obtain general agreement with stakeholders and then work through either the legislature or a rate case. Duke Energy did not think a rate case was likely before the middle of 2019. In a follow-up question about what consensus looked like, Duke Energy stated that when most stakeholders indicate overlapping agreement, they will feel comfortable moving forward.
- Duke Energy indicated that they believed ISOP would indicate that the Plan's technologies would be good investments into the future.
- When asked about whether Duke Energy should state publicly a commitment to renewable generation, Duke Energy noted that they currently have carbon reduction and sustainability goals which tie directly to increasing levels of renewable generation. Increasing these goals needs to align with direction set by policy makers and the priorities and interests of our customers.
- When asked how stakeholders should support this grid plan if Duke Energy is planning to use natural gas for the next 50 years, Duke Energy noted there are a range of opinions among customers, policy makers and regulators about the role of natural gas going forward.
- When asked how the current plan compares to the original Power/Forward plan, Duke Energy noted that they both added and removed items from the original plan based on Stakeholder feedback, and that the value proposition has improved as a result.

Appendix 1: Feedback from Executive Summary

After Duke Energy presented an initial executive summary of their view on the future of the grid, their process for creating an improvement plan and their draft filing plan, participants were asked "Based on what you just heard, what are the most urgent questions you have for Duke Energy?" Participants wrote their questions on post-it notes and RMI staff grouped the questions into categories. Below, we document each question (modified slightly for clarity).

Cost of the Plan and Rate Impacts

- How will these investments, if approved, impact customer bills? How much customer expense will be saved per dollar spent?
- How does the 2-billion-dollar cost cause rates to rise only 1% per year?
- How will this plan lower costs overall for residential customers and utilize clean technologies to do so?
- Rate increases are used to recover costs. What about revenue recovery for savings obtained with IVVC/CVR, energy efficiency and DER?
- If the grid is more efficient, will the savings impact rates?
- The original Power Forward plan was ~$13.8B. What are Duke's plans (and schedule) to address the elements in the P/F plan that we don't see in the Grid Improvement plan?
- Is the upper bound of the plan cost-effective, and how will the plan variances be handled?
- Is there really no Phase II in the works that would bring this plan closer to the original P/F proposal of approximately $13.8B?
- Show us the money* (*Value proposition – what will it do for us?)
- What is the definition of 'value'?

Duke Energy's Methodology

- What cost/benefit analysis has been done on each component of the plan and on the entire plan? Is it available to us?
- What is the methodology for "cost-effectiveness" justification – especially as differences between customers, shareholders, citizens, and society are addressed?
- Why is Duke still prioritizing marginal reliability improvements over cost-effective modernization that could pay for itself?
- What baseline will these improvements be compared to?
- Can you envision making the plan a 5-year plan and making the cost-effectiveness methodology clear, transparent, and inclusive of stakeholder participation?
- I still have questions about Grid Modernization vs Grid Improvement.
- How do you separate routine maintenance from Grid Improvement/Modification?
- Does 'grid mod' and 'grid improvement' need to be evaluated separately?
- Why can't the 'old grid' handle the new demands?
- Why is grid improvement distinct from regular and customary work that Duke Energy performs as part of its normal mandate (as opposed to grid modernization that includes distinct, new upgrades)?

Large Customer Impacts

- What is the value/payback to transmission level customers?
- What improvements directly impact industrial/transmission?
- Are transmission-related costs going to be recovered through the transmission formula rate?

Distributed Energy Resources (DER) Capability

- If the plan is approved, will Duke Energy remove barriers to more customer-owned DERs?
- What level of DER (capacity/saturation) and pace of DER integration will the current plan facilitate? Related, why would a second plan be necessary?
- Given the lower cost of renewables, could Duke set a target for renewable generation percent that exceeds requirements?
- How will this plan help integrate renewable energy DERs and reduce carbon emissions?
- How does this plan lay a solid proactive foundation for expanding solar/DER?
- Which aspects/elements of the plan will drive/enable higher DER and energy efficiency adoption?
- Why is expansion/investment in solar/wind (DER) a lower priority?
- How much more renewable energy will this plan enable in North Carolina?
- How robust will the grid be to integrate and scale up energy generated from a) customers on the distributed system b) utility-scale battery storage, on-shore/offshore wind, and EV infrastructure?

Cost Allocation

- Why is Duke planning to recover the bulk of the costs for this plan from residential customers who receive the fewest tangible benefits?
- How are the costs of the proposed projects split between: wholesale/retail and transmission/distribution production?
- How will the financial pie be split up? What are the allocation factors?
- What is the per year cost allocation to industrial classes in years 1 to 5?
- How do you ensure that grid improvement investment is distributed equitably (both the costs and the benefits)?

Broader Context

- Will customers truly get a bigger role in managing their own usage and costs and will programs that enable those savings be integrated into grid improvement plans (i.e., designed to have some impact on customer costs)?
- How will 'beyond the meter,' customer facing solutions provide grid benefits while working in concert with a non-regulated, competitive market?
- How is this draft grid improvement plan informing the company's IRP – is there a way that these investments defer the need for new generation?
- How does cost recovery interact with larger business model reforms?
- What new regulatory recovery mechanisms will enable the grid modernization objectives?

Technology Composition

- Which technology is possibly too new and may change too much in 5 years?
- Is AMI (Smart Meter) roll out contingent on this plan getting approved?
- How does future flexibility factor into prioritization of projects — (e.g. fuel cells make certain investments obsolete or stranded)
- What role will TUG play in 'new' draft grid improvement plan? (Didn't hear it discussed in presentation.)
- Ability to work with large customers to place EV facilities at customer locations.
- What determines the 'bucket' that certain tools/measures line up in?

Other Questions

- Why do all these measures have to be approved in one package?
- How would the best interest of customers be presented if Duke was to pursue the South Carolina 'rate step up' model?
- What tool does Duke Energy need to give the NCUC authority to approve the implementation of Grid Modernization?
- Define what consensus means to Duke Energy?
- What assurances can you give us that customers will receive all available benefits from these investments?
- Have you already started implementing any of these grid improvements?

Online Polling on Topics of Interest

During the welcome session, using online polling, stakeholders were asked to describe what two grid improvement topics they most interested in discussing. The results are in Figure 9.

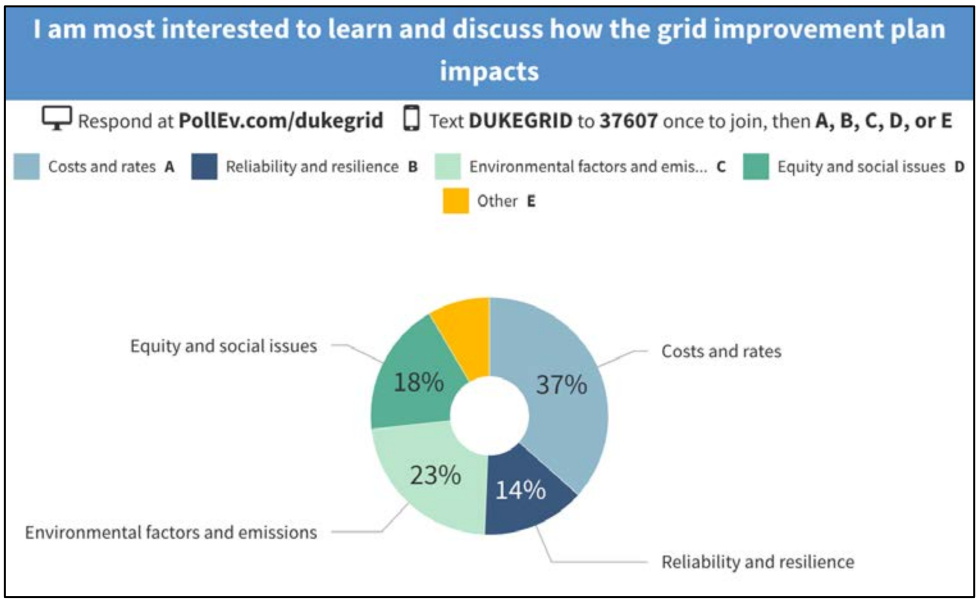

Figure 9. Initial online poll asking stakeholders what grid improvement impacts they would most like to discuss.

Appendix 2: Megatrends and Implications

Question and answer in plenary

After hearing Duke Energy's description of the megatrends and their implications for North Carolina's grid, stakeholders asked questions in plenary that were answered in real-time by Duke Energy representatives. Here, we summarize the questions posed by stakeholders and notes from the responses of Duke Energy staff.

- Q: On Cyber security, Duke only offer proxies for the trend but does not really provide supporting data. This section needs more substance.

- It is a challenge to provide the level of detail for cyber threats as compared to physical threats. By their nature, cyber threats are not visibly apparent unless they are successful. Also, many details of cyber threats are kept confidential to prevent proliferation of information that can be exploited by cyber terrorists.
- We don't want to overdo the cyber investment, but also want to make sure we are being responsible.

- Q: There are absent megatrends including stark economic inequality and increasing numbers of your customers in poverty. This is a trend worth including.
  - Duke Energy considered including low-income economic issues as its own trend. We struggled with paring down the total number from 30-40 initial trends.
  - We find that implementing the projects with the best benefit-to-cost ratios can help low-income customers in the long run through cost savings.
- Q: Why isn't climate change named specifically? I know it is captured a bit in weather.
  - Duke Energy did its best to pare down the megatrends. Climate change is a lightning rod topic for some. We thought we could more universally engage with stakeholders by citing undisputed facts we can state as part of trends, including that some cities and companies are making clean energy goals.
- Q: The given implications are qualitative — how are the color-coded charts in pre-read created?
  - Implications are more quantitative in the near-term and more qualitative in the mid-to-long term.
  - Duke Energy is happy to share how we created them. The process was similar to the cost-benefit analysis.
- Q: How will the grid plan relate to Executive Order 80? Will you modify the plan given the Executive Order?
  - Duke Energy will treat the Executive Order as key stakeholder input.
- Q: Can Duke be more transparent about the types of weather-related events you are expecting?
  - We use weather predictions from professional forecasters, such as those who define the 100-year flood zones. Then, we internally prioritize projects.
- Q: How impactful are these megatrends to other utilities, including non-electric utilities?
  - There are a lot of common trends we face, but we focus on trends most important to North Carolina.
- Q: On geographic and demographic trends, you glaze over the impact on rural areas. Can you explain your justification that how rural areas will be impacted even more if you <u>don't</u> do the plan?
  - It is difficult to address rural areas because improving service to a small number of customers can be very expensive, whereas urban projects have more impact per dollar.
  - We look for opportunities where new technologies provide cost-effective solutions for rural customers (e.g. potentially batteries).

- Q: The connection between a lower carbon future and increased cost [in your color charts] is hard to understand given that the clean, future technologies are the lowest cost generation.
  - Generation resources and the Infrastructure required to support delivery to customers have to be considered holistically. Duke Energy looks for opportunities to address many trends, problems, and/or opportunities at once. IVVC/SOG is an example of a program that can meet many goals at a lower cost.
- Q: Regarding increased costs, there are many people who may experience decreased costs. Depending on the conversation, some customers may benefit more than others. Did you give any thought to that with regards to the first implication 'Increased Cost'?
  - Duke Energy sees increased costs as the reality.
  - We need to structure programs to ensure that we are optimizing the cost/benefits for all of our customers appropriately.
- Q: One trend we have seen is large cost over-runs in many places, not necessarily in Duke Energy territory. Are you having internal conversations about how to prevent that from happening?
  - Duke Energy has a natural incentive to manage our costs because it is part of the cost-benefit analysis.
  - In South Carolina, our filing includes 'not-to-exceed' costs.
  - Duke has been good at managing costs historically. The ranges of costs in the draft plan indicate possible variations in the cost of each program.
- Q: Regarding economic megatrends, my take is that the pre-read seems to presume more or less steady-state economic trajectory. But we have stock markets, trade wars … it is hard to believe things are going to be hunky dory for another 10 years. How does that scramble the equation?
  - Duke Energy would handle any X factor, war stock market crashes, etc. with real-time program triage.

Poll Everywhere

After the question and answer, stakeholders were asked to respond to an anonymous online poll (Figure 3 above) that assessed stakeholder agreement with Duke Energy's megatrends.

In plenary, some stakeholders offered explanations for their responses

- Closer to 100%: This stakeholder noted that Duke has significantly modified the plan from Power/Forward and has worked with stakeholders, held workshops using RMI as a facilitator, and included analysis from Navigant. This stakeholder's organizations wants to continue working with Duke Energy with to ensure technological benefits will serve customers.
- 50%: This stakeholder noted that Duke Energy has modified the plan based on stakeholder feedback. The stakeholder still wants to see more underlying data and transparency.

- 75%: This stakeholder supported much of the plan but was concerned about whether the workshop's feedback will be incorporated. If the feedback does make it into the plan, the stakeholder said they would be closer to 100%.
- Less than 50%: This stakeholder felt that if analysis showed that projects would quickly save money, then they should not require a new plan with special, dedicated funding.
- Less than 50%: The stakeholder felt that if the net present value of the self-optimized grid (SOG) was so dramatic, the project should be started, and the savings used to fund the remainder of the plan.
- <50%: This stakeholder was unwilling to score the program highly without cost recovery information.

Table Discussions

Table discussions were focused on two questions, 'Where do you share common ground? and 'What's missing?'. Stakeholders wrote their thoughts on post-it notes. After the conversations, Duke Energy staff reported what they heard at their table:

Table A: In their conversations, stakeholders mostly agreed that the trends seem right. However, they would like to see more details and specificity and comparison to other states. For the concentrated growth trend (and customer expectations), stakeholders asked, as services grow, why can't Duke Energy simply add modern technologies? For weather, improvements may not benefit from technology as much as from process improvement. Stakeholders asked for Climate Change to be addressed specifically.

Table B: There was general agreement on the trends and implications, but the list was missing some things. Some stakeholders expressed that the growing rate of technology obsolescence is a megatrend in itself. This could affect the ability to implement the plan effectively. Also, the table surfaced a lack of interest in working for utilities – the lack of workers could inhibit implementation.

Table C: Stakeholders felt that flat load growth was buried and that the load implications of EV's and electrification may have large load implications that were not addressed. Similarly, stakeholders indicated that the list is too cautious in how it addresses climate change. There should be more emphasis on electric vehicles, social factors, and health. Stakeholders asked how one would define customer expectations and how one would know what customers are asking for. Stakeholders asked about what Duke Energy is doing proactively with Integrated Resource Planning, customer interactions, and urban/rural differences.

Table D: This table's discussions did not achieve consensus. Considering expectations for renewable DER, the table agreed that was on point. They had good discussions on cyber security and weather but differed on cyber: Some said that this is something Duke should already do; there were already dollars set aside for that. Also, funds were already allocated for billing with Customer Connect. Some at the table noted that customer expectations are different for each customer classes, and within different age groups.

Table E: At this table, there was concurrence on weather, physical and cyber threats. There was a lot of interest from industrial/manufacturing where a number of stakeholders had similar concerns – especially about costs. There is a lot of manufacturing in North Carolina and a lot of competitiveness – higher costs could cause lost businesses. The table agreed hurricanes and weather are causing recovery costs. The table indicated that quantitative analysis of avoided costs and how could they be passed on to customers was missing from the plan's justification. For example, storm costs were $0.9B – could those saved costs be shared?

Another comment from the discussions: The megatrends were missing utility business model reforms. Until Duke Energy really recognizes the changing utility landscape, it will be hard to comprehensively address many issues, including grid improvements.

Written Stakeholder Input

Below, we report the comments that stakeholders wrote on post-it notes. When necessary, we lightly edited the content to be understandable by readers who did not attend the workshop.

Where do we share common ground?

- Technology advancements → There will be significant growth in beyond-the-meter load from new technologies (e.g., electric vehicles). How can we integrate these while retaining reliability?
- Most agreed generally with the megatrends, but we would like more substantiation and a comparison to other states
- Agree, but need more detail on technology advancement and lower carbon future.
- Agree on DER/Renewables, customer expectations, and lower carbon future.
- Agree: Technology advancements, concentrated population growth, and the impact of weather.
- Agree: Most of the megatrends are good. However, the details of how to address them are the key.
- Common ground: New and emerging threats, e.g. cybersecurity
- Agree: The grid may have a reduced ability to manage and integrate DER.
- Agree: Overall, the trends are real and need to be addressed
- Common ground: Cyber security 'megatrends'
- Impact of weather events (climate change)
- Aligned: The trends are real
- We agree some measures for grid modernization are needed
- Aligned: Technology improvements, grid improvements, and reliability (weather, security)
- Weather
- Aligned: Customer expectation i.e. 'mission'
- Aligned: Threats to infrastructure
- Aligned: Weather
- Agree there is a growing number and scope of true threats to grid infrastructure
- Reduced reliability during extreme weather events, 500-year storms (common)
- Threats
- Customer expectations
- Increased costs are a reality today — whether through grid improvement or response to storms. For examples, the $900M cost in 2018
- Agree with lower carbon future environmental trends and integrating DER's
- Agree with need to integrate customer-sited DER, but utility-scale DER is much more prominent in North Carolina
- Agree with general trends. However, the biggest question is how different programs fit in the 'Maintain' vs 'Grid Modernization' investment categories.
- Share common ground: Need to accommodate new clean power system solutions at large scale without hindering growth and cost competitiveness
- I agree that there have been improvements in renewable energy
- Customer expectations are changing — customers expect and want more DER's, specifically solar.

- Agree that cyber threats need to be addressed. Believe physical threats are more related to weather events and power plants.
- General concern for new justifiable technology investments when balanced by costs and the impact on low-income customers.
- Overall price tag more reasonable (possibly even too low)

<u>What's Missing? Where Do You Differ?</u>

- Disagree: Total lack of climate change
- Disagree: No specific mention of sustainability
- Disagree: Trends show a comfort in dealing with physical/cyber violence and a discomfort in dealing with climate change.
- Cyber and physical security — Duke is supposed to address these with their existing mandate. Money has been set aside for addressing these threats already for some time.
- Customer Connect and Billing System upgrades should be part of Duke's usual business, not a special program.
- Missing: The regulatory model needs to change to effectively accommodate DER.
- Customer expectations — Not all customers want the same thing.
- Disagree: What evidence is there that physical threats to grid infrastructure are a significant problem?
- Weather impacts — We need new and better forecasts than those shown.
- There is a lack of proactive DER planning and goals from Duke Energy.
- Missing: Connection for business model and every-day/residential customers.
- Missing: The technology trends should include more investments in EVs and efficient electrification.
- Weather – New technologies may not prevent increases in outage events and duration. Process improvements could help.
- Concentrated growth — In new areas where growth and infrastructure are installed, Duke should be installing new technologies as part of its normal work to add service for these customers.
- Climate Change — Duke Energy should address climate change directly.
- Differ: These are not the only trends — changing electric utility business models should be an added trend.
- Missing: How does this plan enhance the mission of the military in NC?
- Customer Expectations — As existing infrastructure is replaced; the baseline practice should be to use new technologies during replacements.
- Differ: Low carbon and environmental (kind of differ) (due to policy)
- Differ: The implications are not logically consistent.
- How do you balance economically attractiveness vs economic concerns
- In terms of competitiveness for North Carolina – we must balance having a modern grid with higher energy costs.
- Economic Competitiveness – increasing costs harm North Carolina as some industrial customers may leave causing loss of electric load.
- What is grid modernization vs normal operations and maintenance?
- Is it time to consider a new regulatory model?
- Is this the right direction?
- What are the checks and balances on Duke Energy if this plan is passed?

- Missing: There is no strategic prioritization of the trends. There is no policy leadership perspective for health and innovation.
- Critical items should already be in progress as required by Duke Energy's existing mandates.
- There is no mention of cost avoidance.
- What are critical needs vs. wants? As an example: security vs smart meters.
- The trend of non-utility technologies supplanting utility functions needs to be taken into account in projections.
- Missing: There is no mention of changing electric utility business models.
- These are supposed to be trends in Duke's territory, but grid improvement is all about national actions. If you considering national trends, then why is there no consideration of business model reforms.
- Missing: Trends specific to North Carolina are missing (larger scale renewables, Governor's climate executive order).
- Missing: There is no quantitative data supporting the heatmaps that describe the implications.
- Need more details, and specific information is needed on all of the megatrends.
- Missing: Analysis specific to North Carolina
- Missing: Polling data by various entities on what consumers want. This needs to include polls not contracted by Duke.
- Duke Energy needs to show who will incur increased costs, not just that costs will increase. Duke Energy needs to note that new resources acquired by the utility usually cost more than those created by other parties.
- Missing: There are megatrends in the power sector regarding grid modernization, utility business models, and utility platform business models. Resource cost trends need to include who will incur the cost.
- The Macro trends beg the question of what is an appropriate regulatory structure? How do we know we are best addressing the trends?
- Missing: The plan is like driving a round peg into a square hole. A fundamental review and recognition of new business and/or regulatory models may be needed.
- What's missing: The trends and implications are missing how the implementation of clean technology can tangibly lower customer bills.
- In Navigant's benchmarking, there is no apparent correspondence between grid modernization activities and the percent of DER in use.
- Inequality and poverty help drive population changes and how people use energy. This needs to be addressed directly.
- Need to include the growing obsolescence of fossil fuel infrastructure, specifically coal.
- Missing: Inequality and aging populations
- Differ: I don't think the DER/Renewables discussion is being adequately identified for its value and potential.
- Surprised to see projected load growth in North Carolina (nationwide, the trend is declining or flat load growth)
- The implications include an unwarranted reliance on unlikely events that are used to justify the plan. As an example: the threat of an electromagnetic pulse.
- Missing: Electrification and Health

- I would like to see a concretely stated goal for modernization. Is it related to resilience or DER deployment?
- I would like to see Duke Energy take on direct ownership of greenhouse gas issues.
- The transparency in the methodology used is low.
- Missing: Flat load growth, not mentioning climate change by name, and any prioritization or weighting of the trends
- Differ: Do we know customer expectations?
- Differ: Duke Energy should be proactively acting to counter trends with negative implications on customers. For example, climate change and encouraging behaviors that lower costs and reduce impacts.
- Differ: The details and approach are the key, i.e. for technology advancements, why is Duke focused on non-utility DER? How is 'customer expectations' a trend?
- How much is this going to cost? How much am I going to benefit? Need to include information for retail and wholesale customers.

Appendix 3: Program Prioritization Methodology

Question and Answer

- Q: Why are you using non-asset benefits and how will you ensure that costs will be adequately distributed?
  - A: Duke Energy includes costs and benefits related to non-asset issues like momentary interruptions. This reflects the actual value of electricity to customers.
- Q: Outage costs and benefits are different for different customer classes — does the ICE model take that into account?
  - A: Yes, the ICE model does value the costs and benefits according to customer class. The costs associated for <50 kWh and >50 kWh customers are handled differently, to reflect the fact that outages to residential customers are less costly.
- Q: There is some disagreement on how effective the ICE tool is for accurate cost-benefit analysis. How many projects are cost-benefit justified without incorporating values from ICE?
  - A: The answer depends on the project. Some projects, such as targeted undergrounding, are cost-benefit justified without incorporating ICE values. The ICE tool offers a method to assign monetary value to low-probability / high-impact events. Some programs like IVVC don't require use of the ICE tool for cost-benefit analysis. IVVC benefits come primarily from efficiency savings.
- Q: For targeted undergrounding, your analysis shows that the costs are less than the operational savings. If this is the case, why wouldn't you do this project as part of normal operations rather than under the grid improvement plan?
  - A: Targeted undergrounding programs represent an opportunity to save money if the company carefully targets the right projects. Within the normal utility 'least-cost' paradigm that we operate in, we cannot accelerate projects based on longer term savings. Because the current paradigm prevents us from accelerating these kinds of projects, we have included them in the draft grid improvement plan. Also, these programs address several megatrends including increasingly severe storms

- Q: Can you give us examples of projects that directly benefit transmission customers?
  - A: The plan includes transmission programs including hardening the transmission system, transmission line rebuilds, bank replacements, upgrading mechanical equipment to electronic equipment, and substation system intelligence projects that will give us warning before failures occur. In addition, for some of the distribution-size substations, there are potential projects we could include to address power quality.
- Q: The largest benefits for commercial and industrial customers appear to be from the targeted underground programs. Are there any other examples in the grid improvement plan of projects with strong benefits for this customer class?
  - A: Several programs in the plan focus on circuits with large commercial customers and will reduce momentary interruptions. We also believe conductor upgrades will benefit these customers, though the benefits from conductor upgrades may be smaller than those from undergrounding.
- Follow up question: Did Follow up question: Did you consider a cut-out mounted recloser instead?
  - A: Yes, we are considering those and we're currently evaluating that technology so we can accurately determine its effectiveness in mitigating voltage sags and momentary interruptions that would otherwise be eliminated by TUG.
- Q: Has the analysis considered that transmission and distribution wires have 5-7% losses themselves?
  - A: Yes, that is taken into account in the IVVC case. With self-optimizing grid investments, we do not go to that level of detail; we will be upgrading wires for SOG programs and it is difficult to estimate reduced losses from those types of upgrades. If we do obtain significantly lower wire losses, the environmental benefits would increase.
- Q: In a recent rate case, it was noted that Duke Energy was behind in vegetation management and additional funding was approved. What comparisons have you made with that approved vegetation management program and this grid improvement plan?
  - A: This cost-benefit analysis would be somewhat complex, but for a specific tree-trimming project, we assume a ‘5-year trim cycle’ in the calculations, including the costs of climbing poles in certain neighborhoods. We calculate benefits using a 10-year history, and account for major storms in a distinct way, so we would have to make different calculations depending on whether we were on or off the trim cycle. This type of comparison is an area we could focus on for each case going forward.

Appendix 4: Draft Grid Improvement Plan

Q&A following Draft Grid Improvement Plan Presentation

After Duke Energy presented a summary of their draft grid improvement plan, stakeholders were given the opportunity to have their questions answered in plenary by members of the Duke Energy team. The following transcript has been edited lightly for clarity.

- Q: In the heat maps depicting the ability for DERs to connect to the system, where do you get the 10-year period with 300% expansion in rooftop solar. Your numbers are very conservative – it seems the 'red' in the heat map should be closer to 2022 than 2028."
  - A: Our estimate is conservative. We are trying to better quantify that estimate going forward.
  - A: We faced something similar with the Clean Power Plan. Often with these projections, there is a wide range of predictions. We use the median prediction in those situations.
- Q: Before a rate case, will there be an opportunity to see the plan in more granular detail? There are a lot of things in the plan that we support but we would need to see more detail.
  - A: The short answer is 'Yes.' We are not sure what the best way is to provide you with this data. It could be a data dump, or a more focused workshop where we went into greater detail.
- Q: Are the heat maps just for the current plan, or for the entire 10-year investment?"
  - A: The heat maps assume the completion of IVVC and SOG
  - A: The heart of those programs is in urban areas. It is going to take some time to complete those programs. The heat maps assume the full 10-year plan.
- Q: Assuming this plan moves forward, is there going to be a commitment from Duke Energy not to throttle rooftop solar and other DERs? What assurance can we get from Duke Energy?
  - A: We cannot commit 100% to anything, unfortunately. However, we absolutely do not want to justify a program with benefits and then not allow customers to take advantage of them.
- Q: With respect to who gets to benefit from these programs: Are we building a bridge that only leads to 'Duke's front gate?' Or this is a benefit to everyone? Will others be able to own connected resources?
  - A: This plan is designed to do no harm and to provide flexibility. Reasonable minds may differ with each other on what programs make sense.
- Q: What investments will reduce economic disparity?
  - A: When programs benefit every customer, either directly or indirectly, that is when we turn the heat map 'green.' Yellow indicates that only some customers experience benefits. When targeted cost-benefit analysis shows benefits primarily to small groups of customers, there may be social justice reasons for those investments that go beyond economic justifications. Often, a lot of social justice issues require policy responses beyond our scope.
- Q: Why is it 'improvement,' not 'modernization'?
  - A: We have chosen to use the word 'Grid Improvement" because some people get hung up on the precise definition of 'Grid Modernization.' As we think back to the programs in the original Power Forward plan, there were some programs that were not appropriate. We have learned from that and changed the plan accordingly. However, there were some investments that were not modernization but also represented a more forward-thinking approach to grid investments. We changed the name to 'Grid Improvement' because we want people to think more broadly about grid investments than just new technologies.
- Q: There are a lot of assumptions made that are not described in the slides. We really need to better understand those underlying assumptions.
  - A: This goes back to an earlier question — we would love to get that information into stakeholders' hands early and not have it come up during a rate case.
  - A: We need to define that process.

Discussion following Online Polling

After the stakeholders responded to online polling that assessed their support of the draft grid improvement plan, some stakeholders explained why they put their cursor where they did.

- Closer to 75%: This stakeholder indicated they could have placed their cursor closer to 100%. They stated that it was evident that Duke had come a long way in modifying the original Power/Forward plan. Duke Energy had reached out to them, had hired RMI, and had hired Navigant. The plan they presented was much different from what was presented in May. They found these changes very encouraging. From their perspective, they wanted to work with Duke Energy to make sure that all of the benefits of this technology can be there for customers. They are looking forward to working with Duke Energy and are grateful that Duke Energy has changed their approach so dramatically.
- Close to 50%: Duke has taken feedback and modified their plan accordingly. This stakeholder was interested in seeing more of the underlying data and more transparency.
- Close to 75%: This stakeholder was behind the plan for the most part but wanted to see the workshop feedback incorporated into the plan. If the feedback is incorporated, the stakeholder would be closer to 100%.
- Lower Score: This stakeholder said that the cost analysis on targeted undergrounding (TUG) did not make sense. They wanted to know why, if the Net Present Value (NPV) is so much greater than the costs, the work isn't already underway.
- Lower Score: This stakeholder didn't understand why, if the value is so obvious, there needs to be a special plan. Why is this work not part of regular operations? As an example, If the NPV of the Self Optimizing Grid (SOG) is real, it should fund the rest of the program. The stakeholder was not sure what programs in the plan were different from activities conducted in regular operations.
- A Lower Score: This stakeholder didn't give the plan a high score because they still wanted to know the cost recovery mechanism.

Table Discussions

After the plenary discussions, stakeholders were asked to discuss at their tables two questions: "What are the strengths of this plan?" and "What changes would you like to see to this plan?" After the discussion, Duke Energy staff summarized the conversations in plenary:

- Table A: Stakeholders indicated that they appreciated that the cost-benefit analysis was available and that the Duke Energy team included subject matter experts. However, stakeholders still needed to know how costs will be allocated. In addition, stakeholders wanted more details regarding customer expectations, distributed energy resources, and reliability.
- Table B: Stakeholders appreciated having a third party facilitate the workshop. They noted that there are multiple projects and solutions that could resolve the same issues and the stakeholders were not sure the plan was the least-cost way. They also thought it was important to include conversation about utility regulatory structure reform, as the current business model is a barrier to more rapid adaptation and technology adoption.
- Table C: Stakeholders appreciated the greater level of specificity and acknowledged that there the plan includes more than hardening and resiliency benefits. However, they wanted to see more behind-the-meter benefits for large industrial customers and to include rate design and other policies as part of the discussion.

- Table D: Stakeholders were excited to see integrated system operating plan (ISOP) and the distributed energy resources dispatch tool in the plan. They appreciated that the plan reflected stakeholder input. However, the stakeholders wanted to see the rates for each customer class. Also, they said that it would be hard to adequately quantify benefits with the ISOP tool in place. Finally, stakeholders wanted to know, with the SOG, how much distributed energy resources could be incorporated on each circuit.
- Table E: Stakeholders appreciated the detailed plan, and that the plan had more benefits than were in the original Power Forward plan. However, they wanted to better understand rate changes and to see defined costs and rates. They did not want to agree to plan and find out the cost later. Additionally, they wanted to understand why projects are placed in the 'cost-benefit' or 'cost-effective' bucket. They wanted to see a more compelling economic benefit.
- Table F: Stakeholders agreed with the megatrends and scope of the plan. However, stakeholders wanted the costs in the plan to be broken out by customer type, especially for transmission customers. They also wanted the plan to more explicitly include the concerns of customers who inject power on to the grid, as well as take power from it
- Table G: These stakeholders gave Duke credit with moving ahead without a state mandate.

Written notes from table discussions

Below, we document the post-it note comments from the draft grid improvement plan discussions.

<u>Strengths of the plan</u>

- Consideration and visibility of stakeholder input
- More incremental plan that allows changes if needed
- New plan is more focused in terms of scope and includes more details on itemized costs
- Appreciated having a 3rd party facilitator…RMI is respected by the clean energy industry
- More detailed and focused information than last time (comparatively speaking)
- Appreciate the effort to educate stakeholders and public on the individual programs
- Duke appears to be looking holistically at stacked benefits. However, we need more transparency about the methodology to feel confident in the plan.
- Seems like a much better cost-benefit analysis but still need more information
- Plan is an effort at comprehensive planning
- Plan is more discreet and focused than Power/Forward
- Background research and positioning
- Appreciate efforts to show cost-benefit analysis
- Cost-benefit analysis
- Shared subject matter expertise
- More forward thinking than previous plan
- Plan reflects stakeholder feedback
- Directionally like the roadmap
- The plan is a good start for a conversation
- Duke is beginning to embrace cost-benefit analysis -— this is the opposite to 5 years ago
- More focused than last plan but there is still much work to do
- Customer data access, green button
- ISOP

- Like DER enabling projects (Storage)
- Plan reflected stakeholder input
- Great thought went into the plan
- DER dispatch tool
- Megatrends are appropriate and will serve customers well, if we do those things
- Broad scope and impressive
- It is clear that many of the proposed investments are necessary, beneficial and could facilitate a cleaner energy grid and future
- The new plan is right-sized – the previous $13 billion plan was too much to swallow
- Shifted money to more grid modernization
- More targeted TUG
- Appreciate greater level of specificity
- Duke acknowledged that there's more to it than hardening and resilience

Changes you would like to see to the plan

- Missing: Is the plan flexible to take into account different scenarios?
- Is there a proxy for the ICE tool that is used to value outages?
- Rate impacts of the plan by customer class
- Needs to include utility business model change (NY-REV, Performance based rate-making)
- The benefits of the plan seem hard to quantify without ISOP being in place
- Needs to include more quantification of how the plan helps integrate DER
- A number of the improvements should be in base work
- Duke Energy Progress did IVVC without special programs
- Needs a breakdown of the benefits to transmission customers and how programs like transformer replacement benefit transmission customers
- The cost-benefit analysis needs to show how transmission customers benefit, or those customers shouldn't have to pay for it.
- More transparency and information on cost recovery
- What are the cost-effective criteria? And is it different for the various options?
- The plan is not grounded without a state energy vision
- Need detailed listing of design parameters, key assumptions, forecasting scenarios, cost/benefit assumptions
- Need more workshops on each megatrend to dig into the details and make corrections
- Need cost-benefit analysis by rate class
- SETP and IPR – Historical penetration of DER is too conservative. 50% is possible.
- Need an accurate set of assumptions — value is not real
- More transparency on data and analysis used to justify the plan
- More info on impacts for each class and the plan's recovery mechanism
- Need Duke to commit to what customer programs it will offer. It is not enough to just improve grid technologies. What programs will Duke commit to?
- Need a data dump
- Duke should shift away from marginal reliability improvements and place a bigger focus on energy efficiency and demand side management.
- Need to know the plan's cost allocations to each customer group

- "Customer expectations" is too general a term - no info is provided on reliability expectations
- More details on cost-benefits for each customer segment
- Need more details on transmission investments and specific benefits for large industrial customers
- Many of the "improvements" still do not justify a return on equity and are instead basic operations
- Duke Energy needs to define reasonable costs and rates as these terms are used repeatedly
- Revisit plan more frequently to consider emerging trends and tech
- Will megatrends still be applicable with unexpected events and landscape
- Show how solutions address multiple problems
- Regulatory barriers
- Further certainty of program/project costs
- Far more effort to support, advance and integrated DER
- Define guiding principles for all work efforts behind the meter
- Climate change should be a megatrend and the $$ should be focused on the investments that help to mitigate and adapt and at least do no harm
- Better integrate the specific customer programs, rate design benefits, etc.
- Opportunity for more flexibility — are we missing other areas by focusing on grid only?
- Transparently reveal how projects are bucketed
- Create compelling value proposition using hard economics
- Risk of agreeing to the plan and then figuring out how to pay for it
- Residential battery storage offering like the Green Mountain Power program
- Can Duke incent battery storage in rural areas to help reliability for [customers like] John's mom? Cost could be split between Duke and the customer
- Would like to see a renewable energy target: how much will you enable?
- Microgrids for critical infrastructure
- How much will it cost and recovery mechanism

Appendix 5: Transcript of final Q&A with Duke Energy Staff

- Q: The draft grid improvement plan includes interconnection improvements. Lower interconnection charges would be a significant benefit. How will the plan affect interconnection charges?
  - A: The grid improvement plan will increase the number and total capacity of interconnections that the grid can accommodate. This benefit does not include any reduction in interconnection charges.
- Q: You mentioned there would be a deferred counting mechanism. What guard rails would there be on the amount that Duke Energy spends?
  - A: The scope of the improvements is limited by the resources we have to actually do the work. I don't think we could implement improvements faster than what is in the plan given current resources. In addition, provisions would be put in place for any program we implement to ensure that scope and cost commitments are met.
- Q: Are the different numbers in the plan for each program ranges for possible costs?
  - A: Yes — those are class 3 ranges, meaning we add 30% to be conservative. You should feel comfortable with the estimates.

- Q: The company, on a recent call, brought up legislative and regulatory options. We are now about 2 months away from legislative sessions and we haven't started to discuss cost recovery options. What is the expected planning?
  - A: Given the legislative schedule, the timing for discussions would be now. But, as of now, we do not have a legislative plan. I am happy to talk about what the plan in SC has — they have the option for a multi-year rate plan. Duke Energy does not wish to go to the legislature without stakeholder input.
- Q: I still don't have a feel for how the plan scales renewable energy connection. Does it match the integrated resource plan?
  - A: IVVC has conservation voltage reduction. This would allow us to tighten the voltage band and operate in the middle of the band. This allows us to add more renewable energy without the variation in generation causing the line voltages to vary outside of allowed limits. That is one example. The plan also includes power components that allows us to make settings changes more quickly. The self-optimized grid (SOG) helps us with power flow — it allows us to make changes to the grid to support behind-the-meter solar and electric vehicles (EVs). The plan also allows us to prepare for advanced EV support.
  - A: We have modestly valued the addition of DER in our analysis.
- Q: Ideally all of these programs will allow lots of new customer programs such as efficiency and demand response. Have you started developing those programs and/or working with 3rd parties to do so?
  - A: Yes, and yes. With some of the customer programs, we have been careful not to get too far ahead of the available grid technology. For example, for time-of-use pricing, we have been thinking about foundational projects like AMI that enable these new programs.
  - A: We are talking about key foundational pieces that would allow us to implement customer programs, but actual programs require the grid being ready.
- Q: I am feeling the stress of timing. This is a work in progress, there may be future meetings, and then we may eventually get to consensus. But the General Assembly meets in January. I am concerned about how we bridge those time constraints, so we don't end up in an epic battle.
  - A: Everything is easier if there is general agreement. As for the rate case, no one has said we need to do that now. Given the time required, the earliest we could begin a rate case would be mid-2019.
  - Q: But you just filed a rate case in South Carolina. Will you not do that in North Carolina at the same time?
  - A: Ideally yes – but it may be difficult if there are issues.
- Q: You have talked about getting to consensus. What does that look like? When do we turn the other away?
  - A: I see it as a Venn diagram – if there is a core with overlapping agreement, then you can judge there is agreement. In a sense, 'you know it when you see it,' and then you move forward. There will always be some stakeholders on the edges [of the Venn diagram] that do not agree.
  - A: At my table, when we were able to unpack things, perspectives changed. At some point, we will reach diminishing returns with further discussions and it will time to move forward with the proposal (or not).

  - A: Our experience was very different in South Carolina. There, we had closer to 80% agreement at the workshop. When North Carolina has a similar level of agreement, we will see that as consensus.
- As you go down the Integrated System Operation Planning (ISOP) path, are you confident that the interim measures will not be obsolete?
  - A: With 85% certainty, yes. The plan designers have been asked to make sure that is the case.
- Is there a grid in the US or elsewhere that you would point to as the gold standard for a modern grid?
  - A: I don't think so yet. Navigant has some utilities that they benchmark off of.
  - A: We are not the first utility to move toward SOG or conservation voltage reduction (CVR). Some of these are tried and true – we think now is the appropriate time for these improvements in North Carolina.
- To justify SOG and other programs, why not have a Climate Change related goal of getting to some percentage, say 80%, of clean energy by some year. It seems like an opportunity to get ahead of carbon taxes. Instead, you are simply projecting that there will be some amount of DERs and trying to improve the grid to accommodate it. Why not take a leadership goal and strive towards a certain percent of clean energy?
  - A: I think about that in 3 prongs: Policy makers, customers and us. Our policy makers are ahead of us. We have corporate goals and we have our coal fleet. Is there consensus on that? I think we are where we should be in North Carolina. Our customers are leading that without having to have us drive it.
  - A: If you think about the draft grid improvement plan, we don't have a renewables goal in it. But we have corporate level goals and grid improvement will support those goals.
- Q: When you sell this to the public, folks will ask, 'Why improve the grid if you are just going to use natural gas for the next 50 years?'
  - A: We are going to have customers, regulators and policy makers with a range of opinions.
- Q: Given Duke's corporate goals and grid modernization goals, if we pass the draft grid improvement plan, will you say that the corporate goals achieve some percent clean energy?
  - A: Yes, to the degree that grid improvement enables clean energy and/or carbon reduction goals we will make that connection.

Appendix 6: End-of-Workshop Survey Comments

Below, we directly transcribe all comments that participants provided in writing in addition to their numerical responses to the end-of-workshop survey. We also provide a summary of the numerical responses to survey questions #3 and #4.

Question 1: On a scale of 1-10, how well did this workshop enhance your understanding of the grid improvement plan?

- Much clearer on inputs, elements of plan, approach to valuation, not just cost (rated 8)
- Pre-meeting material was helpful, but it did not have enough detail to understand fully (rated 6)
- Need more details about assumptions (rated 8)
- Not a very deep dive (rated 7)
- Still need some additional data and details, but it was informative. Thanks (rated 8)
- Would appreciate more transparency to DER planning and cost-benefit analysis (rated 4)

- PDF before handout was very helpful! (rated 8)
- Still need to see more 'under the hood' (rated 7)
- Details for transmission Improvements / added value (rated 4)
- Need to get 'data dump' and independently evaluate (rated 8)
- Dial in a little more on specific technologies and what they do (rated 6)
- I've been a part of the South Carolina process, so I got some advanced notice. (Rated 6)
- I still don't follow how chosen investments address megatrends; nothing about alternatives considered or rejected (graded 6)
- We need specific information about how this plan will benefit and what it will cost large load customers (rated 3)

Question 2: On a scale of 1-10, how satisfied are you with the opportunity to provide feedback to Duke Energy at this workshop?

- Were taken seriously, but the new plan looks like the old plan in better packaging (rated 7)
- Technical question needs (rated 7)
- Great Job! (rated 9)
- Lots of opportunity throughout day (rated 10)

Question 3: On a scale of 1-10, how well did this workshop enhance your understanding about other stakeholders' point of view?

The responses to question #3 are shown in Figure 10, at right. Below, we list the comments to this question:

- Great 'segments' at table (rated 8)
- I'd like to hear more from commercial and industrial customers (rated 4)
- Lots of people in the room I don't think we heard from in the big group discussions (rated 7)

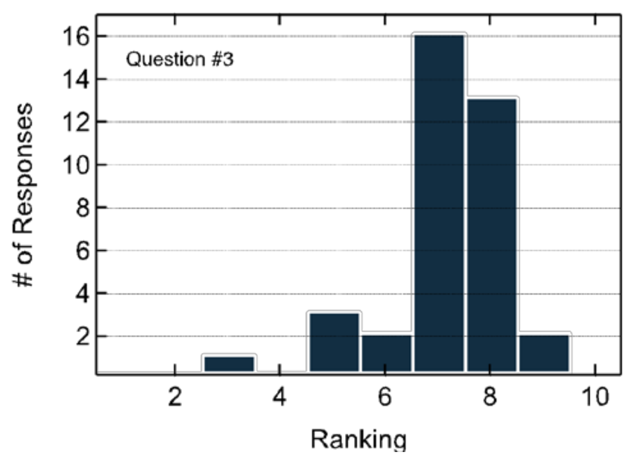

Figure 10. In their responses to survey questions #3, stakeholders indicated that they generally learned more about other stakeholders' points of view.

Question 4: On a scale of 1-10, how willing are you to engage in potential future follow-up conversations with Duke around the grid improvement plan?

The results to question #4 are shown in Figure 11, at right.

The two written stakeholder comments on this question are listed below:

- I'm always happy to engage (rated 10)
- Any way we can help (rated 10)

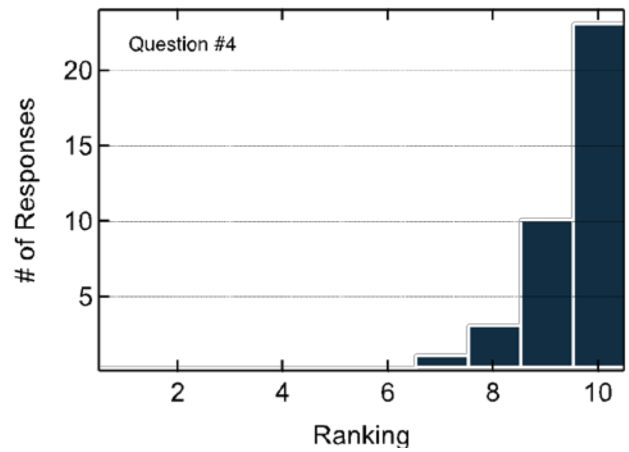

Figure 11. The responses to question #4 indicate that stakeholders are overwhelmingly willing to continue conversations with Duke about grid improvement.

Question 5: What did you find most useful about this day? Why?

- Information and dialogue
- Opportunity to ask questions and engage in discussions
- More details on plan
- Opportunity to explore enhancements that enable DER penetration
- In-depth details provided by subject matter experts; helpful in understanding plan
- Great Q&A sessions
- More interaction about details
- Seeing other groups' concerns and needs
- Opportunity to discuss strengths and weaknesses was helpful to talk through
- Viewpoints of other stakeholders
- Q&A, discussions at tables
- Interactive, facilitated structure
- Stakeholder engagement
- Issues identified and what plan is lacking in scope (not including regulatory and business model reforms).
- Lots of viewpoints, strong disconnect between Duke Energy and stakeholder expectations, Duke Energy wants to listen to others concerns but not sure they are ready to hear what they are asked to change.
- Example of the project/program differences
- Candid conversation
- Great explanation of new plan and underlying rationale
- Hearing others
- The briefing materials were excellent. Rocky Mountain Institute was good.
- Last session: Coaching questions, Data dump, Q&A
- Open question period for Duke Energy.
- Meeting the new Director
- Flow and breaking up presentations with discussion

Question 6: What changes would you suggest for future meetings?

- Please continue to have these meetings!

- Encourage more people to speak up and offer diverse viewpoints and make an effort to increase racial diversity of stakeholders (and include more voices of low-income /fixed-income customers
- More discussion on rate impacts
- Do the data dump before the next meeting
- Shorter meetings
- This was good
- More inter-group/table interaction. May meeting did this well.
- Smaller breakout with various viewpoints
- Mixing up groups to get additional perspectives
- Expand scope to regulatory reform
- Accompanying technical analysis, summary reports and white papers & summary of key assumptions
- Say the page # of a slide you are showing
- Get someone to talk about cost recovery aspects of grid improvements, particularly if different from traditional cost recovery of transmission and distribution investments, operations and maintenance.
- More of the same.
- Not much — well done
- Perhaps working groups for more technical issues and/or specific constituencies (break out by subject matter interests)

Question 7: Please use this space to provide any additional written comments to Duke Energy about their grid improvement plan?

- I remain very concerned that there is a big mismatch between projected/perceived benefits and costs to residential customers.
- Thank you!
- Show us the (rate) money
- I'd like the focus on clean energy to focus on how to integrate and save customers' money. Also, storage should be more explored and used to full potential.
- Would be good to engage stakeholders before pushing any legislation
- Need more detail on what is being proposed and the support for making an extraordinary expenditure
- Step in the right direction toward greater transparency. Long way still to go!
- Thanks.
- Overall, great – but needs more focus on private DER
- Draw a distinction between how it benefits and costs shareholders and customers
- This is a multi-billion-dollar plan. I can' support it until I see the data dump.
- Overall, need a better idea of what Duke sees as the utility of the future and how this plan gets us there, with specific breakdown of costs.

Stakeholder Webinar:
North Carolina Grid Improvement Plan

April 2019

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What You've Told Us

- Take a more holistic view of grid improvement / grid modernization *(e.g., incorporate IRP, ISOP, etc.)*
- Offer more on implications of recent filings and proceedings related to the Grid Improvement Plan
- Provide more clarity around the data room and its contents
- Share more details of analysis behind the Grid Improvement Plan
  - Basis for megatrends
  - Cost/Benefit Analyses
  - Goals & metrics
- Improve the overall stakeholder engagement process

Today's Objective

- Level set with participants on the context for Duke Energy's Grid Improvement Plan, considering recent developments in the NC electricity sector.

- Provide stakeholders more detailed explanation of the plan, including analytic elements of interest to stakeholders that were not discussed or available in our November workshop.
  - Data room intro
  - Megatrend implication heat maps
  - GIP goals and metrics
  - Sample cost/benefit analysis

- Respond to top-of-mind stakeholder questions coming from November workshop and subsequent interactions with Duke Energy.

- Solicit feedback from participants to shape the agenda and objectives for workshop in May.

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Agenda

- Welcome & Overview
- Landscape of Relevant Events in NC
- Overview of Current Plan
- Featured Discussion Modules
  - Data room
  - Megatrend implication heat maps
  - Goals/metrics for the plan
  - Cost/Benefit Analyses
  - Program prioritization methodology
- Q&A
- Workshop Topic Priorities & Recommendations
- Close

Today's Presenters

John Burnett
Deputy General Counsel

Jay Oliver
GM Grid Solutions
Engineering & Technology

Robert Sipes
VP Western Carolinas
Modernization

Webinar Logistics

QUESTIONS & COMMENTS

- Participants are welcome to enter questions and comments at any time using the Q&A button at the top of your screen (viewable only by webinar hosts)
- Participant input will be reviewed real-time and queued for response during the Q&A segment of the webinar
- Webinar hosts will address as many questions/comments as time allows
- All questions / comments received will be shared in a post-webinar report. This will be done without attribution to the participant

TOPIC PRIORITIES & RECOMMENDATIONS

- During this segment, input and feedback will be solicited on two specific areas:
  1) Webinar participants will be asked for input on the a list of potential topics received from stakeholders for the upcoming May workshop.
  2) Webinar participants will also be invited to suggest additional topics

WEBINAR HOUSEKEEPING

- To minimize background noise during this webinar, voice participation will be disabled.
- Should you have problems during the webinar, please email Miko Palmer (miko.palmer@duke-energy.com) for assistance
- To enable viewing at a later time, this webinar will be recorded
- All webinar materials will be available in the data room for future access.

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Warm-up Questions

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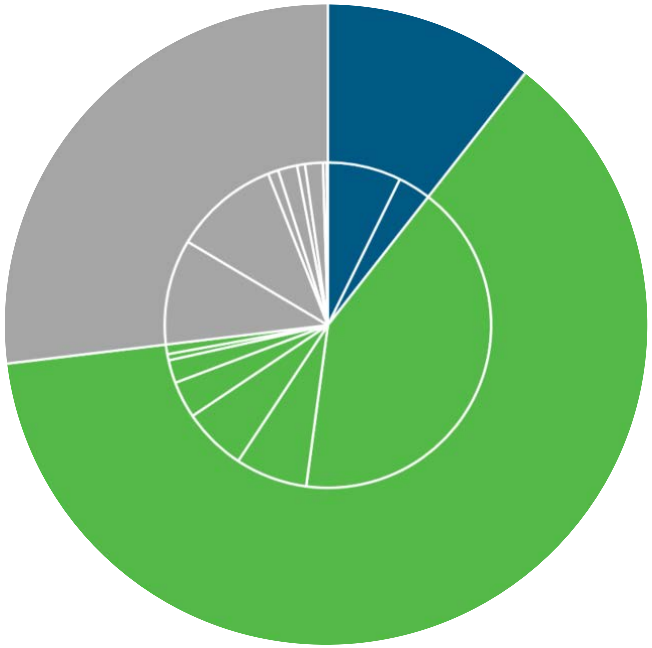
Landscape of Relevant NC Events

- Executive Order 80 and Related DEQ Work
- Commission Order – Rate Designs to Leverage AMI
- Emerging ISOP/IRP discussions
- SC Rate case proceeding
- EV Pilot filing
- Legislative filing
- Engaging Cities with Carbon Reduction Goals

NC Grid Improvement Plan Portfolio Summary

Program	3 Year Range
PROTECT	**$164 - 266M**
Physical Security	$113 - 184M
Cyber Security	$51 - 83M
OPTIMIZE	**$973 - 1580M**
SOG	$412 - 670M
Distribution H&R	$111 - 180M
IVVC DEC	$123 - 200M
Transmission H&R	$98 - 159M
TUG	$57 - 93M
Energy Storage	$103 - 167M
Transmission Bank Replacement	$36 - 58M
D-OIL Breaker Replacements	$10 - 15M
T-OIL Breaker Replacements	$15 - 24M
DSDR peak shaving to CVR in DEP	$8 - 13M
MODERNIZE	**$418 - 680M**
T&D Communications	$163 - 264M
Distribution System Automation	$92 - 150M
Transmission System Automtation	$71 - 115M
T&D Enterprise Systems	$16 - 26M
ISOP	$30 - 48M
DER Dispatch Tool	$12 - 20M
Electric Vehicle Charging	$27 - 45M
Power Electronics for volt/var control	$6 - 10M
Customer Data Access	$2 - 3M
Total	**$1,600 - 2,500M**



Influence of Stakeholder Input

CURRENT
Grid Improvement Plan (NC)

Dollars in 000's

	2020 - 2022
PROTECT	**$164-266M**
Physical Security	$113-184M
Cyber Security	$51-83M
OPTIMIZE	**$973-1580M**
SOG	$412-670M
Distribution H&R	$111-180M
IVVC DEC	$123-200M
Transmission H&R	$98-159M
TUG	$57-93M
Energy Storage	$103-167M
Transmission Bank Replacement	$36-58M
D-OIL Breaker Replacements	$10-15M
T-OIL Breaker Replacements	$15-24M
MODERNIZE	**$418-680M**
T&D Communications	$163-264M
Distribution System Automation	$92-150M
Transmission System Automtation	$71-115M
T&D Enterprise Systems	$16-26M
ISOP	$30-48M
DER Dispatch Tool	$12-20M
Electric Vehicle Charging	$27-45M
Power Electronics for volt/var control	$6-10M
Customer Data Access	$2-3M
	$1,600 - 2,500M

PREVIOUS
Power/Forward Carolinas (NC)

Dollars in 000's

	2018 - 2027	2020 - 2022	
Physical Security			*new program*
Cyber Security			*new program*
SOG	$1,267	$518	*unchanged*
Distribution H&R	$3,379	$1,181	↓ 75%
IVVC DEC			*new program*
Transmission	$2,195	$834	
TUG	$4,962	$1,787	↓ 92%
Energy Storage			*new program*
Transmission Bank Replacement			
D-OIL Breaker Replacements			
T-OIL Breaker Replacements			
T&D Communications	$447	$177	*unchanged*
Distribution System Automation	$140	$54	
Transmission System Automtation			
T&D Enterprise Systems	$339	$37	*unchanged*
ISOP			
DER Dispatch Tool			
Electric Vehicle Charging			
Power Electronics for volt/var control			
Customer Data Access			
	$12,730M	$4,588M	↓ Significantly

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Intro to Data Room

TERMS OF USE

- All documents in the data room are free for you to use, share, and reference as needed.
- If you are subscribed to the data room you will receive email notifications whenever new documents are added

NORTH CAROLINA

- Folders partially populated
- Documents currently available
  - CBA's for IVVC/DEC, DSDR/DEP, multiple transmission projects
- Documents coming soon
  - CBA's for Self Optimizing Grid, several TUG targets
- Documents available by May workshop
  - GIP Economic Benefits Assessments (IMPLAN)

SOUTH CAROLINA

- Folders fully populated
- Methodologies used for SC analyses are the same as those for NC

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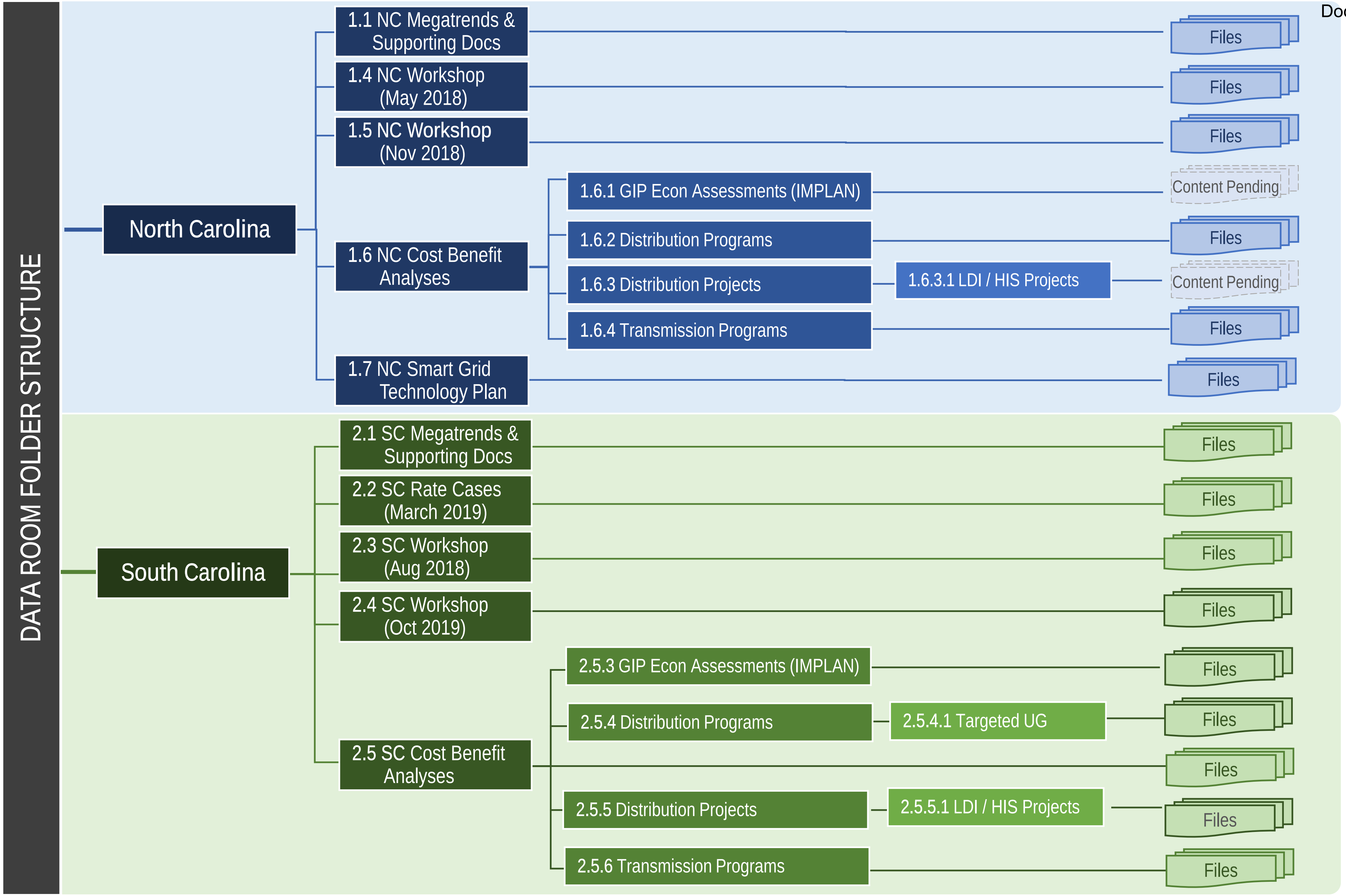
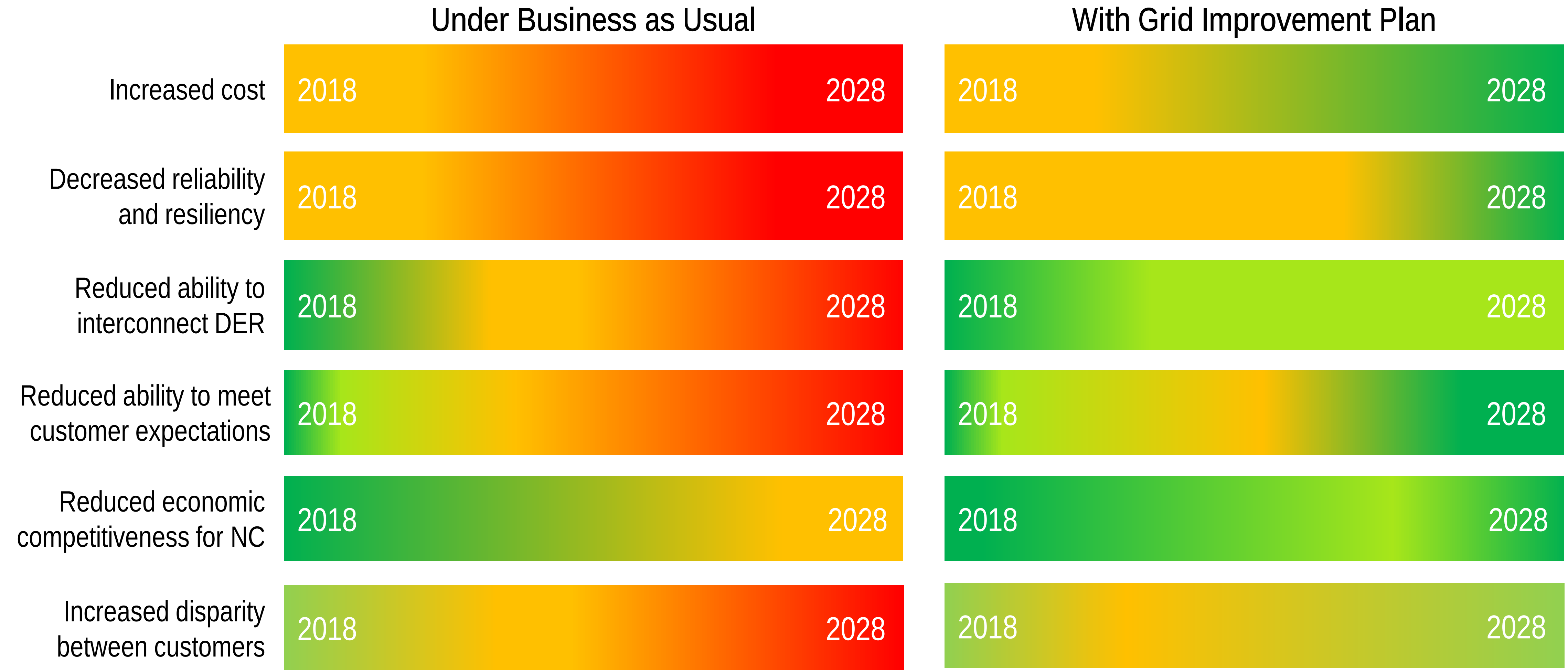
Data Room Map



Implications of Customer Impacts (BaU vs GIP)

Over time, the Grid Improvement Plan will reduce the degree of severity of the implications experienced under business as usual.



Level of severity of implication: = Manageable = Some issues = Many issues

Under Business as Usual

Green to Yellow gradually to Red

2018 — 2028

2018-2020 (green to lime green): Declining reliability due to aging infrastructure, increasing storm activity, and concern over electricity pricing are starting to impact customer satisfaction: JD Power Residential scores for DE-NC in 2nd/3rd Quartile of like utilities 2015-2018, but Commercial customer score below that of peer utilities in South Region with recent 672/678 DEC/DEP scores vs 731 for top utility

2021-2024 (yellow): Interest in rooftop solar expected to triple from current levels by 2021 while reliability metrics continue to worsen leading to increasing customer dissatisfaction. MED events (expected to average an additional 3 MEDs/year by 2023) further hurting reliability and putting upward pressure on cost of service.

2025-2027 (moving to red): By 2025 DER integration limitations become widespread. In 2027 residential solar reaches price parity with retail electricity costs, and solar installed capacity expected to increase 9% per year from 2018-2017). [Source: NC Megatrend II] Inability to provide charging infrastructure for EVs in some areas becomes a problem (EVs reach 3-4% of light-duty vehicle stock). Reliability has continued to decline (by 2028, SAIDI reaching 220-230, SAIFI grows to 1.2 in some areas, and CEMI6 growing by 50% to affect almost 5% of customers). Electricity prices are increasing to pay for MED and non-MED recovery activities and customers are not able to benefit from cost-effective behind the meter or grid-connected DERs.

<u>Details</u>

Overall customer wants: [Source: SECC]

- Low and reasonable energy prices; save money by using energy more efficiently
- Reliability: prevent and reduce length of outages
- Reducing greenhouse gas emissions; make it easier to connect renewables and provide cleaner central generation
- Greater choice and options for energy technologies and pricing.
- Generational change: millennials and up & coming generation favor cleaner energy and more choice much more strongly than older generations

JD Power Measurements –Overall customer Sat

With Grid Improvement Plan

Gradual Green to Yellow back to Green

2018 — 2028

2018-2020 (green to lime green): Initial reliability investments in Targeted Undergrounding (TUG), Distribution Automation (DA), and Self-Optimizing Grid (SOG) projects begin to improve reliability for targeted areas and slowly begin to impact overall customer satisfaction results (VVC, Power Electronics, Cyber Security deployed, but significant effects not yet seen on large scale.

2021-2025 (lime-green to yellow): Continued reliability investments in TUG, DA, SOG are required to continue improved reliability trend in targeted neighborhoods complete by 2025). By end of this period IVVC, Power Electronics, and DER dispatching tool help ease integration of DERs.

2026-2028 (yellow to green): effects of investments noted above continue to accumulate. TUG, DA, SOG continue to reduce impacts of non-MED reliability issues as well as the most significant costs and impacts of increased MED occurrence. CEMI6 % of customers impacted expected to be reduced by 2.5x from the BaU scenario. Distributed PV growth is accommodated more easily, and in SOG areas is completely accommodated w/o extra investment. Cyber Security helps prevent infrastructure attacks, reducing disruption and the corresponding expenses.

<u>Details</u>

Reliability in General (non-MED)

- NC SAIDI and SAIFI expected to improve considerably over BaU.
- CEMI6 % of customers impacted could be reduced by 2.5x from the BaU scenario.

<u>Key Programs</u>

- IVVC in DEC and DSDR peak shaving to CVR in DEP – allow more efficient use of customer electricity by running at lower voltage still within ANSI standards—leading to customer savings
- SOG – provides more reliable and efficient use of the grid.
- TUG – reduces many weather and vegetation related faults to improve

Under Business as Usual

Green to Yellow gradually to Red

2018 2028

JD Power Measurements –Overall customer Sat

Elements scored: Power Quality and Reliability, Price, Billing & Payment, Communications, Corp. Citizenship, Customer service.

- *Residential Scores*: DE-NC moving up from bottom 3rd quartile to bottom 2nd quartile (2015 thru 2017), but trend reversed in 2018, moving back into 3rd quartile.
- Key declines in price and billing areas (2018); quality/reliability and citizenship significant areas of underperformance (2015-2018); while communications and customer service continued to get better
- *Commercial Scores* (from 2015), DEC/DEP scored lower than peers in the South Region large utilities (678 and 672 respectively, vs top score of 731 from GA Power), and were near the bottom of the group.

MEDs – Major Event Days—reliability and cost drivers

- Trending upwards for past 10 years for the Carolinas. Trend shows 6 more MEDs/year in 2018 than 2008 (from trend of 13 to over 19).
- MEDs are disruptive to reliability and expensive to respond to and address problems created.
- Each MED costs $millions, raising cost of service
- National Weather Service has cited an 80% increase in the number of severe weather events impacting the U.S. from 2000 to 2016

Reliability in General (non-MED)

- NC SAIDI projected to raise from 155-165 in 2017, to 220-230 in 2028. Bottom quartile performance. [Source: P/F NC White Paper, 11-02-17]
- NC SAIFI and momentaries also growing worse. Projected to move from 1.04 in 2017 to 1.12-1.20 in 2028.
- CEMI6 % of customers impacted expected to raise from under 3% to over 4.5% by 2028, leading to increased customer dissatisfaction.

With Grid Improvement Plan

Gradual Green to Yellow back to Green

2018 2028

Key Programs

- TUG – reduces many weather and vegetation related faults to improve reliability in targeted areas. Targeting areas of most need first.
- Energy Storage – supports two-way power flow by absorbing excess generation from solar for later use, for additional DER integration.
- Distribution Automation – supports dynamic and growing distribution system loads in a more sustainable way while minimizing power quality issues that often accompany a large-scale transition to solar power.
- Power Electronics – More DER integration.
- Cyber Security—allows DERs to be securely connected, and thus allows better visibility (e.g., smart inverter connections.)
- T&D Communications—enables more grid visibility for DER monitoring and integration.
- ISOP—enables stacked value of DER resources to be integrated more readily into grid planning. Helps, enables more integration at lower cost overall.
- DER Dispatch Tool – DER manageability (system visibility & load control).
- EV Charging – direct enablement of DER and meeting customer desires for more product choice and options.

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Under Business as Usual	With Grid Improvement Plan
Green to Yellow gradually to Red  Aging infrastructure—Urban/Rural divide • Like-for-like replacement of technology will not lower costs or improve reliability • BaU will continue to exacerbate differences between higher growth and metropolitan areas (Wake and Mecklenburg counties expected to grow 24% through 2028) vs. rural and lower growth areas, as opportunities for grid upgrades are minimal in these lower growth areas. • Grid will increasingly have less ability to integrate DERs Ability to Access Net Metered PV—satisfaction driver • The growing adoption of private solar has led to an increasingly complex circuit impact studies, longer interconnection application queues and potentially longer queue times for DER interconnection applicants. As DER hosting capacity becomes more limited and circuits overly congested, indefinite moratoria on interconnections to some circuits may be required. Increased Customer Reliance on Electricity—businesses and consumers growing more reliant on the grid. • More automation and electrical appliances in homes and businesses • Electrification and fuel switching for various applications is increasing (heat-pumps, water heat, gas to electric) • Nationally, electric vehicle use is growing: EVs are expected to make up 3-4% of SC light-duty vehicle stock by 2028.	Gradual Green to Yellow back to Green 

Cost Benefit Analysis (CBA) Overview

ELEMENTS OF ANALYSES

Self-Optimizing Grid

Cost Benefit Analysis Review

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Portfolio Selection Process

PROGRAM CATEGORIZATION

Each program was categorized as *Protect*, *Modernize*, or *Optimize.*

- PROTECT – programs targeted at hardening and defending the grid against physical and cybersecurity attacks
- MODERNIZE – programs that take advantage of rapid technology advancements that improve performance or mitigate risks (i.e., oil to vacuum replacements, modem upgrades, communication infrastructure modernization, electromechanical to digital)
- OPTIMIZE – transformative programs that significantly change the characteristics and performance of the grid. These are CBA informed (e.g., self-optimizing grid, integrated volt/VAR control, transmission line uplift, targeted undergrounding)

FUNDING PRIORITIES

1 FIRST

Protect portfolio was selected and funded first.
The ability withstand the new and everchanging threats to grid must be addressed first.

2 SECOND

Programs that enabled our ability address megatrends.
Generally *Optimize* and *Modernize* programs that address more megatrends were funded higher.
Three programs address all seven megatrends: self-optimizing grid (SOG), integrated volt/VAR control (IVVC), and enterprise communications; These three programs reflect 50% of the entire *Optimize* and *Modernize* portfolios.

3 THIRD

Finally, we assured the portfolio remained balanced by funding those programs that addressed the least amount of megatrends. Even though these programs make up a small portion of the overall portfolio it would be short sighted to eliminate them altogether.

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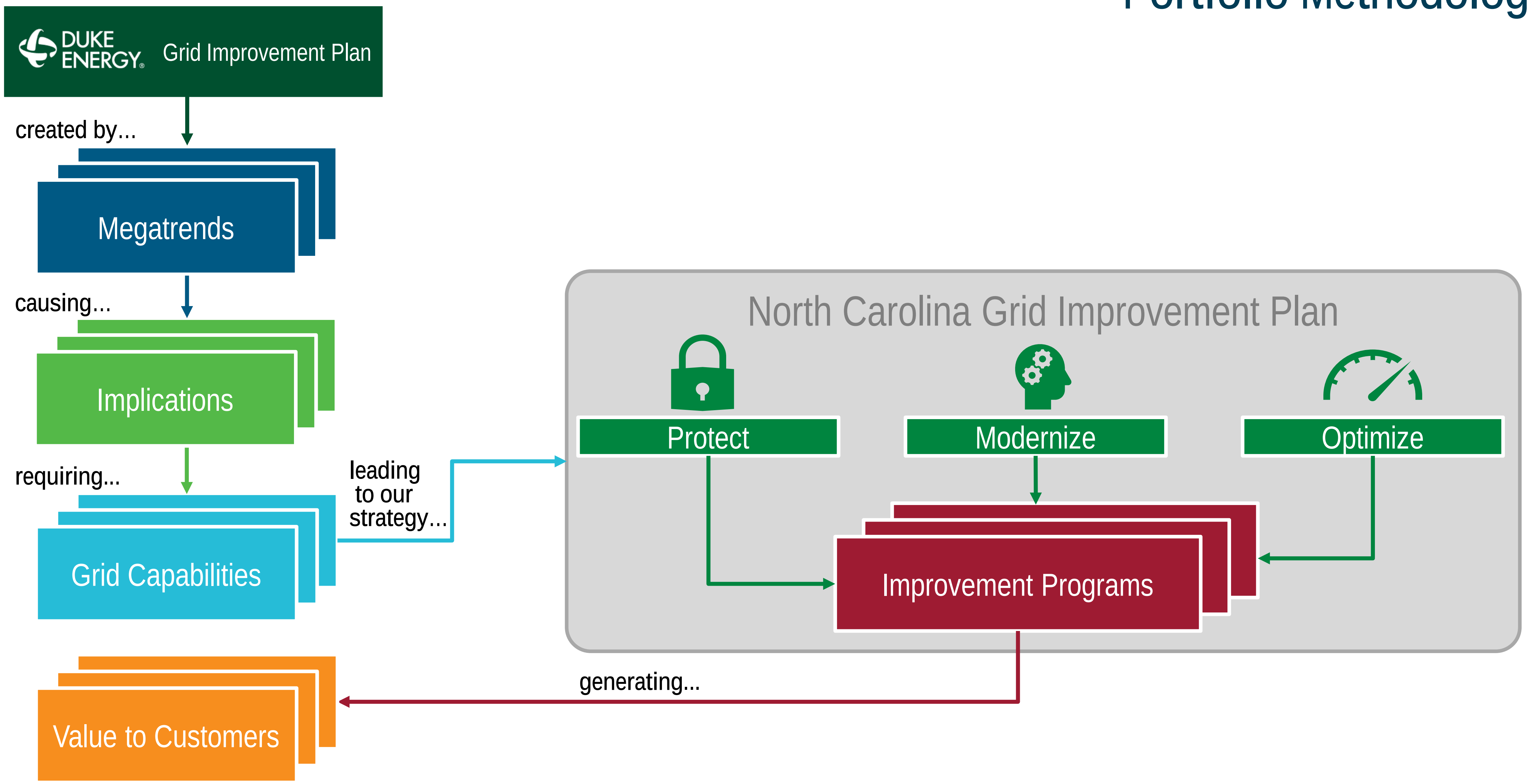
Portfolio Methodology



OPTIMIZE
Optimize the total customer experience

MODERNIZE
Leverage enterprise systems and technology advancements

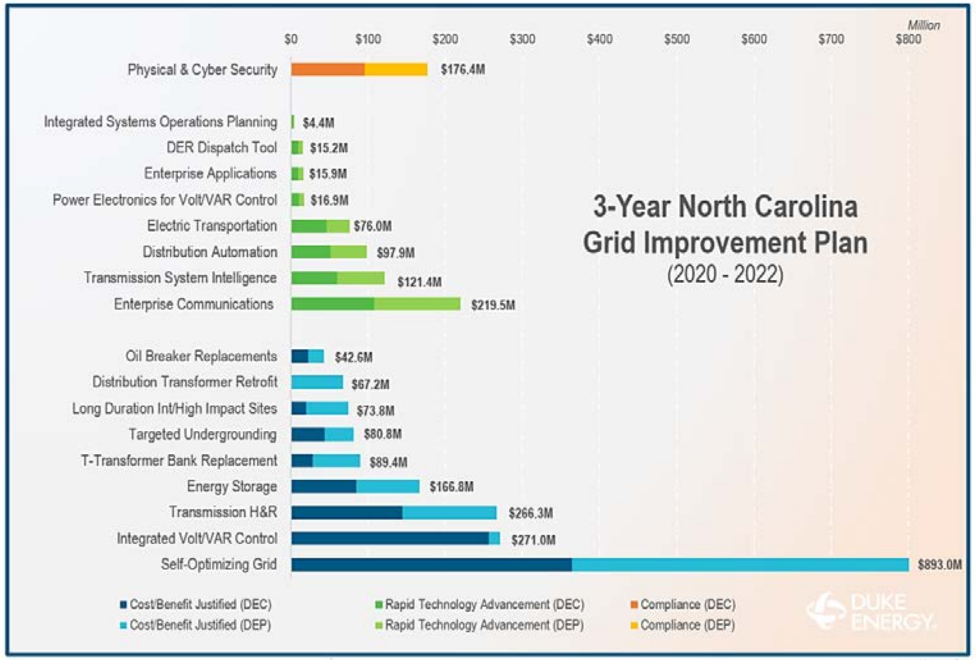
PROTECT
Reduce threats to the grid

Portfolio Methodology

NC Grid Improvement Plan
to begin addressing all 7 megatrends

MEGATRENDS

1. Rise and sophistication of threat of physical and cyber attacks on grid infrastructure
2. Rapid advancement and impacts of technology of renewables and distributed energy resources (DERs)
3. Rapid advancement and new capabilities / functionalities of devices and systems that operate and manage the T&D grids
4. Shifts in customer expectations and use of the grid from generations past
5. Increases in environmental commitments from the international, and customer communities
6. Significant increase in number, severity and impact of weather events
7. Heavily concentrated population and business growth in urban and suburban areas



All Capital $

	GIP PROGRAMS	I - Phys & Cyber Threats	II - Adv Tech (Solar/Battery)	III - Environmental Policy	IV - Weather	V - Grid Improv Tech	VI - Concentrated Growth	VII - Cust Expectation	NC DEC Total	NC DEP Total	NC Total	NC GIP Investment Priority
Protect	Physical & Cyber Security	x	x			x		x	$95.4M	$81.0M	$176.4M	
Optimize	Self-Optimizing Grid	x	x	x	x	x	x	x	$363.4M	$529.5M	$893.0M	1st
	Integrated Volt/VAR Control	x	x	x	x	x	x	x	$256.0M	$15.0M	$271.0M	2nd
	Harden &Resiliency [T]		x	x	x			x	$144.5M	$121.8M	$266.3M	3rd
	Targeted Underground				x			x	$43.1M	$37.7M	$80.8M	
	Energy Storage		x	x	x		x	x	$84.5M	$82.3M	$166.8M	
	Transformer Retrofit [D]				x			x	$0.0M	$67.2M	$67.2M	
	Long Duration Interruptions				x			x	$19.2M	$54.6M	$73.8M	
	Transformer Bank Repl [T]		x	x				x	$27.8M	$61.6M	$89.4M	
	Oil Breaker Rpl [T/D]			x		x		x	$21.8M	$20.8M	$42.6M	
Modernize	Enterprise Communications	x	x	x	x	x	x	x	$107.9M	$111.5M	$219.5M	4th
	Distribution Automation		x	x	x	x		x	$50.8M	$47.1M	$97.9M	
	System Intelligence [T]		x	x		x		x	$59.8M	$61.6M	$121.4M	
	Advanced Enterprise Systems		x	x		x		x	$9.4M	$6.5M	$15.9M	
	ISOP/ADP		x	x		x	x	x	$2.7M	$1.7M	$4.4M	
	DER Dispatch		x	x		x		x	$9.4M	$5.8M	$15.2M	
	Electic Transportation		x	x					$45.6M	$30.4M	$76.0M	
	Power Electronics		x	x		x		x	$10.5M	$6.4M	$16.9M	
											$2694.4M	

Q & A

Workshop Topic Priorities & Recommendations

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NORTH CAROLINA GRID IMPROVEMENT PLAN

PRE-READ PACKET

FOR STAKEHOLDER WORKSHOP

05/16/2019

DUKE ENERGY

INTRODUCTION TO THIS PRE-READ DOCUMENT AND ROCKY MOUNTAIN INSTITUTE'S ROLE AS WORKSHOP FACILITATOR

ABOUT THIS DOCUMENT

- This read-ahead packet includes information about the May 16th workshop, including:
  - Workshop objectives, agenda, and list of attendees
  - The framework by which Duke Energy thinks about Cost Benefit Analysis methodology
- Please familiarize yourself with these materials so that you are prepared for the workshop and ready with any questions.

ROCKY MOUNTAIN INSTITUTE'S ROLE

- Rocky Mountain Institute (RMI) has been contracted by Duke Energy to act as a neutral facilitator for the this workshop.
- RMI is an independent, nonprofit organization with 35 years of experience in analysis and partnerships around electric grid investment and regulatory innovation across the United States and globally.
- RMI's role in this workshop includes:
  - Preparatory interviews with many stakeholders
  - Design of the April 25 pre-workshop webinar
  - Agenda design & facilitation of the workshop
  - Preparation of a post-event summary report

We look forward to seeing you on May 16th !

WORKSHOP OBJECTIVES, AGENDA & PARTICIPANTS

North Carolina University Club | 4200 Hillsborough Street | Raleigh, North Carolina 27606

WORKSHOP OBJECTIVES:

- Provide detailed updates and information to address grid improvement plan questions and priorities stakeholders have identified during the pre-workshop webinar
- Identify and discuss the areas of the plan where stakeholder interest in influencing the final plan is highest and most feasible
- Create and scope opportunities for Duke Energy and stakeholders to commit and work together on areas of the current and future plan

8:30 am	Sign in
9:00 am	Welcome Level setting & Webinar take-aways CBA deep-dives with Duke Energy subject-matter experts
12:15 pm	Lunch
1:15 pm	Cost and cost recovery DER enablement Stakeholder engagement Next steps & check out
4:00pm	Adjourn

Coffee and water will be provided throughout the day. Lunch and afternoon snacks will also be provided.

PARTICIPATING ORGANIZATIONS INCLUDE:

- ABB
- Advanced Energy
- Appalachian Voices
- Bailey & Dixon, LLP
- Clean Air Carolina
- Corning
- Carolina Utility Customers Association
- Environmental Defense Fund
- Marine Corps Installations East
- NC Conservation Network
- NC Housing Coalition
- NC Justice
- NC WARN
- NC Department of Environmental Quality
- NC Sustainable Energy Association
- North Carolina's Electric Cooperatives
- Nicholas Institute - Duke University
- Natural Resources Defense Council
- NCUC – Public Staff
- Southern Environmental Law Center
- Sierra Club
- University of South Carolina
- Varentec

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NORTH CAROLINA GRID IMPROVEMENT PLAN

MEGATRENDS IMPACTING NORTH CAROLINA

FOR STAKEHOLDER WORKSHOP

05/16/2019

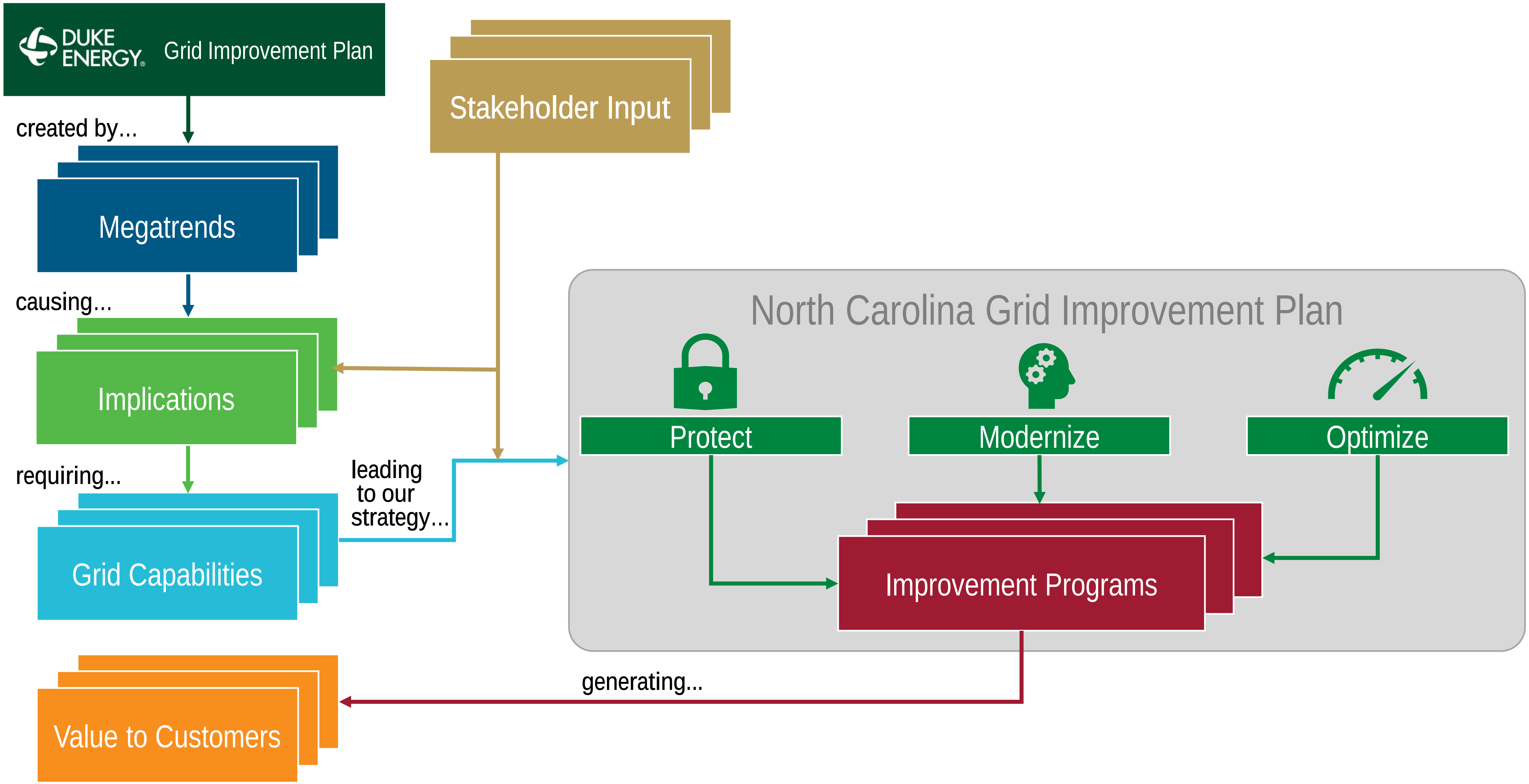
DUKE ENERGY

TRENDS IN OUR SERVICE TERRITORY

In the context of the emerging distributed electric system, Duke Energy has recognized multiple trends and facts that warrant recognition and analysis.

I	Threats to grid infrastructure
II	Technology advancements – Renewables and DER
III	Lower carbon future and other environmental trends
IV	Impact of weather events
V	Grid improvement
VI	Concentrated population growth
VII	Customer expectations

PORTFOLIO METHODOLOGY



PORTFOLIO SELECTION PROCESS

PROGRAM CATEGORIZATION

Each program was categorized as *Protect*, *Modernize*, or *Optimize.*

- PROTECT – programs targeted at hardening and defending the grid against physical and cyber attacks
- MODERNIZE – programs that take advantage of rapid technology advancements that improve performance or mitigate risks (i.e., oil-to-vacuum replacements, modem upgrades, communication infrastructure modernization, electromechanical-to-digital upgrades)
- OPTIMIZE – transformative programs that significantly change the characteristics and performance of the grid. These are cost benefit analysis informed (e.g., self-optimizing grid, integrated volt/VAR control, transmission line uplift, targeted undergrounding)

FUNDING PRIORITIES

1 **FIRST**

Protect portfolio was selected and funded first.
The ability to withstand the new and everchanging threats to the grid must be addressed first.

2 **SECOND**

Programs that enabled our ability to address megatrends.
Generally *Optimize* and *Modernize* programs that address more megatrends were funded higher.
Three programs address all seven megatrends: self-optimizing grid (SOG), integrated volt/VAR control (IVVC), and enterprise communications; These three programs reflect 50% of the entire *Optimize* and *Modernize* portfolios.

3 **THIRD**

Finally, we assured the portfolio remained balanced by funding those programs that addressed the least amount of megatrends. Even though these programs make up a small portion of the overall portfolio it would be short sighted to eliminate them altogether.

OPTIMIZE
Optimize the total customer experience

MODERNIZE
Leverage enterprise systems and technology advancements

PROTECT
Reduce threats to the grid

Portfolio Methodology

NC Grid Improvement Plan
to begin addressing all 7 megatrends

Megatrends

DRAFT

	GIP PROGRAMS	I - Phys & Cyber Threats	II - Adv Tech (Solar/ Batter..	III - Environmental Policy	IV - Weather	V - Grid Improvement Tech	VI - Concentrated Growth	VII - Customer Expectation	NC - DEC Total ($M)	NC - DEP Total ($M)	NC TOTAL ($M)
Protect	Physical & Cyber Security	x	x			x		x	$107.4	$80.7	$188.1
Optimize	Self-Optimizing Grid	x	x	x	x	x	x	x	$433.9	$269.4	$703.3
Optimize	Integrated Volt/VAR Control	x	x	x	x	x	x	x	$161.9	$15.0	$176.9
Optimize	Harden &Resiliency [T]		x	x	x			x	$167.0	$70.0	$237.0
Optimize	Targeted Underground				x			x	$58.6	$54.1	$112.7
Optimize	Energy Storage*		x	x	x		x	x	$80.3	$155.3	$235.6
Optimize	Transformer Retrofit [D]				x			x	$10.3	$109.7	$120.0
Optimize	Long Duration Interruptions				x			x	$12.8	$15.8	$28.6
Optimize	Transformer Bank Repl [T]		x	x				x	$83.0	$169.0	$252.0
Optimize	Oil Breaker Rpl [T/D]			x		x		x	$57.4	$155.0	$212.4
Modernize	Enterprise Communications	x	x	x	x	x	x	x	$149.9	$88.6	$238.5
Modernize	Distribution Automation		x	x	x	x		x	$86.7	$41.9	$128.6
Modernize	System Intelligence [T]		x	x		x		x	$29.0	$3.6	$32.6
Modernize	Enterprise Applications		x	x		x		x	$19.3	$13.1	$32.4
Modernize	ISOP		x	x		x	x	x	$2.7	$1.7	$4.4
Modernize	DER Dispatch		x	x		x		x	$9.4	$5.8	$15.2
Modernize	Electric Transportation*		x	x					$38.2	$25.2	$63.4
Modernize	Power Electronics		x	x		x		x	$0.7	$1.1	$1.8
											$2,484.5

**Note: Energy Storage projects and Electric Transportation have been excluded from all totals*

DUKE ENERGY.

BENEFITS OF IMPROVING THE GRID

Societal

- Lower impact to global environment
- Avoided water impacts
- Avoided land impacts
- Reduced blackouts *(security & well-being)*
- Improved quality of life
- Improved access to data
- Better customer experience

Indirect (to third parties)

- Improved economics for the state
- Increased competitiveness for the state
- Increased employment for the state
- Increased global DER enablement
- Increased transportation electrification enablement

Indirect Value (risk reduction)

- Increased system redundancy
- Improved power quality
- Improved system stability
- Avoided ancillary services
- Improved employee safety
- Reduced chance of environmental incident
- Reduced remediation costs
- Increased public safety

Direct value (captured by customer)

- Avoided business revenue loss
- Avoided equipment damage
- Avoided spoilage
- Avoided ancillary costs *(hotel, generator, lost work)*
- Increased customer-owned DER enablement
- Decreased energy use or use off peak

Direct value (captured by utility)

- Avoided transmission capacity
- Avoided transmission losses
- Avoided distribution capacity
- Avoided distribution losses
- Avoided generation capacity
- Avoided fuel costs
- Deferred capital cost
- Avoided power purchase
- Lower restoration costs
- Theft reduction
- Improved utility operations *(i.e., lower O&M)*
- Avoided CO_2
- SO_2 emission reduction
- NO_X emission reduction
- Hg emission reduction
- Particulate matter emission reduction

SELF OPTIMIZING GRID (SOG) COST-BENEFIT SUMMARY

What success looks like

- 193,000 customer outages reduced annually
- Customers affected by momentary outages reduced through segmentation up to 75% per circuit
- Distribution system hosting capacity for affected circuits increased by approximately 60%

Cost-Benefit Highlights and Insights

- SOG benefits all customer classes
  - 40% of benefits ($451M) are for prevented outages to small commercial and industrial customers
- SOG increases hosting capacity
  - Today, there are approximately 145 MW of private solar installed on the distribution system
  - SOG increases hosting capacity from approximately 496 MW to 835 MW
- Hosting capacity benefit estimates are calculated from capacity, emissions and energy savings
  - Emissions savings: $5/ton CO_2 in 2025 and rising rapidly
  - Capacity savings: $63/kw
  - Energy savings: $14/MWh

Supporting data room document: SOG_DEC-DEP_NC_19-22_vF 5-11-19.xlsx

SELF OPTIMIZING GRID (SOG) COST-BENEFIT SUMMARY

DUKE ENERGY

Net present SOG costs are $678M

- NPV costs include capital and ongoing expenses
- Capital expenses include switch automation, circuit segmentation, capacity additions, software, and connectivity. They total $752M from 2019 through 2022.
- Ongoing expenses include cellular bill, operations support and maintenance; These costs continue for the life of the equipment and are $775K to $1.9M per year
- Timeline for costs: Capital expenses are $106M in 2019, $160M in 2020, $229M in 2021, and $257M in 2022

Net present SOG benefits are $1.1B

- $641M in benefits arise from avoided outages
- $322M in benefits arise from avoided momentary outages
- Additional benefits from DER enablement & peak shaving
- Timeline for benefits: Reliability benefits extend evenly over the 30-year life of the equipment, hosting capacity benefits increase over time with the estimated CO_2 price

Key Notes about Analytic Method

- Key assumption is that energy provides value to customers and that energy is an enabling product for our society. Therefore improvements to power quality have tangible value to customers
- The ICE Calculator, funded by the DOE, is the industry standard for estimating this value
- Valued hosting capacity additions with only energy savings, avoided capacity, and CO2 reductions

Supporting data room document: SOG_DEC-DEP_NC_19-22_vF 5-11-19.xlsx

INTEGRATED VOLT VAR CONTROL (IVVC) COST-BENEFIT SUMMARY

DUKE ENERGY

What success looks like

- Reduce distribution system peak by approximately 1.1%
- Reduce generation fuel costs by approximately 1.0%
- Less peak load on the grid reduces need to build additional peaking generation
- Enable integration of distributed energy resources such as private solar

Cost-Benefit Highlights and Insights

- The largest IVVC benefit is to customers in the form of avoided fuel costs
- Integrated control of capacitor banks provides greater ability to reduce reactive power (VARs), resulting in less apparent load on the system
- More efficient grid due to lower line losses and reduced reactive power
- Lower emissions due to grid efficiencies
- To achieve maximum benefits for voltage optimization, IVVC operating modes include:
  - Year-round demand reduction
  - Emergency demand reduction during peak periods
- Additional non-quantified benefits include:
  - Optimized control of Volt/VAR devices improves the grid's ability to
  - respond to intermittency
  - Automated response to system dynamic reconfigurations (SOG)

Supporting data room document: IVVC_DEC_NC Only_19-23_vF 5-6-19.xlsm

INTEGRATED VOLT VAR CONTROL (IVVC) COST-BENEFIT SUMMARY

Net present IVVC costs are $450M

- NPV costs include capital and ongoing expenses
- Capital expenses include automation of substation level voltage regulation and capacitors, automation of distribution line voltage regulation and capacitors, and integration of the substation and distribution Volt/Var devices into a single control system totaling $344M over 5 years
- Ongoing expenses include cellular costs, operations support, and maintenance. These costs continue for the life of the equipment and are $3.5M to $5.7M per year

Net present IVVC benefits are $544M

- $276M in benefits arise from avoided generation fuel costs
- $84M in benefits arise from avoided generation capacity costs
- $86M in benefits arise from environmental benefits (CO_2, SO_2, NOX)
- Timeline for benefits are measured over a 26-year evaluation period consistent with the Duke Energy IRP

Key Notes about Analytic Method

- Key assumptions include the use of the industry standard PROSYM tool which includes the operating characteristics of power plants, fuel prices, plant efficiencies, and utilization of an hourly dispatch model based on the mix of generation
- Assume an average conservation voltage reduction (CVR) factor of 0.7 on IVVC circuits, which was proven from a DEC IVVC pre-scale deployment

Supporting data room document: IVVC_DEC_NC Only_19-23_vF 5-6-19.xlsm

TRANSMISSION LINE PROJECT COST-BENEFIT SUMMARY
SPINDALE-FAIRVIEW 44-KV LINE REBUILD

DUKE ENERGY

What success looks like

- Fewer customer outages: reduction in System Average Interruption Duration Index (SAIDI)
- Shorter outage duration: reduction in Sustained Outage per Hundred Miles per Year (OHMY-S)

Cost-Benefit Highlights and Insights

- The greatest line outage risks in DEC are attributed to the 44-kV transmission system due to the original design of the system combined with significantly deteriorated infrastructure, which leads to increasing failures
- Transmission 44-kV circuits in DEC are being rebuilt to 100-kV standards to:
  - Harden structure and components against extreme weather (wind, lightning, etc.)
  - Reduce vegetation-related outages
  - Reduce opportunity for animal contact outages
- Newer improved infrastructure will mitigate frequency of access issues related to line locations in rugged mountainous terrain
- Additional non-quantified benefits include:
  - Call out savings from tree removal
  - Less frequent failures from aging assets
  - Fewer pole/tower inspections

Supporting data room document: Trans_Line Projects_DEC_NC-SC_19-20_multiple_vF 5-3-19.xlsx

DUKE ENERGY

Net present costs are $8M

- NPV of costs represent capital expenses
- Capital expenses include asset replacement of tower structures, static lines and overhead conductor
- Timeline for costs deployed is 2019-2022 with the majority in 2021 ($7M) and 2022 ($1M)

Net present benefits are $110M

- NPV of benefits represent customer savings
- Customer savings include transmission reliability benefits from a risk-based model of replacement valuation for tower structures, static lines, and overhead conductor
- Timeline for benefits are measured over a 30-year evaluation period

Key Notes about Analytic Method

- Transmission value models within the Copperleaf C55 analytic tool utilize guided questionnaires and data repositories, including the ICE tool to measure the value of avoided risks, benefits and costs
  - Specific to this cost-benefit analysis, the transmission line risk model values the risk associated with replacing or refurbishing a line asset
  - The reliability risk component values the impact of an outage to a Duke customer
- Candidate locations are selected based on asset condition and current outage observations

Supporting data room document: Trans_Line Projects_DEC_NC-SC_19-20_multiple_vF 5-3-19.xlsx

July 9, 2019

VIA ELECTRONIC FILING

M. Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Report of Third NC Grid Improvement Technical Workshop Docket Nos. E-2, Sub 1142 and E-7, Sub 1146

Dear Ms. Jarvis:

Duke Energy Progress, LLC and Duke Energy Carolinas, LLC held a third Technical Workshop regarding Grid Improvement on May 16, 2019. I enclose the report prepared by Rocky Mountain Institute, the independent organization that facilitated the workshop.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,

Camal O. Robinson

cc: Parties of Record

Enclosure

Summary Report of Duke Energy North Carolina Grid Improvement Stakeholder Workshop

May 16, 2019 – Raleigh, North Carolina

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Executive Summary

Duke Energy hosted a workshop with North Carolina stakeholders on May 16, 2019 to increase stakeholder involvement, input and support for the Grid Improvement Plan (GIP). Duke Energy contracted Rocky Mountain Institute (RMI) as a third party to design the agenda and facilitate the workshop itself. RMI is the author of this summary report.

The workshop convened 41 stakeholders at the North Carolina State University Club in Raleigh; in addition, 11 Duke Energy staff were in attendance.

In this report, RMI summarizes the day's discussions, question and answers, survey results and outcomes. The report's synthesis does not attribute specific comments to specific parties, to respect the ground rules agreed to by participants at the beginning of the meeting. Specifically, participants agreed that what was discussed at the workshop could be shared publicly, but specific comments could not be attributed to individuals without their permission. The Appendix documents survey responses from the workshop.

Duke Energy will use the stakeholder feedback from the workshop and this report to inform the filing of the GIP, which is anticipated to occur later this year, and as a formative element of future stages of planning and stakeholder engagement.

Workshop Objectives

The workshop was organized around three objectives, listed below. RMI defined these objectives in consultation with Duke Energy and other participants interviewed in advance of the event.

1. Provide detailed updates and information to address grid improvement plan questions and priorities stakeholders have identified during the webinar.
2. Identify and discuss the areas of the plan where stakeholder interest in influencing the final plan is highest and most feasible.
3. Create and scope opportunities for Duke and stakeholders to commit and work together on areas of the current and future-plan.

In addition, Duke Energy held a technical webinar on April 25, and used participant polling to identify priority areas of interest for stakeholder discussion. The following topics identified during the webinar formed the basis for discussions and activities in the workshop: cost-benefit analysis, cost and cost recovery, DER enablement thru grid improvement. Workshop discussions and Q&A sessions were focused on:

- Breakout discussions on Cost Benefit Analysis (CBAs) for Self-Optimized Grid (SOG) SOG/Integrated Volt-Var Control (IVVC) and the Transmission Line Rebuild
- Breakout discussions on the goals and metrics for the GIP.
- DER enablement
- Cost and cost recovery
- Future stakeholder engagement and processes. Workshop Insights

Key Takeaways

The following key insights were synthesized by RMI from workshop discussions and from the perspectives expressed by Duke Energy and by stakeholders. These perspectives do not represent consensus of the entire stakeholder group.

- Duke Energy clarified that the Grid Improvement Plan they intend to file later this year represents a set of 'no regrets' investments that are required to build core grid capability to respond to megatrends, and are a technical prerequisite to future grid improvements that will enable the electricity system to meet ambitious stakeholder goals (that were raised in prior stakeholder engagements and in this workshop).
- Duke Energy brought internal subject matter experts to provide greater detail about the CBAs developed for various programs within the plan (IVVC, SOG and Transmission Line Rebuild). The CBA detail included a description of costs, benefits, and an overview of the analytic spreadsheet models used to generate cost-benefit results. These breakout conversations generated significant energy and participation from the broad stakeholder group. Key insights included:
    - Stakeholders generally assessed that Duke Energy has taken a conservative approach in many of the CBA assumptions, which could potentially result in overestimation of costs or underestimation of grid benefits from the investments. For these reasons, stakeholders requested a sensitivity analysis to provide a range for the costs and benefits.
    - Many stakeholders requested more details on assumptions and the methodology of analysis, replacement and upgrade prioritizations and the allocation of environmental benefits (especially with respect to the Transmission Line Rebuild CBA). Stakeholders requested comparable CBA summaries and work sessions for other programs in the GIP, in order to learn more about and provide feedback on these other plan components.
        - Since the workshop, Duke Energy has scheduled a series of webinars to focus on technical details of the other CBA's.
    - Stakeholders asked how carbon reduction benefits were quantified and monetized in the CBA.
        - Duke Energy agreed to provide more information on how carbon reduction benefits might be monetized.
    - Stakeholders seek to understand how investments are related to specific customer classes (especially with respect to transmission line rebuild) and how other cost-recovery efforts (e.g. SB 559 and securitization) impact these efforts.
        - Duke Energy has confirmed that this will be determined by the Utilities Commission, but the Company assumes that the Commission will approve costs allocations in the manner that they have traditionally done so.
- Duke Energy provided an outline of overarching GIP objectives using the framework of "protect, modernize and optimize," as a starting point for discussion about goals and metrics for the GIP.
    - Many stakeholders requested an increase in transparency of the analysis supporting the development of this framework, as well as the allocation of customer and utility benefits described.

  - Many stakeholders were concerned with how and whether the GIP provided equitable benefits to urban and rural customers, as well as to LMI customers. Several stakeholders requested that Duke Energy provide the upfront cost of, monetized benefit from, and quantified end goals of the GIP as they pertain to all customer classes.
    - Duke Energy is willing to work with stakeholders going forward to determine how performance against goals and targets should be reported.
  - Some stakeholders voiced concern that benefits were looked at through a "utility lens" rather than the lens of maximizing benefits to customers. For example, increasing customer participation and penetration #'s can be a benefit to the utility, but stakeholders would instead like to see emphasis on the benefits customers get from aggregated participation.
  - Many stakeholders were interested in collaborating on and influencing detailed and quantified goals and metrics, as well as defining a process for how Duke Energy could be held accountable for performance goals.
  - Beyond the GIP, the discussion raised interest from several stakeholders in contributing to and informing performance-based rate making with Duke Energy.
    - Duke is willing to collaborate with stakeholders to discuss potential changes to the NC regulated utility business model and is interested to hear ideas that stakeholders have.
- Duke Energy provided an overview explaining how the current GIP enables DER adoption and integration. The overview addressed challenges to DER enablement relating to ownership, maintenance, roles and responsibilities, and technical limitations.
  - Many stakeholders want to understand how benefits from DER enablement (through the GIP) can be monetized. Stakeholders voiced that analysis to better understand the technical constraints and monetized benefits from DER enablement should be addressed in the near term.
    - For projects or programs that enable more customer-owned DERs, Duke Energy has not assigned a quantitative value to the enablement of customer-owned DERs through the GIP but instead listed this as a qualitative benefit. Duke Energy acknowledged that the Company's applicable benefit values are understated.
- Duke Energy discussed current legislation (e.g. SB 559) and the impacts of this legislation on the GIP filing through cost and cost recovery.
  - Several stakeholders expressed frustration that Duke Energy was siloing the discussion and regulatory treatment of GIP from that of rate recovery.
  - Stakeholders asked whether there was an opportunity for a deferral and/or support for a separate docket that would address long-term business model reform transformation and grid planning.
    - Duke Energy does not believe that a docketed proceeding is appropriate for this collaboration.
- Participants requested several specific types of stakeholder engagement with Duke Energy on the GIP going forward:
  - Requests for actions before the filing:
    - Several stakeholders felt unclear about the impact from current stakeholder engagement, and if/how stakeholder input has and will be

meaningfully used in the GIP filing. In response, many stakeholders requested to see evidence and/or explicit explanations demonstrating how stakeholder feedback has thus far been incorporated.
    - Stakeholders requested similar engagement and technical discussion with subject matter experts as was conducted with the CBAs at the workshop.
    - Many stakeholders requested future engagement to be focused by stakeholder group (e.g. industrial, LMI, environmental, etc.)
  - Requests for actions after the filing:
    - Several stakeholders were skeptical about how a "clean slate" for stakeholder engagement could be realized after the filing this year, given that the filing will have created a polarized foundation for future stakeholder discussions. What is possible under a "clean slate" scenario? What is not possible?
- Stakeholders asked how a future integrated planning structure (ISOP) could inform future grid modernization/improvement investments. Duke Energy stated that this would be dependent on the outcome of the ISOP planning process
  - Many stakeholders requested increased detail on how the GIP discussions would influence and impact the parallel IRP and regulatory discussions.
  - Several stakeholders felt that the current IRP was outdated and discordant with the goals of the GIP and the state.
  - Several stakeholders voiced a strong interest in having influence on the plan for resource integration.
  - Some stakeholders expressed that they really appreciated the open process for input in the GIP, but that stakeholder processes needed to be revamped across other topics as well, in order to demonstrate genuine interest in stakeholder input.
    - Duke Energy expressed a commitment to consistent, dependable and transparent stakeholder engagement, and encouraged ongoing feedback from stakeholders on how the Company can improve stakeholder engagement activities.
- Stakeholders were generally satisfied with the workshop and its ability to enhance their understanding of the GIP (average survey result of 7/10).
  - First time attendees expressed strong satisfaction with the workshop, while several stakeholders who had attended prior workshops felt that no new information was discussed.
  - Several stakeholders expressed frustration that despite the workshop, they felt they have little-to-no ability to impact the GIP filing this year.
  - Many stakeholders expressed interest in topic focused and/or sector (e.g. C&I customers) focused engagement moving forward and were interested in attending such sessions through webinars, or a Day-At-Duke.
  - Survey results showed stakeholders had strong "willingness to engage in future conversations" with Duke Energy, averaging 9.3/10.

Workshop Agenda and Attendee List

Before the workshop, Duke Energy prepared and sent stakeholders pre-read documents including a CBA slide deck for three programs: SOG, IVVC and Transmission Line Rebuild. In addition, stakeholders were forwarded the April 25th webinar link and the report from the November workshop.

Workshop Agenda

The workshop agenda was designed based on feedback and polling from stakeholders during Duke Energy's April 25 webinar and previous workshops.

Time	Session	Objective Addressed
9:00-9:30	Welcome, Introduction, Review Agenda and Objectives	
9:30-9:50	Grid Improvement Plan Introduction	1
9:50-12:15	Breakout Conversations: (1) IVVC + SOG CBAs, (2) Transmission Line Rebuild CBA, and (3) Goals and Metrics	1, 2
12:15-1:15	Lunch	
1:15-1:50	Cost and Cost Recovery	1, 2
1:50-3:10	Opportunities and Future Stakeholder Engagement	2, 3
3:10-3:40	DER Enablement	1, 2
3:40-3:55	Question and Answer	1, 2, 3
3:55-4:00	Closing Remarks and Adjournment	

Attendee List

The workshop convened 41 stakeholders at the North Carolina State University Club in Raleigh; four RMI staff facilitated the workshop, and 11 Duke Energy staff were in attendance.

Last Name	First Name	Organization
Adair	Sarah	Duke Energy
Ayers	Chris	Public Staff - NCUC
Bayless	Charles	NCEMC
Bowman	Kendal	Duke Energy
Bragg	Scott	Evergreen Packaging
Brooks	Jeff	Duke Energy
Brookshire	Daniel	NC Sustainable Energy Association
Brown	Justin	Duke Energy
Burnett	John	Duke Energy
Chan	Coreina	RMI
Coppola	Barbara	Duke Energy
Culley	Thad	Vote Solar
Delli-Gatti	Dionne	Environmental Defense Fund
DeMay	Stephen	Duke Energy
Edge	Chris	Duke Energy
Finnigan	John	Environmental Defense Fund
Fitch	Tyler	Vote Solar
Floyd	Jack	Public Staff - NCUC
Fondacci	Luis	NCEMCS
Garvin	Martin	Duke Energy
Gill	Harry	Duke Energy
Hahn	Steven	AARP

Hicks	Warren	Bailey & Dixon, LLP
Holder	Nathan	Advanced Energy
Howard	Preston	NCMA
Hughes	Mike	Duke Energy
Johnson	Peter	Ernst & Young
Keener	Mark	Duke Energy
Klein	PJ	Corning
Kruse	Susan	Duke Energy
Ledford	Peter	NC Sustainable Energy Association
Lillis	Genevieve	RMI
Luhr	Nadia	Public Staff - NCUC
Maley	Dan	Duke Energy
Martinez	Luis	NRDC
Masemore	Sushma	NCDEQ
McAward	Ryan	Duke Energy
McIlmoil	Rory	Appalachian Voices
Meyer	Jason	RMI
Musilek	Jim	NCEMC
Neal	David	SELC
O'Donnell	Kevin	CUCA
Oliver	Jay	Duke Energy
Palmer	Miko	Duke Energy
Poger	Lisa	Duke Energy
Redd	Cameron	SELC
Ripley	Alford	NC Justice
Robertson	Sally	NC WARN
Rogers	David	Sierra Club
Sandler	Simon	NCSU
Schull	Matt	Electricities
Scott	Will	NC Conservation Network
Sides	Jim	MCIEAST
Sipes	Robert	Duke Energy
Smith	Benjamin	NC Sustainable Energy Association
Thompson	Gudrun	SELC
Trathen	Marcus	Brooks Pierce
VonNessen	Joey	University of South Carolina
Walker	Faucette	Nutrien
Weiss	Jennifer	Nicholas Institute - Duke University
Williamson	David	Public Staff - NCUC
Williamson	Tommy	Public Staff - NCUC
Wills	Kristen	NC WARN
Zanchi	Roberto	RMI

Workshop Discussion and Outcomes

During the level setting introduction, Duke Energy identified the Grid Improvement Plan (GIP) as a foundational plan intended to address the seven megatrends that affect both customers and industry. The 18 initiatives within the GIP were previously prioritized by Duke Energy based on the number of megatrends addressed by each program. Duke Energy removed programs from the original Power Forward filing that were deemed to not address these megatrends. Duke Energy stated their intention was to use stakeholder input from this workshop to further prioritize programs within the GIP.

Cost Benefit Analysis

Duke Energy brought internal subject matter experts to provide greater detail about the CBAs developed for various programs within the plan (IVVC, SOG and Transmission Line Rebuild). The CBA detail included a description of costs, benefits, and an overview of the analytic spreadsheet models used to generate cost-benefit results. These breakout conversations generated significant energy and participation from the broad stakeholder group.

Question and Answer *Cost/Benefit Analyses – General* Below are a list of general Cost/Benefit Analyses questions posed by stakeholders throughout the day. Some of the answers below were provided by Duke Energy during the workshop and others were detailed by Duke Energy post-workshop.	
What does Duke Energy mean by a “Clean Slate” given the GIP and current priorities that have been identified?	**The grid improvement plan currently under consideration is a first step in preparing Duke Energy’s grid for how the electric power grid will operate in the future. It is a foundational no-regrets step that can be built upon with future iterations. While it appears likely that future iterations will be required, Duke Energy has not begun planning for what those will be. Clean slate refers to the opportunity to begin planning for future iterations now together with interested stakeholders.**
Can Duke Energy work with stakeholders to estimate a range of benefits and costs for each program through sensitivity analyses to help address current conservative estimates?	**Where it is feasible and there is clear value/benefit for sensitivity analyses we’re willing to consider doing them. We would want to discuss the need and anticipated value/benefit with stakeholders first due to the significant time and resource commitments that would likely be required.**
Can Duke Energy work with stakeholders to define difficult-to-quantify value drivers?	**Identifying and quantifying value drivers associated with many of the grid improvement programs and projects is critically important as we progress down the path of grid modernization and improvement. Duke Energy is very interested in working with stakeholders on this important issue.**
How does Duke Energy evaluate the cost/benefit of DER’s?	**For projects or programs that enable more customer-owned DERs, the Company did not assign a quantitative value to this enablement but instead listed this as a qualitative benefit. Therefore, to the extent that private DER enablement can be measured quantitatively, the Company’s applicable benefit values are understated.**
What alternative CBA’s were reviewed but rejected?	**As Duke Energy has considered different programs and projects to be included in the GIP, we have taken a gated approach to making those decisions/choices. The first gate that is considered is megatrends. If a project/program addresses**

	few/none of the megatrends it is rejected from consideration. The second gate is stakeholder feedback, and some projects and programs were eliminated based on stakeholder input. Finally, once projects/programs pass through the first two gates, a formal CBA is performed, where applicable, and if projects/programs do not pass that analysis, they are rejected for inclusion.
Is Duke able to explore the value to rural customers through separate CBA's? Is there a metric for ensuring the benefits are equitable for urban and rural customers? (e.g. SOG and IVVC)	**Some programs in the GIP benefit all customers regardless of where they are located, and location-specific CBAs for those programs are not needed. At the project level, such as targeted undergrounding and battery storage, those projects are location specific, so CBAs for those projects have already accounted for customer locations.**
Can Duke Energy calculate benefits that result from synergies across programs (not just within)? How do you ensure that projected benefits aren't double counted across CBA's?	**Cost-benefit analyses (CBA) are created at a project and program level. Each CBA identifies distinct value to customers and are often aimed at different segments of the grid. As an example, self-optimizing grid is typically targeted at the circuit backbone to assist in reliability improvements and to create 2-way power flow capability, targeted undergrounding (TUG) targets problem areas on branch line circuits and customer premises, transformer retro-fit targets specific local service level equipment, transmission investments are aimed at substation and bulk power infrastructure. Additionally, a portfolio level cost benefit analysis will show a summary of the net benefits divided by the net costs from CBA and IMPLAN analyses from those projects and programs in the optimize part of the GIP framework. While Duke Energy has not calculated benefits that result from synergies across programs, additional benefits could be demonstrated.**
Can Duke Energy provide more information on how carbon reduction benefits might be monetized?	**Yes**
The IVVC has 3-line items on savings, what would be an example of that metric for which you have certainty 5 years from now?	**These are tied to the assumptions of the IRP and specifically tracked on lower system voltages and system average voltage decrease. The assumption is that because it is lower, the CVR function would be calculated into fuel savings.**
Will there be a lag on GIP benefits since the new customer information system will not be in services until 2021/2022? Would timing of the new system have any impact on whether GIP costs	**Benefits of the GIP to customers will begin accruing immediately. Implementation of the new customer information system could potentially provide greater capabilities and functionality that would enable more benefit/value for customers over and above what is accounted for in the current plan CBA's.**

are in base rates vs. being shown as a fixed charge on customer bills?	
What is in store for Phase 2 (following the GIP) in terms of tools or techniques for CBA long term?	**The Company appreciates any feedback that stakeholders may have on how to use new tools or techniques for cost/benefit analysis going forward.**

Question and Answer *Cost/Benefit Analyses – AMI* Below are a list of Cost/Benefit Analyses (AMI) questions posed by stakeholders throughout the day. Some of the answers below were provided by Duke Energy during the workshop and others were detailed by Duke Energy post-workshop.	
Are the benefits indicating operational value or customer value? Are the benefits for customers such as increased control and convenience suggesting TOU and that customers have information that allows them to control off peak home times? What is the actual cost or the monetized benefit?	**AMI is a foundational investment that provides both operational and customer benefits. The AMI cost benefit analyses for DEC and DEP quantified operational benefits such as performing connects and disconnects remotely, reading the meter remotely, and the ability to interrogate a meter remotely to see if a location has power. In each of these cases, there is an operational benefit by not sending a truck to the premise. The Company also noted the qualitative benefits for increased customer convenience, control, and transparency by providing access to interval and remote data from smart meters. Additionally, customers benefit from programs such as Pick Your Due Date, Usage Alerts, and time-of-use rate offerings. DEC recently filed multiple pilots in its North Carolina jurisdiction to assess potential dynamic pricing rate opportunities.**
How does Duke Energy measure for customer benefits and customer engagement (for example whether peak demand has been reduced and if customers have shifted their usage as opposed to how many connections there have been)?	**Duke Energy measures customer benefits and customer engagement in its customer programs enabled by AMI through tracking program participation and conducting customer feedback surveys. The Company plans to use customer engagement in its evaluation of the DEC dynamic pricing pilots when considering permanent rate offerings to all customers that incent load shifting during times with higher cost of service.**
Why is preventing a high bill surprise listed as a benefit?	**Customers who want to have more real-time transparency into their energy use value this as a qualitative benefit.**
Would the business case for AMI that accounts for benefits attributable to rate design and peak-shaving be a worthy	**AMI is a foundational investment that enables further programs, such as rate design and peak-shaving, which are best evaluated independently. Duke Energy has taken the first step**

inclusion in the rate case? Are we missing an opportunity to highlight real benefits to the customer program?	**in its evaluation of dynamic price rate designs with the nine pilot designs proposed by DEC to begin in October 2019. These pilots were developed after stakeholder discussions and seek to evaluate customer acceptance and response to different rate structures.**

Breakout Conversation: SOG/IVVC

In the SOG/IVVC deep dive, Duke Energy explained the methodology and assumptions behind the cost-benefit analysis for the IVVC and SOG programs and answered stakeholders' questions. In a case of IVVC deployment, Duke Energy identified a 1.1% demand reduction and 1% aggregated fuel savings to customers. In this methodology, Duke Energy applied fuel costs to a base case scenario and compared this to IVVC deployment over 26 years.

In addition, Duke Energy briefly discussed the reliability benefits associated with SOG, referencing that the program is expected to reduce 193,000 outages annually. When layered alongside IVVC, Duke Energy highlighted a 1% voltage reduction. Stakeholders asked questions about the incremental assumptions, depreciation schedules, the prioritization of deployment, fuel costs and environmental benefits. The assumptions behind the estimates in the SOG and IVVC CBAs were agreed to be conservative by both Duke Energy staff and stakeholders.

Breakout Conversation: Transmission Line Rebuild

Duke Energy discussed transmission line rebuild under three scenarios: a full system rebuild including disposal, a partial rebuild that could involve a section of line, or a replacement rebuild focused on replacing communications system or underground fiber. Duke Energy outlined three key considerations and evaluations for a transmission line rebuild including reliability (ensuring delivery, quality and a reduction in outages to customers), resilience (ensuring the system is able to return to full functionality following an event, and hardening (ensuring the system is prepared to withstand a possible event).

Participants at the transmission break-out table voiced initial questions relating to customer classes, the cost-benefit of resiliency, methodology, and the allocation of this transmission rebuild outside of business-as-usual maintenance. Participants asked technical questions focused on pole replacement plans, replacement prioritization, rebuild timelines, voltage level reporting, ‘soft costs’, substation upgrades, voltage class, capacity and right-of-ways.

Question and Answer *Transmission Line Rebuild* Below are a list of Transmission Line Rebuild questions posed by stakeholders in the breakout group. Some of the answers below were provided by Duke Energy during the workshop and others were detailed by Duke Energy post-workshop.	
What parts of Duke Energy’s transmission system currently have rebuild programs underway or	**DEP is targeting discrete Hardening & Resiliency improvements on the 115kV and 230kV voltage class; these projects not only replaces end of life**

planned? Provide the following details: • DEP and/or DEC • Voltage class • Total line miles for each voltage class, line miles already rebuilt, and total line miles targeted for rebuild. For rebuild program(s) already underway, what year were those programs started? For those not started, if any, when do we plan to start?	**static/ground wire which could result in a line outage upon failure, they also expand the communication capability by installing fiber optic ground wire, enabling high speed relaying and remote monitoring and control functions. The 3-year plan includes 78.5 miles of static replacements. Under these projects wood poles are replaced with steel poles than can withstand much higher wind loading and are not susceptible to ground rot or pest infestation.** **DEC is rebuilding targeted 44kV transmission lines to 100kV specifications. The projects in the 3yr plan add up to approximately 80 miles, targeted at the highest risk lines from a customer outage perspective.** **DEC has approximately 1600 44kV transmission line segments totaling 2,815 miles.** **DEP has approximately 360 transmission line segments (115kV and 230kV) totaling 5,954 miles. Line rebuild projects are not new to Duke Energy Transmission although the pace and scale of these projects needs to be accelerated to meet enhanced customer reliability expectations. It is estimated that <5% of circuit mileage has been rebuilt.**
For line rebuild projects, how is a decision made to include in base work vs. GIP work?	**GIP work including line rebuilds does not fall under the maintain category, it falls under the optimize category. Both DEC and DEP have existing capital improvement line rebuild projects underway, although this is on a very limited basis. Through Grid Improvement, the pace and scale of these projects will be greatly accelerated in order to deliver reliability benefits to the customer in a shorter time period. Specifically excluded from GIP work, and classified as base maintain work, is time based wood pole circuit inspections to identify degraded poles in need of replacement, and the corrective replacements of those poles on a one-by-one basis.**
Do you widen the R/W's during line rebuilds?	**In some instances, Duke may reclaim ROW to the full legal easement width during line rebuild projects. It would be the rare exception to obtain additional ROW for a line rebuild. In DEC, rebuilding 44kV lines to the 100kV standard results in taller structures, elevating conductor above more vegetation, which reduces outage impacts from trees falling onto the lines from outside the ROW. This same benefit is achieved in some DEP projects through conversion from H-frame**

	horizontal framing to mono-pole phase over phase framing.
What is the plan to replace wood poles? How is pole replacement work coordinated with line rebuild projects?	**All planned line projects will always include changing wood poles to steel or concrete, designed to the latest codes and standards.**
How are line rebuild projects prioritized? Voltage? Radial feed? Other?	**Duke Energy uses Copperleaf C55 to model the criticality of the line, the health of a line, and rank these with a score. We use the ICE (Interruption Cost Estimator) tool to determine the reduction in customer outages that would be achieved with the rebuild.** **The probability of failure of an asset is determined using a Condition vs. Probability of Failure curve, which is calculated as a logistic regression that is specific to either Substation or Line assets. These curves are based on historical industry data specific to the asset category. The asset Condition is assigned a numerical value ranging from 10 (new) to 0 (imminent failure). Condition 3 represents end of life, typically assumed to be 40 years for substation and line assets. Condition is determined by a Subject Matter Experts based on a combination of field inspections, maintenance and test history, and age. The condition score is plotted on the regression curve and a probability of failure is determined. Probability will range from 0-30% for substation assets, and 0-1% for line assets (per individual structure, then multiplied out per number of spans). Frequency of failure is further determined by multiplying Probability of Failure times the number of asset being assessed in each grouping. Additional prioritization weighting factors include voltage level, the redundancy value (radial or networked), lost redundancy exposure, environmental risk, safety risk, and financial risk.**
Will rebuilding lines to higher voltage class increase capacity of the lines?	**Although the 44kV rebuild are built to 100kV standards, Duke Energy is not energizing to 100kV. The conductors and insulation is sized for this but the substation equipment would need to be replaced in order to energize to this level. The line rebuilds would facilitate future opportunities to increase voltage level though, as system demand warranted.** **The driver for the work and benefits from the higher voltage class is a reduction in customer outages; less vegetation impacts will be experienced due to taller structures, less animal impacts will be experienced due to larger phase**

	spacing, and fewer equipment failures will be experienced due to installation of modern equipment.
What line voltage levels are subject to NERC oversight/compliance standards?	**Bulk Electric System (BES) components are subject to the Operating & Planning Standards published by NERC, BES components are generally 100kV and above with some specific Inclusions and Exclusions**
CBA Questions • Are additional kwh sales due to increased line reliability considered for hardening projects? • In the ICE tool, are costs normalized to account for regional differences?	**Duke Energy is using 'hard numbers' in outage costs and is not including revenue changes or improvements to safety for public and workers. Duke Energy conducts internal prioritization around the 'soft costs' and benefits.** **The ICE meta-dataset includes 34 different datasets from surveys fielded by 10 different utility companies between 1989 and 2012. Once the datasets from the various studies were combined, a two-part regression model was used to estimate customer damage functions that can be generally applied to calculate customer interruption costs per event by season, time of day, day of week, and geographical regions within the U.S. for industrial, commercial, and residential customers.**
How do tracking/reporting requirements for GIP work compare to those for base work?	**All Transmission projects falling under the Grid Improvement Plan are tracked in one of four categories: System Intelligence, Line Hardening & Resiliency, Substation Hardening & Resiliency, or Security. This facilitates financial tracking and reporting specific to GIP work.**
How are substation upgrades considered in this CBA?	**Substation Hardening & Resiliency projects including breaker and transformer bank replacements are cost/benefit analyzed using a proactive versus reactive evaluation. Under the proactive model, assets are replaced prior to failure which eliminates extended customer outages. Under a reactive model, the asset fails and result in an unplanned customer outage of extended duration. The ICE tool is used to determine the customer cost of the outage, which is then compared against the cost of replacing the asset proactively.**

Breakout Conversation: Goals and Metrics

Duke Energy provided a framework for goals and metrics centered on the three categories of the GIP: protect, modernize and optimize. Duke Energy referred to goals and metrics outlined in the pre-reading deck during this discussion.

- Protect: Duke Energy highlighted the difficulty in reporting metrics under the protect category but identified a zero-incidence rate as the ultimate goal.
- Modernize: Cost effectiveness was described as the most useful metric, in addition to functionality and creeping obsolesce.
- Optimize: the "hard metrics" of cost and benefits were described to apply at the program and project level with anticipated benefit to customer classes.

Participants at the goals and metrics break-out table voiced initial questions relating to impact and data transparency specific to customer classes, accountability in terms of tracking and evaluation, DER metrics, cost/ expense allocation and performance-based rate making. Following the introduction to goals and metrics lead by Duke Energy, participants asked questions relating to the allocation and equitable distribution of customer benefits and cost savings, accountability, customers costs and rate impacts, customer information, monitoring the equitable allocation of benefits across rural and urban environments, as well as the utility of the future and specifically, performance-based rate making.

Question and Answer *Metrics and Reporting* Below are a list of Metrics and Reporting questions posed by stakeholders in the breakout group. Some of the answers below were provided by Duke Energy during the workshop and others were detailed by Duke Energy post-workshop.	
If the GIP is approved, how is Duke Energy currently planning to report performance against the plan?	**Duke Energy would report under 3 categories:** **a. Operations: Are we doing the work we said we would do within the time, manner and scope set out?** **b. Cost-effectiveness: Are we within budget and managing unexpected circumstances with agility.** **c. Benefits: Are expected benefits being achieved..**
Is Duke Energy willing to work with stakeholders to determine what the goals/targets for the GIP should be?	**Yes**
Is Duke Energy willing to work with stakeholders to determine how performance against goals/targets should be reported?	**Yes**
Is Duke Energy willing to be held accountable for achieving goals/targets associated with the GIP?	**Yes, the Company is already held accountable for the goals it plans to achieve with the GIP when it files them with the Commission and the Company would have to justify any material variances from those goals.**

Is Duke Energy willing to work with stakeholders to determine the incentives/penalties related to goal/target achievement?	**The Company is held accountable for the goals it plans to achieve with the GIP when it files them with the Commission and the Company would have to justify any material variances from those goals. The Company does not need any incentives to meet the goals it plans to achieve. The Commission already has penalties at its disposal if the Company does not meet its goals without justification for not meeting them.**

Deep Dive Conversation: DER Enablement

Duke Energy discussed DER enablement (specifically privately-owned rooftop solar and pilot storage projects) in the context of the current GIP, as well as in future phases of Grid Improvement. Duke Energy highlighted the challenge associated with enabling technologies that would support DER implementation. In addition, Duke Energy discussed the challenges associated with enabling business processes to support the technology including ownership, maintenance and responsibility.

In the case of SOG, Duke Energy discussed reconducting smaller wires to increase capacity, and the circuit-by-circuit methodology adopted to calculate this increase in potential hosting capacity. In addition, Duke Energy outlined net metering projections for capacity using anticipated rooftop solar installations over the next 20-30 years. Duke Energy outlined the opportunity to leverage SOG to ensure costs associated with increasing wire size are not passed on as incremental costs to customers as solar is added to the system in the absence of available capacity.

Participants asked questions relating to net metering, temporal data and the visibility of solar installations, and the monetization of DER benefits. Stakeholders expressed interest in taking advantage of DER opportunities soon and as such, requested further transparency on any technical restraints that would prevent DER enablement in the near term.

Deep Dive Conversation: Cost and Cost Recovery

Duke Energy provided an overview on current legislation and implications for filing if the current legislation were to pass. Duke Energy is planning to file rate cases in 2019 for DEC and DEP. In those rate cases, Duke Energy will file the GIP as outlined in the data room, pre-reads and the CBA. In the filing, Duke will ask the commission for a deferral of costs over 3 years with a weighted average cost of capital return. If senate bill 559 becomes law as it is written today, Duke Energy put up relevant provisions that could be used for the GIP. Duke Energy discussed the three options (retroactive, real-time, and forward-looking) for a multi-year GIP with participants.

Scenarios:

1. Retroactive: deferral mechanism with proceeding on back end
2. Real Time: annual review and move into rates
3. Forward-Looking: Projections ongoing with true-up on back end. May not be feasible given existing statutes.

At the completion, Duke Energy proposed a multi-year rate plan (MYRP) for the filing of the base rate case. This plan would include filing of the rate case with a 3-year deferral regardless of SB 559, with the addition of an alternative MYRP for the Commission to consider.

Participants asked questions relating to the language within SB 559, the potential for a deferral option, and support for a docket that would separate long term business model reform transformation and grid planning. Stakeholders seemed particularly concerned about whether this would be filed within a rate case, or as a separate docket that would separate long term business model reform from grid planning.

Question and Answer *Rate Impacts/Cost Recovery Regulation* Below are a list of Rate Impacts/Cost Recovery/Regulation questions posed by stakeholders throughout the day. Some of the answers below were provided by Duke Energy during the workshop and others were detailed by Duke Energy post-workshop.	
For the GIP, how will costs be allocated across customer classes?	**This will be determined by the Utilities Commission, but the Company assumes that the Commission will approve costs allocations in the manner that they have traditionally done so.**
To assist customers with planning, what are Duke Energy's estimates for rate increases in the coming years?	**Specific rate increases or decreases in the coming years are not known at this time.**
Can Duke Energy quantify the financial burden to low income customers from the GIP? How will projected direct financial benefits to these customers offset these costs?	**Since the GIP is cost-benefit justified at the total portfolio level, all customers, including low-income customers, are expected to save money once the GIP is implemented.**
Can Duke Energy provide data/evidence of how LMI customers can/will curb usage to get benefits from the GIP?	**Yes. Depending on the project/program there will be both direct and secondary benefits that LMI customers will experience. Reduced usage is just one of those benefits.**
If storm securitization legislation passes, what impact would it have on transmission line rebuilds or any other GIP program or project, when line segments or other infrastructure intended to be upgraded are rebuilt during storm restoration?	**Storm securitization would have no impact.**
Does Duke Energy agree that the issues of recovery mechanisms and the GIP should be addressed together? If so, how does Duke	**Yes. Duke plans to address cost recovery in its request for the approval of the Grid Improvement Plan.**

propose that this be accomplished?	
Is Duke Energy willing to work with stakeholders on reform of NC's regulated electric utility business model? Would you be willing to establish a separate docket for this purpose?	**Duke is willing to collaborate with stakeholders to discuss potential changes to the NC regulated utility business model and is interested to hear ideas that stakeholders have. Duke does not believe that a docketed proceeding is appropriate for this collaboration.**

Deep Dive Conversation: Stakeholder Engagement

Participants took part in a real-time survey and identified on a spectrum in response to the statement *"a blue-sky stakeholder workshop is required to kick-off and chart any path going forward after this initial filing."* Participants self-sorted along a spectrum from 'Completely agree' to "Completely disagree.' Approximately 40% of the participants stood at the end of "completely agree;" the remainder were spread relatively uniformly between this group and "Completely Disagree."

To explain why participants had positions themselves where they were standing:

- Some who stood at the end of Completely Disagree end of the spectrum commented that "Duke Energy's stakeholder engagement is ingenuine" given it was a requirement of the Commission and given the original Power Forward plan was filed without stakeholder engagement. In addition, one participant stated that "this is the third workshop and we still have not seen feedback incorporated."
- Participants positioned close to the middle of the spectrum suggested success was conditional based on several variables. Some stakeholders stated that "this is the first workshop in which we all have a stake, " that it "is self-evident if you want to buy-in, you need to engage early," and that "blue sky is valuable but once you have a filing the posture changes and litigation makes it difficult to have blue sky."
- At the Completely Agree end of the spectrum, a participant commented that "the open discussion [upfront] is valuable because once you have an initial filing, there's going to be litigation."

In general discussion following the survey, some stakeholders agreed that a blue-sky stakeholder workshop is essential in creating a unified path forward, but that it should form the initial step of planning to build consensus. Other stakeholders felt that in general, given the change in posture that occurs following a filing, blue sky engagement is better planned for after filings have occurred.

Plus - "What has been working for you"

Participants responded to a 'plus' and 'delta' prompt, reflecting their experience of the current stakeholder engagement process. Under the 'plus' category, participants responded to the prompt "what has been working for you?" Participant responses are reflected below:

- Stakeholders appreciated the sharing of data and increased level of detail provided in the data room for CBAs and the Grid Improvement Plan
- Stakeholders positively acknowledged the use of webinars, pre-reads, needs assessments and workshops to set priorities and shape the agenda for the workshop.

- Many stakeholders acknowledged and appreciated the in-person contact, listening and involvement of senior Duke Energy management and their willingness to respond to questions and incorporate thoughts and feedback.
- While some participants felt that stakeholder groups were not represented at the workshop, others expressed appreciation for the large and diverse stakeholder workshop.
- Stakeholders generally appreciated the use of a third-party facilitator and asked for one going forward for stakeholder engagements.

Delta - “What changes would you like to suggest”

Under the ‘delta’ category, participants responded to the prompt, "what changes would you like to suggest?" Participant responses are reflected below:

- While stakeholders appreciate and acknowledge the workshops as being a useful process for engagement, unexpected activities such as SB 559 continue to erode trust.
- Many stakeholders felt that ongoing litigation made it difficult to have ‘blue sky’ conversations focused on topics such as decarbonization.
- Many stakeholders stated that this process should have been undertaken prior to the filing and before design of the GIP, in order for there to be collaboration on the principles of the draft plan and end goals (and consequently buy-in)
- Stakeholders were generally interested in seeing evidence and/or explicit explanations demonstrating how their thoughts and feedback from the stakeholder engagement process were being incorporated.
- There is a request from many stakeholders for engagement to be consistent, ongoing and transparent rather than ad-hoc
- Stakeholders need to understand the benefits and implications of the GIP on customer classes with specific reference to rate making and rate recovery.
- There was an interest from stakeholders in understanding in depth other stakeholder group perspectives through short presentations that would provide space for specific recommendations from sectors (e.g. business, renewables, low-income and environmental)
- Some stakeholders felt their feedback was not being incorporated or informing the GIP filing later this year.
- While stakeholders generally appreciated the process, some stakeholders felt that surveys would be a valuable addition to the process to make the most of stakeholder time.
- One stakeholder suggested holding future stakeholder engagements outside of Raleigh.

Question and Answer *Stakeholder Engagement* Below are a list of Stakeholder Engagement questions posed by stakeholders throughout the day. Some of the answers below were provided by Duke Energy during the workshop and others were detailed by Duke Energy post-workshop.	
Can Duke Energy create a process for consistent, dependable, transparent and timely stakeholder engagement (e.g. meetings, surveys)	**Yes, we are working hard to create such a process. We have begun using different tools to engage stakeholders more effectively and efficiently. We are also constantly asking stakeholders for feedback on how we can improve stakeholder engagement activities. Duke Energy is committed to making stakeholder engagement a normal way of conducting business in NC.**
Is Duke Energy willing to hold technical sessions, before making any rate case filings, where their technical experts can meet/talk with stakeholder/3rd party technical experts? Can these sessions be sector specific where appropriate?	**Yes, we have already scheduled a series of webinars to focus on technical details of the CBA's.**
In stakeholder forums (workshops, webinars, etc.) can Duke Energy provide time for stakeholder groups to share sector specific views/recommendations (e.g. business, renewables, low-income and environmental)?	**Yes, stakeholder engagement should provide stakeholders with an opportunity to clearly express their views and the analysis they use to support them, if they are relevant to the topic at hand and presented in a constructive and efficient way. Duke Energy is committed to listening to what stakeholders have to say.**
Does the data room have the functionality to ask/answer questions?	**No. We will investigate ways that this might be accomplished and notify stakeholders if/when we have something in place.**
Can Duke Energy include everything in the data room that they intend to file in the future rate case?	**Yes, with respect to the Grid Improvement Plan, and the Company has already posted much of what it will file in the data room already.**

Suggested topics for future stakeholder engagement

Stakeholders proposed the following suggestions for future stakeholder enggement in grid modernization efforts.

- ISOP/IRP/IDP
    - Background on what ISOP is and how would it integrate into the GIP
    - Integration of ISOP into current IRP for DER and central plan generation.
- Rate design
- EV: rate design, charging infrastructure and pricing structures
- Performance-based rate making (not led by Duke Energy)

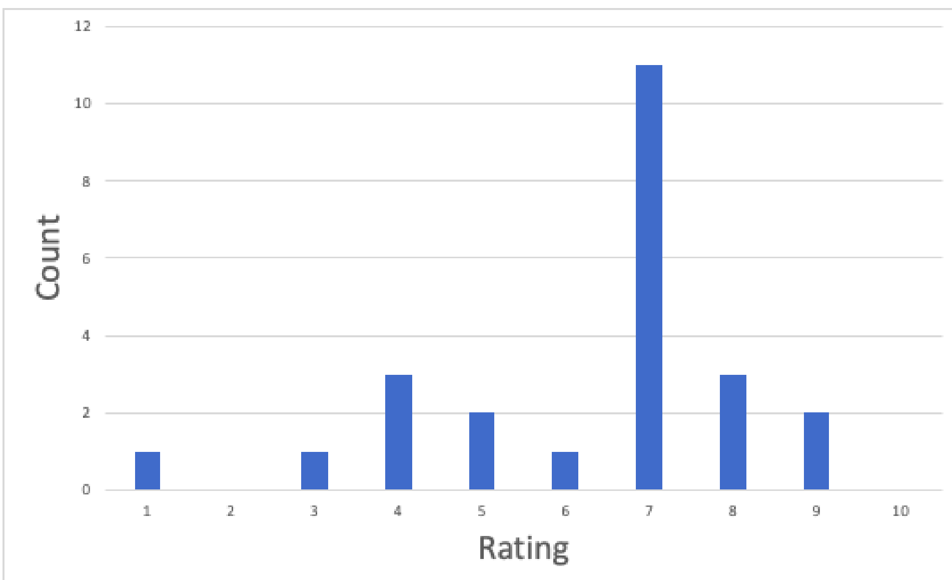
- Low-Income energy burdens
- Utility of the future
- Development of Distribution Operators
- Just transition planning for coal plant communities
- Big picture consensus on targets/goals so we can plan how to get there from here
- Data Room including the ability to ask questions and show answers
- Stakeholder groups present views
- Net metering
- Energy storage implementation and protocols
- SB 559

Appendix: Survey Results

There were 41 stakeholders present at the North Carolina Grid Improvement Plan workshop. The end-of-workshop survey was received by 24 of 41 participants, a survey completion rate of 59%. The survey results indicate that participants generally appreciated the chance to provide feedback to Duke Energy and the in-depth analysis provided by the CBAs. Overall satisfaction from participants with the workshop experience was relatively high with an average across Questions 1-5 of 7/10. All respondents showed a willingness to continue engagement in future conversations about grid improvement with Duke Energy.

1. On a scale of 1-10, how well did this workshop enhance your understanding of the proposed grid improvement investments?

Participants answered with an average of 6.3/10. Respondents demonstrated uncertainty in understanding how these investments constituted grid improvement as compared to a traditional utility investment and how the GIP would impact rates. Several participants felt that “nothing new was discussed” or that “they knew many of the details already” while others felt it was an “effective session as a first-time attendee”. Most respondents commented that the CBAs were helpful though some further stated they would like to look more deeply into the CBAs.



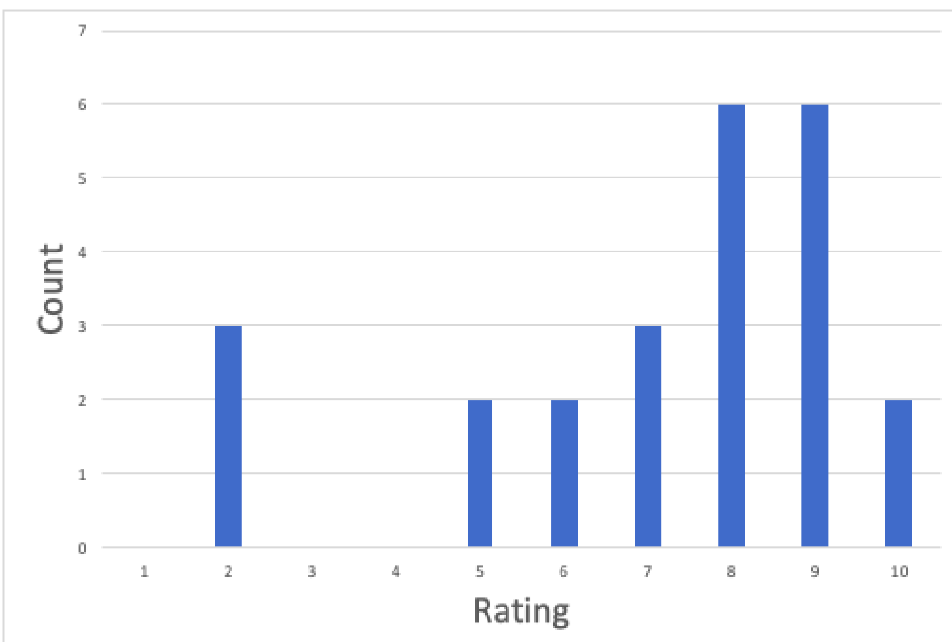
Comments:

- What makes some of these investments ‘grid improvement’ versus traditional utility investment?
- Effective session as a first time attendee
- Didn’t really get any new info on the plan. RMI spent a lot of time getting feedback on process and future feedback.
- Nothing new was discussed

- I knew many of the details already. Good presentation.
- During breakouts, certain respondents dominated discussion and would have appreciated more moderation. Seems clear that some topics were omitted
- No rate increase numbers. We need cost increase values.
- Would like more in depth "dives" into the CBA for each project
- Anticipated looking more deeply into the CBAs
- Still need more detail on scope of the entire plan and parts
- It was informative in many ways especially given I am a 1st time attendee
- CBAs
- CBA on IVVC was helpful
- For individual topics covered

2. On a scale of 1-10, how satisfied are you with the opportunity to provide feedback and dialogue with Duke Energy at this workshop?

Participants answered with an average of 7.1/10, however demonstrated divergence in responses. Some participants commented that the session provided lots of opportunities to give feedback, an opportunity to share and appreciation for the face-to-face engagement, while others felt that they "would like more dialogue with Duke and less process related feedback." One respondent commented that "Duke has ignored stakeholder feedback," and "a rate case is the wrong venue to discuss."



Comments:

- Conversations were cut short many times
- Would like more dialogue with Duke and less process related feedback
- I felt this was more exploratory as a workshop than collaborative

- Duke representatives at tables made frank conversations more difficult
- Disheartening to learn that stakeholder feedback wasn't included in phase 1 of grid modernization and that Duke has ignored stakeholder feedback that a rate case is the wrong venue to discuss.
- We were given the opportunity to share
- Access to the data room and access to Duke resources
- Glad for face-to-face with key folks
- Lots of opportunities to give feedback

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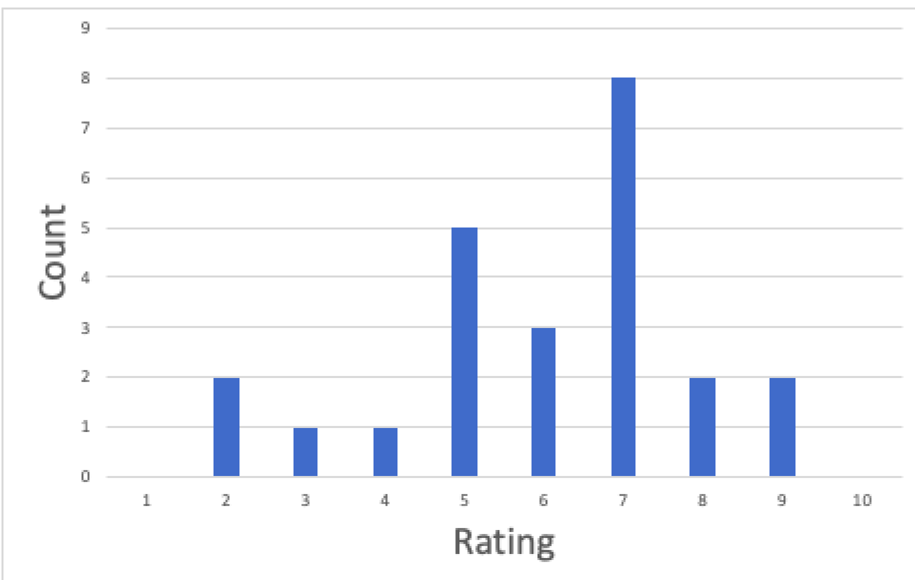
3. On a scale of 1-10, how well did this workshop enhance your understanding about other stakeholders' points of view?

Participants answered with an average of 6/10. While participants overall suggested that the workshop provided a good opportunity to "hear from other folks," there were several comments that participants would like the opportunity to give and receive sector perspectives, or "to hear from other stakeholder groups." There was a suggestion that some customer views were not represented in the workshop.

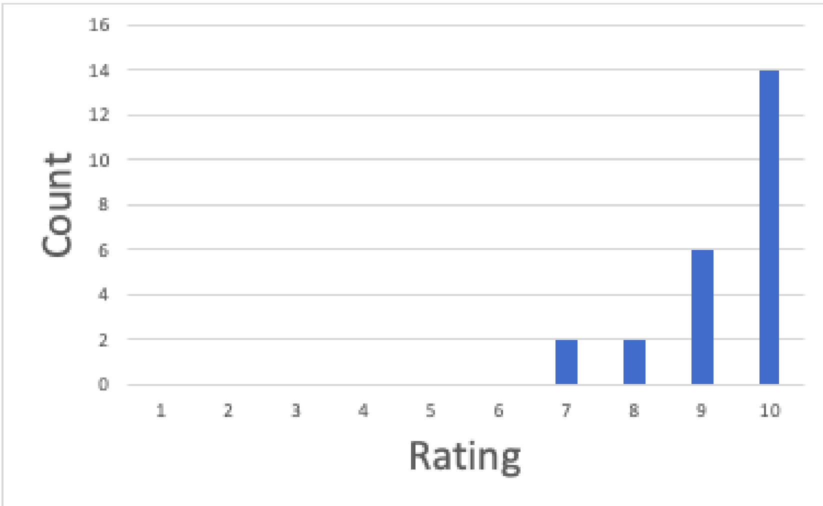


Comments:

- I'd be interested to hear more from other stakeholder groups like industrial customers, tech customers etc.
- Having more diverse stakeholders is a good thing
- Would be good to give stakeholder groups a chance to give sector perspectives
- Lots of perspectives, maybe sub-contractors of different stakeholders with GIP then come back
- Would like to make sure all customer views are represented at future workshops.
- I know most positions already
- Great to hear from other folks and public staff

4. On a scale of 1-10, how willing are you to engage in potential future conversations with Duke Energy around grid improvement?

Participants answered with an average of 9.3/10. There was strong consensus that "more communication is necessary," and an interest from participants in continuing the dialogue. One participant indicated that they would be more willing to engage "in a case where my feedback is incorporated."

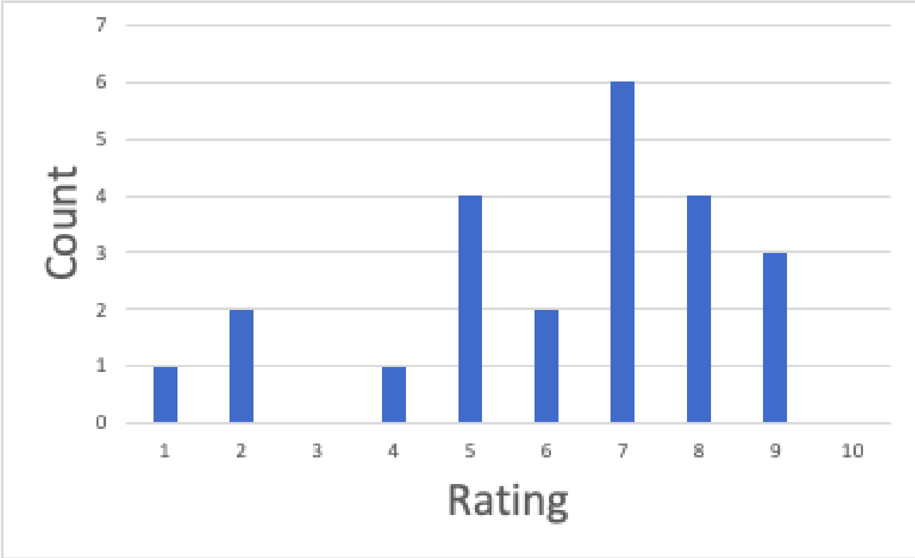


Comments:

- It is a necessity
- More communication is necessary, not just with industrial customers
- Only if you provide cost numbers
- But I'd love to do this in a case where my feedback is incorporated
- Always interested in continuing dialogue

5. On a scale of 1-10, how effective was this workshop in providing a foundation for new kinds of conversation and collaboration going forward?

Participants answered with an average of 6.0/10. Many of the comments from participants voiced frustrations with the level commitment from Duke Energy in incorporating feedback and implementing collaborative ideas into the plan. Several comments include: "it's the same conversation as [the] last two but nothing has come of those," "not sure on the opportunity for changes to this plan since it is being characterized as almost ready to file," and that there are "hang ups on what Duke is already moving forward with."



Comments:

- Seems like RMI spent a lot of time in this area
- More details on cost benefit analysis
- Not sure the opportunity for changes to this place since it is being characterized as almost ready to file.
- It's the same conversation as last two, but nothing has come of those.
- Actual commitment from Duke would be key
- Mixed: "Clean slate" moving forward but hang-ups on what Duke is already moving forward with.
- Frustrating to hear that this plan is already fully baked
- Need to see the workshops actually incorporate collaboration and then result in implementing collaborative ideas.

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6. What did you find most useful about this day? Why?

Participants generally felt that the detail provided in the CBAs deep dive breakouts was the most useful activity for the day. Many stakeholders further appreciated the face-to-face contact with stakeholders and senior staff at Duke Energy, in accordance with the "open process and willingness to listen," as well as "learn from past mistakes and actions."

Comments:

- Didn't find much useful
- More details on cost benefit analysis
- Additional information and hand-outs
- Face-to-face discussion with key staff and stakeholders
- Discussion with Duke senior management and other stakeholders
- Learning Duke's plan to include grid mod in the rate case applications
- Cost recovery, admission on follow-on phases

- Networking with duke and other stakeholders
- Offline conversations with Duke personnel
- Breaking out into tables to discuss CBAs (SOG and IVVC)
- Duke did a good job of being open to hear options for stakeholders
- Deep dive into IVVC and SOG CBA but only because previous explanation was lacking previously
- Deep Dives
- Interaction with other stakeholders
- Stakeholder views
- SME Analysis (CBA). The starting point with #s – need 10 year forecast
- Breakout sessions and deep dives
- Open process, willingness to listen. Questions still remains whether the stakeholders were heard and what action will be taken/revised
- Willingness to engage participants
- IVVC CBA
- CBA discussion
- Duke is putting forward an effort hear from stakeholders and learning from past mistakes and actions

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7. *What information is still needed for the Data Room? What other changes or improvements are needed?*

Many participants were "not sure," had "not looked at it yet," and required more time to "assess the site for an answer." Several participants requested customer specific information to reflect customer classes, while others requested "more granular data on CBAs and prioritization decision making."

Comments:

- Not sure yet
- Not looked at it yet
- Need to assess the site for an answer
- Don't know yet
- Have not had time to look at it
- Still need to access – Duke have not been very forthcoming in getting me the access.
- Need to see what has been updated in the past 2 weeks
- Anything Duke plans to file in the future rate case
- 10-year rate forecast
- Customer specific information for large customers. Cost per customer class.
- Ability to ask questions and provide feedback
- Full CBA information. More granular data on prioritization decision making
- Some insight into what could be proposed in future phases of this.
- CBA on each part of GIP with summary of each

8. Would you be interested in attending a "Day-at-Duke?" If so, how would you want to use the time?

All respondents were interested in attending a Day-at-Duke. The responses on how to use the time were significantly fragmented. Many participants commented more analysis on the CBAs and meetings with specific departments within the company would be valuable. Many felt that customer, technology (transmission and/or storage) or program specific segmented meetings would be most useful. Several other participants showed interest in "Duke Energy's larger goals," or the "long term generation plans."

Comments:

- Yes - presentations/discussions/problem solving
- Yes - More CBA analysis and review all parts of Grid Mod
- Yes - Perhaps a meeting/session with AARP executive council
- Yes – would like a walk-through of how these costs will be divided up amongst different customer classes.
- Yes – CBA analysis (open up excel)
- Yes already have
- Yes but not sure what that would mean
- Yes - Meetings with departments to understand them well
- Yes - Technology-specific or program-specific issues
- Yes - With other industrial customers
- Yes - Focused subject matter or customer segment meetings
- Yes - Transmission upgrades (44kV in DEC)(230kV in DEP)
- Yes – mostly with CBA, amount and available interval load data
- Yes – see DER pilot
- CBA work through in excel
- Yes – talk about energy storage, add developers potentially
- Yes
- Yes – discussions about next steps after this phase and discussions about long term generation plans
- Maybe specific webinars instead of full day at Duke Energy
- Know Duke Energy's larger goals.
- Not sure

9. Would you be interested in attending another webinar? If so, how would you want to use the time?

Participants were generally interested in attending future webinars. Again, many respondents suggested deeper dives into the CBAs or other CBAs not discussed in the workshop. In addition, several participants suggested segmenting webinars for stakeholder groups to present ideas and to discuss the future involvement of stakeholder segments in grid modernization and

ISOP. Others indicated an interest in further discussing DER Enablement and energy efficiency.

Comments:

- Yes
- Yes ASAP, more time before filing is better
- Maybe
- Pipeline
- Yes, deeper dives into CBA for top priority projects
- Yes, go into other CBAs
- Yes on CBAs
- Mostly would attend
- Yes, exploratory on SOG CBA and collaborative on rate design, storage, ISOP, etc.
- Yes - setting principles and goals for GIP
- Only if new material
- With other industrial customers (e.g. segmented)
- Yes, to present ideas for future stakeholder involvement in Grid Mod and ISOP
- Yes, send a pre-survey to get input ahead of time
- Yes, discuss DERs behind the meter DSM, and EE opportunities

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Report of Third NC Grid Improvement Technical Workshop, in Docket No. E-7, Sub 1146 and E-2, Sub 1142, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the following parties:

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This the 9th day of July, 2019.

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BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2018-319-E

In the Matter of:	)	
	)	**REBUTTAL TESTIMONY OF**
Application of Duke Energy Carolinas, LLC	)	**JAY W. OLIVER**
for Adjustments in Electric Rate Schedules	)	**FOR DUKE ENERGY**
and Tariffs and Request for Accounting Order	)	**CAROLINAS, LLC**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND CURRENT POSITION.

A. My name is Jay W. Oliver. My business address is 400 South Tryon Street, Charlotte, North Carolina. I am employed by Duke Energy Business Services, LLC ("DEBS") as General Manager, Grid Solutions Engineering and Technology. DEBS provides various administrative and other services to Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I did.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to portions of the testimony filed by Mr. Anthony Sandonata, witness on behalf of the South Carolina Office of Regulatory Staff ("ORS") regarding the need for a separate proceeding to review and analyze the Company's proposed Grid Improvement Plan; and to respond to South Carolina Solar Business Alliance, Inc. witnesses Mr. Hamilton Davis and Mr. Chris Villarreal regarding their assessments of the Company's Grid Improvement Plan.

III. REBUTTAL TESTIMONY

Q. WHAT IS THE SCOPE OF YOUR REBUTTAL TESTIMONY?

A. In my rebuttal, I respond to several issues regarding the Company's proposed Grid Improvement Plan. I do not respond to the testimony of Kevin O'Donnell, filed on behalf of the South Carolina Energy Users Committee, given the fact that Mr. O'Donnell does not address any substantive issues regarding the proposed Grid Improvement Plan ("Plan") for South Carolina but instead offers his personal reflections on past and outdated issues in North Carolina along with his unsupported speculation about hypothetical expenditures in the future that are not sponsored by the Company.

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. In reviewing the testimony of the Office of Regulatory Staff ("ORS") and other parties who discussed the Company's proposed Grid Improvement Plan for South Carolina, I identified three central themes that were present across those testimonies. I have arranged my rebuttal testimony to respond to those three themes. At the outset, however, I would note that no intervenor contested the seven major grid improvement megatrends I identified in my testimony, nor did anyone dispute the fact that these megatrends are having and will continue to have a meaningful impact on South Carolina. In fact, several intervenors[1] affirmatively agreed with these megatrends and commended the Company for properly identifying and expounding on them. Therefore, it seems that no party seriously

[1] Witness Sandonato, on behalf of the Office of Regulatory Staff, page 11; Witness Villareal, on behalf of the South Carolina Solar Business Alliance, page 9; Witness Davis, on behalf of the South Carolina Solar Business Alliance, page 14.

contests the fact that South Carolina has a real and present need to address each of these seven megatrends with grid improvement interventions.[2]

Q. WHAT ARE THE THREE THEMES THAT YOU IDENTIFIED IN YOUR REVIEW OF ORS AND INTERVENOR TESTIMONY?

A. With the established fact that South Carolina needs some form of grid improvement to address these impending megatrends, ORS and several intervenors raise three principal issues: (1) a separate proceeding is needed to review the Company's proposed Grid Improvement Plan; (2) more information is needed regarding the benefits that the proposed Grid Improvement Plan will provide; and (3) the proposed Grid Improvement Plan's design; namely that the Company's proposed Plan did not provide detail as to what the Company will do in the years that follow the Plan to continue with grid improvement efforts.

Q. WILL YOU PLEASE SUMMARIZE YOUR RESPONSES TO THESE THREE ISSUES?

A. Yes. The ORS and other parties[3] take issue with the Company seeking an advance prudence review of the Grid Improvement Plan and they lament the extensive amount of information that the Company has filed to support the Plan even though a report that ORS cites in its testimony speaks to the benefits of an advance prudence review. This aversion to an advance review is confusing to me because all of these same stakeholders, including ORS, have consistently stated that they

[2] One intervenor witness questioned how the programs and projects in the Grid Improvement Plan aligned with the megatrends that the Company identified. In Exhibit 2, pages 2 through 24, to my direct testimony, I provided a detailed analysis of how the Plan would impact these megatrends over the next ten years. In Exhibit 5 to this testimony, I provide an additional narrative and source document that was used to create that exhibit in my direct testimony.

[3] Witness Sandonato, on behalf of the Office of Regulatory Staff, page 5; Witness Davis, on behalf of the South Carolina Solar Business Alliance, page 13; Witness Tillman, on behalf of Walmart, page 14.

want to be engaged and provide input to the Plan in advance of the Company taking action on it. These same parties, in the two previous stakeholder workshops that the Company conducted in South Carolina, have also requested that the Company provide an extraordinary amount of detail and supporting documentation to support the Plan and now they cry foul because we have done so. Stated simply, parties cannot fairly ask to be engaged and provide advance input on this Plan and then refuse to provide input claiming that an advance review of the Plan is somehow unfair.

Next, and oddly contrary to their argument that advance reviews are unfair to customers, the ORS and other parties[4] state that they need more detailed information on the expected benefits that the Grid Improvement Plan will provide so they can review them in advance of any approvals. Notably, neither ORS nor any other party ever asked for additional detail on Plan benefits throughout the discovery process. Nonetheless, I have provided extensive additional detail to support the benefits expected from the Plan in my exhibits to this rebuttal testimony.

Finally, the SC Solar Business Alliance raises several questions as to why the Plan was not designed to solve issues that they appear to have with South Carolina's renewable energy polices and interconnection procedures. I explain that these issues are being addressed in other forums and that the Company's Plan is designed to address the megatrends that no party disputes are impacting South Carolina right now.

[4] Witness Sandonato, on behalf of the Office of Regulatory Staff, page 5; Witness Davis, on behalf of the South Carolina Solar Business Alliance, page 13; Witness Tillman, on behalf of Walmart, page 14.

Q. WILL YOU PLEASE NOW SPEAK TO THE FIRST MAJOR ISSUE RAISED BY PARTIES IN THIS PROCEEDING REGARDING THE COMPANY'S PROPOSED RATE STEP UPS FOR RECOVERY OF GRID IMPROVEMENT PLAN COSTS?

A. Yes. The ORS first states that it did not have sufficient time to properly review and analyze the Company's proposed plan within this matter. Based on this allegation, the ORS suggests that the proposed Grid Improvement Plan be reviewed in a separate proceeding outside of this one. The issue of whether ORS has had proper time in this proceeding to review the Grid Improvement Plan and whether they have diligently attempted to do so is beyond the scope of my expertise, but however the Grid Improvement Plan is reviewed, there must be some mechanism in place to avoid the debilitating effects that regulatory lag has on deploying a grid improvement plan for the State.

Q. WHAT DO YOU MEAN WHEN YOU SAY THAT REGULATORY LAG HAS A DEBILITATING EFFECT ON DEPLOYING A GRID IMPROVEMENT PLAN?

A. It is important for stakeholders to recognize that just like any other company that has to manage a monthly budget and pay bills, a regulated utility has a limited amount of funds to pay a given amount of expenses. Unlike unregulated companies that can simply raise the price of their products as they see fit to cover incremental expenses, the Company's income stream to pay for projects needed to maintain a base level of service to customers in South Carolina is set by the Commission in base rate proceedings like this one and once that revenue stream is set, the Company cannot increase it without filing another base rate case[5]. This means that every day, the Company must decide what projects and programs it will deploy and which ones that it will not, which, in turn, means that programs and projects must compete against each other for funding priority. Thus, in order to fund incremental work like the Grid Improvement Plan, the Company must borrow money between its rate cases to pay for new work, and borrowing money naturally comes with a cost.

In instances where the Company has large, centralized projects that take longer to complete (such as building a new power plant), regulatory rules allow the utility to apply a carrying charge to the funds that the Company has to borrow and pay interest on to complete this work as a principle of fundamental fairness. In other words, one cannot reasonably expect the company to borrow money and pay interest on that money on behalf of customers to build a power plant that will serve those customers and then not pay the Company back for the money it borrowed plus the interest it had to pay on it. However, the same regulatory rules that apply to these large, time-intensive projects do not apply to smaller and quickly-installed programs and projects like those included in the Grid Improvement Plan. To ensure that utilities are not discouraged from these smaller programs that deliver benefits more quickly to customers, regulators often enact measures to avoid the problem of regulatory lag such as rider recovery, rate adjustment step ups, or deferral accounting treatment with returns for such projects.

[5] In South Carolina, I understand that there are limitations as to how often a company may file rate cases which exacerbates the issue of regulatory lag.

Q. ARE YOU SUGGESTING THAT THE COMPANY WILL NOT PERFORM ANY OF THE WORK IN THE GRID IMPROVEMENT PLAN IF THE COMMISSION DOES NOT APPROVE SOME METHOD TO AVOID REGULATORY LAG ON THOSE PROJECTS?

A. No, but without a reasonable method to address regulatory lag, the work in the Grid Improvement Plan would have to be sub-optimized, delayed, diminished in scope and effectiveness, and potentially not done at all in some instances given the fact that the Company cannot reasonably be expected to obtain incremental funding for these projects at a substantial loss. In such a situation, the Company would have to try and perform small pieces of the Grid Improvement Plan over a much longer period of time within its existing revenues, delaying important benefits and potentially essential improvements for customers.

Q. WHAT OTHER ISSUES DID PARTIES HAVE WITH THE COMPANY'S PROPOSED GRID IMPROVEMENT RATE STEP UPS?

A. ORS and other parties[6] contend that it is unfair and unwise for the Company to obtain an advance prudence review of the Grid Improvement Plan. They also contend that the Company's proposed method of recovery unfairly disconnects customers from the O&M costs savings that they will enjoy under the Plan.

Q. WILL YOU PLEASE RESPOND TO THE FIRST ISSUE REGARDING PRUDENCE REVIEWS?

A. Yes. The ORS and other parties are correct that the Company has requested that the Commission review the proposed three-year Grid Improvement Plan for

[6] Witness Sandonato, on behalf of the Office of Regulatory Staff, page 5; Witness Davis, on behalf of the South Carolina Solar Business Alliance, page 13; Witness Tillman, on behalf of Walmart, page 14.

prudence in this proceeding but they are incorrect to suggest that this request is unfair or ill-advised[7]. First, these parties argue that the Company should just do whatever grid improvement work that it wants to do and then come back to stakeholders after this work is done to see if everyone agrees that the work was prudent. While this is the traditional way that the Company conducts its base operations work, it is not the way that stakeholders have previously requested that the Grid Improvement Plan be reviewed through our engagement process. In fact, the Company has uniformly heard that stakeholders want to be engaged and have their input heard in developing and deploying a grid improvement plan for the State and the Company has accommodated this request by conducting stakeholder workshops prior to filing the Grid Improvement Plan in this proceeding. Further, rather than just filing information on historical grid improvement work that the Company has performed and asking for an after-the-fact review of that work, the Company, pursuant to what stakeholders have asked for, filed an unprecedented amount of detail outlining the work that the Company plans to do to improve the grid in South Carolina over the next three years so that those same stakeholders can be engaged and weigh in on that plan as many of them have done. This is exactly the process that ORS cites to in Witness Sandonato's testimony on page 8, lines 16-17 wherein he cites a report from GridLab (page 14). Therefore, it is confusing to me why any party in this proceeding has suggested that an advance prudence review

[7] It is important to note that the Company is not requesting that the Commission approve the prudence of the execution of the Grid Improvement Plan and the ultimate costs and benefits that will flow from the Plan, and the Company agrees that that the prudence of those issues should be determined in future proceedings. Instead, the Company has asked the stakeholders in this proceeding to address any issues of prudence with the substance and content of the Grid Improvement Plan which is an entirely reasonable request prior to the Company deploying the Plan.

of the substance of the Grid Improvement Plan is unwarranted when they have all uniformly asked to review and provide input on the Plan before the Company deploys it.[8]

Q. WHAT IS YOUR RESPONSE TO THE ALLEGATION THAT THE COMPANY'S PROPOSED METHOD OF COST RECOVERY DISCONNECTS OPERATIONS AND MAINTENANCE COSTS SAVINGS FROM THE RECOVERY OF GRID IMPROVEMENT COSTS?

A. Some parties[9] alleged that it would be unfair for the Company to recover the ongoing costs of the Grid Improvement Plan in a rate step-up mechanism without also capturing the ongoing O&M savings that the Company anticipates it will achieve with the Plan. If the Commission approves the Company's proposed grid rate step ups, the Company does not have any issue with those annual step ups being offset by the amount of O&M costs that the Company anticipates saving during those same periods, subject to true up for both costs and savings. If the Commission does not approve the proposed grid step ups but instead approves deferral accounting treatment for Grid Improvement Plan costs with a carrying charge, then the issue of O&M savings being disconnected with cost recovery is no longer relevant because both grid improvement costs and grid improvement savings would be considered at the same time in a future base rate proceeding.

[8] A testament to the wisdom of advance prudence reviews for grid improvement initiatives is found in this very case where all the parties were able to express their questions and concerns and have those issues addressed prior to the Company deploying its proposed Plan.
[9] Witness Tillman, on behalf of Walmart, at page 23.

Q. WHAT IS THE NEXT MAJOR THEME THAT YOU OBSERVED IN ORS AND INTERVENOR TESTIMONY?

A. All the parties who spoke to the Company's Grid Improvement Plan stated that they would like to see more detailed information regarding the benefits that the Plan is expected to provide customers. Many parties also stated that they would like to see quantifiable targets for grid improvement to measure the ongoing performance of the Grid Improvement Plan. Finally, ORS, by citation to a report authored by a non-party, suggests that the costs of the Company's proposed Plan may be understated by fifty percent which, in turn, would negatively impact the Company's cost/benefit analyses.

Q. WILL YOU PLEASE RESPOND TO THE FIRST ISSUE REGARDING MORE DETAIL ON THE BENEFITS THAT THE GRID IMPROVEMENT PLAN WILL PROVIDE SOUTH CAROLINA CUSTOMERS?

A. Yes. Several parties stated that the Company needs to specifically state whether the proposed Grid Improvement Plan and its associated method of cost recovery will avoid future rate cases; eventually lower rates; provide better service; provide better reliability; and enable customer options such as rooftop solar, electric vehicles, and energy conservation. The short answer is "yes," and the proposed Grid Improvement Plan can help do all of these things for South Carolina customers as detailed in my pre-filed direct testimony and as further explained here.

In Exhibit 1 to this testimony, I have included cost/benefit analyses and the underlying data sources and work sheets for all the programs and projects in the "Optimize" portion of the Company's proposed Plan which encompasses more than sixty percent of the costs for the Plan.[10] Exhibit 2 to this testimony shows that the programs in the Company's plan designed to optimize the South Carolina grid have a positive net present value ratio of 4.2. This means that for every dollar spent on these programs and projects, South Carolina customers should receive a payback of $4.20 in primary benefits. Also in Exhibit 2 of this testimony, I have included a total primary benefit analysis of the entire Grid Improvement Plan portfolio, and this document shows that all the costs in the plan (costs to protect, modernize, and optimize the South Carolina Grid) have a positive total net present value benefit ratio of 3.0. This means that for every dollar spent on the total Plan, South Carolina customers should receive a payback of $3.00 in primary benefits. In Exhibit 3 to this testimony, I have included an analysis of the primary and secondary benefits that the Grid Improvement Plan should provide to customers and residents of South Carolina, and this document shows that all the costs in the plan (costs to protect, modernize, and optimize the South Carolina Grid) have a positive total net present value secondary benefit ratio of 1.7. This means that for every dollar spent on the total Plan, South Carolina customers and residents should receive an additional payback of $1.70 in secondary benefits. Finally, as reflected in Exhibit 3, if both the primary and secondary benefits of the Grid Improvement Plan are considered together, the total Grid Improvement Plan should provide South Carolina customers and residents a positive total net present value of 4.7, meaning that every dollar spent on the Plan should provide a payback of $4.70.

[10]Cost/benefit analysis is only appropriate for certain types of costs in a grid improvement plan and other costs (such as physical and cyber security and core system operating systems) should only be reviewed to ensure that they have been selected and deployed in reasonable manner. The GridLab report for South Carolina that ORS cites to in its testimony recognizes this fact on page 22 of their report.

Q. IN YOUR DISCUSSION OF THE BENEFITS OF THE GRID IMPROVEMENT PLAN, YOU REFER SEVERAL TIMES TO PRIMARY (DIRECT) AND SECONDARY (INDIRECT) BENEFITS. WOULD YOU PLEASE EXPLAIN THE DISTINCTION BETWEEN THESE TWO SETS OF BENEFITS?

A. Yes. Primary benefits consist of value that is directly captured by the Company and by customers. Examples of primary benefits captured by the Company are things like avoided deployments of outage restoration crews, avoided equipment replacement costs, avoided operations and maintenance savings, and other "hard costs" that can easily be estimated and quantified. Direct benefits captured by customers are things like avoided lost product, avoided damaged equipment costs, avoided lost wages, and other expenses that cost customers money. In Exhibit 4 to this testimony, I have included a graphic example of a "benefits pyramid" that shows how the benefits of electric utility projects are thought about and evaluated in the industry. As can been seen from this graphic and from the cost/benefit results in Exhibit 3, the Company's proposed Grid Improvement Plan is justified in its entirety just on primary benefits alone. However, the proposed Grid Improvement Plan for South Carolina also provides indirect, secondary benefits to customers through risk reduction; value to third parties, and value to society as a whole, which are reflected on the top three rungs of the benefits pyramid displayed on Exhibit 4. Of these indirect/secondary benefits, the Company has estimated the indirect value of the Plan to third parties, and the details of this evaluation are reflected in Exhibit 3. However, the Company has not attempted to value the indirect benefits of risk reduction and the benefits to society as a whole for the Grid Improvement Plan, which means that the benefits of the Plan are understated and are greater than what the Company has calculated.

Q. WHAT IS YOUR RESPONSE TO THE ASSERTION THAT THE GRID IMPROVEMENT PLAN SHOULD HAVE QUANTIFIABLE TARGETS AND METRICS TO MEASURE THE PERFORMANCE AND RESULTS OF THE WORK IN THE PLAN?

A. I agree with this contention, and the cost/benefit analyses in Exhibit 1 to this testimony provide those metrics for each of the projects and programs that are appropriate for such metrics.[11] Specifically, the cost/benefit analyses performed by the Company detail, among other things, the amount of O&M savings the Company anticipates from the Plan; the amount of avoided capital costs the Company anticipates from the Plan; and the amount of outages that each of the programs and projects within the Plan are anticipated to avoid.

Q. SINCE THE GRID IMPROVEMENT PLAN DOES HAVE QUANTIFIABLE TARGETS AND METRICS TO MEASURE THE PERFORMANCE AND RESULTS OF THE WORK IN THE PLAN, IS THE COMPANY WILLING TO GUARANTEE THAT PERFORMANCE AND THOSE RESULTS?

A. I believe that the Company already provides a guarantee on the performance of the work that it does through prudence reviews that are inherent in the regulatory process. To explain, unlike unregulated companies that are free to spend their

[11] Some programs/projects cannot be effectively measured by detailed performance metrics and targets. For example, computer hardware and software that enables grid assets to communicate with each other either works or does not work, and measures taken to prevent substations from flooding in major storms either keep water out or do not keep water out.

money any way that they see fit, a regulated utility must always prove to regulators that the work it performs delivers customers the value that they pay for. For example, if the Company builds a generation facility that is supposed to deliver 100 megawatts of power to customers, that unit must deliver 100 megawatts of power to customers unless the Company has a reasonable and prudent reason why it is not doing so. If the Company does not have a reasonable and prudent reason for work not delivering the value it is supposed to, the Company is subject to a disallowance for the cost of that work. The work to be performed in the Grid Improvement Plan is no different. If customers do not get the value they pay for under the Plan, the Company remains at risk for a prudence disallowance unless the company can provide reasonable and prudent reasons as to why they did not.

Q. EARLIER, YOU MENTIONED A REPORT REFERENCED BY ORS SUGGESTING THAT THE COSTS OF THE GRID IMPROVEMENT PLAN MAY BE UNDERSTATED BY AS MUCH AS FIFTY PERCENT, THEREBY LOWERING THE COST TO BENEFIT RATIOS OF PROGRAMS AND PROJECTS IN THE PLAN. CAN YOU PLEASE ELABORATE?

A. Yes. The testimony of ORS Witness Sandonato cites a third-party report released by an organization known as GridLab. This organization released a report titled "Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers" ("GridLab SC Report") that purports to analyze Duke Energy's Grid Improvement Plan across both DEC and DEP in South Carolina. In the GridLab SC Report, the GridLab organization states the following regarding the Company's proposed Grid Improvement Plan for South Carolina:

> "Duke Energy appears to estimate costs based on the capital it will spend to implement the Plan. However, customers pay more than capital costs. On top of capital costs, customers must pay Duke Energy profits, corporate income taxes, and interest expenses, as well as South Carolina Gross Receipts taxes, local property taxes on assets, and South Carolina Regulatory Fees. These costs, called carrying charges, grow larger as the useful life of the assets grows longer. Most assets in the Plan are long-lived, and are expected to last 20-30 years. In GridLab's experience, carrying charges add anywhere from 50% to 100% to the ultimate cost to customers of long-lived assets (15-20 years or more). Other costs missing from Duke Energy's benefit-cost analyses include increases in asset operations and maintenance costs over time. GridLab recommends that customer benefit-to-cost ratios be re-calculated, with all costs customers will be asked to pay considered."

Q. IS THIS CONTENTION IN THE GRIDLAB REPORT ACCURATE?

A. No, it is not. Let me first say that I am not criticizing the GridLab SC Report for raising this issue because they did not have visibility into the detail of how the Company has calculated costs for the Plan at the time when they authored their report, and they are not a party to this case capable of conducting discovery. In its cost/benefit analyses for the Grid Improvement Plan, the Company has, through its process of discounting to calculate the NPV, used a discount rate that includes the cost of interest, shareholder return, and corporate income taxes. If the project causes incremental, ongoing maintenance cost, then those costs are also included in the cost/benefit analyses and escalated over time. For example, the inclusion of the SC weighted average cost of capital (discount rate for NPV) can be seen in cost benefit analyses provided in Exhibit 1.

Q. CAN YOU ELABORATE ON THE THIRD AND FINAL MAJOR THEME THAT YOU IDENTIFIED IN INTERVENOR TESTIMONY?

A. Yes. The third and final major theme that I observed stated concerns with how the Company has designed the Grid Improvement Plan. Within this major theme, I identified the following sub-issues that I will respond to in the balance of my testimony:

1. The Plan does not address South Carolina renewable generation interconnection issues;
2. The Plan does is not designed to encourage and enable additional utility-grade solar to be added to the grid;
3. The Plan is not the product of integrated systems planning and thus, has not avoided the construction of large grid investments such as new substations and lines;
4. The Plan does not fully address customer data access and new rates that are enabled by smart meters;
5. The Plan does not contain details on alternatives that were considered in lieu of the programs and projects in the Plan;
6. The Company's testimony does not adequately describe how all the programs and projects in the Plan work together; and
7. The Plan stops at three years and does not inform stakeholders what comes next.

Q. WHAT IS YOUR RESPONSE TO CONCERNS THAT THE PROPOSED GRID IMPROVEMENT PLAN DOES NOT ADDRESS LARGE RENEWABLE GENERATION INTERCONNECTION ISSUES IN SOUTH CAROLINA?

A. I completely agree that the Plan does not address issues regarding the policies, procedures, and positions of stakeholders regarding the interconnection of large renewable energy resources in South Carolina because that is not what the Plan is designed to do, nor should it be. I understand that state and federal rules and policies dictate how these interconnection issues are addressed, and I further understand that vibrant discussions regarding these issues are ongoing in South Carolina in other forums. While there are some programs and projects in the Plan that may provide ancillary benefits to interconnection issues that are secondary to their primary purposes (such as voltage management, more capacity for distributed energy resources on the distribution system via aspects of the Self-Optimizing Grid program, and upgrades to certain transmission line structures and power transformation assets), the Company cannot and should not attempt to get ahead of federal and state rules and evolving policy issues regarding interconnection in the Grid Improvement Plan.

Q. WHAT IS YOUR RESPONSE TO THE STATEMENTS THAT THE PROPOSED GRID IMPROVEMENT PLAN DOES NOT ENCOURAGE AND ENABLE INCREMENTAL LARGE RENEWABLE ENERGY GENERATORS TO BE ADDED TO THE GRID?

A. Much like my highly-related discussion of interconnection issues for these large renewable generation assets, the Grid Improvement Plan is not designed and should not be designed to lead, or worse, get ahead of rules, policies, and robust engagement on renewable energy policy in South Carolina. While I can say with confidence that the Grid Improvement Plan will "do no harm" to large renewable generators and may, (through secondary, ancillary benefits), help enable some of these resources, the Company's proposed Plan is designed to address the megatrends that I identified in my direct testimony in a comprehensive and cost-beneficial manner.

Q. HOW DO YOU RESPOND TO ARGUMENTS THAT THE GRID IMPROVEMENT PLAN IS NOT THE PRODUCT OF A MATURE PLANNING PROCESS THAT HAS THE CAPABILITY TO DEFER LARGE, TRADITIONAL CAPITAL INVERSTMENTS SUCH AS NEW SUBSTATIONS OR NEW POWER LINES?

A. Some intervenors[12] suggest that an integrated resource planning analysis would have yielded superior options to the programs and projects in the Company's proposed Plan. I disagree and address those arguments later in my testimony when I discuss alternative options for the Plan. However, for the intervenors who have suggested that the Company's proposed Plan is deficient because it is not the result of a mature and functioning integrated system operations planning process ("ISOP") that can analyze potential investment choices in an interrelated fashion between generation, transmission, distribution, and other potential resources and tools, I disagree that the Company's Plan is deficient as it does include the deployment of ISOP, but I agree that ISOP will be a useful tool when completed.

Q. PLEASE EXPLAIN WHAT YOU MEAN?

A. A modern deployment of integrated systems operations planning[13] is a cutting-edge and evolving process that requires thoughtful design and deployment. In our regulated jurisdictions, stakeholders usually are not criticizing Duke Energy for not

[12] Witness Villareal, on behalf of the South Carolina Solar Business Alliance, page 14; Witness Davis, on behalf of the South Carolina Solar Business Alliance, pages 13 and 15.
[13] I provide more detail on ISOP and what it does in my direct testimony in Exhibit 9, page 39.

already having ISOP in place but instead are requesting that they be included to provide stakeholder input as the Company designs and perfects its ISOP deployment. This is due to the fact that those stakeholders realize that the electric industry as a whole has not yet perfected the ISOP process because the costs, capabilities, and the viability of new grid assets, such as batteries and distributed energy resources, are changing every day. As discussed in my direct testimony and reiterated here, the Company is well underway in developing ISOP today, including gathering input from stakeholders, and the Company cannot reasonably be criticized for not having this tool in place now.

Q. WHAT IS YOUR POSITION REGARDING CRITICISMS THAT THE GRID IMPROVEMENT PLAN DOES NOT DETAIL HOW CUSTOMERS WILL BENEFIT FROM ACCESS TO THEIR USAGE DATA AND FROM NEW RATE DESIGNS THAT ARE ENABLED BY ADVANCED METERING CAPABILITIES?

A. I agree that smart meters; new rates that result from them; and enhanced availability of usage data for customers are all important aspects of the Grid Improvement Plan. However, other witnesses in this case, such as Witnesses Schneider and Pirro, are better positioned to discuss the details of these issues for South Carolina.

Q. HOW DO YOU RESPOND TO ARGUMENTS THAT THE COMPANY DID NOT PERFORM AN ALTERNATIVES OPTIONS ANALYSIS FOR PROJECTS AND PROGRAMS IN THE GRID IMPROVEMENT PLAN?

A. I first need to provide clarity on what an alternative options analysis means, and will use a substation flood mitigation project in the Company's Plan as an example to explain two varying types of alternative options analyses. The first type of alternative options analysis using this example involves conducting an inventory of the potential actions you can take to prevent a substation from flooding, including taking no action at all. In this type of analysis, the choices available to the Company are to allow the substation in question to flood and take no action; elevate the equipment in the substation; deploy perimeter boundary interventions to keep water from entering the station; or relocate the station entirely. This type of analysis is logical and reasonable, and is exactly the kind of analysis that the Company performed in designing the proposed Grid Improvement Plan. You could also apply this analysis for other work, such as determining how to harden electric poles to extreme wind standard by using a concrete pole, a steel pole, or bracing and guying techniques.

The second type of alternative options analysis is the type that some intervenors in this case suggest that the Company should have used, and I take issue with this suggestion. This second type of alternative options analysis is where, using my two examples above, the Company asks whether it can abandon the use of substations and poles altogether thereby eliminating any worry that they will flood or break in extreme wind conditions. This type of theoretical thinking, while perhaps possible in the distant future, is not realistic today and cannot be seriously considered as some intervenors may suggest.[14]

[14] These types of arguments are much like the suggestion that the electric industry should convert to 100% renewable energy now, a feat that could very well be impossible. See https://www.wsj.com/articles/the-green-new-deals-impossible-electric-grid-11550705997

Q. DID ANY INTERVENORS OFFER SPECIFIC EXAMPLES OF PROGRAMS OR PROJECTS THAT THEY CONTEND THE COMPANY SHOULD HAVE USED IN LIEU OF THE ONES IN THE COMPANY'S PROPOSED PLAN?

A. Yes, some did. Witness Villareal states, or at least infers, that the Company should use "smart inverters" instead of deploying its Integrated Volt/VAR Control ("IVCC") program in South Carolina. It appears, however, that Witness Villareal either does not understand how IVCC works and/or does not understand that IVCC and smart inverters can actually complement each other. The Company's IVCC proposal is a "no regrets" foundational program that delivers needed value today (to include energy conservation, reduced line losses, fuel savings, and Self-Optimizing grid circuit reconfiguration) while providing a circuit voltage profile more compatible with deep distributed energy resource ("DER") penetration. The circuits that passed the cost/benefit screening process are generally concentrated around urban core areas that are generally not suitable for utility-scale solar due to higher land costs and a lack of undeveloped land. It is perfectly aligned however with areas where residential choices to participate in rooftop solar are most likely to occur in concentrated amounts. Some other general observations regarding Witness Villareal's argument are:

- Use of inverters to effectively manage the integration of intermittent DER assets will not make the foundational investments of IVVC obsolete, but are in fact one of several options for how the value created by IVVC investments are preserved (along with power electronics for voltage management, storage for solar smoothing, and other advanced modern equipment).

- As stated, the circuits not included in the current IVVC program are generally those in the rural areas where large scale utility solar tends to locate. The scenario Witness Villareal raises makes the flawed assumption that these investments are in direct competition when they in fact are complementary. IVVC infrastructure provides voltage management capability needed today to support circuit re-configuration and to operate the grid more efficiently to the benefit of our customers. As DER penetration rises, the need will emerge for this capability to be augmented by assets with the speed to manage DER intermittency and DER power quality induced issues. Addressing these issues involves assets like smart inverters, storage for solar smoothing, and power electronics, and represents investments layered on top of (rather than instead of) a base IVCC foundation.
- GridLab's analysis in Virginia in the Dominion case cites IVVC and SOG investments as industry best practices that should be part of foundational investments in grid modernization investments.

Q. THE GRIDLAB SC REPORT CITED BY ORS SUGGESTS THAT DUKE ENERGY SHOULD EVALUATE ALTERNATIVES TO THE PROPOSED $36 MILLION FOR SUBSTATION PHYSICAL SECURITY. CAN YOU PROVIDE YOUR OPINON ON THAT SUGGESTION?

A. Page 43 of Oliver Exhibit 4 in my direct testimony states that the physical substation security subprogram "enhances the grid resiliency as part of the overall

Transmission Security program. Tier 1 site enhancements include high security perimeter fencing and lighting, intrusion detection technology, new security enclosure buildings, hardening of existing control houses, security cameras, and access control. Tier 2 site enhancements include high security perimeter fencing and lighting." The criteria used to determine what work is necessary in this area are discussed at length in my direct testimony on pages 33-34. There simply are no better alternatives to addressing the substation physical security projects than these, nor has ORS or any other party offered any. To the extent that ORS or any other party is suggesting that the Company should not secure these substations using these measures, that suggestion is misguided and would be out of line with evolving industry standards.

Q. THE GRIDLAB SC REPORT THAT ORS CITES ALSO SUGGESTS THAT DUKE ENERGY SHOULD EVALUATE ALTERNATIVES TO $41 MILLION FOR ENTERPRISE COMMUNICATIONS NETWORK INVESTMENTS. CAN YOU EXPLAIN WHY THAT SUGGESTION IS MISGUIDED?

A. The smart meter communications network is already deployed for DEC and is in the process of being deployed for DEP, as discussed extensively in the testimony of Company witness Schneider, so there was no need to mention it in the Grid Improvement Plan. Interestingly, the transition to 4G/5G mentioned by GridLab is addressed as part of the "Next Generation Cellular" program discussed on page 47 of Oliver Exhibit 4. The other programs mentioned as part of Enterprise

Communications serve different functions than the advanced meter communications infrastructure, and GridLab doesn't discuss those programs.

Q. SCSBA WITNESSES VILLAREAL AND DAVIS GENERALLY SUGGEST THAT THE COMPANY'S PLAN SHOULD BE REJECTED BECAUSE IT WAS NOT DEVELOPED THROUGH "BEST PRACTICES" IN PLANNING? HOW DO YOU RESPOND?

A. Witness Davis, who cited the GridLab SC Report for best practices in distribution planning, may not have read the report that GridLab released regarding Dominion's grid plan in Virginia titled "Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders" ("GridLab VA Report") [15]. The GridLab VA Report recommended a majority of the substantive investments included in the Company's Plan. The GridLab VA Report listed "software to improve grid reliability, resilience, and DER hosting capacity" and "software to improve grid energy efficiency" as "characteristics of a "no regrets" grid modernization plan" (GridLab VA Report, page 9). Regarding improved reliability, resilience, and DER hosting capacity, the GridLab VA Report says, "Better grid state visibility, analytics, and reconfiguration are not only useful for accommodating DER in a reliable manner; these same capabilities can also improve grid reliability and resilience irrespective of installed DER capacity" (GridLab VA Report, page 10). The Company's plan obtains those capabilities through its Self-Optimizing Grid program, which is described as part of increased grid configuration flexibility on page 11 of the

[15] [See GridLab Virginia Report:
https://static1.squarespace.com/static/598e2b896b8f5bf3ae8669ed/t/5bbe4f71e2c4835fa247183f/1539198852367/GridLab_VA+GridMod_Final.pdf

GridLab VA Report. As for improving grid energy efficiency, the GridLab VA Report says, "A certain type of software called "Integrated Volt-VAR Optimization" software improves grid efficiency by optimizing, as the name implies, the voltage and VAr (power factor) of electricity delivered to customers" (GridLab VA Report, page 11). The Company's Plan also delivers that functionality as part of its IVVC program. Therefore, it is odd to me that parties in this case continue to cite GridLab's work as support for arguments against the Company's proposed Plan when the GridLab's reports actually support the Company's Plan in multiple material aspects.

Q. CAN YOU ELABORATE ON THE ADVANCED DISTRIBUTION PLANNING TOOL THAT WAS INCLUDED AS ONE OF THE GIP PROJECTS AND HOW IT WILL HELP SUPPORT INTEGRATED DISTRIBUTION PLANNING?

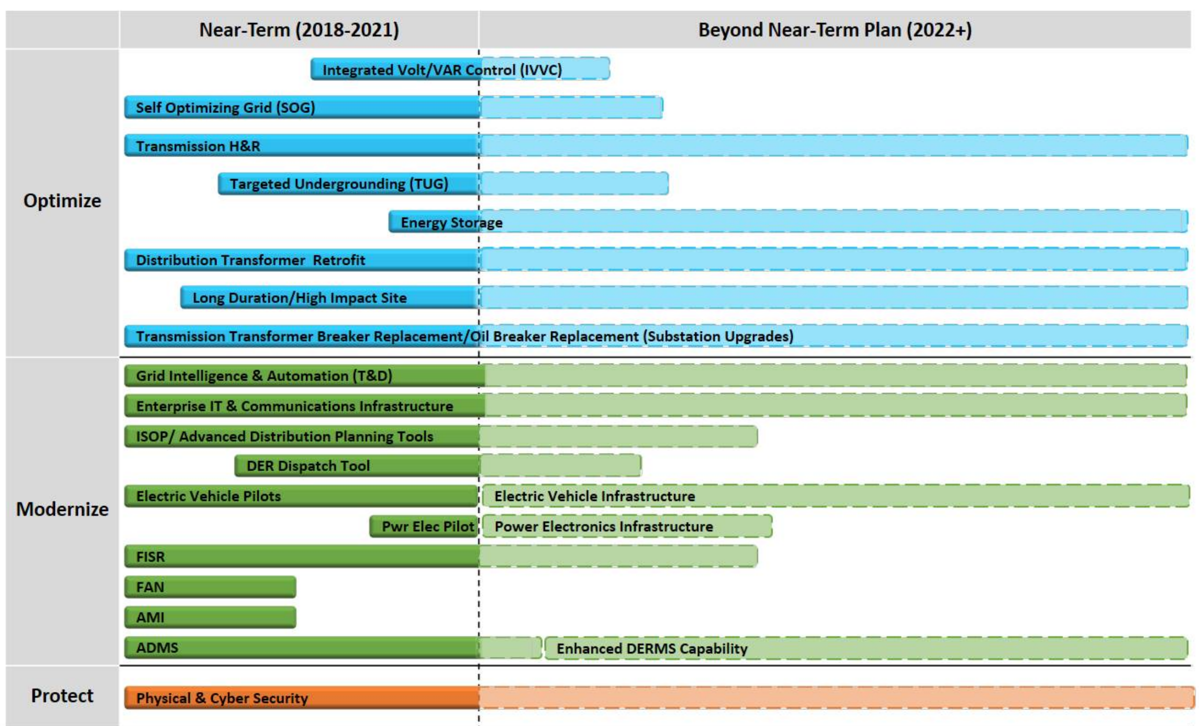
A. The current distribution planning process is an intensive manual effort that comprises: Circuit load flow model updates, load forecasting, and evaluating improvements to the grid to alleviate capacity and reliability issues. With an increasing presence of intermittent DER being added to the distribution system, this approach to distribution planning needs to evolve.

The Advanced Distribution Planning (ADP) process and tool set evolves our distribution planning process to address the presence of DER on the grid. The ADP tool that is under development incorporates computational models for time based power flow calculations which include the new distributed resources (e.g. solar, storage, EV's) and support evaluations of potential solutions including traditional solutions and new alternative distributed resource solutions. The process will help support increased alignment between distribution, transmission and generation improvements being considered for the grid. ADP creates an integrated distribution planning framework which enables the business to optimize traditional solutions and DER integration across the system.

Q. MOVING ON TO THE NEXT ISSUE THAT INTERVENORS RAISE IN THE MAJOR THEME OF PLANNING THE GRID IMPROVEMENT PLAN, WHAT DO YOU SAY IN RESPONSE TO ALLEGATIONS THAT THE COMPANY DID NOT PROVIDE ADEQUATE DETAILS ON HOW THE PROGRAMS AND PROJECTS IN THE PLAN ALL WORK TOGETHER?

A. Witness Villarreal contends that the Company's Grid Improvement lacks cohesiveness and is a random collection of projects and programs without thoughtful design. In his testimony, he cites Xcel Energy's Minnesota grid improvement plan as effectively being the "gold standard" for effective plan synergies. Based on the figure 7 graphic from page 23 of Witness Villarreal's testimony, however, the Company's SC Grid Improvement Plan aligns well with Xcel Energy's Minnesota plan. In fact, it appears to me that the Company is ahead of where Xcel is today. The graphic below depicts the SC Grid Improvement Plan in a similar graphic layout as the one in Witness Villarreal's testimony. This graphic demonstrates that the SC Grid Improvement Plan contains many of the same components included in Xcel's plan. DEC SC has already deployed smart meters, Field Area Network (FAN) and filed a SC Electric Vehicle Pilot. The Company has already been advancing work on Integrated Systems Operations Planning and advanced planning tools that the entire electric industry is grappling with as we seek to cost effectively integrate DER onto the grid. Additionally, the Company doesn't see a need to wait to begin evaluating and cost effectively integrating IVVC, energy storage and non-wires alternatives as depicted in Witnesses Villarreal's graphic and instead is doing so now. Through our stakeholder feedback sessions in SC, stakeholders wanted to see newer technologies such as IVVC, energy storage, non-wires alternatives, EV infrastructure show up faster in the Company's plan and we have met that desire in our proposed Plan.

South Carolina Grid Investments (Planned & Road Mapped)



Q. HOW DOES THE ADDITIONAL GRAPHIC HIGHLIGHTED BY WITNESS VILLARREAL ON PAGE 24 OF HIS TESTIMONY CONSTRAST WITH THE SC GRID IMPROVEMENT PLAN?

A. The second graphic in Witness Villareal's testimony is myopic in nature and only focuses on levels of DER as a presumptive "sole outcome" for a grid improvement plan. In contrast to this unilateral view of grid improvement, the Company performed a much broader and holistic analysis of impacts to the grid highlighted through the seven major grid improvement megatrends outlined in my testimony of which increased DER was one of seven. Additionally, in Exhibit 3 of my direct testimony, I highlight the implications of not implementing the Grid Improvement Plan tying those implications to all the megatrends, including DER enablement. I am happy to say that the SC Grid Improvement Plan seeks to begin to solve for all seven megatrends, not just DER for its SC customers by increasing monitoring and visibility, increasing automation, increasing distributed intelligence, improving reliability, hardening for resiliency, enabling voltage control, accommodating two-way power flows, modernizing grid operations, improving cyber security, improving physical security, expanding customer options and capabilities, and increasing hosting capacity.

Q. WITNESS VILLARREAL INFERS THAT THE COMPANY MAY BE LOOKING SHORT-TERM AND MAY BE MISSING OPPORTUNITIES TO LAY THE FOUNDATION FOR MODERATE TO HIGH LEVELS OF DER ADOPTIONS. IS THAT TRUE?

A. No. As noted previously, the Company has already been working on IVVC, SOG, ISOP, AMI, ADMS and seeks to enhance Distributed Energy Resource Management (DERMS) capabilities with the current plan set forth in SC. If anything, we along with the stakeholder input, see the need to react faster to the megatrends specifically happening in SC than Witness Villarreal recommends.

Q. WHAT IS THE FINAL ISSUE THAT INTERVENORS RAISE REGARDING THE DESIGN OF THE GRID IMPROVEMENT PLAN?

A. Some intervenors[16] expressed concerns that the Company's proposed Plan did not provide detail as to what the Company will do in the years that follow the Plan to continue with grid improvement efforts. Our current three-year plan is a "no regrets" package of well-coordinated grid improvements. It does not need a "phase 2" to be cost effective. The plan begins preparing the SC grid for the implications resulting from the megatrends highlighted in my testimony. Also, the current stakeholder informed three-year plan begins to prepare the SC grid for growth in privately owned DER and electric vehicles, but even if this growth does not occur, the plan still is cost effective and warranted. This is proven in our cost benefit analyses.

[16] Witness Villareal, on behalf of the South Carolina Solar Business Alliance, at pages 13, 14 and 18.

That being said, the current three-year plan does set South Carolina up for other improvements that could warrant a second phase of the plan, and we plan to engage and work with stakeholders before deploying any such plan. Below are potential programs for consideration and stakeholder input:

1. **Phase 2 of Self-Optimizing Grid**. The current 3-year SOG plan enables 228 circuits with approximately 300,000 customers. Our vision is to serve approximately 80% of SC customers from the Self-Optimizing Grid that enables two-way power flow and dynamic switching.
2. **Phase 2 of IVVC**. The current four-year IVVC plan enables 74 of DEC SC total 218 substations. A phase 2 project could focus on the next, most cost effective, group of substations and circuits.
3. **Increased Implementation of Power Electronics**. The current IVVC and SOG programs set up the basic capacity, automation, and Volt/VAR control mechanisms to manage the 21st century grid. As privately owned DER grows, power electronics will be essential to managing the rapid and dynamic effects of multiple, small scale intermittent resources.
4. **44 KV projects that enable solar capacity**. Through continuing coordination with stakeholders and regulators, these projects may afford new opportunities that provide value to customers.
5. **ISOP Optimization**. As the Company and the industry continues to develop and deploy ISOP, best practices and lessons learned can be utilized to optimize the ISOP process.

6. **Increased use of Energy Storage.** Energy Storage is part of our current three-year plan but is still in a startup phase. We believe many more opportunities will exist as batteries become more cost effective and as we learn more about their capabilities on the grid.

This list is certainly not comprehensive. It is intended to lay out options that build off of the currently proposed three-year plan. We are committed to continued stakeholder to help inform a more comprehensive list.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Stakeholder Webinar: North Carolina Grid Improvement Plan
Smart-Thinking Grid

June 2019

DUKE ENERGY®

Agenda

- Welcome & Overview
- Webinar Logistics
- Benefit Concepts & Analysis
- Featured Discussion Module
  - Smart-Thinking Grid CBA
- Q&A
- Close

Webinar Logistics

QUESTIONS & COMMENTS

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TOPIC PRIORITIES & RECOMMENDATIONS

- During this segment, input and feedback will be solicited on the specific areas:
  1) Smart-Thinking Grid
  2) Webinar participants will also be invited to suggest additional topics for future webinars

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- Should you have problems during the webinar, please email **Miko Palmer** (miko.palmer@duke-energy.com) for assistance
- To enable viewing at a later time, this webinar will be recorded
- All webinar materials will be available in the data room for future access.

DUKE ENERGY.

Benefits from Improving the Grid

Societal

- Lower impact to global environment
- Avoided water impacts
- Avoided land impacts
- Reduced blackouts *(security & well-being)*
- Improved quality of life
- Improved access to data
- Better customer experience

Indirect (to third parties)

- Improved economics for the state
- Increased competitiveness for the state
- Increased employment for the state
- Increased global DER enablement
- Increased transportation electrification enablement

Indirect Value (risk reduction)

- Increased system redundancy
- Improved power quality
- Improved system stability
- Avoided ancillary services
- Improved employee safety
- Reduced chance of environmental incident
- Reduced remediation costs
- Increased public safety

Direct value (captured by customer)

- Avoided business revenue loss
- Avoided equipment damage
- Avoided spoilage
- Avoided ancillary costs *(hotel, generator, lost work)*
- Increased customer-owned DER enablement
- Decreased energy use or use off peak

Direct value (captured by utility)

- Avoided transmission capacity
- Avoided transmission losses
- Avoided distribution capacity
- Avoided distribution losses
- Avoided generation capacity
- Avoided fuel costs
- Deferred capital cost
- Avoided power purchase
- Lower restoration costs
- Theft reduction
- Improved utility operations *(i.e., lower O&M)*
- Avoided CO_2
- SO_2 emission reduction
- NO_x emission reduction
- Hg emission reduction
- Particulate matter emission reduction

Smart-Thinking Grid

Cost Benefit Analysis Review

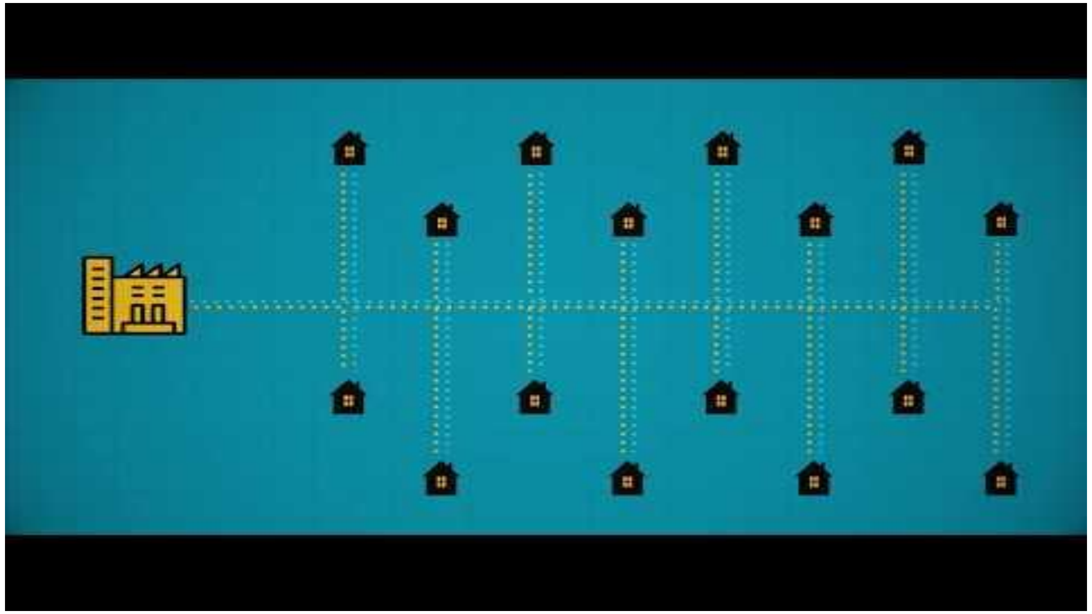
Smart-Thinking Grid

A SMART, SELF-HEALING GRID that predicts maintenance, quickly identifies outages and intelligently reroutes service to keep power on for customers.

Equipment health monitoring ↔ Outage identification and isolation

Intelligent two-way flow of electricity ↔ Automatic switching and restoration

Outage identification and isolation ↔ Automatic switching and restoration



DUKE ENERGY®

Smart-Thinking Grid

Where we are today

Duke Energy's smart-thinking grid comprises more than 350 self-healing networks already installed across our six-state service area, delivering significant benefits to customers. These networks reduce the number of power outages, as well as the duration of outages.

If outages do occur on a smart-thinking grid, power is typically restored in **less than a minute**. In 2017, our self-healing networks operated 330 times to **prevent** over **330,205 outages**. Smart-thinking grid technology helped our customers **avoid** over **46 million minutes** in **outage time**.

More improvements are planned as part of Duke Energy's multi-state grid improvement initiative.
When completed, roughly **80 percent** of all customers will be served by a smart-thinking grid.

DUKE ENERGY.

Smart-Thinking Grid

The Self-Healing Networks were a foundational step in the progression towards the Smart-Thinking Grid.

Instead of having individual circuit pairs that can back each other up, the integrated grid network will allow for multiple circuit rerouting options to re-energize segments and minimize customer outage events.

The Smart Thinking Grid will further segment the circuits to **minimize** the **number of customers affected by sustained outages** and ensures the necessary **capacity** and **connectivity** to fully leverage the segmentation.

Under this program, circuits will have **automated switches** deployed according to guidelines, which outline automated switches approximately **every 400 customers**, or **3 miles** in circuit segment length, or **2 MW** peak load.

Smart-Thinking Grid

SMART-THINKING GRID CUSTOMER BENEFITS SNAPSHOT

Inception to date*	Self-healing networks	Number of customers saved from outages**	Minutes of customer outages prevented***
Duke Energy Carolinas (DEC)	69	256,185	45,412,339
Duke Energy Progress (DEP)	102	355,858	58,635,137
Duke Energy Indiana (DEI)	22	91,045	10,766,730
Duke Energy Kentucky (DEK)	11	66,092	10,222,904
Duke Energy Ohio (DEO)	38	540,908	72,089,506
Duke Energy Florida (DEF)	117	396,154	32,811,355
Duke Energy Cumulative	**359**	**1,706,242**	**229,937,970**

*DEO values since 2009; DEC, DEI: 2012; DEK: 2013; DEP: 2014; DEF: 2015
**Total number of customers who would have experienced power outages if self-healing technology had not been installed.
***Total number of power outage minutes prevented for customers because of self-healing technology operations.

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SMART-THINKING GRID COST-BENEFIT SUMMARY

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What success looks like

- 193,000 customer outages reduced annually
- Customers affected by momentary outages reduced through segmentation up to 75% per circuit
- Distribution system hosting capacity for affected circuits increased by approximately 60%

Cost-Benefit Highlights and Insights

- Benefits all customer classes
  - 40% of benefits ($451M) are for prevented outages to small commercial and industrial customers
- Increases hosting capacity
  - Today, there are approximately 145 MW of private solar installed on the distribution system
  - Increases hosting capacity from approximately 496 MW to 835 MW
- Hosting capacity benefit estimates are calculated from capacity, emissions and energy savings
  - Emissions savings: $5/ton CO_2 in 2025 and rising rapidly
  - Capacity savings: $63/kw
  - Energy savings: $14/MWh

Supporting data room document: SOG_DEC-DEP_NC_19-22_vF 5-11-19.xlsx

SMART-THINKING GRID COST-BENEFIT SUMMARY

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Net present costs are $678M

- NPV costs include capital and ongoing expenses
- Capital expenses include switch automation, circuit segmentation, capacity additions, software, and connectivity. They total $752M from 2019 through 2022.
- Ongoing expenses include cellular bill, operations support and maintenance;
  These costs continue for the life of the equipment and are $775K to $1.9M per year
- Timeline for costs: Capital expenses are $106M in 2019, $160M in 2020, $229M in 2021, and $257M in 2022

Net present benefits are $1.1B

- $641M in benefits arise from avoided outages
- $322M in benefits arise from avoided momentary outages
- Additional benefits from DER enablement & peak shaving
- Timeline for benefits: Reliability benefits extend evenly over the 30-year life of the equipment, hosting capacity benefits increase over time with the estimated CO_2 price

Key Notes about Analytic Method

- Key assumption is that energy provides value to customers and that energy is an enabling product for our society. Therefore improvements to power quality have tangible value to customers
- The ICE Calculator, funded by the DOE, is the industry standard for estimating this value
- Valued hosting capacity additions with only energy savings, avoided capacity, and CO2 reductions

Supporting data room document: SOG_DEC-DEP_NC_19-22_vF 5-11-19.xlsx

Q & A

Stakeholder Webinar: North Carolina Grid Improvement Plan Targeted Undergrounding (TUG)

June 2019

DUKE ENERGY®

Agenda

- Welcome & Overview
- Webinar Logistics
- Benefit Concepts & Analysis
- Featured Discussion Module
  - Targeted Undergrounding (TUG) CBA
- Q&A
- Close

Webinar Logistics

QUESTIONS & COMMENTS

- Questions can be submitted using the Q&A chat button at the top of your screen (viewable only by webinar hosts). The webinar will remain on mute until the later part of the presentation when the line will be opened for verbal discussion.
- Participant input will be reviewed at real-time for response throughout the workshop
- Webinar hosts will address as many questions/comments as time allows
- Please enlarge screen to 100% during presentation using the selection on the upper right-hand corner

TOPIC PRIORITIES & RECOMMENDATIONS

- During this segment, input and feedback will be solicited on the specific areas:
  1) Targeted Undergrounding
- Webinar participants will also be invited to suggest additional topics for future webinars

WEBINAR HOUSEKEEPING

- Should you have problems during the webinar, please email **Miko Palmer** (miko.palmer@duke-energy.com) for assistance
- To enable viewing at a later time, this webinar will be recorded
- All webinar materials will be available in the data room for future access.

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Benefits from Improving the Grid

Societal

- Lower impact to global environment
- Avoided water impacts
- Avoided land impacts
- Reduced blackouts *(security & well-being)*
- Improved quality of life
- Improved access to data
- Better customer experience

Indirect (to third parties)

- Improved economics for the state
- Increased competitiveness for the state
- Increased employment for the state
- Increased global DER enablement
- Increased transportation electrification enablement

Indirect Value (risk reduction)

- Increased system redundancy
- Improved power quality
- Improved system stability
- Avoided ancillary services
- Improved employee safety
- Reduced chance of environmental incident
- Reduced remediation costs
- Increased public safety

Direct value (captured by customer)

- Avoided business revenue loss
- Avoided equipment damage
- Avoided spoilage
- Avoided ancillary costs *(hotel, generator, lost work)*
- Increased customer-owned DER enablement
- Decreased energy use or use off peak

Direct value (captured by utility)

- Avoided transmission capacity
- Avoided transmission losses
- Avoided distribution capacity
- Avoided distribution losses
- Avoided generation capacity
- Avoided fuel costs
- Deferred capital cost
- Avoided power purchase
- Lower restoration costs
- Theft reduction
- Improved utility operations *(i.e., lower O&M)*
- Avoided CO_2
- SO_2 emission reduction
- NO_X emission reduction
- Hg emission reduction
- Particulate matter emission reduction

Targeted Undergrounding (TUG)

Cost Benefit Analysis Review

Targeted Undergrounding

Leveraging historic data to strategically move hard-to-access overhead power lines underground to improve reliability for customers

TARGETED UNDERGROUNDING BENEFITS

- Significantly reduce outages
- Minimize momentary interruptions
- Restore power faster
- Eliminate tree trimming in hard-to-access areas

Targeted undergrounding drives **higher reliability** by significantly reducing risk on outage-prone power line segments.

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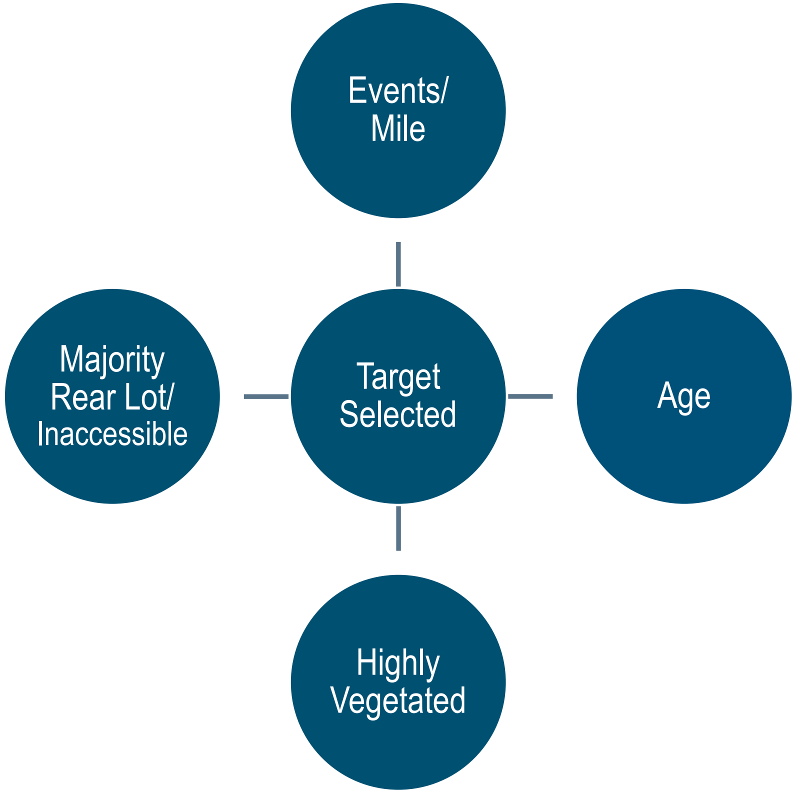
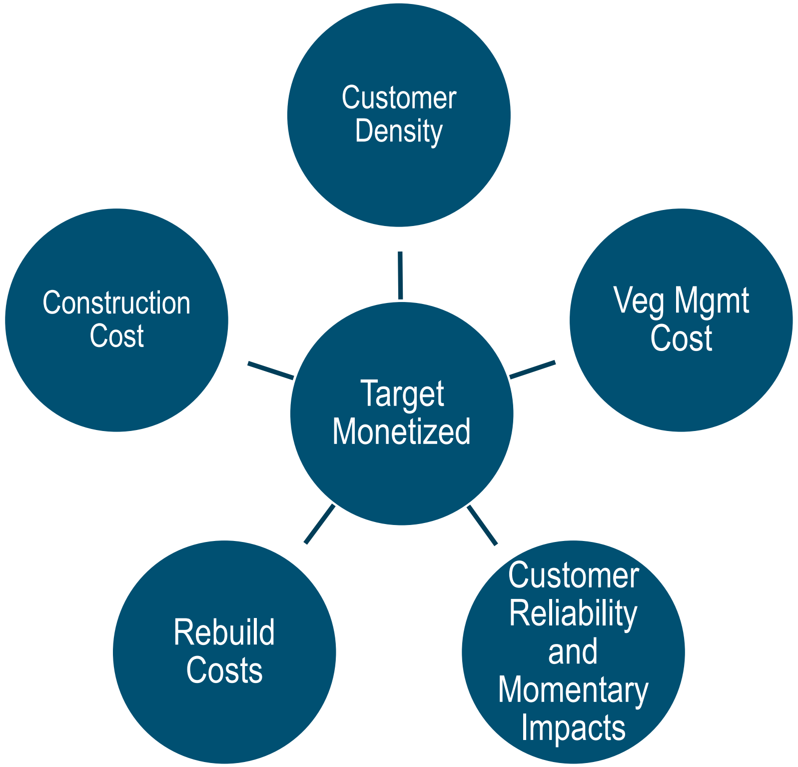
Target Selection Evolution

Original Approach



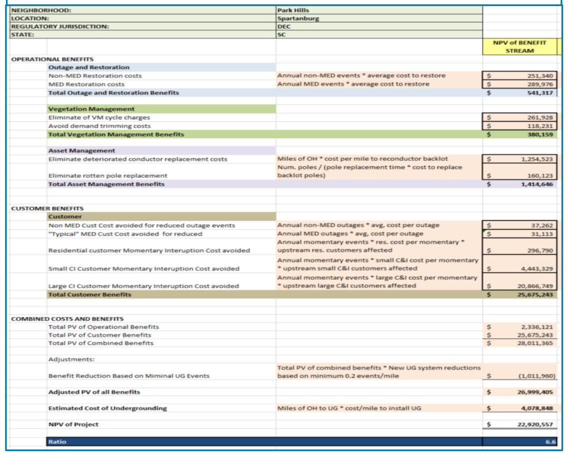
New Approach Integrating Cost Benefit Analysis



Cost Benefit Analysis (CBA) Process

Scope

CBA



NEIGHBORHOOD:		Park Hills	
LOCATION:		Spartanburg	
REGULATORY JURISDICTION:		DEC	
STATE:		SC	
			NPV of BENEFIT STREAM
OPERATIONAL BENEFITS			
	Outage and Restoration		
	Non-MED Restoration costs	Annual non-MED events * average cost to restore	$ 251,340
	MED Restoration costs	Annual MED events * average cost to restore	$ 289,976
	Total Outage and Restoration Benefits		$ 541,317
	Vegetation Management		
	Eliminate of VM cycle charges		$ 261,928
	Avoid demand trimming costs		$ 118,231
	Total Vegetation Management Benefits		$ 380,159
	Asset Management		
	Eliminate deteriorated conductor replacement costs	Miles of OH * cost per mile to reconductor backlot	$ 1,254,523
	Eliminate rotten pole replacement	Num. poles / (pole replacement time * cost to replace backlot poles)	$ 160,123
	Total Asset Management Benefits		$ 1,414,646
CUSTOMER BENEFITS			
	Customer		
	Non MED Cust Cost avoided for reduced outage events	Annual non-MED outages * avg, cost per outage	$ 37,262
	"Typical" MED Cust Cost avoided for reduced	Annual MED outages * avg, cost per outage	$ 31,113
	Residential customer Momentary Interuption Cost avoided	Annual momentary events * res. cost per momentary * upstream res. customers affected	$ 296,790
	Small CI Customer Momentary Interuption Cost avoided	Annual momentary events * small C&I cost per momentary * upstream small C&I customers affected	$ 4,443,329
	Large CI Customer Momentary Interuption Cost avoided	Annual momentary events * large C&I cost per momentary * upstream large C&I customers affected	$ 20,866,749
	Total Customer Benefits		$ 25,675,243
COMBINED COSTS AND BENEFITS			
	Total PV of Operational Benefits		$ 2,336,121
	Total PV of Customer Benefits		$ 25,675,243
	Total PV of Combined Benefits		$ 28,011,365
	Adjustments:		
	Benefit Reduction Based on Miminal UG Events	Total PV of combined benefits * New UG system reductions based on minimum 0.2 events/mile	$ (1,011,960)
	Adjusted PV of all Benefits		$ 26,999,405
	Estimated Cost of Undergrounding	Miles of OH to UG * cost/mile to install UG	$ 4,078,848
	NPV of Project		$ 22,920,557
	Ratio		6.6

Costs & Benefits

Costs & Benefits	Sources
Project Deployment Cost	Assumption of per mile installation cost based on prior work experience and future projections
Operational Savings - Veg Management Savings	**Vegetation Management** – Estimated based on double sided conventional chip costs/ vegetated backlot mile and demand trimming over 30 years
Operational Savings - Avoided Asset Management Costs	**GIS** – wire size <1/0 that would need to be included in small wire replacement program
Operational Savings - Avoided Outage Restoration Costs	**OMS History** – Outage events eliminated
Customer Savings - Avoided Momentary Interruption Costs	**GIS** – Circuits involved **Customer Data Warehouse** – Customer mix (Residential, <50,000kWh/year-Small & Medium C&I , >50,000kWh/year-Large C&I) on those circuits **ICE Tool** – information above used as input into ICE (Interruption Cost Estimator).
Customer Savings - Local Customer Avoided Outage Costs	Cost per customer event

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Supporting data room document: TUG_DEC-DEP_NC_19-22_Consolidated_vF 5-8-19.xlsm

					Customers				NPV Costs			NPV Benefits					
			Location	State	TUG Direct	Residential	Small C&I	Med/Lg C&I	Capital	O&M	Total	Operational	Customer	Other	Total	BCA Ratio	OP Ratio
	Programs																
	Targeted Underground								$165,300,113	$8,040,529	$173,340,642	$158,750,730	$1,918,578,597	$0	$2,077,329,327	12.0	0.9
NC-DEC	2019	Druid Hills	Hendersonville	NC	661	4,959	566	67	$4,512,412	$226,947	$4,739,358	$4,961,478	$25,496,500		$30,457,978	6.4	1.0
NC-DEC	2019	Lake Crest Drive	Kernersville	NC	278	2,231	207	47	$969,000	$50,161	$1,019,161	$644,627	$16,542,428		$17,187,055	16.9	0.6
NC-DEC	2019	Pine Island Road	Charlotte	NC	93	1,577	117	21	$705,500	$36,521	$742,021	$1,120,742	$16,647,556		$17,768,298	23.9	1.5
NC-DEC	2019	Smallwood	Charlotte	NC	224	2,117	201	30	$843,386	$43,100	$886,486	$1,709,719	$12,445,049		$14,154,768	16.0	1.9
NC-DEP	2019	Bent Creek	Asheville	NC	586	958	98	15	$8,549,573	$398,752	$8,948,325	$5,823,466	$41,152,588		$46,976,054	5.2	0.7
NC-DEP	2019	Beverly Hills	Asheville	NC	393	3,107	297	51	$2,732,503	$128,057	$2,860,560	$2,986,545	$36,533,506		$39,520,052	13.8	1.0
NC-DEP	2019	Foxcroft	Raleigh	NC	53	5,426	147	19	$3,227,039	$153,375	$3,380,415	$3,002,607	$9,128,960		$12,131,567	3.6	0.9
NC-DEP	2019	Kings Grant	Wilmington	NC	1,158	2,005	179	25	$10,568,458	$488,295	$11,056,753	$6,847,712	$130,659,214		$137,506,926	12.4	0.6
NC-DEP	2019	Russell Hills	Cary	NC	765	5,812	738	195	$4,242,660	$203,149	$4,445,809	$3,934,483	$164,041,206		$167,975,689	37.8	0.9
NC-DEC	2020	Barcelona Ave	Durham	NC	33	1,842	52	4	$448,677	$23,226	$471,904	$404,242	$2,122,896		$2,527,138	5.4	0.9
NC-DEC	2020	Colony Park Beech Hill	Durham	NC	304	4,143	345	44	$1,423,193	$71,255	$1,494,449	$1,205,844	$13,419,030		$14,624,873	9.8	0.8
NC-DEC	2020	Colony Woods	Chapel Hill	NC	404	1,577	82	9	$3,565,472	$178,092	$3,743,565	$3,314,482	$10,155,463		$13,469,945	3.6	0.9
NC-DEC	2020	Foxcroft Forsyth	Winston-Salem	NC	71	1,241	64	19	$701,568	$36,317	$737,886	$891,422	$7,320,572		$8,211,995	11.1	1.2
NC-DEC	2020	Green Knolls	Rockingham	NC	97	1,143	156	9	$628,148	$32,517	$660,665	$689,480	$3,139,100		$3,828,580	5.8	1.0
NC-DEC	2020	Grimesdale	Hendersonville	NC	212	1,640	230	8	$2,674,496	$136,003	$2,810,499	$1,718,535	$5,457,474		$7,176,010	2.6	0.6
NC-DEC	2020	Mountain View	Andrews	NC	88	290	214	29	$538,413	$27,871	$566,284	$637,410	$10,495,342		$11,132,752	19.7	1.1
NC-DEC	2020	Raintree	Charlotte	NC	1,181	3,054	372	2	$1,574,450	$81,503	$1,655,953	$1,762,822	$31,887,101		$33,649,923	20.3	1.1
NC-DEC	2020	Remount at Camp Green St	Charlotte	NC	163	1,397	93	39	$954,459	$49,408	$1,003,868	$1,819,541	$33,065,435		$34,884,975	34.8	1.8
NC-DEC	2020	Sedgefield & Marsh	Charlotte	NC	108	361	27	2	$799,462	$41,385	$840,846	$763,231	$802,965		$1,566,195	1.9	0.9
NC-DEC	2020	Stonehaven	Charlotte	NC	784	1,295	41	5	$4,350,335	$219,186	$4,569,521	$3,141,960	$5,713,902		$8,855,862	1.9	0.7
NC-DEC	2020	Town and Country	Burlington	NC	581	1,096	220	52	$5,216,651	$260,890	$5,477,542	$4,720,716	$27,877,212		$32,597,927	6.0	0.9
NC-DEC	2020	Tunnel RD	Marion	NC	58	804	73	8	$742,357	$38,429	$780,786	$845,636	$2,320,516		$3,166,153	4.1	1.1
NC-DEC	2020	Westview	Winston-Salem	NC	392	1,306	50	10	$4,150,279	$208,135	$4,358,414	$2,470,433	$7,581,989		$10,052,422	2.3	0.6
NC-DEC	2020	Windsor Park	Charlotte	NC	2,371	11,639	1,793	2	$14,133,254	$691,421	$14,824,675	$12,658,716	$31,472,371		$44,131,087	3.0	0.9
NC-DEP	2020	Alan Street	Angier	NC	83	2,058	298	30	$970,775	$47,417	$1,018,192	$1,227,236	$26,378,418		$27,605,654	27.1	1.2
NC-DEP	2020	Biltmore South	Biltmore Forest	NC	283	1,788	238	69	$3,505,504	$165,684	$3,671,189	$3,965,846	$226,947,976		$230,913,822	62.9	1.1
NC-DEP	2020	Brookhaven	Raleigh	NC	327	3,457	350	51	$4,079,262	$190,518	$4,269,780	$4,066,405	$46,410,027		$50,476,432	11.8	1.0
NC-DEP	2020	Glen Arden	Arden	NC	335	1,944	209	19	$1,851,661	$89,769	$1,941,430	$2,227,139	$40,464,496		$42,691,635	22.0	1.1
NC-DEP	2020	Harbor Island	Wrightsville Beach	NC	358	1,514	372	84	$591,167	$48,184	$639,352	$1,667,100	$108,390,410		$110,057,511	172.1	2.6
NC-DEP	2020	Princess Place Belvedere	Wilmington	NC	364	1,640	195	16	$2,293,792	$108,026	$2,401,818	$2,950,103	$25,079,506		$28,029,609	11.7	1.2
NC-DEP	2020	Vance Street	Sanford	NC	829	2,256	556	64	$5,839,862	$274,449	$6,114,310	$4,287,598	$52,103,427		$56,391,025	9.2	0.7
NC-DEC	2021	Chanteloupe Dr	Hendersonville	NC	27	1,819	138	2	$540,223	$27,965	$568,188	$571,928	$1,138,764		$1,710,693	3.0	1.0
NC-DEC	2021	Elizabeth	Charlotte	NC	297	2,806	338	88	$853,396	$44,177	$897,573	$1,524,542	$34,990,559		$36,515,101	40.7	1.7
NC-DEC	2021	Hendrix Street	Greensboro	NC	318	724	132	19	$524,565	$33,630	$558,195	$970,641	$3,856,039		$4,826,681	8.6	1.7
NC-DEC	2021	Louise Rd	Winston-Salem	NC	194	1,702	106	15	$1,283,276	$65,179	$1,348,455	$1,614,423	$5,018,497		$6,632,920	4.9	1.2
NC-DEC	2021	Mountainbrook	Charlotte	NC	1,109	4,896	746	6	$7,271,541	$366,703	$7,638,244	$6,951,552	$19,073,395		$26,024,947	3.4	0.9
NC-DEC	2021	Philip St	Winston-Salem	NC	48	195	130	43	$367,978	$19,049	$387,027	$495,058	$8,831,814		$9,326,872	24.1	1.3
NC-DEC	2021	Pine Valley Hillandale	East Flat Rock	NC	75	353	89	15	$782,932	$40,359	$823,291	$977,776	$4,634,169		$5,611,946	6.8	1.2
NC-DEC	2021	Queens Rd W	Charlotte	NC	845	4,378	496	71	$4,503,876	$230,106	$4,733,982	$6,276,723	$50,795,051		$57,071,774	12.1	1.3
NC-DEC	2021	Rick St off Rankin Rd	Mt Holly	NC	59	2,489	230	33	$438,442	$22,696	$461,138	$599,624	$5,761,192		$6,360,816	13.8	1.3
NC-DEC	2021	River Crest Dr	Sylva	NC	19	753	45	1	$610,687	$31,613	$642,300	$708,091	$686,720		$1,394,811	2.2	1.1
NC-DEC	2021	Rolling Roads	Greensboro	NC	383	2,552	229	37	$2,127,368	$107,585	$2,234,953	$2,490,689	$28,128,222		$30,618,912	13.7	1.1
NC-DEC	2021	Woodlark Lane	Charlotte	NC	144	1,190	201	34	$931,689	$48,230	$979,919	$1,626,477	$18,130,967		$19,757,444	20.2	1.7
NC-DEP	2021	Mockingbird Rd	Swannanoa	NC	85	728	112	7	$1,596,976	$76,854	$1,673,831	$1,481,968	$5,713,173		$7,195,141	4.3	0.9
NC-DEP	2021	Tramwood	Angier	NC	50	2,362	233	2	$711,684	$34,431	$746,115	$805,256	$3,126,584		$3,931,840	5.3	1.1
NC-DEP	2021	Wrightsville Ave Newton St	Wilmington	NC	99	2,363	305	17	$614,316	$29,701	$644,017	$761,845	$6,659,496		$7,421,341	11.5	1.2
NC-DEC	2022	Bonclarken	Hendersonville	NC	201	1,419	217	14	$1,855,131	$94,527	$1,949,657	$1,705,491	$8,177,531		$9,883,022	5.1	0.9
NC-DEC	2022	Ewing Ave near East Blvd	Charlotte	NC	321	2,904	423	102	$1,232,417	$62,888	$1,295,305	$2,097,844	$54,195,398		$56,293,242	43.5	1.6
NC-DEC	2022	Lake Lure N of 74	Lake Lure	NC	213	1,569	427	38	$3,149,223	$160,344	$3,309,567	$2,527,505	$38,570,868		$41,098,373	12.4	0.8
NC-DEC	2022	Riverwood Hills	Sylva	NC	39	447	40	1	$706,325	$36,563	$742,889	$1,236,276	$1,265,632		$2,501,908	3.4	1.7
NC-DEC	2022	Westover Hills	Charlotte	NC	300	2,659	360	97	$1,999,714	$101,795	$2,101,508	$3,509,242	$53,259,222		$56,768,465	27.0	1.7
NC-DEP	2022	Biltmore North	Asheville	NC	483	3,919	574	92	$5,813,956	$276,092	$6,090,048	$6,147,681	$128,948,995		$135,096,676	22.2	1.0
NC-DEP	2022	Lakeview Park	Asheville	NC	675	2,092	302	34	$6,350,360	$301,999	$6,652,359	$6,105,677	$116,558,443		$122,664,120	18.4	0.9
NC-DEP	2022	Royal Pines	Asheville	NC	973	3,368	375	6	$7,162,994	$340,849	$7,503,843	$7,027,351	$30,407,760		$37,435,111	5.0	0.9
NC-DEP	2022	Town Mountain	Asheville	NC	1,883	1,880	157	18	$16,487,274	$739,149	$17,226,423	$12,069,791	$119,397,473		$131,467,263	7.6	0.7

TAB NAME: SUMMARY

- Contains complete listing of individual project data:
  - Jurisdiction
  - Year to Deploy
  - Location
  - Customer Counts
  - NPV Cost Summaries
  - NPV Benefit Summaries
  - Benefit to Cost Ratios

DUKE ENERGY.

Supporting data room document: TUG_DEC-DEP_NC_19-22_Consolidated_vF 5-8-19.xlsm

NEIGHBORHOOD:	ALL YEARS TAB SUMMARY	Back to Summary
LOCATION:	ALL	
REGULATORY JURISDICTION:	DEC/DEP	
STATE:	NC	
DISCOUNT RATE:	Discount Rate (WACC) DEC/DEP-NC	6.80%
PROJECT START (Year):	2019 - 2022	
PROJECT LIFESPAN (Years):	30	

	NPV of COST/BENEFIT STREAM	2019	2020	2021	2022	2023	2024	2025
		0	1	2	3	4	5	6
COSTS								
Project Capital	$ 165,300,113	$ 8,840,000	$ 28,820,950	$ 42,378,798	$ 46,216,377	$ 40,990,184	$ 18,482,213	$ 3,773,739
Project O&M	$ 4,959,003	$ 265,200	$ 864,629	$ 1,271,364	$ 1,386,491	$ 1,229,706	$ 554,466	$ 113,212
Total Project Costs	**$ 170,259,116**	$ 9,105,200	$ 29,685,579	$ 43,650,162	$ 47,602,868	$ 42,219,889	$ 19,036,680	$ 3,886,951
UG Restoration Costs	$ 3,081,525	$ -	$ 2,212	$ 17,369	$ 46,345	$ 96,551	$ 175,046	$ 233,403
Total On-Going O&M	**$ 3,081,525**	$ -	$ 2,212	$ 17,369	$ 46,345	$ 96,551	$ 175,046	$ 233,403
Total Capital Costs	$ 165,300,113	$ 8,840,000	$ 28,820,950	$ 42,378,798	$ 46,216,377	$ 40,990,184	$ 18,482,213	$ 3,773,739
Total O&M (Project + Ongoing)	$ 8,040,529	$ 265,200	$ 866,840	$ 1,288,732	$ 1,432,837	$ 1,326,257	$ 729,513	$ 346,615
Total Costs	**$ 173,340,642**	$ 9,105,200	$ 29,687,790	$ 43,667,530	$ 47,649,213	$ 42,316,441	$ 19,211,726	$ 4,120,354
OPERATIONAL BENEFITS								
Outage and Restoration								
Non-MED Restoration costs	$ 65,786,181	$ -	$ 42,104	$ 431,643	$ 1,146,469	$ 2,209,348	$ 3,695,285	$ 4,984,197
MED Restoration costs	$ 29,820,645	$ -	$ 16,842	$ 167,976	$ 415,690	$ 821,864	$ 1,702,053	$ 2,238,433
Total Outage and Restoration Benefits	**$ 95,606,826**	-	58,946	599,619	1,562,160	3,031,212	5,397,338	7,222,630
Vegetation Management								
Eliminate of VM cycle charges	$ 9,729,083	$ -	$ -	$ -	$ -	$ -	$ 87,978	$ 141,946
Avoid demand trimming costs	$ 4,705,453	$ -	$ 8,200	$ 67,240	$ 155,072	$ 247,254	$ 325,846	$ 361,824
Total Vegetation Management Benefits	**$ 14,434,535**	**$ -**	**$ 8,200**	**$ 67,240**	**$ 155,072**	**$ 247,254**	**$ 413,824**	**$ 503,771**
Asset Management								
Eliminate deteriorated conductor replacement costs	$ 48,709,369	$ -	$ 581,137	$ 4,355,852	$ 7,248,093	$ 12,993,506	$ 19,720,233	$ 15,477,689
Eliminate rotten pole replacement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Asset Management Benefits	**$ 48,709,369**	$ -	$ 581,137	$ 4,355,852	$ 7,248,093	$ 12,993,506	$ 19,720,233	$ 15,477,689
CUSTOMER BENEFITS								
Customer								
Non-MED customer cost avoided for reduced outage events	$ 2,783,705	$ -	$ 2,303	$ 23,368	$ 53,356	$ 99,378	$ 155,124	$ 203,775
MED customer cost avoided for reduced outage events	$ 2,238,967	$ -	$ 946	$ 11,448	$ 31,762	$ 59,171	$ 116,773	$ 153,809
Residential customer Momentary Interuption Cost avoided	$ 30,458,125	$ -	$ 31,419	$ 292,690	$ 590,516	$ 997,116	$ 1,644,239	$ 2,249,452
Small CI customer Momentary Interuption Cost avoided	$ 381,176,793	$ -	$ 270,630	$ 3,054,711	$ 7,353,633	$ 11,869,021	$ 20,336,068	$ 29,143,360
Large CI customer Momentary Interuption Cost avoided	$ 1,501,921,007	$ -	$ 1,708,940	$ 7,723,101	$ 33,224,011	$ 60,227,255	$ 93,707,423	$ 114,089,225
Total Customer Benefits	**$ 1,918,578,597**	$ -	$ 2,014,238	$ 11,105,318	$ 41,253,278	$ 73,251,941	$ 115,959,626	$ 145,839,620
COMBINED COSTS AND BENEFITS								
Total PV of Operational Benefits	$ 158,750,730	$ -	$ 648,283	$ 5,022,711	$ 8,965,325	$ 16,271,972	$ 25,531,395	$ 23,204,089
Total PV of Customer Benefits	$ 1,918,578,597	$ -	$ 2,014,238	$ 11,105,318	$ 41,253,278	$ 73,251,941	$ 115,959,626	$ 145,839,620
Total PV of Combined Benefits	$ 2,077,329,327	$ -	$ 2,662,521	$ 16,128,029	$ 50,218,603	$ 89,523,913	$ 141,491,021	$ 169,043,709
Project and On-Going Costs	$ 173,340,642	$ 9,105,200	$ 29,687,790	$ 43,667,530	$ 47,649,213	$ 42,316,441	$ 19,211,726	$ 4,120,354
Combined NPV of Project	**$ 1,903,988,685**	$ (9,105,200)	$ (27,025,269)	$ (27,539,502)	$ 2,569,390	$ 47,207,472	$ 122,279,295	$ 164,923,355
Ratio of NPV Benefits to NPV Costs	12.0							
Ratio of NPV Operational Benefits to NPV Costs	0.9							
Cumulative Net Benefits		$ (9,105,200)	$ (27,025,269)	$ (27,539,502)	$ 2,569,390	$ 47,207,472	$ 122,279,295	$ 164,923,355

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
	7	8	9	10	11	12	13	14	15	16	17	18
Project Capital	$ 3,868,082	$ 3,964,785	$ 4,063,904	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Project O&M	$ 116,042	$ 118,944	$ 121,917	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Project Costs	$ 3,984,125	$ 4,083,728	$ 4,185,821	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UG Restoration Costs	$ 239,238	$ 245,219	$ 251,350	$ 287,948	$ 295,146	$ 302,525	$ 310,088	$ 317,840	$ 325,786	$ 333,931	$ 342,279	$ 350,836
Total On-Going O&M	$ 239,238	$ 245,219	$ 251,350	$ 287,948	$ 295,146	$ 302,525	$ 310,088	$ 317,840	$ 325,786	$ 333,931	$ 342,279	$ 350,836
Total Capital Costs	$ 3,868,082	$ 3,964,785	$ 4,063,904	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total O&M (Project + Ongoing)	$ 355,281	$ 364,163	$ 373,267	$ 287,948	$ 295,146	$ 302,525	$ 310,088	$ 317,840	$ 325,786	$ 333,931	$ 342,279	$ 350,836
Total Costs	$ 4,223,363	$ 4,328,947	$ 4,437,171	$ 287,948	$ 295,146	$ 302,525	$ 310,088	$ 317,840	$ 325,786	$ 333,931	$ 342,279	$ 350,836
Non-MED Restoration costs	$ 5,108,802	$ 5,236,522	$ 5,367,435	$ 6,095,889	$ 6,248,287	$ 6,404,494	$ 6,564,606	$ 6,728,721	$ 6,896,939	$ 7,069,363	$ 7,246,097	$ 7,427,249
MED Restoration costs	$ 2,294,394	$ 2,351,753	$ 2,410,547	$ 2,804,086	$ 2,874,188	$ 2,946,043	$ 3,019,694	$ 3,095,187	$ 3,172,566	$ 3,251,880	$ 3,333,177	$ 3,416,507
Total Outage and Restoration Benefits	7,403,195	7,588,275	7,777,982	8,899,976	9,122,475	9,350,537	9,584,300	9,823,908	10,069,506	10,321,243	10,579,274	10,843,756
Eliminate of VM cycle charges	$ 95,000	$ 627,351	$ 1,124,876	$ 1,420,279	$ 1,761,870	$ 1,202,008	$ 381,462	$ 650,759	$ 977,567	$ 1,770,006	$ 1,113,825	$ 2,269,865
Avoid demand trimming costs	$ 370,870	$ 380,142	$ 389,645	$ 409,627	$ 419,868	$ 430,364	$ 441,124	$ 452,152	$ 463,455	$ 475,042	$ 486,918	$ 499,091
Total Vegetation Management Benefits	**$ 465,870**	**$ 1,007,492**	**$ 1,514,521**	**$ 1,829,906**	**$ 2,181,738**	**$ 1,632,372**	**$ 822,585**	**$ 1,102,911**	**$ 1,441,022**	**$ 2,245,048**	**$ 1,600,742**	**$ 2,768,956**
Eliminate deteriorated conductor replacement costs	$ -	$ -	$ -	$ 7,311,699	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Eliminate rotten pole replacement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Asset Management Benefits	$ -	$ -	$ -	$ 7,311,699	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-MED customer cost avoided for reduced outage events	$ 208,869	$ 214,091	$ 219,443	$ 258,029	$ 264,480	$ 271,092	$ 277,869	$ 284,816	$ 291,936	$ 299,234	$ 306,715	$ 314,383
MED customer cost avoided for reduced outage events	$ 157,655	$ 161,596	$ 165,636	$ 215,823	$ 221,219	$ 226,749	$ 232,418	$ 238,228	$ 244,184	$ 250,289	$ 256,546	$ 262,960
Residential customer Momentary Interuption Cost avoided	$ 2,305,688	$ 2,363,330	$ 2,422,413	$ 2,836,717	$ 2,907,634	$ 2,980,325	$ 3,054,833	$ 3,131,204	$ 3,209,484	$ 3,289,722	$ 3,371,965	$ 3,456,264
Small CI customer Momentary Interuption Cost avoided	$ 29,871,944	$ 30,618,743	$ 31,384,211	$ 35,289,589	$ 36,171,828	$ 37,076,124	$ 38,003,027	$ 38,953,103	$ 39,926,930	$ 40,925,104	$ 41,948,231	$ 42,996,937
Large CI customer Momentary Interuption Cost avoided	$ 116,941,455	$ 119,864,992	$ 122,861,616	$ 137,181,137	$ 140,610,666	$ 144,125,932	$ 147,729,081	$ 151,422,308	$ 155,207,865	$ 159,088,062	$ 163,065,263	$ 167,141,895
Total Customer Benefits	$ 149,485,611	$ 153,222,751	$ 157,053,320	$ 175,781,294	$ 180,175,827	$ 184,680,222	$ 189,297,228	$ 194,029,659	$ 198,880,400	$ 203,852,410	$ 208,948,720	$ 214,172,438
Total PV of Operational Benefits	$ 7,869,065	$ 8,595,768	$ 9,292,503	$ 18,041,581	$ 11,304,213	$ 10,982,909	$ 10,406,886	$ 10,926,819	$ 11,510,528	$ 12,566,291	$ 12,180,017	$ 13,612,712
Total PV of Customer Benefits	$ 149,485,611	$ 153,222,751	$ 157,053,320	$ 175,781,294	$ 180,175,827	$ 184,680,222	$ 189,297,228	$ 194,029,659	$ 198,880,400	$ 203,852,410	$ 208,948,720	$ 214,172,438
Total PV of Combined Benefits	$ 157,354,676	$ 161,818,519	$ 166,345,823	$ 193,822,875	$ 191,480,039	$ 195,663,132	$ 199,704,113	$ 204,956,477	$ 210,390,928	$ 216,418,701	$ 221,128,737	$ 227,785,150
Project and On-Going Costs	$ 4,223,363	$ 4,328,947	$ 4,437,171	$ 287,948	$ 295,146	$ 302,525	$ 310,088	$ 317,840	$ 325,786	$ 333,931	$ 342,279	$ 350,836
Combined NPV of Project	$ 153,131,313	$ 157,489,571	$ 161,908,652	$ 193,534,928	$ 191,184,893	$ 195,360,606	$ 199,394,025	$ 204,638,637	$ 210,065,141	$ 216,084,770	$ 220,786,458	$ 227,434,314
Cumulative Net Benefits	$ 153,131,313	$ 157,489,571	$ 161,908,652	$ 193,534,928	$ 191,184,893	$ 195,360,606	$ 199,394,025	$ 204,638,637	$ 210,065,141	$ 216,084,770	$ 220,786,458	$ 227,434,314

	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
	19	20	21	22	23	24	25	26	27	28	29	30
Project Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Project O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Project Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UG Restoration Costs	$ 359,607	$ 368,597	$ 377,812	$ 387,258	$ 396,939	$ 406,863	$ 417,034	$ 427,460	$ 438,147	$ 449,100	$ 460,328	$ 471,836
Total On-Going O&M	$ 359,607	$ 368,597	$ 377,812	$ 387,258	$ 396,939	$ 406,863	$ 417,034	$ 427,460	$ 438,147	$ 449,100	$ 460,328	$ 471,836
Total Capital Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total O&M (Project + Ongoing)	$ 359,607	$ 368,597	$ 377,812	$ 387,258	$ 396,939	$ 406,863	$ 417,034	$ 427,460	$ 438,147	$ 449,100	$ 460,328	$ 471,836
Total Costs	$ 359,607	$ 368,597	$ 377,812	$ 387,258	$ 396,939	$ 406,863	$ 417,034	$ 427,460	$ 438,147	$ 449,100	$ 460,328	$ 471,836
Non-MED Restoration costs	$ 7,612,931	$ 7,803,254	$ 7,998,335	$ 8,198,294	$ 8,403,251	$ 8,613,332	$ 8,828,666	$ 9,049,382	$ 9,275,617	$ 9,507,507	$ 9,745,195	$ 9,988,825
MED Restoration costs	$ 3,501,919	$ 3,589,467	$ 3,679,204	$ 3,771,184	$ 3,865,464	$ 3,962,100	$ 4,061,153	$ 4,162,682	$ 4,266,749	$ 4,373,418	$ 4,482,753	$ 4,594,822
Total Outage and Restoration Benefits	11,114,850	11,392,721	11,677,539	11,969,478	12,268,715	12,575,433	12,889,819	13,212,064	13,542,366	13,880,925	14,227,948	14,583,647
Eliminate of VM cycle charges	$ 1,722,705	$ 899,404	$ 486,138	$ 460,858	$ 2,465,232	$ 1,830,141	$ 3,051,444	$ 1,557,480	$ 194,468	$ 593,678	$ 1,349,843	$ 3,616,542
Avoid demand trimming costs	$ 511,568	$ 524,357	$ 537,466	$ 550,903	$ 564,675	$ 578,792	$ 593,262	$ 608,094	$ 623,296	$ 638,878	$ 654,850	$ 671,222
Total Vegetation Management Benefits	**$ 2,234,273**	**$ 1,423,761**	**$ 1,023,604**	**$ 1,011,761**	**$ 3,029,907**	**$ 2,408,934**	**$ 3,644,706**	**$ 2,165,574**	**$ 817,764**	**$ 1,232,556**	**$ 2,004,693**	**$ 4,287,764**
Eliminate deteriorated conductor replacement costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Eliminate rotten pole replacement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Asset Management Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-MED customer cost avoided for reduced outage events	$ 322,243	$ 330,299	$ 338,556	$ 347,020	$ 355,696	$ 364,588	$ 373,703	$ 383,045	$ 392,621	$ 402,437	$ 412,498	$ 422,810
MED customer cost avoided for reduced outage events	$ 269,534	$ 276,272	$ 283,179	$ 290,258	$ 297,515	$ 304,952	$ 312,576	$ 320,391	$ 328,400	$ 336,610	$ 345,026	$ 353,651
Residential customer Momentary Interuption Cost avoided	$ 3,542,670	$ 3,631,237	$ 3,722,018	$ 3,815,068	$ 3,910,445	$ 4,008,206	$ 4,108,411	$ 4,211,122	$ 4,316,400	$ 4,424,310	$ 4,534,917	$ 4,648,290
Small CI customer Momentary Interuption Cost avoided	$ 44,071,860	$ 45,173,657	$ 46,302,998	$ 47,460,573	$ 48,647,088	$ 49,863,265	$ 51,109,847	$ 52,387,593	$ 53,697,283	$ 55,039,715	$ 56,415,707	$ 57,826,100
Large CI customer Momentary Interuption Cost avoided	$ 171,320,442	$ 175,603,453	$ 179,993,540	$ 184,493,378	$ 189,105,713	$ 193,833,356	$ 198,679,189	$ 203,646,169	$ 208,737,323	$ 213,955,756	$ 219,304,650	$ 224,787,267
Total Customer Benefits	$ 219,526,749	$ 225,014,918	$ 230,640,291	$ 236,406,298	$ 242,316,456	$ 248,374,367	$ 254,583,726	$ 260,948,319	$ 267,472,027	$ 274,158,828	$ 281,012,799	$ 288,038,119
Total PV of Operational Benefits	$ 13,349,124	$ 12,816,482	$ 12,701,144	$ 12,981,238	$ 15,298,622	$ 14,984,366	$ 16,534,524	$ 15,377,638	$ 14,360,130	$ 15,113,481	$ 16,232,641	$ 18,871,410
Total PV of Customer Benefits	$ 219,526,749	$ 225,014,918	$ 230,640,291	$ 236,406,298	$ 242,316,456	$ 248,374,367	$ 254,583,726	$ 260,948,319	$ 267,472,027	$ 274,158,828	$ 281,012,799	$ 288,038,119
Total PV of Combined Benefits	$ 232,875,873	$ 237,831,400	$ 243,341,435	$ 249,387,537	$ 257,615,078	$ 263,358,733	$ 271,118,251	$ 276,325,957	$ 281,832,157	$ 289,272,309	$ 297,245,440	$ 306,909,529
Project and On-Going Costs	$ 359,607	$ 368,597	$ 377,812	$ 387,258	$ 396,939	$ 406,863	$ 417,034	$ 427,460	$ 438,147	$ 449,100	$ 460,328	$ 471,836
Combined NPV of Project	$ 232,516,266	$ 237,462,803	$ 242,963,622	$ 249,000,279	$ 257,218,138	$ 262,951,871	$ 270,701,216	$ 275,898,497	$ 281,394,011	$ 288,823,209	$ 296,785,112	$ 306,437,693
Cumulative Net Benefits	$ 232,516,266	$ 237,462,803	$ 242,963,622	$ 249,000,279	$ 257,218,138	$ 262,951,871	$ 270,701,216	$ 275,898,497	$ 281,394,011	$ 288,823,209	$ 296,785,112	$ 306,437,693

	2050	2051	2052	2053	2054	2055	Totals
	31	32	33	34	35	36	
Project Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ 201,399,032
Project O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,041,971
Total Project Costs	$ -	$ -	$ -	$ -	$ -	$ -	**$ 207,441,003**
UG Restoration Costs	$ 388,569	$ 211,173	$ 141,217	$ -	$ -	$ -	$ 9,875,056
Total On-Going O&M	$ 388,569	$ 211,173	$ 141,217	$ -	$ -	$ -	**$ 9,875,056**
Total Capital Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 201,399,032
Total O&M (Project + Ongoing)	$ 388,569	$ 211,173	$ 141,217	$ -	$ -	$ -	$ 15,917,026
Total Costs	$ 388,569	$ 211,173	$ 141,217	$ -	$ -	$ -	**$ 217,316,058**
Non-MED Restoration costs	$ 8,475,080	$ 5,097,135	$ 3,209,760	$ -	$ -	$ -	$ 210,710,014
MED Restoration costs	$ 3,638,421	$ 2,219,418	$ 1,605,653	$ -	$ -	$ -	$ 96,107,290
Total Outage and Restoration Benefits	12,113,501	7,316,553	4,815,414	-	-	-	**306,817,304**
Eliminate of VM cycle charges	$ 778,646	$ 535,248	$ 1,461,025	$ -	$ -	$ -	$ 34,627,644
Avoid demand trimming costs	$ 567,602	$ 282,081	$ 126,496	$ -	$ -	$ -	$ 14,417,276
Total Vegetation Management Benefits	**$ 1,346,248**	**$ 817,329**	**$ 1,587,520**	**$ -**	**$ -**	**$ -**	**$ 49,044,920**
Eliminate deteriorated conductor replacement costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,688,208
Eliminate rotten pole replacement	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Asset Management Benefits	$ -	$ -	$ -	$ -	$ -	$ -	**$ 67,688,208**
Non-MED customer cost avoided for reduced outage events	$ 370,601	$ 235,782	$ 143,476	$ -	$ -	$ -	$ 8,943,635
MED customer cost avoided for reduced outage events	$ 287,814	$ 186,400	$ 149,148	$ -	$ -	$ -	$ 7,348,936
Residential customer Momentary Interuption Cost avoided	$ 3,751,546	$ 2,132,240	$ 1,633,363	$ -	$ -	$ -	$ 97,525,256
Small CI customer Momentary Interuption Cost avoided	$ 49,176,461	$ 27,177,254	$ 20,663,386	$ -	$ -	$ -	$ 1,220,205,980
Large CI customer Momentary Interuption Cost avoided	$ 174,380,344	$ 95,185,807	$ 75,430,349	$ -	$ -	$ -	$ 4,744,376,964
Total Customer Benefits	$ 227,966,765	$ 124,917,483	$ 98,019,722	$ -	$ -	$ -	**$ 6,078,400,770**
Total PV of Operational Benefits	$ 13,459,749	$ 8,133,883	$ 6,402,934	$ -	$ -	$ -	$ 423,550,432
Total PV of Customer Benefits	$ 227,966,765	$ 124,917,483	$ 98,019,722	$ -	$ -	$ -	$ 6,078,400,770
Total PV of Combined Benefits	$ 241,426,514	$ 133,051,365	$ 104,422,656	$ -	$ -	$ -	**$ 6,501,951,202**
Project and On-Going Costs	$ 388,569	$ 211,173	$ 141,217	$ -	$ -	$ -	$ 217,316,058
Combined NPV of Project	$ 241,037,945	$ 132,840,193	$ 104,281,439	$ -	$ -	$ -	**$ 6,284,635,144**
Cumulative Net Benefits	$ 241,037,945	$ 132,840,193	$ 104,281,439	$ -	$ -	$ -	**$ 6,284,635,144**

TAB NAMES: 2019 TAB SUMMARY
2020 TAB SUMMARY
2021 TAB SUMMARY
2022 TAB SUMMARY
ALL YEARS TAB SUMMARY

- Contains summary of cost and benefit line items by year and in total
- Detail cash flow by year for lifecycle

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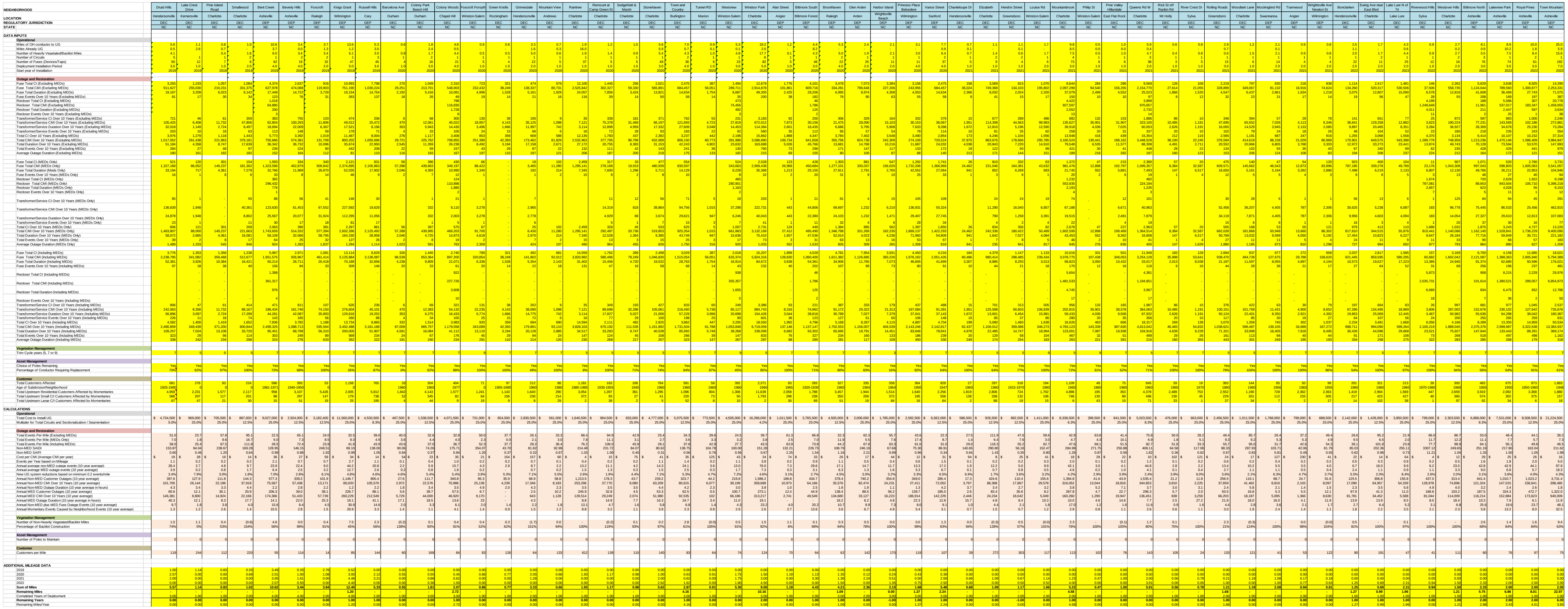

TAB NAME: AREA DATA - CONDENSED

- Contains individual project data and calculations related to operational, outage, and customer items
- Used for individual CBA modeling

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ASSUMPTIONS (FIXED)

Operational		
Multiplier for Cleared Operations	2.7	
Sectionalization Divider	4	
O&M adder based on Capital	3.0%	
Outage and Restoration		
Minumum Average UG Events per Mile	0.20	
DEC Average Cost per Non-MED Outage Event	$ 5,477	
DEC Average Cost per MED Outage Event	$ 16,431	
DEP Average Cost per Non-MED Outage Event	$ 4,742	
DEP Average Cost per MED Outage Event	$ 14,227	
Vegetation Management		
Cost/Mile to Trim Vegetation	$ 24,000	
Annual Demand Trimming Costs	$ 8,000	Will vary by neighborhood
Asset Management		
Cost/Mile to Install UG (Note 1)	$ 850,000	
Deteriorated Conductor Replacement Timeframe	30	
Pole Replacement Timeframe	50	
Cost/Mile to Replace Deteriorated Backlot OH conductor	$ 375,000	
Cost to Replace Backlot Poles	$ 3,000	
Customer		
Residential Customer %	100%	
Small C/I Customer %	0%	
Large C/I Customer %	0%	

Standard assumptions for all areas - review if standard applies

ICE TABLE

Table ES-1: Estimated Interuption Cost per Event, Average kW and Unserved kWh (US 2013$) by Duration and Customer Class							
Interruption Cost	Interruption Duration						
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours	48 Hours (calculated)
	0.0	0.5	1.0	4.0	8.0	16.0	48.0
Cost per Event							
Medium and Large C&I (Over 50,000 Annual kWh)							
Cost per Event	$12,952.00	$15,241.00	$17,804.00	$39,458.00	$84,083.00	$165,482.00	$491,078.00
Cost per Average kW	$15.90	$18.70	$21.80	$48.40	$103.20	$203.00	
Cost per Unserved kWh	$190.70	$37.40	$21.80	$12.10	$12.90	$12.70	
Small C&I (Under 50,000 Annual kWh)							
Cost per Event	$412.00	$520.00	$647.00	$1,880.00	$4,690.00	$9,055.00	$26,515.00
Cost per Average kW	$187.90	$237.00	$295.00	$857.10	$2,138.10	$4,128.30	
Cost per Unserved kWh	$2,254.60	$474.10	$295.00	$214.30	$267.30	$258.00	
Residential							
Cost per Event	$3.90	$4.50	$5.10	$9.50	$17.20	$32.40	$93.20
Cost per Average kW	$2.60	$2.90	$3.30	$6.20	$11.30	$21.20	
Cost per Unserved kWh	$30.90	$5.90	$3.30	$1.60	$1.40	$1.30	

FINANCIAL ASSUMPTIONS

Assumption	Value	Source
Escalation Rate	2.50%	Duke Energy Standard Assumptions (provided by Treasury)
Discount Rate (WACC) DEC-SC	7.05%	Duke Energy Standard Assumptions (provided by Treasury)
Discount Rate (WACC) DEC-NC	6.80%	Duke Energy Standard Assumptions (provided by Treasury)
Discount Rate (WACC) DEP-SC	7.00%	Duke Energy Standard Assumptions (provided by Treasury)
Discount Rate (WACC) DEP-NC	6.80%	Duke Energy Standard Assumptions (provided by Treasury)

TAB NAME: LOOKUPS

- Contains standard assumptions used commonly for all CBAs
  - Cost metrics
  - Operational metrics
  - ICE table
  - Inflation rate
  - Discount rate (individual jurisdiction Weighted Average Cost of Capital)

DUKE ENERGY.

Supporting data room document: TUG_DEC-DEP_NC_19-22_Consolidated_vF 5-8-19.xlsm

NEIGHBORHOOD:	Windsor Park	Back to Summary
LOCATION:	Charlotte	
REGULATORY JURISDICTION:	DEC	
STATE:	NC	
DISCOUNT RATE:	Discount Rate (WACC) DEC-NC 6.80%	
PROJECT START (Year):	2020	
PROJECT LIFESPAN (Years):	30	

	NPV of COST/BENEFIT STREAM	2019	2020	2021	2022	2023	2024	2025	2026	2027
		0	1	2	3	4	5	6	7	8
COSTS										
Project Capital	$ 14,133,254	$ -	$ 1,306,875	$ 2,679,094	$ 4,119,107	$ 4,766,264	$ 4,885,421	$ -	$ -	$ -
Project O&M	$ 423,998	$ -	$ 39,206	$ 80,373	$ 123,573	$ 142,988	$ 146,563	$ -	$ -	$ -
Total Project Costs	**$ 14,557,251**	$ -	$ 1,346,081	$ 2,759,467	$ 4,242,680	$ 4,909,252	$ 5,031,983	$ -	$ -	$ -
UG Restoration Costs	$ 267,424	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,339	$ 24,948	$ 25,572
Total On-Going O&M	**$ 267,424**	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,339	$ 24,948	$ 25,572
Total Capital Costs	$ 14,133,254	$ -	$ 1,306,875	$ 2,679,094	$ 4,119,107	$ 4,766,264	$ 4,885,421	$ -	$ -	$ -
Total O&M (Project + Ongoing)	$ 691,421	$ -	$ 39,206	$ 80,373	$ 123,573	$ 142,988	$ 146,563	$ 24,339	$ 24,948	$ 25,572
Total Costs	**$ 14,824,675**	$ -	$ 1,346,081	$ 2,759,467	$ 4,242,680	$ 4,909,252	$ 5,031,983	$ 24,339	$ 24,948	$ 25,572
OPERATIONAL BENEFITS										
Outage and Restoration										
Non-MED Restoration costs	$ 5,303,810	$ -	$ -	$ -	$ -	$ -	$ -	$ 482,725	$ 494,793	$ 507,163
MED Restoration costs	$ 1,528,335	$ -	$ -	$ -	$ -	$ -	$ -	$ 139,101	$ 142,578	$ 146,143
Total Outage and Restoration Benefits	**$ 6,832,145**	-	-	-	-	-	-	621,826	637,371	653,306
Vegetation Management										
Eliminate of VM cycle charges	$ 1,053,902	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoid demand trimming costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Vegetation Management Benefits	**$ 1,053,902**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Asset Management										
Eliminate deteriorated conductor replacement costs	$ 4,772,670	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,082,538	$ -	$ -
Eliminate rotten pole replacement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Asset Management Benefits	**$ 4,772,670**	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,082,538	$ -	$ -
CUSTOMER BENEFITS										
Customer										
Non-MED customer cost avoided for reduced outage events	$ 204,843	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,644	$ 19,110	$ 19,588
MED customer cost avoided for reduced outage events	$ 147,520	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,426	$ 13,762	$ 14,106
Residential customer Momentary Interuption Cost avoided	$ 1,743,928	$ -	$ -	$ -	$ -	$ -	$ -	$ 158,723	$ 162,691	$ 166,758
Small CI customer Momentary Interuption Cost avoided	$ 28,380,870	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,583,076	$ 2,647,653	$ 2,713,845
Large CI customer Momentary Interuption Cost avoided	$ 995,211	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,579	$ 92,843	$ 95,164
Total Customer Benefits	**$ 31,472,371**	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,864,448	$ 2,936,060	$ 3,009,461
COMBINED COSTS AND BENEFITS										
Total PV of Operational Benefits	$ 12,658,716	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,704,363	$ 637,371	$ 653,306
Total PV of Customer Benefits	$ 31,472,371	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,864,448	$ 2,936,060	$ 3,009,461
Total PV of Combined Benefits	$ 44,131,087	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,568,812	$ 3,573,431	$ 3,662,767
Project and On-Going Costs	$ 14,824,675	$ -	$ 1,346,081	$ 2,759,467	$ 4,242,680	$ 4,909,252	$ 5,031,983	$ 24,339	$ 24,948	$ 25,572
Escalation		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deployment percentage		$ -	$ -	$ -	$ -	$ -	$ -	$ 24,339	$ 24,948	$ 25,572
Combined NPV of Project	**$ 29,306,412**	$ -	$ (1,346,081)	$ (2,759,467)	$ (4,242,680)	$ (4,909,252)	$ (5,031,983)	$ 10,544,472	$ 3,548,483	$ 3,637,195
Ratio of NPV Benefits to NPV Costs	**3.0**									
Ratio of NPV Operational Benefits to NPV Costs	**0.9**									
Cumulative Net Benefits		$ -	$ (1,346,081)	$ (2,759,467)	$ (4,242,680)	$ (4,909,252)	$ (5,031,983)	$ 10,544,472	$ 3,548,483	$ 3,637,195

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
	9	10	11	12	13	14	15	16	17	18
COSTS										
Project Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Project O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Project Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UG Restoration Costs	$ 26,211	$ 26,866	$ 27,538	$ 28,226	$ 28,932	$ 29,655	$ 30,397	$ 31,157	$ 31,936	$ 32,734
Total On-Going O&M	$ 26,211	$ 26,866	$ 27,538	$ 28,226	$ 28,932	$ 29,655	$ 30,397	$ 31,157	$ 31,936	$ 32,734
Total Capital Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total O&M (Project + Ongoing)	$ 26,211	$ 26,866	$ 27,538	$ 28,226	$ 28,932	$ 29,655	$ 30,397	$ 31,157	$ 31,936	$ 32,734
Total Costs	$ 26,211	$ 26,866	$ 27,538	$ 28,226	$ 28,932	$ 29,655	$ 30,397	$ 31,157	$ 31,936	$ 32,734
OPERATIONAL BENEFITS										
Outage and Restoration										
Non-MED Restoration costs	$ 519,842	$ 532,838	$ 546,159	$ 559,813	$ 573,808	$ 588,153	$ 602,857	$ 617,928	$ 633,377	$ 649,211
MED Restoration costs	$ 149,796	$ 153,541	$ 157,380	$ 161,314	$ 165,347	$ 169,481	$ 173,718	$ 178,061	$ 182,512	$ 187,075
Total Outage and Restoration Benefits	669,638	686,379	703,539	721,127	739,155	757,634	776,575	795,989	815,889	836,286
Vegetation Management										
Eliminate of VM cycle charges	$ -	$ 588,634	$ -	$ -	$ -	$ -	$ 665,985	$ -	$ -	$ -
Avoid demand trimming costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Vegetation Management Benefits	**$ -**	**$ 588,634**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 665,985**	**$ -**	**$ -**	**$ -**
Asset Management										
Eliminate deteriorated conductor replacement costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Eliminate rotten pole replacement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Asset Management Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CUSTOMER BENEFITS										
Customer										
Non-MED customer cost avoided for reduced outage events	$ 20,077	$ 20,579	$ 21,094	$ 21,621	$ 22,162	$ 22,716	$ 23,284	$ 23,866	$ 24,462	$ 25,074
MED customer cost avoided for reduced outage events	$ 14,459	$ 14,820	$ 15,191	$ 15,571	$ 15,960	$ 16,359	$ 16,768	$ 17,187	$ 17,617	$ 18,057
Residential customer Momentary Interuption Cost avoided	$ 170,927	$ 175,201	$ 179,581	$ 184,070	$ 188,672	$ 193,389	$ 198,223	$ 203,179	$ 208,258	$ 213,465
Small CI customer Momentary Interuption Cost avoided	$ 2,781,691	$ 2,851,233	$ 2,922,514	$ 2,995,577	$ 3,070,466	$ 3,147,228	$ 3,225,908	$ 3,306,556	$ 3,389,220	$ 3,473,950
Large CI customer Momentary Interuption Cost avoided	$ 97,543	$ 99,982	$ 102,482	$ 105,044	$ 107,670	$ 110,361	$ 113,121	$ 115,949	$ 118,847	$ 121,818
Total Customer Benefits	$ 3,084,698	$ 3,161,815	$ 3,240,860	$ 3,321,882	$ 3,404,929	$ 3,490,052	$ 3,577,304	$ 3,666,736	$ 3,758,405	$ 3,852,365
COMBINED COSTS AND BENEFITS										
Total PV of Operational Benefits	$ 669,638	$ 1,275,013	$ 703,539	$ 721,127	$ 739,155	$ 757,634	$ 1,442,560	$ 795,989	$ 815,889	$ 836,286
Total PV of Customer Benefits	$ 3,084,698	$ 3,161,815	$ 3,240,860	$ 3,321,882	$ 3,404,929	$ 3,490,052	$ 3,577,304	$ 3,666,736	$ 3,758,405	$ 3,852,365
Total PV of Combined Benefits	$ 3,754,336	$ 4,436,828	$ 3,944,399	$ 4,043,009	$ 4,144,084	$ 4,247,686	$ 5,019,864	$ 4,462,726	$ 4,574,294	$ 4,688,651
Project and On-Going Costs	$ 26,211	$ 26,866	$ 27,538	$ 28,226	$ 28,932	$ 29,655	$ 30,397	$ 31,157	$ 31,936	$ 32,734
Escalation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deployment percentage	$ 26,211	$ 26,866	$ 27,538	$ 28,226	$ 28,932	$ 29,655	$ 30,397	$ 31,157	$ 31,936	$ 32,734
Combined NPV of Project	$ 3,728,125	$ 4,409,962	$ 3,916,861	$ 4,014,783	$ 4,115,152	$ 4,218,031	$ 4,989,467	$ 4,431,569	$ 4,542,358	$ 4,655,917
Cumulative Net Benefits	$ 3,728,125	$ 4,409,962	$ 3,916,861	$ 4,014,783	$ 4,115,152	$ 4,218,031	$ 4,989,467	$ 4,431,569	$ 4,542,358	$ 4,655,917

	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
	19	20	21	22	23	24	25	26	27	28
COSTS										
Project Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Project O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Project Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UG Restoration Costs	$ 33,552	$ 34,391	$ 35,251	$ 36,132	$ 37,035	$ 37,961	$ 38,910	$ 39,883	$ 40,880	$ 41,902
Total On-Going O&M	$ 33,552	$ 34,391	$ 35,251	$ 36,132	$ 37,035	$ 37,961	$ 38,910	$ 39,883	$ 40,880	$ 41,902
Total Capital Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total O&M (Project + Ongoing)	$ 33,552	$ 34,391	$ 35,251	$ 36,132	$ 37,035	$ 37,961	$ 38,910	$ 39,883	$ 40,880	$ 41,902
Total Costs	$ 33,552	$ 34,391	$ 35,251	$ 36,132	$ 37,035	$ 37,961	$ 38,910	$ 39,883	$ 40,880	$ 41,902
OPERATIONAL BENEFITS										
Outage and Restoration										
Non-MED Restoration costs	$ 665,441	$ 682,077	$ 699,129	$ 716,608	$ 734,523	$ 752,886	$ 771,708	$ 791,001	$ 810,776	$ 831,045
MED Restoration costs	$ 191,752	$ 196,546	$ 201,460	$ 206,496	$ 211,659	$ 216,950	$ 222,374	$ 227,933	$ 233,631	$ 239,472
Total Outage and Restoration Benefits	857,194	878,623	900,589	923,104	946,181	969,836	994,082	1,018,934	1,044,407	1,070,517
Vegetation Management										
Eliminate of VM cycle charges	$ -	$ 753,501	$ -	$ -	$ -	$ -	$ 852,518	$ -	$ -	$ -
Avoid demand trimming costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Vegetation Management Benefits	**$ -**	**$ 753,501**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 852,518**	**$ -**	**$ -**	**$ -**
Asset Management										
Eliminate deteriorated conductor replacement costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Eliminate rotten pole replacement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Asset Management Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CUSTOMER BENEFITS										
Customer										
Non-MED customer cost avoided for reduced outage events	$ 25,701	$ 26,343	$ 27,002	$ 27,677	$ 28,369	$ 29,078	$ 29,805	$ 30,550	$ 31,314	$ 32,097
MED customer cost avoided for reduced outage events	$ 18,509	$ 18,971	$ 19,446	$ 19,932	$ 20,430	$ 20,941	$ 21,464	$ 22,001	$ 22,551	$ 23,115
Residential customer Momentary Interuption Cost avoided	$ 218,801	$ 224,272	$ 229,878	$ 235,625	$ 241,516	$ 247,554	$ 253,743	$ 260,086	$ 266,588	$ 273,253
Small CI customer Momentary Interuption Cost avoided	$ 3,560,799	$ 3,649,819	$ 3,741,065	$ 3,834,591	$ 3,930,456	$ 4,028,718	$ 4,129,435	$ 4,232,671	$ 4,338,488	$ 4,446,950
Large CI customer Momentary Interuption Cost avoided	$ 124,864	$ 127,985	$ 131,185	$ 134,465	$ 137,826	$ 141,272	$ 144,804	$ 148,424	$ 152,135	$ 155,938
Total Customer Benefits	$ 3,948,674	$ 4,047,391	$ 4,148,575	$ 4,252,290	$ 4,358,597	$ 4,467,562	$ 4,579,251	$ 4,693,732	$ 4,811,076	$ 4,931,352
COMBINED COSTS AND BENEFITS										
Total PV of Operational Benefits	$ 857,194	$ 1,632,125	$ 900,589	$ 923,104	$ 946,181	$ 969,836	$ 1,846,599	$ 1,018,934	$ 1,044,407	$ 1,070,517
Total PV of Customer Benefits	$ 3,948,674	$ 4,047,391	$ 4,148,575	$ 4,252,290	$ 4,358,597	$ 4,467,562	$ 4,579,251	$ 4,693,732	$ 4,811,076	$ 4,931,352
Total PV of Combined Benefits	$ 4,805,867	$ 5,679,515	$ 5,049,164	$ 5,175,393	$ 5,304,778	$ 5,437,398	$ 6,425,850	$ 5,712,666	$ 5,855,483	$ 6,001,870
Project and On-Going Costs	$ 33,552	$ 34,391	$ 35,251	$ 36,132	$ 37,035	$ 37,961	$ 38,910	$ 39,883	$ 40,880	$ 41,902
Escalation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deployment percentage	$ 33,552	$ 34,391	$ 35,251	$ 36,132	$ 37,035	$ 37,961	$ 38,910	$ 39,883	$ 40,880	$ 41,902
Combined NPV of Project	$ 4,772,315	$ 5,645,124	$ 5,013,913	$ 5,139,261	$ 5,267,743	$ 5,399,436	$ 6,386,940	$ 5,672,783	$ 5,814,602	$ 5,959,968
Cumulative Net Benefits	$ 4,772,315	$ 5,645,124	$ 5,013,913	$ 5,139,261	$ 5,267,743	$ 5,399,436	$ 6,386,940	$ 5,672,783	$ 5,814,602	$ 5,959,968

	2048	2049	2050	2051	2052	2053	2054	2055	Totals
	29	30	31	32	33	34	35	36	
COSTS									
Project Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,756,760
Project O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 532,703
Total Project Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 18,289,463**
UG Restoration Costs	$ 42,950	$ 44,023	$ 45,124	$ -	$ -	$ -	$ -	$ -	$ 876,507
Total On-Going O&M	$ 42,950	$ 44,023	$ 45,124	$ -	$ -	$ -	$ -	$ -	**$ 876,507**
Total Capital Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,756,760
Total O&M (Project + Ongoing)	$ 42,950	$ 44,023	$ 45,124	$ -	$ -	$ -	$ -	$ -	$ 1,409,209
Total Costs	$ 42,950	$ 44,023	$ 45,124	$ -	$ -	$ -	$ -	$ -	**$ 19,165,969**
OPERATIONAL BENEFITS									
Outage and Restoration									
Non-MED Restoration costs	$ 851,821	$ 873,117	$ 894,945	$ -	$ -	$ -	$ -	$ -	$ 17,383,741
MED Restoration costs	$ 245,459	$ 251,595	$ 257,885	$ -	$ -	$ -	$ -	$ -	$ 5,009,262
Total Outage and Restoration Benefits	1,097,280	1,124,712	1,152,830	-	-	-	-	-	**22,393,003**
Vegetation Management									
Eliminate of VM cycle charges	$ -	$ 964,545	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,825,184
Avoid demand trimming costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Vegetation Management Benefits	**$ -**	**$ 964,545**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,825,184**
Asset Management									
Eliminate deteriorated conductor replacement costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,082,538
Eliminate rotten pole replacement	$ -	$ -	$ -						$ -
Total Asset Management Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 7,082,538**
CUSTOMER BENEFITS									
Customer									
Non-MED customer cost avoided for reduced outage events	$ 32,899	$ 33,721	$ 34,564	$ -	$ -	$ -	$ -	$ -	$ 671,394
MED customer cost avoided for reduced outage events	$ 23,692	$ 24,285	$ 24,892	$ -	$ -	$ -	$ -	$ -	$ 483,510
Residential customer Momentary Interuption Cost avoided	$ 280,084	$ 287,087	$ 294,264	$ -	$ -	$ -	$ -	$ -	$ 5,715,888
Small CI customer Momentary Interuption Cost avoided	$ 4,558,124	$ 4,672,077	$ 4,788,879	0	0	0	0	0	$ 93,020,990
Large CI customer Momentary Interuption Cost avoided	$ 159,836	$ 163,832	$ 167,928	$ -	$ -	$ -	$ -	$ -	$ 3,261,897
Total Customer Benefits	$ 5,054,636	$ 5,181,002	$ 5,310,527	$ -	$ -	$ -	$ -	$ -	**$ 103,153,680**
COMBINED COSTS AND BENEFITS									
Total PV of Operational Benefits	$ 1,097,280	$ 2,089,258	$ 1,152,830	$ -	$ -	$ -	$ -	$ -	$ 33,300,725
Total PV of Customer Benefits	$ 5,054,636	$ 5,181,002	$ 5,310,527	$ -	$ -	$ -	$ -	$ -	$ 103,153,680
Total PV of Combined Benefits	$ 6,151,916	$ 7,270,260	$ 6,463,357	$ -	$ -	$ -	$ -	$ -	**$ 136,454,405**
Project and On-Going Costs	$ 42,950	$ 44,023	$ 45,124	$ -	$ -	$ -	$ -	$ -	$ 19,165,969
Escalation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deployment percentage	$ 42,950	$ 44,023	$ 45,124	$ -	$ -	$ -	$ -	$ -	**$ 876,507**
Combined NPV of Project	$ 6,108,967	$ 7,226,236	$ 6,418,233	$ -	$ -	$ -	$ -	$ -	**$ 117,288,435**
Cumulative Net Benefits	$ 6,108,967	$ 7,226,236	$ 6,418,233	$ -	$ -	$ -	$ -	$ -	**$ 117,288,435**

TAB NAMES: [INDIVIDUAL PROJECT NAME]

- One tab per individual project
- Contains the Cost Benefit Analysis (CBA) summary information and calculations
  - All cost line items
  - All benefit line items
  - Information shown annually for the evaluation lifecycle
- Shows net result of benefit to cost ratio

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Selected Standard CBA Assumptions

COST ASSUMPTIONS	
UG cost per mile to deploy	$850,000
O&M adder to project capital	3%

BENEFIT ASSUMPTIONS	
Avoided cost per non-major event outage (DEC)	$5,477
Avoided cost per major event outage (DEC)	$16,431
Avoided cost per mile of vegetation management	$24,000
Avoided cost per mile of OH conductor replacement	$375,000

NPV ASSUMPTIONS	
Weighted average cost of capital (DEC-NC)	6.8%
Inflation Rate	2.5%
Evaluation period (years)	30

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Overview of CBA Calculations

COSTS	
Project Capital	
Project O&M	
Total Project Costs	
UG Restoration Costs	
Total On-Going O&M	
Total Capital Costs	
Total O&M (Project + Ongoing)	
Total Costs	
OPERATIONAL BENEFITS	
Outage and Restoration	
Non-MED Restoration Costs	
MED Restoration Costs	
Total Outage and Restoration Benefits	
Vegetation Management	
Eliminate of VM Cycle Charges	
Avoid Demand Trimming Costs	
Total Vegetation Management Benefits	
Asset Management	
Eliminate Deteriorated Conductor Replacement Costs	
Eliminate Rotten Pole Replacement	
Total Asset Management Benefits	
CUSTOMER BENEFITS	
Customer	
Non-MED Customer Cost Avoided for Reduced Outage Events	
MED Customer Cost Avoided for Reduced Outage Events	
Residential Customer Momentary Interruption Cost Avoided	
Small CI Customer Momentary Interruption Cost Avoided	
Large CI Customer Momentary Interruption Cost Avoided	
Total Customer Benefits	

COST ITEMS	
Project Capital	Cost/Mile to Install * Miles of OH Conductor to UG
Project O&M	Project Capital * O&M Adder
UG Restoration Costs	Min. Avg. UG Events/Mile * Miles of OH Conductor to UG * Avg. Cost/Non-MED Outage Event

OPERATIONAL BENEFIT ITEMS	
Non-MED/MED Restoration Costs	Average Annual Outage Events * Average Cost per Outage Event
Elimination of VM Cycle Charges	Cost/Mile to Trim Vegetation * Miles of OH Conductor to UG
Avoided Demand Trimming Costs	Annual Demand Trimming Costs (if applicable…greater than 5 year trim cycle)
Eliminate Deteriorated Conductor Replacement Costs	Cost/Mile to Replace Deteriorated Backlot OH conductor * Miles of OH Conductor to UG * Percentage of Conductor Requiring Replacement
Eliminate Rotten Pole Replacements	Note: not used currently…assume all poles remain

CUSTOMER BENEFIT ITEMS	
Non-MED and MED Customer Cost Avoided for Reduced Outage events	Residential Annual Customer Outages * Net Outages Avoided with UG * Residential Outage Value (ICE)
Customer Momentary Interruption Cost Avoided	Annual Momentary Events Caused by Neighborhood Events* Momentary Cost/Event (ICE) * Upstream Customers Affected by Momentaries

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Windsor Park Example

Top 1/3 worst performing line sections

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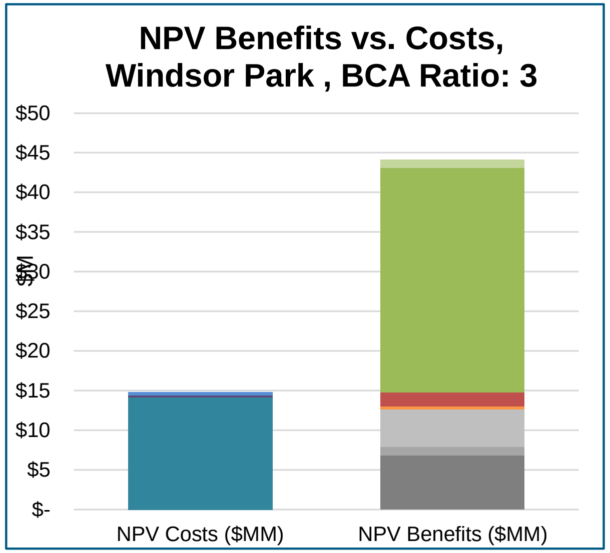
Windsor Park Example

		NPV of COST/BENEFIT STREAM
COSTS		
Total Capital Costs	$	14,133,254
Total O&M (Project + Ongoing)	$	691,421
Total Costs	**$**	**14,824,675**
OPERATIONAL BENEFITS		
Non-MED Restoration costs	$	5,303,810
MED Restoration costs	$	1,528,335
Total Outage and Restoration Benefits	**$**	**6,832,145**
Eliminate of VM cycle charges	$	1,053,902
Avoid demand trimming costs	$	-
Total Vegetation Management Benefits	**$**	**1,053,902**
Eliminate deteriorated conductor replacement costs	$	4,772,670
Eliminate rotten pole replacement	$	-
Total Asset Management Benefits	**$**	**4,772,670**
CUSTOMER BENEFITS		
Non-MED customer cost avoided for reduced outage events	$	204,843
MED customer cost avoided for reduced outage events	$	147,520
Residential customer Momentary Interuption Cost avoided	$	1,743,928
Small CI customer Momentary Interuption Cost avoided	$	28,380,870
Large CI customer Momentary Interuption Cost avoided	$	995,211
Total Customer Benefits	**$**	**31,472,371**
COMBINED COSTS AND BENEFITS		
Total PV of Operational Benefits	$	12,658,716
Total PV of Customer Benefits	$	31,472,371
Total PV of Combined Benefits	$	44,131,087
Combined NPV of Project	**$**	**29,306,412**
Ratio of NPV Benefits to NPV Costs		**3.0**

WINDSOR PARK DATA

- Located in Charlotte, NC (DEC)
- 2,371 residential customers
- Built in 1960's
- Averaged 4 non-major event day outages annually over previous 10 years
- Approximately 19 miles of OH – 85% consists of small, non-standard wire
- 92% of OH conductor is considered "back lot" or not easily accessible
- 6 circuits impacted for momentaries by upstream customers
  - Residential – 11,639
  - Small & Med. C&I – 1,793
  - Large C&I – 2
- Vegetation trim cycle – 5 years



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TUG Cost-Benefit Portfolio Summary

What success looks like

- 55 Projects or equivalent scope planned and deployed from 2019 to 2022
- Combined benefit to cost ratio of 12.0
- Approximately 221 miles in 2019 to 2022 scope

Cost-Benefit Highlights and Insights

- Net present costs are $173M
  - Project capital costs - $165M
  - Project O&M costs - $8M
- Net present benefits are $2,077M
  - Operational Benefits - $159M
  - Customer Benefits - $1,918M
- Additional societal benefit impacts from IMPLAN analysis performed by Dr. Von Nessen

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Q & A

Stakeholder Webinar: North Carolina Grid Improvement Plan
Transmission Programs Cost/Benefit Analysis

June 2019

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Agenda

- Welcome & Overview
- Webinar Logistics
- Benefit Concepts & Analysis
- Featured Discussion Module
    - Transmission Programs CBA
- Q&A
- Close

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Webinar Logistics

QUESTIONS & COMMENTS

- Questions can be submitted using the Q&A button in the upper right-hand corner of your screen (viewable only by webinar hosts). If you can hear the audio, please type 'Yes' using the Q&A button to demonstrate this functionality
- Questions presented using the Q&A button will be reviewed at real-time for response throughout the workshop
- We will open the line up for discussion multiple times throughout the presentation. To avoid background noise, we ask that you mute your phone when not speaking
- Webinar hosts will address as many questions as time allows
- You may enlarge screen to 100% or Full-Screen presentation using the selection on the upper right-hand corner

TOPIC PRIORITIES & RECOMMENDATIONS

- During this segment, input and feedback will be solicited on the specific areas:
  1) Transmission Programs
- Webinar participants will also be invited to suggest additional topics for future webinars

WEBINAR HOUSEKEEPING

- Should you have problems during the webinar or need access to the Data Room, please contact Miko Palmer (miko.palmer@duke-energy.com) for assistance
- To enable viewing at a later time, this webinar will be recorded
- All webinar materials will be available in the data room for future access.

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Benefits from Improving the Grid

Societal

- Lower impact to global environment
- Avoided water impacts
- Avoided land impacts
- Reduced blackouts *(security & well-being)*
- Improved quality of life
- Improved access to data
- Better customer experience

Indirect (to third parties)

- Improved economics for the state
- Increased competitiveness for the state
- Increased employment for the state
- Increased global DER enablement
- Increased transportation electrification enablement

Indirect Value (risk reduction)

- Increased system redundancy
- Improved power quality
- Improved system stability
- Avoided ancillary services
- Improved employee safety
- Reduced chance of environmental incident
- Reduced remediation costs
- Increased public safety

Direct value (captured by customer)

- Avoided business revenue loss
- Avoided equipment damage
- Avoided spoilage
- Avoided ancillary costs *(hotel, generator, lost work)*
- Increased customer-owned DER enablement
- Decreased energy use or use off peak

Direct value (captured by utility)

- Avoided transmission capacity
- Avoided transmission losses
- Avoided distribution capacity
- Avoided distribution losses
- Avoided generation capacity
- Avoided fuel costs
- Deferred capital cost
- Avoided power purchase
- Lower restoration costs
- Theft reduction
- Improved utility operations *(i.e., lower O&M)*
- Avoided CO_2
- SO_2 emission reduction
- NO_x emission reduction
- Hg emission reduction
- Particulate matter emission reduction

Transmission Hardening & Resiliency Programs

Cost Benefit Analysis Review

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TGMP Core Programs

Transmission Modernization

- Hardening & Resiliency initiatives for substations and lines
- Physical and cyber security
- System intelligence

Hardening/Resiliency – Substations

Increased operational flexibility, adaptability, and speed during and following outage events

Hardening/Resiliency - Transmission Lines

Transmission Lines designed for severe weather and increased automation across the grid; Improved operational flexibility, adaptability, and speed during and following outage events

Physical/Cyber Security

Improved guards protecting the overall security of the transmission system. Leveraging security measures to detect, defend, and mitigate threats and for rapid recovery should an event occur.

System Intelligence

A smart transmission system allows for faster, more intelligent analysis and response to events and a platform for asset health management.

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Transmission Grid Modernization

Optimize

Hardening & Resiliency of Substations

- **Flooded** Substation Mitigation
- **Oil-filled Breaker** replacements
- **Transformer** bank replacements

Hardening & Resiliency of Lines

- **Modified designs** for extreme flooding, wind and ice
- Wood structures elimination and line **strengthening**
- **Enhanced switching** capability- improved functionality

Protect

Physical & Cyber Security

- Physical **security** improvements at subs
- Eliminating **security** vulnerabilities of field equipment
- Threat identification and analysis **tools**

Modernize

System Intelligence Platforms

- Conditioned-based **monitoring**
- Advanced **fault location & isolation**
- Improved **communication & system intelligence**

Substation Flood Mitigation

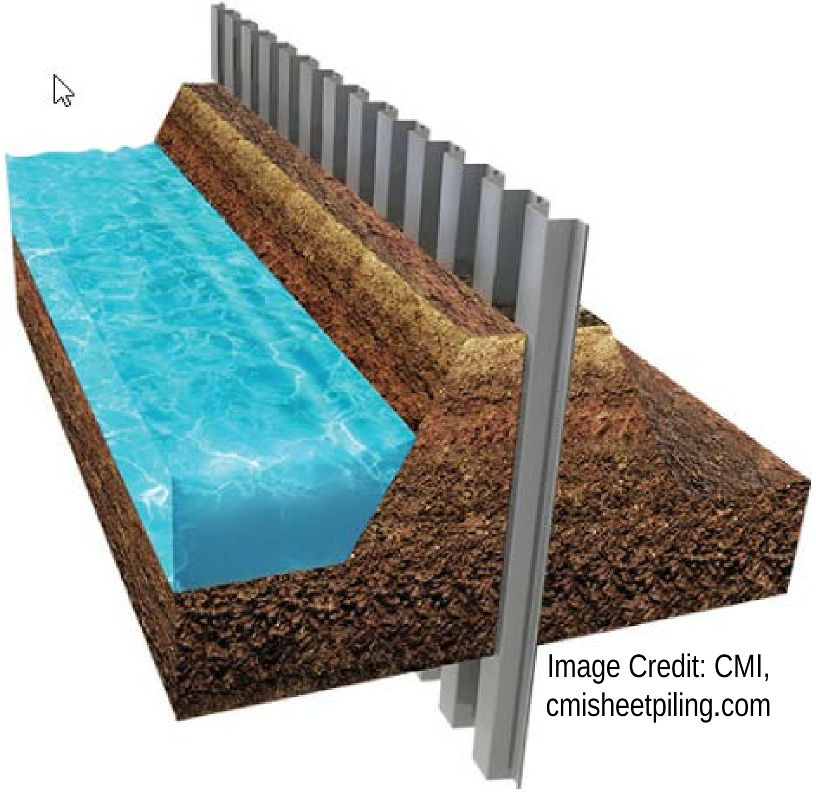
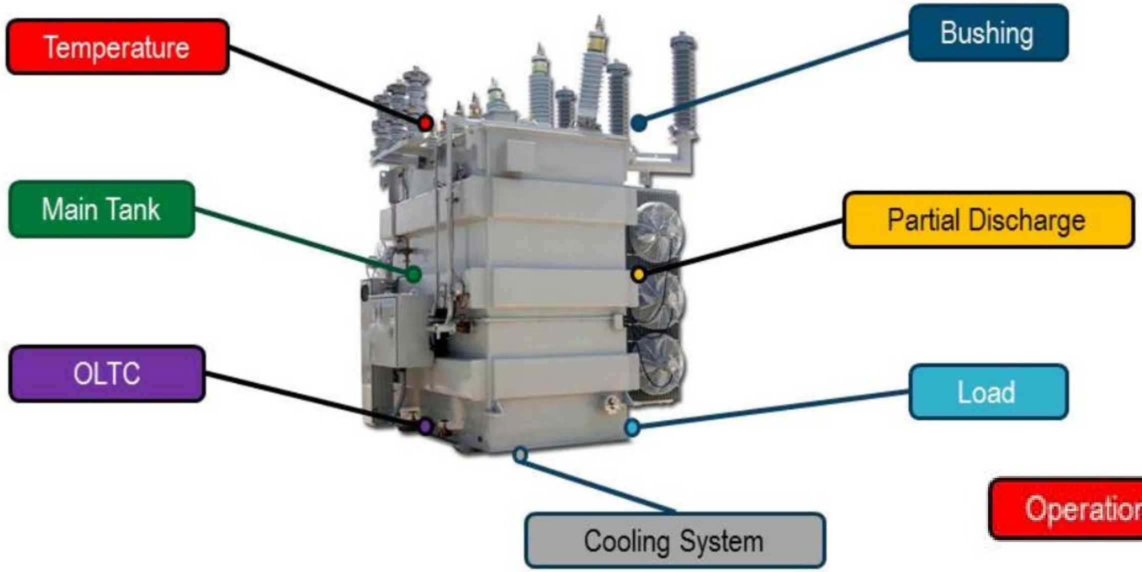


Image Credit: CMI, cmisheetpiling.com



Power Transformer Banks
with Advanced Monitoring

Modernized Gas
Circuit Breaker with
Advanced Monitoring

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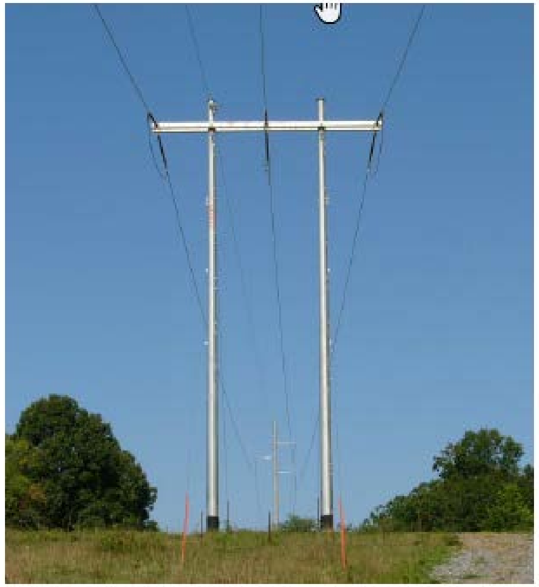
Transmission Line Rebuilds



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Grid Improvement Plan | DOCUMENTS

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Cost Benefit Analysis (CBA) Approach

CBA Category	CBA Approach
Flooded Substation Mitigation	Reinforce- Program level analysis comparing cost to rebuild stations following flooding events vs. cost to reinforce stations. Covers 13 sites unique station in DEP, both NC & SC. Relocate- Site specific analysis using outage history, cost to rebuild, cost to relocate (1 site). Savings includes avoided customer outage costs.
Transmission Line Hardening & Resiliency Projects	Project specific analysis- Use Copperleaf C55 to rank condition & criticality of assets; use ICE calculator to quantify customer outage cost and future savings associated with reduced outages.
Transmission Oil Breaker Replacements	Program level- Use outage history to evaluate customer savings of proactive asset replacement, and compare against cost of reactive replacement. Savings represents avoided customer outage costs.
Transmission Transformer Bank Replacements	Program level- Use outage history to evaluate customer savings of proactive asset replacement, and compare against cost of reactive replacement. Savings represents avoided customer outage costs.

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Questions?

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Substation Flood Mitigation- Reinforce- CBA Summary

What success looks like

- Substations susceptible to flooding during extreme weather events are protected from damage and able to maintain service to customers and support a reliable transmission grid

Cost-Benefit Highlights and Insights

Reinforce

- Thirteen unique DEP stations in scope, selected based on location and past events. Stations will be reinforced with flood walls.
- Net present value
  - Project capital costs, reinforce - $10.4M
  - Operational benefits, avoided rebuild- $21.8M
- Additional societal benefit impacts from IMPLAN analysis performed by Dr. Von Nessen

Key notes about analytic method

- Detailed engineering analysis performed for each site to determine the best solution to meet needs of company and customers
- CBAs significantly different than SC filing due to study findings- most sites evolved to reinforce solution in lieu of relocation, resulting in customer savings

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Substation Flood Mitigation- Reinforce- CBA Summary

Data room file: Trans_Flood Sub_Reinforce_DEP_NC-SC_19-20_All Program_vF 5-3-19

	Greenville 230kV - Flooded Substation	Whiteville 115kV - Flooded Substation (Temp) (1)	Lee S.E. Plant - Flooded Substation	Lumberton 115kV - Flooded Substation	Goldsboro Weil 115kV - Flooded Substation	Wallace 230kV - Flooded Substation	Grifton 115kV - Flooded Substation
Location	Greenville, NC	Whiteville, NC	Goldsboro, NC	Lumberton, NC	Goldsboro, NC	Wallace, NC	Grifton, NC
Customers Affected	Flooding during Hurricane Matthew only. Load was transferred.		Flooding during Hurricane Matthew	No outage/load affected (Florence & Matthew). During Florence, a temporary Tiger Dam was erected to keep out water.	Hurricane Florence; substation flooded; all load transferred to distribution. No CMI	No outage/load affected (Florence)	Load was transferred
Total Customer Minutes Interrupted	None		None	None	None	None	None
Retail customers	N/A		N/A	916	1,488	N/A	3,438
Wholesale	1- Greenville Utilities, 330MW, equivalent to 66,000 customers		N/A- Generation switchyard	Serves the City of Lumberton (COL) POD #4 (1 of 3). COL is an approx. 85 MW Wholesale.	N/A	N/A	N/A
Industrial/ Large C&I	N/A		N/A	Feeds 4 critical customers: Southeastern Regional Medical Center, Kayser-Roth Hoisery, United States Cold Storage (2).	N/A	N/A	N/A
Commercial/ Small C&I	N/A		N/A		2- Case Farms, AP Exhaust products	N/A	N/A
Asset repair costs - rebuild substation after Hurricane	$ 1,686,842	$ -	$ 2,690,658	$ 871,355	$ 1,049,000	$ -	$ 558,000
Asset repair costs - rebuild substation after Hurricane	$ -	$ -	$ -	$ -	$ 5,023	$ 4,885,200	$ 74,582
Budgeted cost for site hardening (flood hazard reinforcement)	$ 546,000	$ 1,526,000	$ 420,000	$ 910,000	$ 1,330,000	$ 2,814,000	$ 658,000
Year	2019	2019	2019	2019	2020	2020	2020

	Total Rebuild Cost (13 sites)	Average Cost (13 sites)					
					Reinforce 4 sites - 2019	$ 3,402,000	
Hurricane Matthew	$ 9,496,249	$ 730,481			Reinforce 9 sites - 2020	$ 7,474,000	
Hurricane Florence	$ 7,505,358	$ 577,335					
Average	**$ 8,500,804**	**$ 653,908**			Repair 13 sites at avg. cost (once)	$ 8,500,804	
					Repair costs for Matthew/Florence	$ 17,001,607	

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Substation Flood Mitigation- Relocate- CBA Summary

What success looks like

- Substations susceptible to flooding during extreme weather events are protected from damage and able to maintain service to customers and support a reliable transmission grid

Cost-Benefit Highlights and Insights

Relocate

- One station will be relocated to eliminate flood hazard- Whiteville 115kV- in particularly vulnerable location and has direct impact on customers based on outage history
- This station also addressed under short term reinforce option- relocate is longer term
- Net present value
  - Project capital costs, relocate - $9.8M
  - Customer benefits, outage savings - $1.4M
  - Operational benefits, avoided rebuild costs- $5M
- Additional societal benefit impacts from IMPLAN analysis performed by Dr. Von Nessen

Key notes about analytic method

- Detailed engineering analysis performed for each site to determine the best solution to meet needs of company and customers
- CBAs significantly different than SC filing due to study findings- most sites evolved to reinforce solution in lieu of relocation, resulting in customer savings

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Substation Flood Mitigation- Relocate- CBA Summary

Data room file: Trans_Flood Sub_Rebuild_DEP_NC-SC_22_Whiteville_vF 5-3-19

	Whiteville 115kV - Flooded Substation (Permanent Relocation)
Outage Begin Time:	9/14/2018 8:08
Load Restored Time:	9/21/2018 18:00
Duration (minutes):	10,672
Customers Affected:	5067 Distribution retail customers, plus 6 critical customers (16.7 MW total)
Total Customer Minutes interrupted (Retail CMI)	54,069,957
Retail customers	5,067
Wholesale	N/A
Industrial	N/A
Commercial (critical customers)	6
Asset repair costs - rebuild substation after Hurricane Matthew	$ 1,511,000
Asset repair costs - rebuild substation after Hurricane Florence	$ 2,250,000
Budgeted cost for site hardening (flood hazard reinforcement)	$ 12,037,769
Deployment Year	2022
Average Cost per Major Rebuild:	$ 1,880,500

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Transmission Line Rebuild Cost-Benefit Summary

What success looks like

Cost-Benefit Highlights and Insights

- 25 Projects scoped and planned for 2019 to 2021, approx. 160 miles; additional projects scoped for 2022
- DEC primary focus is 44kV rebuilds- replacing wood with steel built to 100kV standard, increased height (reduced vegetation impacts), increased BIL (lightning) and increased phase spacing (animals)
- DEP primary focus is replacing failing static ground wire with state-of-the-art fiber optics, replacing wood switch structures, installing steel structures in hard to access locations
- NPV ratio compares avoided outage cost savings to project costs
- Additional societal benefit impacts from IMPLAN analysis performed by Dr. Von Nessen

Key notes about analytic method

- Copperleaf C55 used to rank each project based on asset health, load, configuration, redundancy, cost
  - Transmission Reliability Risk model values the outage cost assuming no action taken; outages and costs are avoided through project implementation
  - Utilizes ICE calculator

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Transmission Line Rebuild Cost-Benefit Summary

Data room files: Trans_Line Projects_DEC_NC-SC_19-20_multiple_vF 5-3-19
Trans_Line Projects_DEP_NC-SC_19-21_multiple_vF 5-3-19

AREA/PROGRAM/PROJECT	Spindale 44kV Rebuild FairviewT					
PERIOD:	2019-2049					
REGULATORY JURISDICTION:	DEC					
STATE:	NC/SC					
	NPV of COST/BENEFIT STREAM	2019	2020	2021	2022	2023
		0	1	2	3	4
COSTS						
INVESTMENT COST						
Investment Cost - Capital	$ 7,568,509	$ 625	$ 201,771	$ 7,398,963	$ 1,086,857	$ -
Investment Cost - O&M	$ -	$ -	$ -	$ -	$ -	$ -
Total Investment Cost	$ 7,568,509	$ 625	$ 201,771	$ 7,398,963	$ 1,086,857	$ -
BENEFITS						
OPERATIONAL BENEFITS						
Operational Savings	$ -	$ -	$ -	$ -	$ -	$ -
CUSTOMER BENEFITS						
Transmission Reliability Benefit - Structure Replaceme	$ 47,398,308	$ -	$ -	$ -	$ -	$ 3,508,666
Transmission Reliability Benefit - Static Line Replacem	$ 29,149,326	$ -	$ -	$ -	$ -	$ 2,157,783
Transmission Reliability Benefit - Conductor Replacem	$ 33,618,568	$ -	$ -	$ -	$ -	$ 1,456,808
Total Customer Benefits	$ 110,166,203	$ -	$ -	$ -	$ -	$ 7,123,256
TOTAL OPERATIONAL/CUSTOMER BENEFITS	$ 110,166,203	$ -	$ -	$ -	$ -	$ 7,123,256
COMBINED COSTS AND BENEFITS						
Combined NPV of Program	$ 102,597,693	$ (625)	$ (201,771)	$ (7,398,963)	$ (1,086,857)	$ 7,123,256
Ratio of NPV Benefits to NPV Costs	14.6					

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Transmission Breaker Cost-Benefit Summary

What success looks like

- Reduced customer outages achieved through proactive asset replacement
- Enhanced grid resiliency through installation of modernized equipment

Cost-Benefit Highlights and Insights

- 2019-2021 scope includes 370 breakers (DEP), 995 breakers (DEC). Additional breakers scoped for 2022.
- Net present benefits include:
  - Operational Benefits – Asset management savings associated with proactive replacement
  - Customer Benefits – Reduced outage cost through avoiding failures and reactive replacement (represents majority of the benefit)
- Net Present Costs include circuit breakers and installation labor
- Additional societal benefit impacts from IMPLAN analysis performed by Dr. Von Nessen

Key notes about analytic method

- Historical outages information used to determine failure impacts (5yr data)
  - Average number of residential, large C&I, small C&I customers with outage impacts from an asset failure
  - Average duration of customer outage from asset failure
  - Utilize ICE calculator to determine cost of customer outage upon failure

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Transmission Breaker Cost-Benefit Summary

Data room files: Trans_Oil Breaker_DEC_NC-SC_19-21_vF 5-3-19
Trans_Oil Breaker_DEP_NC-SC_19-21_vF 5-3-19

Oil Breaker Program CBAs- DEP	DOIL Breakers	TOIL Breakers
# Assets- Total 2019-2021	262	108
# Assets- 2019	79	19
# Assets- 2020	33	31
# Assets- 2021	150	58
Asset Unit Cost (material and labor)	20,800	134,400
Average Customer Minutes Interrupted due to asset failure (CMI)	230,000	3,000
Average # Residential Customers Impacted by asset failure	2,807	71
Average Duration, Minutes (Ave. CMI/#Residential)	82	42
Average Duration, Hours (Ave. CMI/#Residential)	1	1
Average # Wholesale/Muni/Co-op Customers impacted by asset failure	-	30
Average total residential customers impacted by asset failure (Residential + Wholesale)	2,807	101
Average # Commercial Customers impacted by asset failure (# Small C&I customers/# total feeders)	135	N/A
Average # Industrial Customers Impacted by asset failure (# Large C&I customers/# total feeders)	2	2

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Questions?

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Deep Dive- Breaker Replacement- Cost-Benefit Analysis

Data room files: Trans_Oil Breaker_DEP_NC-SC_19-21_vF 5-3-19

PROGRAM		Oil Breakers
	Asset Management	
	Asset Cost - Distribution Oil Breakers	$ 20,800
	Asset Cost - Transmission Oil Breakers	$ 134,400
	Average Remaining Life - Distribution Oil Breakers	5
	Average Remaining Life - Transmission Oil Breakers	10
	Installation Year	2019
	Installation Year	
	Installation Year	

	Total Customer Benefits	**$**	**39,283,888**
COMBINED COSTS AND BENEFITS			
	Total PV of Operational Benefits	$	13,319,270
	Total PV of Customer Benefits	$	39,283,888
	Total PV of Combined Benefits	$	52,603,158
	Project and On-Going Costs	$	18,908,170
	Combined NPV of Project	**$**	**33,694,988**
	Ratio of NPV Benefits to NPV Costs		**2.8**

Transmission Transformer Replacement Cost-Benefit Summary

What success looks like

- Reduced customer outages achieved through proactive asset replacement
- Enhanced grid resiliency through installation of modernized equipment

Cost-Benefit Highlights and Insights

- 2019-2021 scope includes 101 transformers (DEP), 50 transformers (DEC). Additional units scoped for 2022.
- Net present benefits include:
  - Operational Benefits – Asset management savings associated with proactive replacement
  - Customer Benefits – Reduced outage cost through avoiding failures and reactive replacement
- Net Present Costs include transformers and installation labor
- Additional societal benefit impacts from IMPLAN analysis performed by Dr. Von Nessen

Key notes about analytic method

- Historical outages information used to determine failure impacts (5yr data)
  - Average number of residential, large C&I, small C&I customers with outage impacts from an asset failure
  - Average duration of customer outage from asset failure
  - Utilize ICE calculator to determine cost of customer outage upon failure

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Transmission Transformer Replacement Cost-Benefit Summary

Data room files: Trans_Transformer Bank_DEC_NC-SC_19-21_vF 5-3-19
Trans_Transformer Bank_DEP_NC-SC_19-21_vF 5-3-19

Transformer Bank Replacement Program CBAs- DEC	T-D Transformers	T-T Transformers
# Assets- Total 2019-2021	35	15
# Assets- 2019	5	-
# Assets- 2020	13	10
# Assets- 2021	17	5
Asset Unit Cost (material and labor)	665,600	2,384,000
Average Customer Minutes Interrupted due to asset failure (CMI)	892,000	3,500
Average # Residential Customers Impacted by asset failure	1,926	106
Average Duration, Minutes (Ave. CMI/#Residential)	463	33
Average Duration, Hours (Ave. CMI/#Residential)	8	1
Average # Wholesale/Muni/Co-op Customers impacted by asset failure	6,350	70
Average total residential customers impacted by asset failure (Residential + Wholesale)	8,276	176
Average # Commercial Customers impacted by asset failure (# Small C&I customers/# total feeders)	92	N/A
Average # Industrial Customers Impacted by asset failure (# Large C&I customers/# total feeders)	3	1

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Cost Benefit Analysis categories NOT included

CBA Category	Details
Operational Savings – Reduced financial risk	Avoided costs associated with collateral damage from asset failure, regulatory fines, etc.
Operational Savings – Personnel and public safety	Improved safety due to elimination of aged assets with high voltage and stored energy
Operational Savings - Avoided Maintenance costs	Costs associated with reduced inspections and maintenance cycles due to modernized equipment
Operational Savings - Avoided Outage Restoration Costs	Costs associated with outage repair and restore that would be avoided through installation of modernized equipment
Operational Savings – Reduced Environmental Risk	Reduced risk of oil release resulting from failure of aged oil breaker or transformer
Customer Savings - Avoided Momentary Interruption Costs	Mostly applicable to Transmission Line Hardening & Resiliency projects

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Selected Standard CBA Assumptions

ASSET REPLACEMENT PROGRAM CBA ASSUMPTIONS
Proactive replacements in all categories result in zero customer outage minutes
Labor, materials, and miscellaneous costs are equivalent when comparing reactive and proactive replacements

SUBSTATION FLOODING CBA ASSUMPTIONS
Life of flood walls is 30 years or greater
Flooding event occurs every 6 years (Average of major events Floyd, Matthew, Florence over 18 year period)
Customer outages are experienced every-other major flooding event (Whiteville)

GENERIC ASSUMPTIONS	
Weighted average cost of capital (NC/DEP-SC/DEC-SC)	6.8/7.0/7.05%
Inflation Rate	2.5%
Evaluation period (years)	30

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Q & A

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