BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1146

In the Matter of:	)	
	)	**REBUTTAL TESTIMONY OF**
Application of Duke Energy Carolinas, LLC	)	**ROBERT M. SIMPSON III**
For Adjustment of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North	)	**CAROLINAS, LLC**
Carolina	)	

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert M. Simpson III. My business address is 411 Fayetteville Street, Raleigh, North Carolina.

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

A. I am employed by Duke Energy Progress, LLC ("DE Progress") as Director, Grid Improvement Plan Integration for Duke Energy Corporation's ("Duke Energy") Regulated Utilities Operations, including Duke Energy Carolinas, LLC ("DE Carolinas" or "the Company").

Q. DID YOU OFFER ANY DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The primary purpose of my testimony is to address the positions and concerns of Intervenor Witnesses who expressed opinions about the Power/Forward Carolinas initiative and the Grid Reliability and Resiliency Rider, known as the GRR Rider. In my testimony, I first address Ms Boswell and Mr. Williamson and, by incorporation, Mr. Maness of the Public Staff; Mr. Strunk of the Tech Customers; Ms. Golin of the North Carolina Sustainable Energy Association ("NCSEA"); Mr. Alverez of the Environmental Defense Fund ("EDF"), and Mr. O'Donnell of Carolina Utility Customers Association ("CUCA"). I address each testimony completely, addressing each point raised by the Intervenor. Issues I address include, but are not limited to: i) challenging the necessity of the Power/Forward Carolinas initiative and the way the Company is planning to execute the initiative; ii) challenging the goals of the Power/Forward Carolinas initiative; iii) questions regarding the cost-effectiveness of the planned investments; and iv) questions and challenges to the types of investment that are included—or not—in the Power/Forward Carolinas initiative or the GRR Rider. I also discuss the request for reporting, and I elaborate on the economic analysis of the Power/Forward Carolinas plan. I also address concerns raised by Public Staff about the Company's request to fund Vegetation Management to current standards.

Q. IS THERE ADDITIONAL BACKGROUND UPON WHICH YOUR REBUTTAL REGARDING POWER/FORWARD IS BASED?

A. Yes. Over the last several years, we have seen, to varying degrees, a decrease in reliability in the Carolinas. Common metrics that measure reliability, including system average interruption duration index ("SAIDI"), system average interruption frequency index ("SAIFI"), and customers experiencing six or more interruptions per year ("CEMI-6") were all trending in the wrong direction. In other words, outages were becoming more frequent and lasting longer, and it's become increasingly challenging to restore power in emergent, weather driven situations. To continue to ensure reliable electric service to the customers of both utilities, and to institute best practices across the Duke

Energy system in North Carolina, the plan that is now called Power/Forward Carolinas was developed.

The primary goals of Power/Forward Carolinas are to significantly reduce the number and duration of outages the system experiences, and to transform the grid by enabling 21st-century performance capabilities Secondary—but also important—goals include improving the customer experience, by leveraging technology to make payment and usage information more easily accessible, and preparing the grid for the increased adoption of distributed energy resources ("DER"). To understand why this is such a massive undertaking, it is important to understand a little bit about the history of the national electric grid.

Following World War II, most areas of the country, North Carolina included, saw tremendous population growth. The automobile also became commonplace and transportation infrastructure improved, meaning that people could live further from their places of work. City centers became commercial hubs, and people went to live in the suburbs. New homes and neighborhoods were often built in areas where electric service was limited, if it existed at all. The grid we use today is largely the same one that was created to service these areas of expansion following World War II through about 1980. During that timeframe, electricity only had to flow one way, from the generator to the consumer. And if the power went out, it was, at worst, an inconvenience.

Today, our idea of power generation has changed. North Carolina is second in the nation in installed solar generation, which includes not just larger scale projects but also grid-connected, customer-owned, rooftop systems. Our reliance on electricity has also changed. It's common for workplaces to completely shut down when there is a power failure. Power outages also have become even more impactful to essential services in communities, including grocery stores, hospitals, gas stations and the like, all of which have become increasingly reliant on electricity to operate. In today's interconnected, digital society, even momentary power instability can result in millions of dollars of lost productivity, not just for large manufacturing facilities but for offices and other business reliant on electricity. Longer outages can lead to major disruptions of economic systems and can negatively affect a community's ability to proceed with daily activity.

There are several trends that are driving the worsening reliability metrics. The first is weather. Between 2006 and 2017 there has been an increase in the frequency and strength of severe weather events, particularly thunderstorms, severe thunderstorms, and high winds associated with them (otherwise known as 'convective weather events'). Approximately 60 percent of the variation in outage events during this period can be explained by the changes in the number of convective weather events in the Carolinas. Indeed, each additional convective weather event is responsible for almost six additional outage events.

The second trend involves aging equipment. As I explained above, the electric grid that customers depend on today was largely built around 40 to 60 years ago. Although the grid has been well-maintained, even the best maintenance cannot stop the cumulative effects of age on the system. Although older equipment is not necessarily defective equipment, it is more likely to fail when stressed, and takes longer to repair when it does fail. Without additional investment beyond our customary spend in transmission and distribution, approximately 30 percent the the grid will be beyond its design life in the next decade. Although the Company has maintained and maximized its existing grid, there is no doubt that it is time to invest when customary maintenance and investment will support the necessary level of operation.

The individual programs which constitute Power/Forward Carolinas were introduced on pages 30-41 of my direct testimony, and I articulate them again later in this testimony, but from the outset it's important to note that without the Company's Targeted Underground program, we will not be able to achieve a 30 percent reduction in outages on the system. Without the Self-Optimizing Grid program, the inability to automatically isolate outages and reroute and restore power will result in more customers affected for longer periods of time, and a two-way networked delivery system that will enable integration of renewable energy and emerging technologies like battery storage will not exist. Without Hardening and Resiliency investments, the other investments would be undermined by component failure, and increasingly longer duration outages that affect customers' quality of life will continue. Additionally, customers and equipment will be more vulnerable to physical—and cyber—attacks that could have been prevented through strategic efforts to strengthen and protect the grid. Without investment in advanced communication technology, including fiber-optic components in the field, we cannot leverage the full potential of the grid to serve customers safely and reliably because the millions of components powering the grid cannot effectively talk to one another. In other words, without Power/Forward Carolinas, our state, our economy and the energy grid that powers it will not advance to reach their full potential.

Q. ARE THERE ANY WORDS THAT HAVE SPECIAL MEANING WHEN REFERRING TO POWER/FORWARD CAROLINAS?

A. Yes. Throughout my testimony I refer to initiative, programs, and projects. Each means different things. I refer to Power/Forward Carolinas, as a whole, as an initiative. The seven constituent parts of the Power/Forward Carolinas initiative are referred to as 'programs.' 'Projects' are parts of programs. So, as an example, transformer replacement is a project that is part of the Hardening and Resiliency program, which is part of the Power/Forward Carolinas initiative.

II. <u>PUBLIC STAFF</u>

A. VEGETATION MANAGEMENT

Q. DID PUBLIC STAFF MAKE AN ADJUSTMENT TO THE COMPANY'S PROPOSAL FOR VEGETATION MANAGEMENT?

A. Yes, Public Staff did not accept a pro forma adjustment requested by the Company to increase the funding for vegetation management from that included in rates in the last rate case. As I explain below, given prudent increases in spending, known and measurable increases in contractor rates, and the commitment of the Company to its vegetation management cycles, the Company believes it is reasonable for the Commission to approve its request to increase funding for vegetation management. I note that confirmation of the contractor increases I reference later in this testimony was not available until after Public Staff filed its testimony, and I believe this is a key piece of information that the Commission should take note of and that may influence Public Staff's view.

Q. MR. WILLIAMSON ALLEGES THAT THE COMPANY HAS COMPLETED VEGETATION MANAGEMENT ON 88 PERCENT OF ITS TARGET MILES DURING THE FIRST FIVE YEARS OF ITS 5.7.9 PLAN, CREATING A "BACKLOG" OF 3,752 MILES. WHAT IS YOUR RESPONSE?

A. During the last several years the Company has done a great deal of work to determine the optimum level of vegetation management on the DE Carolinas system. As part of this effort, as Mr. Williamson described, the Company performed a vegetation growth study that looked at species and geography and determined the 5.7.9 plan was appropriate. The Company used the results of that study to adopt a reliability based prioritization approach to work-planning with targeted trim dates by classification (old-urban 5-yr cycle, mountain 7-yr cycle, and other 9-yr cycle.) As part of our prioritization process, as circuits become close to the targeted trim cycle, heavier weight is placed on last trim dates within the prioritization process. The Company's last rate case did not fully fund the 5.7.9 plan. As a result, even though the Company has been spending above the vegetation management amounts included in rates from the last rate case, the Company has only been able to complete vegetation management on 88 percent of the planned miles during the five years since the 5.7.9 was adopted. The Company is asking the Commission to include an amount in rates that matches the Company's plans so that vegetation management activity will be funded at the optimum levels.

Q. PUBLIC STAFF WITNESS BOSWELL RECOMMENDS A $2.9M PRO FORMA ADJUSTMENT TO VEGETATION MANAGEMENT TEST YEAR EXPENSES DO YOU AGREE WITH THIS RECOMMENDATION?

A. No, I do not. Ms. Boswell's adjustment only took into account a seven percent increase in contract rates for 2017 and did not take the following items into consideration.

- The 5.7.9 mileage plan is still not funded. Ms. Boswell applied the 2017 contractor rate increase of seven percent to the total production costs for the test year in which the Company did not trim the required miles for the 5.7.9 plan. The Company requests that the 5.7.9 plan be funded and that the increases for 2017 and 2018 be applied to the test year cost per mile. In addition, the updated cost per mile should be multiplied by the required mileage for the 5.7.9 plan of 6,178 miles.
- Ms. Boswell gave no consideration for the 2018 contractor rate increases, since executed contracts could not be provided until they were signed on January 24, 2018. Those contracts resulted in an increase in 2018 rates of 18 percent. The new contracts were reviewed by the Public Staff on January 31, 2018 in the Duke Energy offices in Raleigh. These revised rates applied to the test year cost per mile increase the cost per mile to $9,027 per mile. That rate applied to the 6,178 miles results in production costs of $55.8 million versus the $44.9 million calculated in Ms. Boswell's schedule. The new contracts also include increases for the demand costs. Those are now $2.9 million versus the $2.4 million calculated in Ms. Boswell's schedule.
- In addition, based on new contract rates, the additional labor costs to complete the work miles required in the 5.7.9 plan are $10 million versus the $8.5 million calculated in Ms. Boswell's Schedule. This increase was included in the Second Supplemental Direct Testimony and Exhibits filed

by Company witness Ms. McManeus on January 16, 2018. Accordingly, the Company requests that it be allowed to fund vegetation management at the level that it needs to be performed. This increase is not reflected in Ms. Boswell's schedule, which was filed prior to Ms. McManeus' later information.

- Neither Mr. Williamson nor Ms. Boswell acknowledged the requested increase for transmission vegetation management of $2 million, which included $1 million to cover a 23 percent increase in contract labor rate increases and $1 million to bring the DE Carolinas herbicide program in alignment with DE Progress over a three-year period which, over the long term, will decrease overall program cost and minimize public concerns associated with herbicide spraying of tall brush. This request was not included in Ms. Boswell's schedule.
- All of these updated rates are reflected in the revised NC-3102(D) filed by Company witness Ms. McManeus in her Second Supplemental Direct Testimony and Exhibits on January 16, 2018. That adjustment reflects a total increase of $24,478,000 for Distribution and $2,074,000 for Transmission.

Q. WHAT ACTION DO YOU PROPOSE THE COMMISSION TAKE WITH REGARD TO VEGETATION MANAGEMENT?

A. Although the Company has presented sufficient evidence to justify an increase in vegetation management over the test year, the Company asks the

Commission to reject the adjustment recommended by Ms. Boswell and approve the Company's vegetation management request made in this case for both Distribution and Transmission, especially given the proof of increased contract rates and requested mileage adjustment to fund the 5.7.9 Plan, as updated and supported since the time Public Staff filed its testimony.

B. POWER/FORWARD

Q. WHAT IS YOUR REPONSE TO MR. WILLIAMSON'S SUGGESTION REGARDING ADDITIONAL REPORTING ON POWER/FORWARD TO BE INCLUDED IN THE SMART GRID TECHNOLOGY PLAN ("SGTP") FILING?

A. We are agreeable to including the six reporting items listed in Mr. Williamson's testimony for inclusion in the Company's proposed annual GRR Rider Proceeding in order to aid the Commission in staying apprised on the Company's progress in the Power/Forward initiative. The Company objects to changing the requirements for NCUC Rule R8-60.1 through this rate case, as those Commission rules affect other utilities besides Duke Energy Carolinas.

Q. MR. WILLIAMSON OF THE PUBLIC STAFF QUESTIONED WHETHER THE POWER/FORWARD CAROLINAS DESCRIPTION CONTAINED SUFFICIENT DETAIL TO WARRANT THE COST RECOVERY MECHANISM THE COMPANY SEEKS. DO YOU BELIEVE THAT SUFFICIENT DETAIL EXISTS?

A. Yes. The Power/Forward Carolinas initiative was developed and focused to address the needs of the electric system and Duke Energy Carolinas customers. By necessity, Power/Forward Carolinas addresses almost every part of the grid, and consists of seven programs. Three of the programs in particular were developed and supported with great detail and analysis by professionals and experts in the field who keep cost-effective reliability as their top priority. The first is Targeted Underground, which I will discuss in more detail shortly. The second is the Self-Optimizing Grid program, which serves to isolate outages to as few customers as possible while automatically re-routing and restoring power to everyone else. The third is referred to as Hardening and Resiliency work, which will ensure that the grid is not vulnerable to physical- and cyber-attacks, among other things. The Hardening and Resiliency work was informed by the early study of best practices from both Companies that were later incorporated into the initiative. The Advanced Metering Infrastructure ("AMI"), Transmission Improvements, Communications Network Upgrades, and Advanced Enterprise Systems programs are smaller in terms of the Power/Forward Carolinas budget, but are essential to realizing the maximum benefits of the Power/Forward initiative.[1]

Power/Forward Carolinas has been planned with great detail and, as originally designed, the initiative will be executed over ten years to specifically invest and improve in the areas of the grid that need it most. Additionally, the work plans for Power/Forward Carolinas have been designed with flexibility to enable the Company to take advantage of emerging technologies such as "non-wires" alternatives, to leverage price decreases in alternative solutions that are currently too cost-ineffective to consider, and respond to other developments. The Company has provided economic and technical analysis, and produced documents in response to more than 250 data requests addressing Power/Forward Carolinas in this case. Power/Forward Carolinas—as an initiative—is very well supported.

Work plans for each year of the Power/Forward initiative are to be finalized the year before to support the GRR Rider. The Company anticipates those work plans to be provided within the context of the annual GRR Rider proceeding. This approach enables the Company to hire workers or contractors to complete the projects, and to present detailed financial projections to the Commission for cost recovery through the annual GRR Rider proceeding.

[1] AMI cost recovery is not included in the Company's GRR Rider request.

The Company determined the ten-year scope of Power/Forward Carolinas to be the most practical time period to execute the intiative because that time-frame aligned with the Company's forecast of increased adoption of DER such a solar, storage, and microgrids. If the project scope was shorter, the Company would face higher prices to acquire labor and materials due to the high demand the project generates. Were it longer, the Company would have to deal with potentially significant staff turnover and increased training costs, and a slower realization of benefits. But in any case, this filing is by no means the last detail of Power/Forward Carolinas plans and costs to be submitted to the Commission and intervenors, and the Company envisions a robust, transparent process for the GRR Rider proceeding for the review of historic and future costs to be incurred as detailed within the annual work plans.

Q. MR. WILLIAMSON STATES THAT POWER/FORWARD CAROLINAS SHOULD BE SUPPORTED BY A COST-BENEFIT ANALYSIS TO ENSURE THAT BENEFITS ACCRUE TO CUSTOMERS. HAS THE COMPANY CONDUCTED SUCH AN ANALYSIS?

A. Yes, in multiple ways. EY has conducted a cost-benefit analysis that shows the initiative's direct benefits to customers will exceed its costs and will pay for itself twice over, if indirect benefits are considered.[2] I've provided this report as Simpson Rebuttal Exhibit 1. The EY study estimates that, by 2028, North Carolina businesses will benefit by $1.7 to $2.8 billion per year from reduced outage-related costs and increased sales opportunities.[3] Direct capital investments will support an average of $2 billion of statewide economic output (direct & indirect) and approximately 11,800 jobs throughout the state over the 10-year investment period.[4]. EY further calculates that another 7,250 jobs will be supported or created statewide through higher levels of economic activity associated with improved reliability and the spending associated with the plan.[5] DE Carolinas anticipates ongoing annual cost savings over time resulting from reduced spend on vegetation management, outage restoration activity, and major storm event restoration.

I've also attached as Simpson Rebuttal Exhibit 2 the "Executive Technical Overview" of Power/Forward Carolinas, which describes in detail the various programs within Power/Forward Carolinas and how they provide benefits to North Carolina. Described as the Four Corners of Value, it includes i) customer control, choice and convenience; ii) core reliability

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[2] See Exhibit 1 at 2. Cumulative economic impact of $32.93 billion over the 12 year project period.
[3] See *Id.* at 19. Direct benefits in 2028 are $1.7 billion. In 2028, statewide total economic benefit is $2.8 billion.
[4] *Id.* at 2. Averaging $20.03bn over ten years.
[5] See *Id*. at 3. 19,000 jobs includes 11,791 jobs created through direct, indirect and induced effects; additional economic activity related to reliability improvements will support an estimated average of 7,259 jobs.

improvements; iii) statewide economic benefits; and iv) jobs and community growth.[6]

Furthermore, the Company carefully considered the components of Power/Forward Carolinas to ensure that they were the most cost-effective of any available alternatives, while at the same time leaving flexibility in the work plans to allow for any cost efficiencies or price reductions in the market place. Details on those alternatives considered can be found later in my testimony.

Q. THE PUBLIC STAFF IS CONCERNED THAT SOME PORTIONS OF POWER/FORWARD CAROLINAS SHOULD ACTUALLY BE CONSIDERED AS PART OF THE COMPANY'S EVERYDAY, CUSTOMARY RESPONSIBILITY TO PROVIDE ADEQUATE AND RELIABLE SERVICE. PLEASE EXPLAIN WHY POWER/FORWARD CAROLINAS INVESTMENTS ARE NOT ORDINARY INVESTMENTS.

A. Mr. Maness of the Public Staff stated the projects in Power/Forward Carolinas should be extraordinary, discrete, non-growth related, cost-effective, and focused on grid modernization. On this point we agree, but I think we may see some of the projects in Power/Forward Carolinas through a slightly different lens. Some Power/Forward Carolinas investments may not be based on novel technologies, but the tools to deploy them effectively have only

[6] See Exhibit 2 at 13.

recently been developed. Additionally, deploying these traditional technologies will provide major enhancements to the grid. The Company's aim is to convert its legacy grid to a next-generation grid that will support our digital society and enable emerging technologies that will benefit customers now and into the future. The Company intends to build a grid that is stronger and more reliable when severe weather strikes, that can provide customers with more information about their energy use and tools to save energy and money, and that gives customers more choice in where their power comes from, whether it's from our increasingly clean generation or via distributed generation resources like rooftop solar and in-home battery storage.

Q. MR. WILLIAMSON IS PARTICULARLY CONCERNED ABOUT THE INCLUSION OF TARGETED UNDERGROUND IN THE RIDER BECAUSE HE SEES IT AS A INVESTMENT THAT IS NOT NEW, MODERN, OR EXTRAORDINARY. HOW DO YOU RESPOND?

A. First, it's important to note that whether or not cost recovery for the Company's Targeted Underground program is included in the GRR Rider or is handled through more traditional ratemaking, this is work that needs to be done and Mr. Williamson does not dispute that. Mr. Williamson's testimony addresses cost recovery, and he argues that it is not a novel enough technology to warrant rider treatment. Mr. Williamson is correct that burying lines is by no means a novel technology; however, the data resolution and analytical tools that enable the Targeted Undergrounding program are novel—and necessary—to effectively and cost-efficiently know which lines to bury to reduce the maximum number of outages. Burying lines used to be primarily a cosmetic concern; now, with technology the Company can target where to bury lines for operational reasons. In other words, with its new analytic tools, the Company can identify the precise locations that can be addressed to effectively eliminate 30 to 40 percent of the annual outage events affecting the system, which will benefit all customers through more stable service, fewer truck rolls, and faster restoration following major outage events.

Some of the targeted areas of outlier overhead segments the data analytics identified represent a grid "design basis" from the 1950s and earlier. When power outages occur in these locations modern restoration techniques like bucket trucks can't be used. Due to the location of the many of the current lines, using modern restoration and servicing techniques is impossible. Line technicians instead have to hand carry and climb the poles causing longer restoration times. Although burying lines may be a traditional technology utilized since the 1970's, the grid will benefit greatly from its use, in a very modern, cost effective way.

Consider an older neighborhood with power lines in the back yards. Those lines were erected at a time when there were no bucket trucks, and they are very difficult to access as it involves going through customer yards and fencing. Not only is it difficult to maintain, it is difficult to access during an outage. The Company's modern data analytics have allowed the Company to identify where such areas and neighborhood configurations continually cause problems or delays in restorations. Through the Targeted Underground program, the Company can eliminate these issues.

Each outage event causes two to three brief momentary interruptions in service (blinking lights) as upstream reclosing devices operate. The Targeted Underground program would eliminate 30 percent of these ”blinking light” interruptions. These momentary interruptions impact all the customers and businesses served by these circuits, and in many cases customers and businesses served from the same substation bus experience the momentary interruption due to voltage collapse at the bus from the faults (short circuits). In other words, the targeted underground program benefits all customers. In addition, fault duty exposure is a key predictor of asset life. Faults shorten the asset life of substation transformers, reclosing equipment and voltage equipment upstream from these outlier sections of line. In other words, faults shorten the life of substation transformers, reclosers and equipment upstream from the outage, leading to earlier need to replace the assets and potentially increased cost to customers. Accordingly, in addition to reducing outages, the Company's Targeted Underground program would also drive a 30 percent reduction in electrical and mechanical stresses that shorten the life of equipment. By any measure, the Targeted Undergound program is cost effective and a game-changer for our customers. The Company believes this is is an essential part of modernization.

Q. ON BEHALF OF THE PUBLIC STAFF, MR. WILLIAMSON ALSO QUESTIONS THE INCLUSION OF POLE AND CABLE REPLACEMENT FOR THE SAME REASON. WHAT ARE YOUR VIEWS ON HIS CONCERNS?

A. These are foundational investments included in Power/Forward and are necessary to improve the grid. However, like Targeted Undergrounding, the Company is leveraging work that may seem traditional in a very modern way, as pole and cable replacement from the Hardening and Resiliency programs are an integral part of the Company's modernization efforts.

Q. HOW DO YOU RESPOND TO MR. WILLIAMSON'S VIEW THAT AMI DEPLOYMENT SHOULD NOT BE PART OF THE GRR RIDER BECAUSE THIS PROGRAM PRECEDED THE POWER/FORWARD CAROLINAS INITIATIVE?

A. We do not object for DE Carolinas. Although AMI is part of the Power/Forward Carolinas initiative, the Company is not seeking to recover costs associated with AMI through the GRR Rider.

III. TECH CUSTOMERS

Q. MR. STRUNK, REPRESENTING THE TECH CUSTOMERS, TESTIFIES THAT DE CAROLINAS FAILS TO PROVIDE A COMPELLING DISTINCTION BETWEEN THE TYPES OF NETWORK INVESTMENTS THAT WOULD BE ELIGIBLE FOR RECOVERY UNDER THE GRR RIDER AND THOSE THAT WOULD BE SUBJECT TO TRADITIONAL RATEMAKING. WHAT IS YOUR RESPONSE?

A. The Company's proposal categorized projects requiring spend above customary levels as appropriate for the GRR Rider. This distinction was about the pace of the expenditures, not the classification of the investment. Traditional ratemaking is not the best solution for this type or pace of investment, as explained by Witness McManeus.

Q. WILL THE COMPANY BE ABLE TO MAKE THE DISTINCTION BETWEEN THE COSTS THAT FLOW THROUGH THE GRR RIDER AND MORE TRADITIONAL RATEMAKING?

A. Yes. The Company has the ability to assign accounting code block to the GRR Rider eligible work to keep it separate from the other transmission and distribution work. Based on budget re-allocation information the Company has provided in discovery, Mr. Strunk and other parties have raised some concerns about cost identification between work deemed, by them, as more traditional versus grid modernization projects. I believe that the cost separation between more traditional ratemaking for customary spend and the GRR Rider can be adequately tracked.

Q. MR. STRUNK BELIEVES THAT APPROVAL OF THE GRR RIDER REQUESTED BY THE COMPANY WILL PROVIDE AN INCENTIVE TO RUN TRANSMISSION AND DISTRIBUTION O&M THROUGH THE GRR RIDER RATHER THAN TRADITIONAL RATEMAKING PROCESSES. DO YOU AGREE?

A. No, I do not. Power/Forward Carolinas is comprised of a very specific set of projects, and the Company has been very clear about what those are. In addition, Power/Forward Carolinas has a detailed work plan that is finalized at least a year prior, so any included projects will be subject to scrutiny at the annual rider proceedings before additional work is done. The Company is also able to add an accounting code that would track work charged to the GRR Rider.

Mr. Strunk seems to allege that the Company will force O&M through the GRR Rider as duplicative to the amounts already included in rates. However, no maintenance work is included in Power/Forward, only O&M necessary to install the investments included in the initiative.

There are also procedural safeguards in the Company's GRR Rider, as described by Ms. McManeus. All costs are subject to a prudency evaluation and forward-looking costs are subject to review by the Commission. Accordingly, even if Mr. Strunk were correct—and he is not—on this point, there are safeguards to ensure that only appropriate costs are recovered by the GRR Rider mechanism. Mr. Strunk's point also ignores that the need for the GRR Rider solves what would otherwise be a disincentive to make the investments given regulatory lag. As explained by Ms. McManeus, these grid investments vary dramatically compared to generation investments. There is no AFUDC. It is important to have the presence of a recovery mechanism timed to when assets of an iterative nature go into service.

Q. MR. STRUNK BELIEVES THE RIDER DOES NOT ACCOUNT FOR O&M SAVINGS OR REDUCED GENERATING LOSSES ATTRIBUTED TO LINE LOSS. WHAT IS YOUR RESPONSE?

A. The Company believes it is appropriate that such benefits and savings flow through cost of service to benefit customers by offsetting other costs increases.

Q. MR. STRUNK ALLEGES THAT THE EY STUDY INCORRECTLY ASSESSES THE INDIRECT BENEFITS OF POWER/FORWARD CAROLINAS BY FAILING TO APPLY A NEGATIVE MULTIPLIER TO THE HIGHER ELECTRIC RATES CHARGED AS A RESULT OF POWER/FORWARD CAROLINAS. IS THAT ACCURATE?

A. No, it is not. EY allocated electricity price increases and reliability benefits across all sectors of the economy and households. Response elasticities determine behavioral change and how cost changes are passed to consumers and users. In other words, while not immediately obvious to a reader, the EY study did in fact consider these effects. The reported impacts reflect the dynamic response of businesses and households to changes in electricity prices (increased business and household costs) in addition to the response related to an increase in reliability (decreased business and household costs). For commercial and industrial customers, EY used the elasticities in the North Carolina ("NC") Regional Economic Models, Inc. ("REMI") econometric model to quantify the response to higher business costs. Increased electricity rates were allocated across all sectors of the economy and entered into the model as an increase in business operating costs. For households, increased electricity rates were entered into the model as an increase in household utility costs. Because of this, the dynamic economic impacts do account for the negative impact on the economy of raising rates for residential customers. Results presented in the study show the net benefit, after cost increases.[7]

Q. DO YOU BELIEVE IT'S APPROPRIATE TO CONSIDER INDIRECT COSTS WHEN CONSIDERING THE COSTS AND BENEFITS OF POWER/FORWARD CAROLINAS?

A. I do. I do not believe it is the only data point, but indirect costs and benefits are a data point to understanding the broader effect of the Power/Forward initiative on our customers and state. For example, improved reliability will benefit businesses by reducing direct costs – thereby leading to indirect effects that may include an expansion of economic activities over time through

[7] See Exhibit 1 at 27-31.

additional purchases of raw inputs or hiring of additional employees. Conversely, a direct increase in business costs (through any rate increase) will lead to indirect effects that may include a reduction of economic activities over time through a reduction in purchases of raw inputs or reduced levels of hiring. Indirect effects are captured in the EY study that result from both increases in direct costs and increases in direct benefits.

Q. MR. STRUNK IS CONCERNED THAT THE BENEFITS OF THIS PLAN ARE HARD TO QUANTIFY, AND THAT THE SMALL NET DIRECT BENEFIT LEAVES LITTLE MARGIN FOR ERROR. DO YOU AGREE WITH HIS ASSESSMENT?

A. No. I disagree with Mr. Strunk's singular focus on direct benefits. While he is correct that the net gain is relatively small compared to the overall cost of the initiative, I do not believe that is cause for concern for two reasons. First, the overall net benefit, including indirect benefits, dwarfs the cost of the initiative.[8] Secondly, the Company's project management procedures are quite rigorous and include considerable focus on cost control.

Q. COULD YOU EXPLAIN WHY THE EY REPORT DID NOT CONSIDER ANY RISK ANALYSIS?

A. The EY report did not consider risks to the Power/Forward initiative because the responsibility is on the Company to ensure success according to the goals

[8] See Exhibit 1 at 2. EY estimates a $32.93 billion dollar impact on economic output compared to a $13.84 billion dollar cost.

and budget outlined in its work plan; however, the 10-year Power/Forward initiative is flexible enough to address and mitigate risks in real time as they arise. Projects are scalable and answerable on a yearly basis in a rider, which is long enough to maximize cost savings versus locking down a ten-year work plan in advance.

Q. HOW DOES THE COMPANY PLAN ON ADDRESSING THE RISK ASSOCIATED WITH THE POWER/FORWARD INITIATIVE?

A. The Company has implemented project management discipline tools that exist in the Company and have already been employed on a number of large capital investments. These processes and procedures have been effective and are the standard applied to the Power/Forward initiative. Through this discipline, risks are actively identified, monitored and managed. This is a comprehensive process that rates risk based on probability and impact to the organization. The risks are then monetized and risk triggers are identified and applied by the project management team to manage risk and develop project mitigation plans.

Q. DOES THE COMPANY RECOGNIZE THE RISK ASSOCIATED WITH THE POWER/FORWARD CAROLINAS INVESTMENTS IN TECHNOLOGY?

A. Yes. Mr. Strunk mentions a concern that Power/Forward Carolinas would trigger stranded costs due to technology obsolescence. The Company recognizes that it will need to upgrade technology used in its Power/Forward

Carolinas initiative. Sometimes, such as in the case of the Company's proposed investments in AMI and Self-Optimizing Grid, upgrades are welcome opportunities to leverage new technological capabilities, like when customers of Apple, Facebook and Google are excited by the new capabilities offered by their new products. But, as noted by Mr. Strunk, there are times where the Company and consumers must upgrade technology whether they like it or not. Fortunately, DE Carolinas has plans to ensure that it is prepared to face the risks associated with technology obsolescence.

Q. HOW DOES THE COMPANY PLAN TO ADDRESS THE RISK ASSOCIATED WITH TECHNOLOGY OBSOLESCENCE?

A. Technology risk is addressed in the risk management process of the project management discipline where applicable. The AMI and Self-Optimizing Grid programs will allow the Company to avail itself of new—but mature—technology offerings, rather than remaining stagnant with the limited functionality of drive-by meter reading or manual processes associated with outage restoration that exist today. The Advanced Enterprise Systems program includes funding for continual updates to those systems to address technology obsolescence. Finally, many of the investments included in the Communications Network Upgrades program are designed to specifically address technologies that are soon to be obsolete. The Company has mitigated and planned around the risk identified by Mr. Strunk.

Q. MR STRUNK ALLEGES THAT THE COMPANY'S USE OF A SPREADSHEET-BASED TREND FUNCTION IS NOT SUFFICIENTLY RIGOROUS TO DEMONSTRATE A NEED FOR ACTION. HAS THE COMPANY CONDUCTED ANY FURTHER ANALYSIS ON ITS HISTORICAL RELIABILITY METRICS?

A. Yes, we have. There is evidence based exclusively on historical data that suggests that reliability – as measured by SAIDI – has been deteriorating at a faster rate in recent years. Specifically, a statistical analysis comparing SAIDI trends before and after the year 2012 reveals that SAIDI increased at a statistically higher annual rate between 2012 and 2017 than it did between 2006 and 2012.

In addition to examining historical data, the Company also forecasted future SAIDI and SAIFI trends using both a "best fit" trend line as well as a time-series autoregressive integrated moving average ("ARIMA") model. ARIMA models represent the standard methodology used by statisticians to analyze time-series data. The variability of both the SAIDI and SAIFI data series are relatively high and the historical period considered is relatively short, making it difficult to assign a high confidence level to any specific forecasted value. Nevertheless, in both models, the directional trend is clear and consistent – both SAIDI and SAIFI are projected to increase through the year 2026.

Q. MR. STRUNK ASSERTS THAT THE COMPANY HAS NOT LINKED THE PROPOSED INVESTMENT INITIATIVE TO DEFICIENCIES IN THE EXISTING GRID. DO YOU AGREE?

A. No. As described earlier in this testimony, it is very clear when assessing the state of the DE Carolinas' grid that weather and aged components are contributing to deteriorating system reliability. As severe weather events have increased, so have the number of outages affecting the system. Additionally, as described above, the Company's older systems exacerbate the extent and duration of failures. The three primary components of Power/Forward Carolinas each address these failures. The Targeted Underground program will decrease the number of events by as much as 30 to 40 percent. The Self-Optimizing Grid program will limit the number of people impacted by outages to a fraction of those impacted today, and the Hardening and Resiliency program will replace vulnerable components on the grid. These programs combined will reduce SAIDI and SAIFI by 40 to 60 percent. To say the Company hasn't established a direct link between these improvements and the weaknesses of the current system are simply not accurate. For more information on how the Power/Forward Carolinas initiative impacts the grid, please see the Executive Technical Overview, attached as Simpson Rebuttal Exhibit 2.[9]

[9] Exhibit 2 at 4-6.

Q. MR. STRUNK ASSERTS THAT THE COMPANY HASN'T SHOWN THAT POWER/FORWARD CAROLINAS IS COST EFFECTIVE IN IMPROVING RELIABILITY METRICS VERSUS LOWER-COST ALTERNATIVES LIKE MORE THOROUGH VEGETATION MANAGEMENT. CAN THE COMPANY AGGRESSIVELY TRIM TREES TO IMPROVE ITS RELIABILITY METRICS TO THE SAME EXTENT THE POWER/FORWARD CAROLINAS PROGRAMS CAN?

A. No, I do not agree. But Mr. Strunk raises an important question. He asserts or implies that all events are driven by vegetation management issues, and that more tree trimming could solve the problem at lower cost than the components of Power/Forward Carolinas. It's important to remember that the objective of Power/Forward Carolinas is to eliminate the high number of distribution system events that impact all customers on the targeted circuits.

The composition of the Company's vegetation management program and trim cycles are based on independent studies that establish the most efficient methodology and assist in identifying the optimum level of trimming practices and trim cycle. The studies also identify the best practices and the point of diminishing returns at which additional trimming is no longer cost-effective. More importantly, no other witness has challenged the appropriateness of the Company's vegetation management policies in this docket. In sum, Mr. Strunk is incorrect that the grid investments identified by the Company as necessary could otherwise be accomplished by vegetation management alone.

IV. NCSEA

Q. MS. GOLIN, TESTIFYING ON BEHALF OF NCSEA, ASSERTS THAT, IN ADDITION TO POWER/FORWARD CAROLINAS, THE COMPANY IS PROPOSING INCREASING ITS CUSTOMARY SPEND BY 50 PERCENT TO $850 MILLION PER YEAR. PLEASE EXPLAIN THIS INCREASE AND WHETHER IT IS ACCURATE.

A. The $850 million per year figure cited by Ms. Golin is incorrect because it was calculated using the $4.5 billion five-year customary transmission and distribution capital forecast in my testimony. As explained in Tech Customer Data Request 2-9 which is attached as Simpson Rebuttal Exhibit 3, the Company explained that $1.1 billion was later removed from that number because it was linked to grid modernization initiatives that were in the forecast prior to the announcement of Power/Forward. The Company explained that the removal of the $1.1 billion changed the customary spend down to $3.4 billion over five years which is in line with historical spending. Secondly, Ms. Golin is comparing a much longer eight-year historical spending when formulating her historical average annual spend for comparison to future spend, which is a misleading comparison in that the annual transmission and distribution capital spending has trended upward in more recent years as the Company has recognized the need for more investment in the grid. After accounting for these two items, forecasted spending is in line with historical spending.

Q. MS. GOLIN ASSERTS THAT THERE IS SIGNIFICANT OVERLAP BETWEEN THE CUSTOMARY SPEND AND POWER/FORWARD CAROLINAS, NOTING THAT THEY HAVE SIMILAR DESCRIPTIONS. COULD YOU PLEASE EXPLAIN THE DIFFERENCE BETWEEN PROJECTS INCLUDED IN CUSTOMARY SPEND AND POWER/FORWARD CAROLINAS?

A. The descriptions of some Power/Forward Carolinas components do indeed have similar descriptions as customary transmission and distribution capital spending; however, the difference between the two is that Power/Forward Carolinas spending will address upgrading components to transform the grid, while traditional transmission and distribution capital spending has been focused on asset maintenance for the traditional grid.

Q. MS. GOLIN VOICED SEVERAL CRITICISMS WITH THE EY REPORT, INCLUDING HER CONCLUSION THAT THE STUDY OVERVALUED LOST PRODUCTIVITY DURING OUTAGES, USED OUTDATED DATA, THAT IT FAILED TO ACCOUNT FOR THE NEGATIVE EFFECTS OF INCREASED RATES, AND THAT THE MAJORITY OF BENEFITS IDENTIFIED ARE INDIRECT. HOW DO YOU RESPOND?

A. She is incorrect on each point. First, the estimates of reliability benefits contained in the analysis are based on the Department of Energy ("DOE") Interruption Cost Estimator ("ICE") model, which considers the costs to businesses of spoilage, lost data, lost work in progress, and other similar costs in addition to foregone output during the outage period. While the DOE model and the EY analysis do not break out these costs separately, it is reasonable to assume these costs represent a multiple of simply the value of foregone output. For example, a restaurant losing power for one hour may incur spoilage costs equal to multiple days' worth of revenue. Second, the EY analysis relies on the model published by the DOE. It's my understanding that econometric models such as this one rely on large datasets, and that it would not be unusual for large datasets used in a statistical analysis to be dated by a short period (in this case, roughly 18 months) because of the time it takes to accumulate and process data for use in these types of models. Third, the electric rate changes are reflected in the EY analysis using the REMI model.

The REMI model was run showing a change in the cost of production for businesses equivalent to the aggregate increase in electricity costs and an increase in electricity costs for households. The overall result shown in the EY report has considered these rate changes. And finally, one would expect that the majority of the economic benefits would be indirect. The utility industry interacts with many other sectors within the state's economy and generally has a relatively high multiplier effect as a result. Industries with high multiplier effects have the ability to scale up employment and overall economic activity in ways that other industries cannot. A large multiplier effect is a highly desirable outcome for an industry sector. It's important to note that while the Company believes the economic benefits to the state and our customers support Power/Forward, the Company does not believe that the Commission should approve Power/Forward on those bases alone. There is sufficient operational and reliability need to advance Power/Forward as well, as detailed in numerous discovery requests produced in this case, described in my testimony and captured in the Technical Overview (Simpson Rebuttal Exhibit 2).

Q. MS. GOLIN ASSERTS THAT ONLY A SMALL PORTION OF POWER/FORWARD CAROLINAS SPENDING CONTRIBUTES TO RENEWABLES INTEGRATION. COULD YOU SPEAK ABOUT WHAT ASPECTS OF POWER/FORWARD CAROLINAS WILL ENABLE RENEWABLES?

A. I disagree with the assertion made by Ms. Golin. While enabling DER is not the primary driver for Power/Forward, there are multiple projects in Power/Forward Carolinas that readies and improves the grid for DER integration, including Self-Optimizing Grid, Advanced Enterprise Systems, and AMI. To further explore Self-Optimizing Grid it's important to think through how the grid will evolve over time as we see deeper and deeper quantities of private rooftop solar as well as integration of DER storage. These present different issues than the bulk utility scale solar sites. They come in "small packages," if you will, such that any single site is not so large as to trigger needed investment but as the volume scales you begin to exceed the capabilities of the legacy grid with its one-way power flow design basis. Power/Forward Carolinas integrates lessons learned from jurisdictions whose public policy and retail price of power is high enough that it is driving widespread retail adoption.

Power/Forward Carolinas seeks to proactively build toward capabilities that these jurisdictions are largely "back-fitting" to their distribution grid after local customer experience problems emerge. These lessons learned tell us that one of the key transitions the legacy grid must prepare for is the ability to adapt and support two-way power flow. The Self-Optimizing Grid takes the best of today's self-healing technologies and broadly deploys it across the distribution backbone subsystems and turning it into a "back-bone network". This network will deliver a significant reliability benefit today. At the same time, it prepares the grid for scale adoption of distributed DERs like private roof-top solar. The same ability to re-route power that the Self-Optimizing Grid uses also prepares the grid for this expected wide-spread penetration of third party resources that is coming to North Carolina. This is demonstrated in the table below:

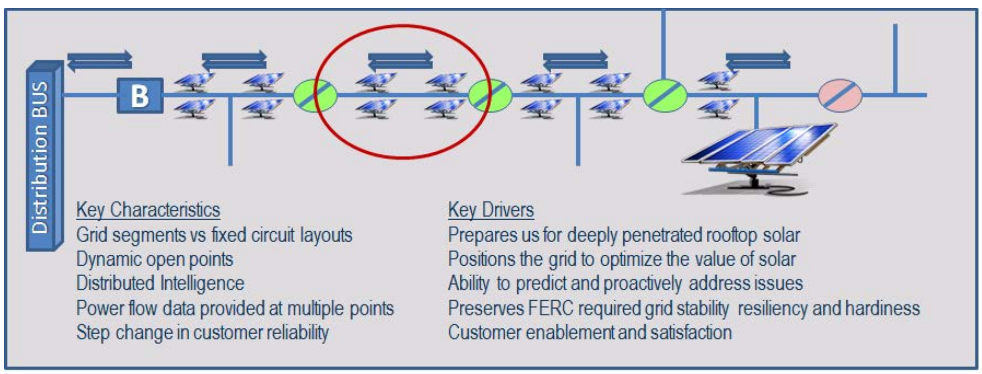

Fig. 1. Self-Optimizing Grid automation & grid intelligence positions for bi-directional power flow

To elaborate on how we see this transition and evolution occurring, as circuits begin to be broadly impacted with distributed roof top solar, the switchable segments established under Self-Optimizing Grid will eventually begin to approach levels where during lightly loaded periods, power flows begin to reverse direction. The investments being made today to take advantage of the high reliability of overhead circuit backbone (comparable to the average underground experience in events/mile) to re-reroute power when events occur to minimize impacts on customers positions the grid to be able to reconfigure circuit layout to consume power locally rather push it upstream. As penetration continues, a switchable segment could reach the point where such re-configuration by itself is not enough to compensate. In such cases, we envision a future where distributed storage is then deployed within that switchable segment and the combination of storage and automatic circuit reconfiguration is leveraged to "manage and optimize" the DER resources. And when the storage within that switchable segment reaches a level of materiality, portions of that segment can be positioned by the company to function as a micro-grid upon loss of both primary source power and alternate re-route capability (as could occur during a major event). The investments within the Self-Optimizing Grid and Power/Forward Carolinas overall are important foundational steps that can scale in a layered way toward a grid composed of reconfigurable segments, with imbedded micro-grids as one of the component assets that make up the grid. Accordingly, Ms. Golin is incorrect in characterization that very little Power/Forward costs address renewables.

Q. DOES THE DE CAROLINAS GRID CURRENTLY HAVE ANY DERs?

A. Yes. The Company has interconnected over 2,500 MW of DER in North Carolina by the end of 2017, with 68 percent of this located on the Company's distribution system. In addition, the Company has invested heavily in utility-owned DER, with 225 MW of operating DER in North Carolina and more under active development. Small, customer-sited DER has proceeded without restriction in North Carolina, with over 5,900 installations totaling 56 MW in service.

Q. MS. GOLIN ASSERTS THAT A HOSTING CAPACITY ANALYSIS IS NECESSARY TO CONTINUE INTEGRATING RENEWABLES. DO YOU AGREE?

A. No. Like many utilities, the Company is involved and educated in industry developments, such as those around hosting capacity analysis. However, not all states are the same, and the Company does not believe that undertaking an extensive hosting capacity analysis at this time, on its own, is a prudent use of customer's resources, especially when so much DER has been and continues to be interconnected with DE Carolinas' system without such analyses.

IREC's white paper, cited by Ms. Golin on page 29, lines 9 through 13, stated:

> "…Perhaps most importantly, HCAs (hosting capacity analyses) should not be developed or implemented in a vacuum, and should be considered in the context of other policy choices and how they may impact how DERs are deployed."

The Company agrees that the significant effort and investment in resources necessary for effective a hosting capacity analysis process should not be taken on lightly, and must be considered in context of other policies.

With all of the activity surrounding greater DER adoption in North Carolina in recent years, including the Renewable Energy Portfolio Standard (Senate Bill 3, 2007) and the Competitive Energy Solutions for North Carolina law (House Bill 589), and the Company's record-setting adoption of DER, it is clear that the Company and North Carolina has moved aggressively on a path of DER adoption, and with heavy stakeholder involvement. However, to-date, North Carolina's path simply has not required hosting capacity analysis in order to be successful and it is not, nor does it need to be, a focus of Power/Forward Carolinas.

Q. MS. GOLIN EXPRESSES CONCERN WITH THE TWELVE EVENTS PER TARGET MILE THRESHOLD FOR TARGETING UNDERGROUNDING OF OVERHEAD CONDUCTORS. WHY WAS THAT THRESHOLD SELECTED, AND HOW WOULD SELECTING A HIGHER THRESHOLD (WHICH WOULD REDUCE COST) IMPACT THE EXPECTED FINAL RELIABILITY METRICS?

A. The Company selected that threshold because that was the point of optimal benefit compared to cost. Going further provides diminished returns. In other words, the cost for additional improvement plateaus. To gain a view of the value at the beginning of such a program, and how it would diminish as you work your down the candidate target list, the Company developed a graph. The Company used this to frame three zones. A zone of maximum value, a zone of good value, and a zone of marginal value. The Company's proposed policy of “at least 50 percent worse than the average overhead rate but not more than 20 percent of vegetated line miles” sits on the boundary of the zone of good value and marginal value. Beyond this rate, each percentage of overhead placed underground fails to yield more than a 20 percent benefit in event reduction; i.e. below this rate, a one percent increase in vegetated line miles placed underground only yields a 1.2 percent reduction in total overhead events. Attached as Simpson Rebuttal Exhibit 4 is an image of that graph.

Q. MS. GOLIN ASSERTS THAT THE COMPANY MAY BE UNDERESTIMATING THE COST OF UNDERGROUNDING LINES IN THE 1,631 PROJECTS WHERE CIRCUIT SEGMENT LENGTH IS GREATER THAN 1 MILE. COULD YOU EXPLAIN HOW THE COMPANY CAME UP WITH ITS COST PROJECTIONS AND HOW ACCURATE THEY ARE?

A. The Company has a high confidence in the Targeted Underground cost estimates. They are based on industry benchmarks by comparing costs with other utilities. I also agree with Ms. Golin that feeder level undergrounding can be much more costly. Back-bone feeder circuits in dense urban areas can run $3 to 5million per mile and in less dense areas where duct banks may not be required $1 million plus per mile can be expected. However, the list that Ms. Golin pulls her information from is the Company’s list of “candidate targets” based on the data analytics events per mile screen, not the final targets. Duke's process begins with this list, but involves a two-step multi-part screen:

- A geo-spatial desk-top screen with Company facilities overlaid on a satellite view of the area. This screening can eliminate candidates just from the mapping view
- A detailed assessment and site visit by experienced and knowledgeable field designers represents the next filter. This step will screen out any high cost segments and is a built-in step of Duke's methodology and process.

Duke's estimate of $400 to 500 thousand per mile is based on the Company's own experience with Distribution overhead facilities, industry reports and benchmarking studies regarding non-back-bone feeder undergrounding. Additionally, after development of the Company's estimate, my team benchmarked data with Dominion, who has multiple years of experience with work like this. DE Carolinas' estimates align tightly with Dominion's actual experience.

Q. MS. GOLIN EXPRESSES CONCERN THAT THE COMPANY'S ASSETS IDENTIFIED IN THE APPLICATION AS BEING BEYOND DESIGN LIFE ARE MERELY BEYOND THEIR LIFE FROM A PLANT ACCOUNTING PERSPECTIVE, BUT NOT AN ENGINEERING PERSPECTIVE. CAN YOU HELP CLARIFY THIS?

A. Yes. I agree with Ms. Golin that transmission and distribution assets frequently perform well beyond their design life. This is evidenced by the age of the Company's assets. DE Carolinas has maintained a significant portion of critical power grid components extending their useful life well beyond design life through our risk based maintenance programs that have been effective in maintaining the infrastructure that was built largely in the 60's, 70's and 80's. But the fact is these assets have already or will reach the end of their useful lives within the next ten years making them more susceptible to age related failure and weather damage.

I do not agree with Ms. Golin's opinion on the useful life of wood poles. Referencing a study I call the Osmose study, she purports that properly maintained and treated wood poles have a predicted service life of more than 100 years in North Carolina.[10] The Osmose study she references does not detail the costly life-extension maintenance program necessary to achieve a 100-year pole life. The DE Carolinas pole inspection and replacement program uses a risk based approach toward inspection and replacement and this approach has yielded a 40-45 year average pole life expectancy for DE Carolinas. The Osmose study cited by Ms. Golin includes data depicting the actual average age of poles in geographical zones including zone 4 (DE Carolinas is in zone 4) to be 43 years which is consistent with the expected useful life used by the Company in its asset aging analyses.

I also do not agree with Ms. Golin on her assessment of the expected useful life of transformers. She references IEEE standards for Transformers

[10] http://www.osmose.com/content/pages/wood-pole-lifecycle-data.

citing an expected useful life of 20-30 years. But then she goes on to say that most transformers never operate at maximum design conditions and as a result life expectancy is much longer than 20-30 years. I agree there are a variety of operating conditions on the grid, but the Company has to manage transformer load and I know from professional experience, as does my team, that what Ms Golin describes is not true for all transformers. Given these circumstances the Company uses a 30-year expected useful life in its asset aging analyses.

The aging analyses referenced above of the DE Carolinas transformers, poles as well as wire are included in Simpson Rebuttal Exhibit 5.

Q. MS. GOLIN STATES THAT THE COMPANY MISSED AN OPPORTUNITY BY FAILING TO INTEGRATE CUSTOMER OWNED DISTRIBUTED GENERATION AS AN ALTERNATIVE TO PROJECTS IN POWER/FORWARD CAROLINAS. DOES THIS MEAN POWER/FORWARD CAROLINAS DOES NOT INTEGRATE ANY DISTRIBUTED GENERATION RESOURCES?

A. No. As Ms. Golin noted, the Company is running pilot projects to explore the integration of DERs as alternatives to Power/Forward Carolinas projects. As the price of DERs continues to drop, their relative competitiveness with currently planned projects will increase, meaning that the odds of their inclusion in the Power/Forward Carolinas plan will increase in the out-years of the initiative. In a very real sense, the flexibility of the plan in the out-years greatly increases the odds of more wide scale deployment of solar, storage, and micro-grids several years down the road.

The Hardening and Resiliency programs also includes a project called Long Duration Outages. This project is focused on areas where there distribution service infrastructure is "single sourced" and there is a pattern of events that impact an entire geographic area for extended periods of time, representing real hardship for a community. It will remedy that by creating backup supply from both traditional and next generation combinations of solar, storage and other DER technologies. In some case there is a ready "traditional option" via a nearby substation. In these cases, the traditional approach has a clear competitive advantage over solar/storage. But in many cases these areas are rural, and remote from other grid infrastructure, and to resolve it would involve unpalatable and costly options (cross country transmission, a new substation and distribution circuits). When events do occur the entire community is out of service; banks, grocery stores, gas stations, emergency services, etc. The high cost of the traditional approach is largely why they remain long duration outage areas. In the short term, the Company will address the low cost traditional options where infrastructure can be readily adapted to support. But in later years the Company will address these kinds of locations with storage and solar/storage solutions. Here they have the clear advantage over a traditional grid infrastructure investments. One of the Company's key objectives in first five years of the

Power/Forward Carolinas initiative is to leverage in-flight deployments of solar/storage in just such isolated areas where the Company needs to fully understand cost to operate, operation methodologies, the life cycle of technologies, and general "durability/readiness" as utility-grade asset.

The Company's intent is to take lessons learned from these sites and begin to scale deployment as the Company moves into the second five years of Power/Forward Carolinas. Duke has two solar storage projects (Hot Springs, NC and Nabb, IN), and the team will leverage knowledge from these projects to develop engineering application guides and planning tools.

Q. MS. GOLIN RECOMMENDS THE COMMISSION INSTITUTE A SEPARATE PROCEEDING. DO YOU BELIEVE THAT'S NECESSARY?

A. I don't believe that a separate proceeding is necessary. I am not aware of any pre-approval process for grid investments in North Carolina like that which is required for major generation investments. From my perspective this is no different from the grid planning the Company hs done for years, but this initiative is more comprehensive in scope and period than is typical. The Company is intentionally being transparent in its plans, both in customer communications and even in discussions and discovery in this case, but the Company does not believe that a separate proceeding is required or advisable. I believe we have looked at the type of things that would be subject of such a proceeding, like the costs and benefit comparisons I've described above, as well as planning cost effective deployment of resources, and we will be establishing a more robust dialogue with stakeholders through the Technical Workshop we are planning to occur later this year. Moreover, the Company believes the annual rider proceeding also gives opportunity for visibility into the Company's plans and expenditures.

V. EDF

Q. MR. ALVAREZ NOTES THAT, DUE TO THE SIZE AND NON-CUSTOMARY NATURE OF THE POWER/FORWARD CAROLINAS INVESTMENTS, MORE COMMISSION SCRUTINY AND STAKEHOLDER ENGAGEMENT IS REQUIRED, PERHAPS THROUGH A SEPARATE PROCEEDING. DO YOU AGREE?

A. No, I don't believe these investments require any more scrutiny than a typical infrastructure project—and that scrutiny has been very thorough in the state of North Carolina. I do believe that an annual rider proceeding will be an appropriate forum for the Commission to evaluate the following year's Power/Forward Carolinas plans for prudency and to allow the Company to demonstrate the reliability benefits the planned projects will bring. For the same reasons as stated earlier in my testimony, I do not believe a separate proceeding is necessary other than the annual rider proceedings proposed by the Company.

Q. MR. ALVAREZ TAKES EXCEPTION WITH THE COST OF UNDERGROUNDING, CITING ITS COST AT $40,767 PER CUSTOMER. ARE THE BENEFITS OF UNDERGROUNDING LIMITED TO THE CUSTOMERS WHOSE SERVICE IS UNDERGROUNDED?

A. No. All the customers of DE Carolinas will benefit from the Targeted Undergrounding Program. The cost cited by Mr. Alvarez is achieved by calculating the customers per line mile using DE Carolinas total customers divided by total overhead line miles. The Company's targeted segments are typically at the distribution edge, in neighborhoods, where customer density is much higher than the system average. The higher density significantly lowers the cost per customer.[11]

Mr. Alvarez frames the benefit of the Targeted Underground program as only those customers who are directly served from these outlier segments, despite considerable evidence to the contrary. All customers are beneficiaries of the proposed Targeted Underground program. These outlier overhead distribution tap line segments represent a little under 10 percent of total primary line miles and 16 percent of total overhead primary line miles. Undergrounding these segments of the grid will eliminate over 50 percent of overhead system events, and over 40 percent of all system events, event

[11] TUG cost per premise estimate: $470,000 per mile divided by 5280 feet per mile or $89 per foot for 600 ft (typical city block) divided by 12 customers (typical number customers per city block) = $4450 per customer premise.

driven momentary interruptions, and event-driven fault duty on distribution substation and circuit equipment. For DE Carolinas, Targeted Undergrounding will result in an 18 percent reduction in SAIDI, 17 percent reduction in SAIFI, a 36 percent reduction in non-major event day outages, and a 30 percent reduction in major event day outages.

Q. MR. ALVAREZ STATES THAT UNDERGROUNDING CAN ALSO SUFFER FROM POOR RELIABILITY. DOES THE COMPANY HAVE INFORMATION ON THE RELIABILITY OF UNDERGROUND CABLES IN THE DISTRIBUTION NETWORK?

A. Yes, I do. The Company's underground cable network experiences, on average 0.2 events per mile, which is equivalent to the best performing overhead segments. However, the average event rate for overhead lines is 0.81 events per mile. The segments targeted for undergrounding must have at least 1.6 events per mile. The worst performing segments experience 19.5 events per mile. By any measure, underground cables have the lowest average events per mile, and are also more tightly clustered around the mean than overhead segments.

As an example, Hurricane Matthew produced rains that resulted in flooding well above all-time records. While confined to the DE Progress service area, underground infrastructure represented aboutabout 32 percent of the infrastructure only accounted for 6.9 percent of customer outages. In the more typical major event day ("MED") events without flooding the underground contribution to customer outages is even smaller than during Hurricane Matthew. In other words, underground lines are more reliable than overhead lines, even in the worst case scenario for underground systems.

Q. MR. ALVAREZ CONTENDS THAT THE EXTENT OF UNDERGROUNDING SHOULD BE REVIEWED BY THE COMMISSION WITH STAKEHOLDER PARTICIPATION. DO YOU BELIEVE THAT IS NECESSARY, AND IF NOT, WHY?

A. No, I do not believe it is necessary. Duke Energy uses a data-driven process that leverages outage history data to look for overhead segments with a consistent pattern of outlier performance. The Company will prioritize locations where vegetation management costs are highand restoration costs and employee risks are higher because of limited truck access.

Over the years there has been for a focus on undergrounding from customers whose main concern is aesthetics or beautification—that is not a selection criteria for the Targeted Undergrounding program. Duke Energy's target selection process included in Power/Forward uses outage history data for overhead tap fuse outages from the past 10 years to define candidate segments for selection. The process also includes the associated transformer and service outage events that occur on the overhead segment to create a list of tap segments ranked by events per mile, while excluding "major event days" (MEDs) impacts. This exclusion normalizes the data set helping us to identify persistent outlier poor performing segments and helps to screen out temporary anomalies from influencing target selection. Additionally, before a candidate location is confirmed, it must go through a two-part multi-variable screening process that includes an initial desktop screening using maps with company facilities overlaid and a detailed field assessment by experienced grid field designers.

Q. DO YOU BELIEVE ADDITIONAL INPUT WOULD BE USEFUL TO THE COMPANY?

A. Yes, although the Company does not support a separate, formal proceeding, Duke Energy values customer and stakeholder engagement in the Power/Forward Carolinas initiative. Additional perspectives and dialog is beneficial, especially as we are implementing new programs. However, for Targeted Undergrounding, data must drive the selection process to ensure overall effectiveness of the program.

Q. MR. ALVAREZ ARGUES THAT THE COMPANY MUST HAVE A PERFORMANCE MEASUREMENT PROGRAM FOCUSED ON THE OUTCOMES OF THE GRID MODERNIZATION INVESTMENTS. DOES THE COMPANY HAVE SUCH PLANS?

A. Yes. The Company has provided reliability performance objectives associated with its Power/Forward Carolinas initiative in its Power/Forward Carolinas: Executive Technical Overview, attached here as Simpson Rebuttal Exhibit 2. An annual GRR proceeding would offer an opportunity for the Company to share how it is progressing toward its performance objectives. Those proceedings would also offer an opportunity to demonstrate how the Company is managing costs of its programs.

Q. MR. ALVAREZ IS CONCERNED THAT POWER/FORWARD CAROLINAS EXCLUDES BENEFITS FROM, AND DOES NOT ADEQUATELY EMPHASIZE, CONSERVATION PROGRAMS LIKE INTEGRATED VOLT-VAR CONTROL ("IVVC"). DO YOU HAVE A RESPONSE?

A. Yes, the Company is working on a cost-benefit analysis for an implementation of IVVC in the DE Carolinas territory. This evaluation will be reported in the 2018 Smart Grid Technology Plan ("SGTP") filing.

Q. WILL IVCC HELP INTEGRATE RENEWABLES ONTO THE DE CAROLINAS GRID BY MODERATING THE VOLTAGE FLUCTUATIONS PRODUCED BY SOLAR GENERATION AS MR. ALVAREZ ASSERTS?

A. IVVC can help provide voltage equity from the substation to the final customer on a circuit, but is not suitable for managing the continuous voltage swings caused by distributed photo-voltaic ("PV") solar. In fact, IVVC may be less effective on circuits that contain high penetrations of PV solar as regulators and capacitors cannot react fast enough to the continuous voltage swings caused by distributed PV solar. Further broad implementations of IVVC technologies will need to be evaluated carefully in regions with such high penetration of solar such as North Carolina.

Q. MR. ALVAREZ STATES THAT DEMAND RESPONSE AND DISTRIBUTED ENERGY GENERATION TARGETED TO SPECIFIC GEOGRAPHIES AND INCREASED GRID FLEXIBILITY AND STATUS VISIBILITY CAN BE APPLIED TO AVOID SUBSTATION CAPACITY UPGRADES. DOES POWER/FORWARD CAROLINAS MAKE USE OF ANY OF THESE METHODOLOGIES?

A. Yes. The Company will consider distributed energy resources as a component in Power/Forward where it is appropriate and cost effective. Most of the substation capacity upgrades provide increased grid flexibility necessary for the Company's Self-Optimizing Grid program, which requires greater substation capacity to ensure adequate load support capabilities to reroute power. The Self-Optimizing Grid program will provide greater visibility and automation for rerouting power, but it won't be possible to reroute power if there isn't sufficient capacity available from unaffected portions of the grid. Demand response is used to reduce peak system load rather than reroute power when an outage occurs. As such, these programs accomplish different goals and are not effective substitutes.

Q. DO YOU HAVE ANY OTHER COMMENTS ON MR. ALVAREZ'S TESTIMONY?

A. Other points raised by Mr. Alvarz have been addressed and answered elsewhere in my testimony.

VI. CUCA

Q. MR. O'DONNELL ALLEGES THAT THE BELLOMY RESEARCH DATA SHOWS THAT CUSTOMER'S WILLINGNESS TO PAY FOR INCREASED RELIABILITY DECREASES AS THE PRICE INCREASES, AND THAT CUSTOMERS ARE UNLIKELY TO SEE VALUE IN A LARGE RATE INCREASE. DO YOU AGREE?

A. No, I do not. The Company commissioned Bellomy Research to better understand customer perceptions of and reactions to Smart Grid investments. The Bellomy Research conclusions, attached as Simpson Rebuttal Exhibit 6, evaluate the appeal to DE Carolinas Residential Customers of upgrading electric grid technology and to determine their reactions to potential monthly bill increases for these upgrades. Customers always desire lower rates—it's a very human reaction when asked about price. The critical finding for the Company was that customers supported the idea of grid improvement, even at increased cost. But the Bellomy study took place well before Power/Forward was fully developed. As such, the study simply asked about increased grid reliability versus a price increase. It did not present customers with an enumeration of benefits, nor did it assign a value to them. However, the EY study attached as Simpson Rebuttal Exhibit 1 clearly states that, when costs are balanced against benefits, all ratepayers should see positive impacts even after accounting for the increase in electric rates, through either direct benefits like a reduction in business losses or through indirect benefits, like increased upward pressure on wages and increased economic activity.[12] While I can't speculate on what would have been, I think this more nuanced presentation to respondents would likely yield different, more favorable results.

Q. MR. O'DONNELL IS CONCERNED THAT THE COMPANY IS NOT WILLING TO OFFER A GUARANTEE REGARDING A PRECISE NUMBER IN OUTAGE REDUCTION. PLEASE EXPLAIN WHY THAT IS.

A. Because Power/Forward in this state consists of hundreds of different projects, scattered throughout the North Carolina, predicting a precise outcome is much more complex than, say, a generating plant. When building a generator, the goals and outcomes are crystal clear: build something that produces power at the lowest possible cost. The test at the end is whether it produces affordable power.

With Power/Forward Carolinas, the Company is upgrading substations, transformers, network communications, reclosers, and undergrounding thousands of miles of wire, among many other things. While the Company has a solid understanding of the impacts these projects will have on the grid, our improvement projections make assumptions about external factors impacting the grid over the project lifetime. If, for example, our assumptions about weather severity are off, it would impact the improvements measured at the end of the initiative. For this reason, the Company is unable

[12] See Exhibit 1 at 15.

to offer guarantees as precise as Mr. O'Donnell wishes regarding the results of Power/Forward Carolinas, and can provide only projections based on historical knowledge and certain reasonable assumptions about future grid performance and outage drivers.

Q. MR. O'DONNELL WORRIES THAT THE VIABILITY OF MANUFACTURERS IN THE STATE WOULD BE THREATENED BY THE RATE IMPACTS OF POWER/FORWARD. CAN YOU ADDRESS HIS CONCERN?

A. While it is true that--all else being equal--a rate increase (or any cost increase) would incentivize a business to relocate elsewhere, to suggest that the rate increases associated with Power/Forward Carolinas would unambiguously result in businesses relocating to other states is not correct. Such a statement ignores the benefits of reliability improvements, does not consider rising utility costs in alternative states, and does not consider the many other factors that firms consider when making location decisions.

Q. MR. O'DONNELL STATES THAT, ACCORDING TO A NORTH CAROLINA CLEAN ENERGY TECHNOLOGY CENTER REPORT, THE SCALE OF POWER/FORWARD CAROLINAS IS LARGER THAN OTHER GRID MODERNIZATION PLANS AROUND THE COUNTRY. CAN YOU EXPLAIN THE SCOPE OF THIS PROJECT AND HOW IT COMPARES TO OTHER UTILITIES?

A. While Power/Forward Carolinas is by no means small, it is important to remember several things. First, no two utilities are the same; and the needs of our state and our customers dictate what we do. Second, the Power/Forward Carolinas initiative is spread across multiple Duke Energy utilities spanning two states, whereas other grid modernization projects are limited to single utilities in a single state. Third, the absolute cost of the project is a very poor indicator of what a customer is getting for their money. The Company is aiming to fundamentally transform the grid and dramatically improve reliability and to prevent degradation to service. The scope of the Power/Forward initiative is broad, but I believe the same results could not be delivered in a more cost-effective manner.

Q. MR. O'DONNELL BELIEVES THE COMPANY HAS NOT BEEN FORTHCOMING WITH ITS RATE IMPACTS. CAN YOU DISCUSS THE COMPANY'S EFFORTS TO BE TRANSPARENT?

A. The Company acknowledges that total costs are not reflective of eventual rate impact to customers. The absence of more data to share on the eventual rate impacts to customers is not due to any intention to not be transparent. It's because the complexity of producing rate impacts has various inputs. The inability to produce precise rate impacts by no means should leave the impression that Duke Energy has been anything less than transparent about its plans. The Company has sought and considered customer and stakeholder input before and during the planning of the Power/Forward Carolinas initiative, and has engaged in the following:

- Issuance of press release regarding the total Power/Forward Carolinas initiative cost estimates – attached as Simpson Rebuttal Exhibit 7.
- The announcement on April 12, 2017 by David Fountain at the NC Energy Conference.
- Discussed Power/Forward Carolinas at more than 150 community, civic and business groups across North Carolina since early 2016.
- Cost have been talked about in testimony and discovery at length and vetted through studies provided in this case.
- Hundreds, if not thousands, of data points supporting Power/Forward provided in discovery.

Q. MR. O'DONNELL QUESTIONS THE NEED FOR POWER/FORWARD CAROLINAS, STATING THAT RELIABILITY IS NOT "BAD" ENOUGH TO WARRANT INVESTMENT. HOW DO YOU RESPOND?

A. I do not agree with this assertion. There is evidence based exclusively on historical data that demonstrates that reliability – as measured by SAIDI – has been deteriorating at a faster rate in recent years. Specifically, a statistical analysis comparing SAIDI trends before and after the year 2012 reveals that SAIDI increased at a statistically higher annual rate between 2012 and 2017 than it did between 2006 and 2012.

In addition to examining historical data, the Company also forecasted future SAIDI and SAIFI trends using both a "best fit" trend line as well as a time-series autoregressive integrated moving average ("ARIMA") model. ARIMA models represent the standard methodology used by statisticians to analyze time-series data. The variability of both the SAIDI and SAIFI data series are relatively high and the historical period considered is relatively short, making it difficult to assign a high confidence level to any specific forecasted value. Nevertheless, in both models, the directional trend is clear and consistent – both SAIDI and SAIFI are projected to worsen through the year 2026 if the Company does not address the needs of the grid.

Q. MR. O'DONNELL QUESTIONS WHETHER ANY ALTERNATIVES TO SELF-OPTIMIZING GRID WERE CONSIDERED. CAN YOU DISCUSS?

A. Self-Optimizing Grid has several objectives. The primary objective of the Self-Optimizing Grid is to address high numbers of customer interruptions ("CI") and customer minutes of interruption ("CMI") associated with the distribution feeder backbone. With a failure rate of 0.2 faults/mile, events are rare, but the resulting CI and CMI drives a lot of system level SAIDI and

SAIFI. The root cause for the high CI and CMI is the radial (one source of power) nature of the legacy infrastructure, with no contingency for loss of power; no ability to re-configure and re-route available power. By modernizing this key component of the legacy grid and you change this dynamic. Automation of the backbone's manual switches and creation of additional circuit ties where proximity allows are potential solutions. Alternatives to be considered are the self-healing technologies options that come from a robust market place of mature, commercially available, proven automation and control technologies and approaches.

The Company needed to decide between centralized intelligence versus decentralized intelligence. Centralized intelligence in self-healing space can manage more complex and varied grid conditions and offer multiple alternatives for re-routing power based on those conditions. Decentralized intelligence typically represents a small range of fixed alternatives (1-2) for re-routing power. Since penetration of DERs and the amount of solar activity in North Carolina has moved the Company in the direction of "centralized intelligence" to support managing the increasing complexity of the grid

The Self-Optimizing Grid program takes the best of today's self-healing technologies and broadly deploys it across the distribution backbone subsystems that act as static radial, single sourced distribution supply and turn it into a dynamic "back-bone network" that supports two-way power flows. Most importantly it delivers a significant reliability dividend today as it is deployed while positioning for scaling private rooftop solar, storage and DER integration as customer adoption grows.

Q. WHAT ABOUT ALTERNATIVES TO TARGETED UNDERGROUND?

A. One screen the Company uses to determine viable alternatives comes from the Company's Emerging Technologies group, which builds a forward looking screen of new technologies. The purpose for this is to assist in identifying when technologies are approaching cost competitiveness (along with a performance reliability) comparable with today's technologies. Some examples include distributed energy resources like solar and storage, as well as micro-grid applications.

Many alternatives like those suggested by Witness O'Donnell and others such as batteries and storage that the Company is monitoring are considered non-competitive (certainly for scale addoption) for premise level deployment within the ten-year horizon, with some just outside the ten-year investment period.

Additionally, because of the large volume of customers they would have to address, applying these technologies at a premise level are impractical because costs per premise are so high. Building grid reliability through targeted undergrounding as an approach is far more cost effective.

For example, the Company also performed a high level screen comparing the proposed Targeted Underground investments to natural gas gen-set; or where natural gas is not available; LP gas. Costs per premise were more than double. A quick check of Tesla's powerwall sizing portal shows capital costs figures even higher with many cost considerations not included. The fundamental weakness to these alternatives though isn't just the much higher costs. It is that the benefits accrue only to those customers at the premise where the alternative technology is provided. Although they are protected from grid failures, the lines still come down andmust be maintained, trees must still be trimmed, and repair trucks still roll. Major event days are still 30 percent longer to fully repair the grid than in a post Targeted Underground world. You still have over 40 percent of the non-MED events occurring, you still have over 40 percent of the event related momentary interruptions occurring, you still have over 40 percent of the fault duty impacting equipment life. It does not solve the underlying macro-issue, the problem statement as framed- these outlier segments of overhead infrastructure are driving a disproportionate share of impacts on all customers. After supplying all those customers with gen-sets, even if you dispute the cost of this simple thumbnail screening, the underlying problem is still unresolved.

Q. MR. O'DONNELL EXPRESSES CONCERN FOR THE WELL-BEING OF THE RENEWBLE ENERGY INDUSTRY. WILL THIS PLAN HAVE A NEGATIVE IMPACT ON RENEWABLES INDUSTRY?

A. Absolutely not. If anything, this plan simplifies the integration of both utility-scale and rooftop solar by installing the infrastructure necessary to allow two-way power flow across our service area.

Q. PLEASE DESCRIBE THE PLAN'S EFFECT ON THE ECONOMY OF NORTH CAROLINA?

A. The Company has, through experts, conducted a cost-benefit analysis that shows the initiative's direct benefits to customers will exceed its costs and will pay for itself twice over, if indirect benefits are considered.[13] I've provided this report as Simpson Rebuttal Exhibit 1. The EY study estimates that, by 2028, North Carolina businesses will benefit by $1.7 to $2.8 billion per year from reduced outage-related costs and increased sales opportunities.[14] Direct capital investments will support an average of $2 billion of statewide economic output (direct & indirect) and approximately 11,800 jobs throughout the state over the 10-year investment period.[15] EY further calculates that another 7,250 jobs will be supported or created statewide through higher levels of economic activity associated with improved reliability and the spending associated with the plan.[16]

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[13] See Exhibit 1 at 2. Cumulative economic impact of $32.93 billion over the 12 year project period.
[14] See *Id.* at 19. Direct benefits in 2028 are $1.7 billion. In 2028, statewide total economic benefit is $2.8 billion.
[15] *Id.* at 2. Averaging $20.03bn over ten years.
[16] See *Id*. at 3. 19,000 jobs includes 11,791 jobs created through direct, indirect and induced effects; additional economic activity related to reliability improvements will support an estimated average of 7,259 jobs.

Q. MR. O'DONNELL BELIEVES THAT THE EY REPORT IS BIASED BECAUSE DUKE HAS PAID EY FOR THE STUDY. IS THE REPORT BIASED?

A. No, absolutely not. The Company asked for, and received, a non-biased view of its plans and the economic affects stemming from them, and that is what the Company received.

Q. MR. O'DONNELL ASSERTS THAT EY GLOSSED OVER THE IMPACT OF INCREASED RATES, AND THAT EY USED OLD UNDERLYING DATA. IS THAT TRUE?

A. No, it is not. The analysis uses estimates from two econometric models. The first (ICE Calculator), was used to estimate benefits that would accrue to customers as a result of improved reliability was produced for the US Department of Energy (last updated in 2015). This is the model that the data vintage noted in this statement. The second model (REMI), was used to estimate the economic impacts in North Carolina and was constructed in May 2017, using the most recently available economic data. Further, the reported impacts reflect the dynamic response of businesses and households to changes in electricity prices (increased business and household costs) in addition to the response related to an increase in reliability (decreased business and household costs). EY allocated electricity price increases and reliability benefits across all sectors of the economy. Response elasticities determine behavioral change and how cost changes are passed to consumers and users.

For commercial and industrial customers, EY used the elasticities in the NC REMI econometric model to quantify the response to higher business costs. Increased electricity rates were allocated across all sectors of the economy and entered into the model as an increase in operating costs. For households, increased electricity rates were entered into the model as an increase in household utility costs. Because of this, the dynamic economic impacts do account for the negative impact on the economy of raising rates for residential customers. Results presented in the study show the net benefit, after cost increases.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

North Carolina impacts of Duke Energy's Power/Forward grid improvement program

Prepared for Duke Energy by EY Quantitative Economics and Statistics (QUEST)

November 2017

Building a better working world

The accompanying analyses were prepared for the use of Duke Energy. The analyses conducted in this report constitute neither an examination nor a compilation of prospective financial statements nor the application of agreed-upon procedures thereto in accordance with the attestation standards established by the American Institute of CPAs (AICPA). Accordingly, EY does not express an opinion on or offer any other assurances as to whether the analyses are presented in conformity with AICPA presentation guidelines or as to whether the underlying assumptions provide a reasonable basis for the analyses.

Executive summary

This study presents the potential economic impacts related to Duke Energy's proposed Power/Forward grid improvement program in North Carolina, which includes investments for the proposed self-optimizing grid, conversion of targeted areas to underground lines, and distribution network hardening and resiliency. This study includes estimates of the temporary economic impacts during the investment period as well as the ongoing benefits to businesses and households from increased electric grid reliability.

Duke Energy will invest an estimated $13.84 billion for facility and grid improvements, supporting jobs and economic activity over the next 10 years related to purchases of construction services, equipment, and increased headcount related to the investment.[1] These impacts occur as additional construction, installation, and maintenance workers are hired to undertake the significant task of hardening the North Carolina energy grid and as Duke Energy invests in on installation/construction services and domestically-sourced materials and equipment. These impacts are described as "one-time" because they do not recur. The total impacts over the investment period are summarized in Table ES-1 ("Duke Energy capital expenditures" column) and Table ES-2.

Power/Forward will also result in increased electricity reliability for Duke Energy's customers. Duke Energy forecasts that outage events will be less frequent and shorter in duration as a result of the infrastructure improvements, with a 40-60% reduction in regular-service outages and an estimated 30% reduction in the frequency and duration of major event outages.[2]

These reductions in outage events and severity will provide more consistent electric service to Duke Energy's customers throughout North Carolina, which will reduce interruption losses, increase productivity, and reduce overall business and household costs associated with outages. These impacts will continue after the investment period. The total impacts over the investment period are summarized in Table ES-1 ("Reliability improvements" column) and Table ES-3.

Table ES-1. Statewide impacts of Duke Energy's Power/Forward program
Millions of 2017 dollars; Totals over the investment period

	Duke Energy capital expenditures	Reliability improvements	Statewide total impacts
Statewide impacts (11-year total)			
Average employment*	11,791	7,259	19,051
Economic output (11 yr. total)	$20,029	$12,905	$32,934
GDP (11 yr. total)	$13,753	$6,602	$20,356
Labor income (11 yr. total)	$9,508	$4,806	$14,313
State & local taxes (11 yr. total)	$1,169	$421	$1,590

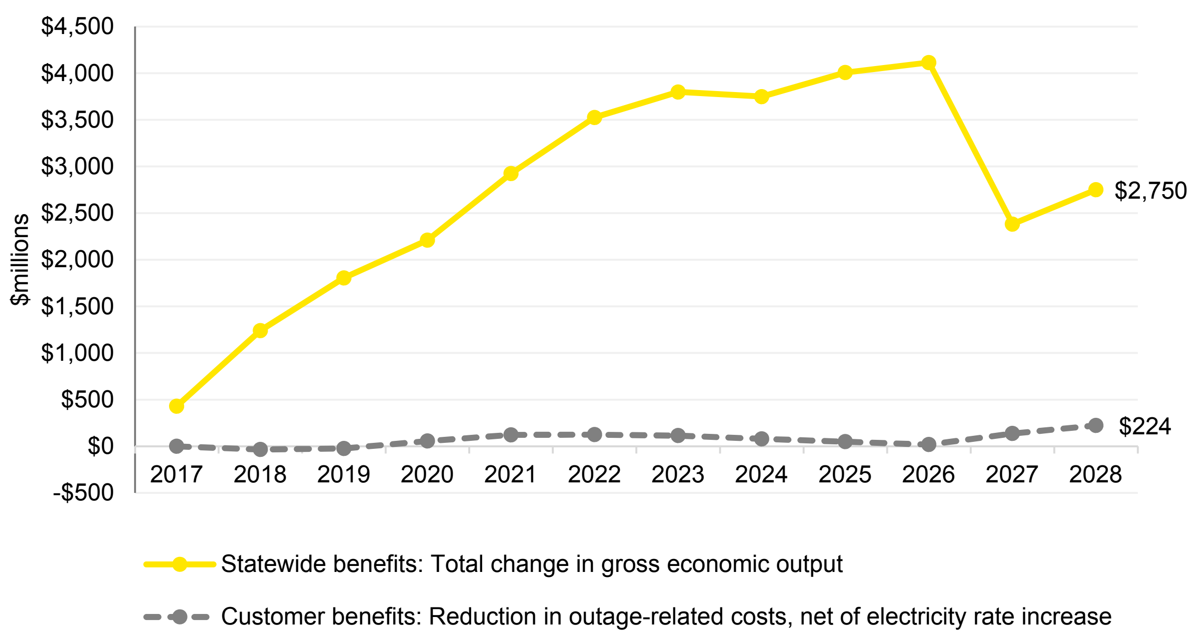
*Average jobs in place in each year.
Note: Figures may not appear to sum due to rounding; Source: Duke Energy management; EY analysis.

[1] Includes $13.3 billion of capital investments in installation and equipment and an additional $500 million of incremental project-related operations and maintenance expenditures.
[2] Projections of reliability improvements provided by Duke Energy management.

Figure ES-1 summarizes the annual impacts in the state:

- **Net benefits for Duke Energy customers:** Reliability improvements for regular service and major events could result in an estimated $1.67 billion in avoided costs annually for North Carolina businesses and households, once the project is complete (2028). Businesses and households will necessarily experience an increase in rates as result of this investment. The annual net benefit to businesses and households after considering this cost increase will reach an estimated $224 million by the end of the project, averaging $80 million per year over the investment period (dashed line in Figure ES-1).
- **Statewide GDP impact:** The analysis quantifies the statewide economic impacts as the effects of Duke Energy's project expenditures and increased electricity reliability flow through the economy.
  - Duke Energy's capital investments will generate $20.03 billion of total economic output in North Carolina, reflecting the share of total expenditures supplied by North Carolina businesses. Of this amount, $13.75 billion will be North Carolina GDP and $6.28 billion will be business-to-business sales (purchases from suppliers).
  - Businesses will respond to lower production costs (positive net benefits) through additional purchases of operating inputs and payments to employees. This activity will support an estimated $12.91 billion of total economic output. Of this amount, $6.60 billion will be North Carolina GDP.
  - **Combined, this economic activity will drive a cumulative impact of $32.93 billion in North Carolina economic output over the 12-year project period from 2017 through 2028 – averaging $2.75 billion per year (solid yellow line in Figure ES-1).**

Figure ES-1. Quantifying the North Carolina impacts of Duke Energy's Power/Forward program
Millions of real 2017 dollars



Note: Includes benefits related to normal-service and MED reliability improvements
Source: Duke Energy management; EY analysis.

Additional key findings:

- Duke Energy's capital expenditures will support an average of **11,791 jobs in North Carolina** over the 10-year investment period (including direct, indirect, and induced effects).
- **Duke Energy will employ an average of 6,200 direct workers (Duke Energy employees and contractors) during each year of the investment period.** Primarily linemen, these jobs will be high-wage, high-skill positions in North Carolina. Duke Energy's investment will require more linemen than are currently employed in the state.[3]
- **Direct employees will earn an average of $110,000 in annual compensation, including the value of wages and benefits.** The direct compensation includes $82,000 of base wages/salaries and $28,000 of benefits. Duke Energy's base wage is 75% higher than the statewide average of $46,500.[4] Over the 10-year period, these employees will earn an estimated **$6.93 billion in personal income.**
- For every 10 direct jobs, 9 additional jobs are supported elsewhere in the state through indirect and induced economic activity – **statewide employment multiplier of 1.9**.
- Additional economic activity related to reliability improvements will support an estimated average of 7,259 jobs during the investment period, including indirect and induced economic activity.
- **During the project period, Duke Energy's capital investments and activity related to reliability improvements will generate nearly $1.59 billion in state and local tax revenues.** Of this total, an estimated $513 million will be direct taxes paid by Duke Energy, including $330 million of state and local sales taxes on electrical equipment and installation materials.

Table ES-1. 10-year statewide economic impacts related to Duke Energy's Power/Forward program spending (installation, equipment, and O&M)
Millions of real 2017 dollars

	Direct: Duke Energy	Indirect & Induced	Total
Total capital investment impacts			
Average employment*	6,201	5,590	11,791
Economic output	$11,559	$8,470	$20,029
GDP	$9,066	$4,688	$13,753
Labor income	$6,925	$2,583	$9,508
State & local taxes	$921	$248	$1,169

*Average jobs in place in each year.
Note: Figures may not appear to sum due to rounding.
Source: Duke Energy management; EY analysis.

[3] In 2015, there were 4,760 electrical line installers and repairers employed in North Carolina. See: US Bureau of Labor Statistics (BLS). Occupational Employment Statistics (OES).
[4] Average wage across all industries. See: US BLS. Quarterly Census of Employment and Wages (QCEW).

Table ES-2. Dynamic economic impacts of improved electric infrastructure relability
Millions of 2017 dollars

	Year 5 2022	Year 11 2028	Cumulative 11-yr. total
Dynamic impacts of reliability improvements			
Employment	5,658	15,256	7,259
Economic output	\$806	\$2,750	\$12,905
GDP	\$407	\$1,434	\$6,602
Labor income	\$313	\$981	\$4,806
State & local taxes	\$26	\$89	\$421

*Average jobs in place in each year.
Source: Duke Energy management; EY analysis.

Contents

Glossary of key terms

- **Backward linkage:** Links an industry to its suppliers or a household (an institution) and the producers of household goods and services.
- **Direct coefficients:** For each dollar outlay for a given industry, the amount used for purchase of goods and services from each industry sector modeled.
- **Economic output:** Economic output is the broadest measure of economic activity and includes value added and total intermediate input purchases (supplier purchases). For most industries, economic output is equivalent to total revenues (production value).
- **Employment:** Employment comprises estimates of the number of jobs, full-time plus part-time, by place of work. Full-time and part-time jobs are counted at equal weight. Employees, sole proprietors, and active partners are included, but unpaid family workers and volunteers are not included.
- **Gross Domestic Product (GDP):** GDP, or value added, includes labor income, indirect business taxes, consumption of fixed capital (depreciation), and mixed income.
- **Indirect effects:** Indirect effects are related to purchases from local suppliers and the subsequent rounds of supplier purchases in the local economy.
- **Induced effects:** Induced effects are related to household consumption spending by direct and indirect employees.
- **Input-output accounts:** The accounting of all current money flows from and to (outlays and outputs) industries and institutions located within the region.
- **Labor income:** All wages, salaries, and benefits (including employer-paid payroll tax/social insurance) received by employees. Labor income includes earnings of proprietors (self-employed income).
- **RPC (Regional purchase coefficients):** The share of goods and services purchased from local suppliers.
- **System Average Interruption Frequency Index (SAIFI):** Total number of sustained (>5 minutes) customer interruptions / Total number of customers served
- **System Average Interruption Duration Index (SAIDI):** customer interruption duration (minutes) / Total number of customers served
- **Taxes:** The estimated tax contribution includes taxes collected by state and local governments throughout North Carolina.

Acronyms and abbreviations

Abbr.	Meaning
C&I	Commercial and industrial
DOE	U.S. Department of Energy
EIA	Energy Information Administration
ICE	Interruption Cost Estimate
IEEE	Institute of Electrical and Electronics Engineers
LBNL	Lawrence Berkeley National Laboratory
MAIFI	Momentary Average Interruption Frequency Index
MED	Major event day
OE DOE	Office of Electricity Delivery and Energy Reliability
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

North Carolina impacts of Duke Energy's Power/Forward program

Duke Energy is proposing to invest $13.84 billion for facility and grid improvements in North Carolina as part of a project that will generate economic benefits throughout the state.[5] These benefits occur in two ways.

First, as Duke Energy makes expenditures related to construction activities and equipment purchases, those dollars support jobs and wages in the state. These impacts occur as a result of the project itself, including the workers involved in undergrounding lines, installing equipment, and the other necessary activities and expenditures related to executing the program's objectives.

In addition to these temporary benefits from the program activities, there are long-term benefits from achieving the program's reliability objectives. As Duke Energy's business and household customers enjoy increased electric reliability due to the improved grid, those customers have reduced costs which create a more favorable environment for business investment and job growth.

Combined, these two types of impacts will support nearly $33 billion of gross state economic output (business production), generating $20 billion of state GDP from 2017 through 2028. Of this GDP impact, an estimated $14 billion will be labor income earned by employees at Duke Energy, as well as employees at Duke Energy contractors, suppliers, customers, and other North Carolina businesses. The economic impacts in this report are expressed in terms of five indicators.

- **Economic output:** Economic output is the broadest measure of economic activity and includes Gross Domestic Product and intermediate input purchases.
- **Gross Domestic Product (GDP):** GDP, or value added, is a component of economic output and includes labor income, payments to capital, and indirect taxes.
- **Labor income:** Labor income is a component of GDP and includes total employee compensation (value of wages and benefits) and proprietor income.
- **Employment:** Employment reflects the total number of full-time jobs (headcount). Direct installation labor is expressed in terms of full-time equivalents (FTEs), including Duke Energy employees and contractors.
- **State and local taxes:** Estimated tax impacts include individual and corporate income taxes, sales and excise taxes, and local property taxes. Income, property, and sales taxes paid by Duke Energy employees (including contractors) on their incomes and purchases are included as direct taxes.

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[5] Includes $13.3 billion of capital expenditures for installation and electrical equipment and an additional $500 million in incremental project-related operations and maintenance expenditures. Specifically, the analysis considers reliability improvements related to a self-optimizing grid, converting targeted areas to underground lines, and distribution network hardening and resiliency.

Part 1: Quantifying the potential impacts in North Carolina of Duke Energy's capital improvements

1. Overview

Duke Energy will invest more than $13.84 billion in North Carolina to upgrade, modernize, and expand its grid capacity in the state – including $13.31 billion in installation and equipment and an additional $530 million in incremental project-related operations and maintenance costs. This investment will temporarily support jobs and incomes in North Carolina. These contributions are referred to as "one-time" effects because they do not recur. This analysis considers impacts related to:

(1) **10-year impacts of construction & installation –** Duke Energy's planned capital expenditures will temporarily support workers in North Carolina, primarily in the power and communications construction sector.

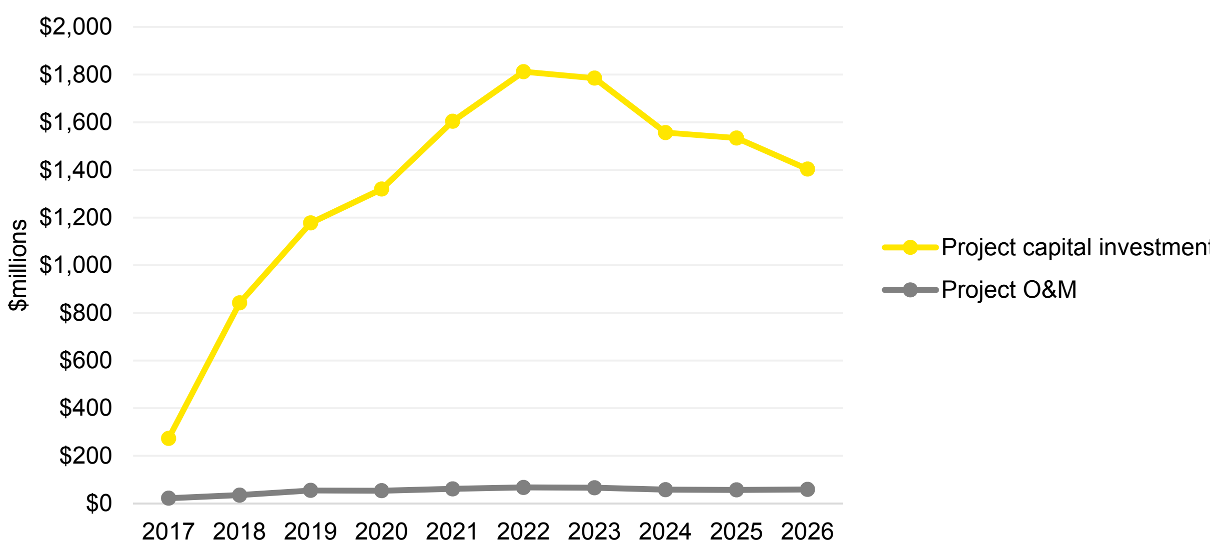
(2) **10-year impacts of equipment purchases** – A portion of Duke Energy's required equipment will be sourced within North Carolina, temporarily supporting manufacturing jobs.

(3) **10-year impacts of incremental (project-related) operations and maintenance –** Incremental operations and maintenance related to the planned infrastructure improvements will support ongoing jobs and incomes across North Carolina.

Figure 1 shows the planned expenditures for project capital investment and project-related operations and maintenance expenditures, by year. Investment will peak in 2022.

Figure 1. North Carolina Power/Forward expenditures, by year

Millions of 2017 dollars



Source: Data provided by Duke Energy management.

Table 1 shows the total impacts over 10 years as a result of Duke Energy's expenditures on the Power/Forward program. Detailed results are presented in the next section. Overall, the program will support an average of 11,791 jobs in North Carolina for ten years and generate a total of $20.03 billion in statewide economic output. Of this economic output impact, $13.75 billion will be state GDP.

Table 1. 10-year statewide economic impacts related to Duke Energy's Power/Forward program spending (installation, equipment, and O&M)
Millions of 2017 dollars

	Direct: Duke Energy	Indirect	Induced	Total
Average annual employment	6,201	1,243	4,347	11,791
Worker years	62,014	12,431	43,468	117,912
Economic output	$11,559	$2,508	$5,962	$20,029
GDP	$9,066	$1,284	$3,403	$13,753
Labor income	$6,925	$737	$1,846	$9,508
State taxes	$518	$49	$114	$681
Statewide local taxes	$403	$26	$60	$489

Note: Figures may not appear to sum due to rounding. Worker years are equivalent to the number of jobs lasting an average of one year each.
Source: EY analysis using the IMPLAN input-output multiplier model and data provided by Duke Energy management.

2. 10-year impacts related to Duke Energy's planned capital investments

This study estimates three types of economic effects related to capital investments and incremental operating costs:

- **Direct effects** include the temporary installation (engineers and line installers) and ongoing maintenance jobs supported by the planned infrastructure improvement projects throughout the state.

- **Indirect (supplier) economic effects** are the result of the Duke Energy's purchases from in-state suppliers (e.g., construction and installation materials, electrical equipment, etc.) and the subsequent rounds of supplier purchases in the state as Duke Energy's suppliers purchase additional goods and services to meet the increased demand.

- **Induced (employee spending) economic contributions** are related to employee household spending. Duke Energy, contractor, and supplier employees spend a portion of their incomes on goods and services from North Carolina businesses. These transactions support employment at retailers, restaurants, service companies, and other businesses.

Duke Energy's $13.84 billion of project expenditures can be expressed as three components: (1) $11.03 billion for installation materials and labor, generating direct construction sector economic output (See Table 2: Installation direct economic output), (2) $534 million of project operations and maintenance (O&M) expenditures (See Table 2: Operations & maintenance direct economic output), and (3) $2.28 billion for purchases of electrical equipment (the NC-sourced equipment is included in Table 2 as an indirect impact).

Duke Energy will employ an average of 6,201 direct Duke Energy employees and contractors for equipment installation and project-related operations & maintenance. Primarily linemen, these jobs will be high-wage, high-skill positions in North Carolina. Duke Energy's investment will require more linemen than are currently employed in the state.[6] Direct employees will earn an average of $110,000 in total compensation, including the value of wages and benefits. The direct compensation includes $82,000 of base wages/salaries and $28,000 of benefits. Duke Energy's base wage is 75% higher than the statewide average of $46,500.[7]

Nearly one-fifth of Duke Energy's investment will be for purchases of electrical equipment, totaling $2.28 billion over 10 years. Duke Energy estimates that 28% of this equipment will be sourced from North Carolina suppliers – generating $639 million of indirect economic output.

Including indirect (supplier) and induced (household spending) effects, Duke Energy's project-related expenditures will support more than $20.03 billion in total economic output throughout the state (approximately equivalent to business sales). Of the total state economic output impact, more than $13.75 billion will be North Carolina GDP, averaging $1.4 billion. The GDP impact includes $9.51 billion of labor income earned by direct, indirect, and induced employees.

The overall employment multiplier for this activity is 1.90 – for every 10 direct Duke Energy employees and contractors working on-site for installation or operations and maintenance, an additional 9 jobs will be supported elsewhere in the state.

[6] In 2015, there were 4,760 electrical line installers and repairers employed in North Carolina. See: US Bureau of Labor Statistics (BLS). Occupational Employment Statistics (OES).
[7] Average wage across all industries. See: US BLS. Quarterly Census of Employment and Wages (QCEW).

Table 2. 10-year statewide economic impacts related to Duke Energy's Power/Forward program spending (installation, equipment, and O&M)

Millions of 2017 dollars

	Direct: Duke Energy	Indirect	Induced	Total
Installation				
Average annual employment	5,917	939	4,027	10,883
Worker years	59,168	9,387	40,274	108,828
Economic output	$11,025	$1,617	$5,524	$18,166
GDP	$8,650	$856	$3,154	$12,660
Labor income	$6,508	$523	$1,711	$8,743
State taxes	$497	$32	$105	$633
Statewide local taxes	$394	$17	$55	$466
Project operations & maintenance				
Average annual employment	285	58	196	539
Worker years	2,846	583	1,961	5,390
Economic output	$534	$89	$269	$893
GDP	$416	$47	$154	$617
Labor income	$416	$28	$83	$527
State taxes	$21	$2	$5	$28
Statewide local taxes	$9	$1	$3	$13
Equipment purchases				
Average annual employment	--	246	123	369
Worker years	--	2,462	1,232	3,694
Economic output	--	$802	$169	$970
GDP	--	$381	$96	$477
Labor income	--	$186	$52	$238
State taxes	--	$15	$4	$19
Statewide local taxes	--	$8	$2	$10
Total capital investment impacts				
Average annual employment	6,201	1,243	4,347	11,791
Worker years	62,014	12,431	43,468	117,912
Economic output	$11,559	$2,508	$5,962	$20,029
GDP	$9,066	$1,284	$3,403	$13,753
Labor income	$6,925	$737	$1,846	$9,508
State taxes	$518	$49	$114	$681
Statewide local taxes	$403	$26	$60	$489

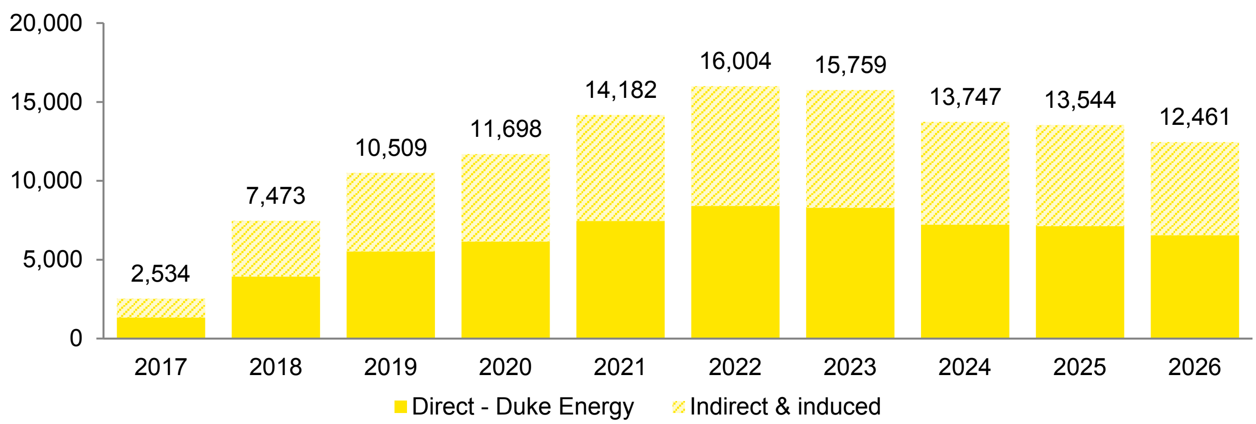
Note: Figures may not appear to sum due to rounding. Worker years are equivalent to the number of jobs lasting an average of one year each.
Source: EY analysis using the IMPLAN input-output multiplier model and data provided by Duke Energy management.

Figures 1 and 2 show the estimated employment and economic output impacts over each year of the investment period. Including direct, indirect, and induced effects, Duke Energy's project expenditures will support an average of 11,791 jobs – totaling 117,912 "worker years." Worker years are the total number of jobs lasting an average of one year each. These jobs include contractors and engineers, as well as employees at installation material and electrical equipment suppliers. See Figure 1 for the estimated jobs supported in each year of the investment period. Workers supported by capital expenditure impacts will earn an estimated $80,600 in average labor income (total compensation) statewide.

The project expenditures will generate an annual average of $2.00 billion of gross economic output in North Carolina during the 10-year investment period – for a total impact of $20.03 billion (see Figure 2).

Figure 1. North Carolina temporary employment impact of capital expenditures, by year

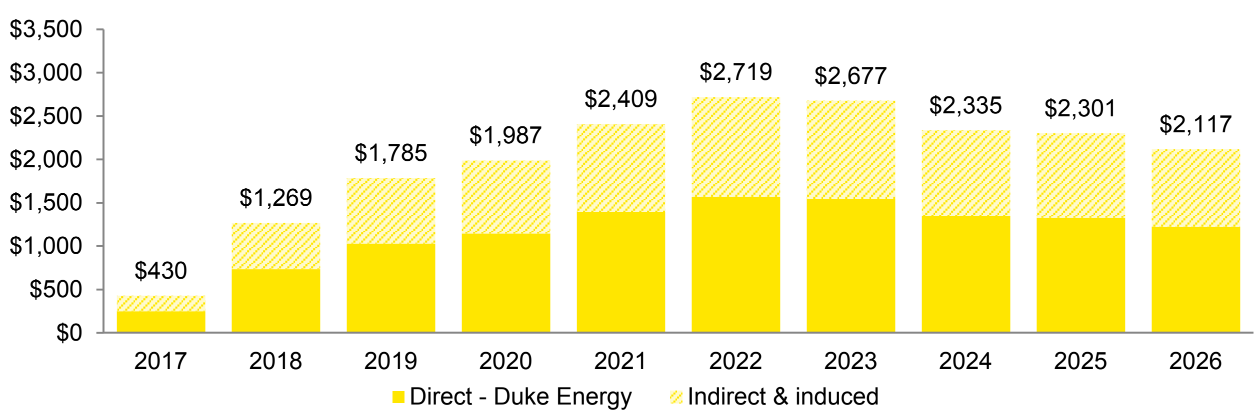
Average statewide employment impact = 11,791 jobs



Source: EY analysis using the IMPLAN input-output multiplier model and data provided by Duke Energy management.

Figure 2. North Carolina gross economic output impact of capital expenditures, by year

Millions of 2017 dollars; Average economic output = $2.0 billion



Source: EY analysis using the IMPLAN input-output multiplier model and data provided by Duke Energy management.

Duke Energy's Power/Forward expenditures will generate an estimated $1.17 billion in public-sector tax revenues throughout North Carolina, including an estimated $388 million in state sales taxes and $262 million in state individual income taxes. See Table 3.

Table 3. 10-year state and local tax impacts related to Duke Energy's Power/Forward program spending (installation, equipment, and O&M)
Millions of 2017 dollars

	Direct tax	Indirect & Induced	Total tax contribution
State taxes			
Sales & use taxes	$319	$70	$388
Personal income	$189	$73	$262
Other taxes	$10	$20	$30
Total state taxes	**$518**	**$163**	**$681**
Local taxes			
Property taxes	$85	$64	$149
Other local taxes, statewide	$135	$21	$156
Total local taxes	**$220**	**$85**	**$306**
Total state & local taxes	**$738**	**$248**	**$986**
Incremental property tax from Increased value of NC assets	$183	--	$183
Total state & local taxes, incl. incremental property taxes	**$921**	**$248**	**$1,169**

Note: Figures may not appear to sum due to rounding.
Source: EY analysis using the IMPLAN input-output multiplier model and data provided by Duke Energy management.

Part 2: North Carolina economic impacts of Duke Energy's improved electric infrastructure reliability

In addition to the temporary impacts of Duke Energy's direct spending presented in Part 1, grid improvements will also promote a stronger state economy by reducing outage-related costs for Duke Energy's customers.

This analysis estimated the economic and tax effects related to a reduction in business and household costs from increased reliability related to the improved and expanded grid. The analysis considers reliability improvements related to integrating a self-optimizing grid, converting targeted areas to underground lines, and distribution network hardening and resiliency.

The impacts in this section are additive to the results presented in Part 1.

3. Direct business and household benefits and costs

This section outlines the estimated direct impact on business and household costs as a result of Duke Energy's planned grid improvements. This section includes (1) the estimated change in reliability measures, including normal-service reliability and major events and (2) the estimated net impact on business and household costs.

Duke Energy estimates that the Power/Forward grid improvements could reduce the number and duration of interruptions during normal service for the average customer by 40-60%, relative to the projected reliability without investment. The changes in these reliability metrics were then translated into the benefits of improved reliability for businesses and households:

- **Business benefits** are measured as a reduction in business operating costs (e.g. shutdown and restart costs, spoilage and damage, health and safety effects) as a result of reliability improvements (with investment vs. baseline with no investment).
- **Household benefits** are measured as a reduction in household costs (e.g. spoilage, property damage, health and safety effects) resulting from reliability improvements.[8]

These benefits are partially offset by the necessary increase in electricity prices to support the investment. Costs for businesses and households are the estimated increased electricity rates, based on projections provided by Duke Energy.

[8] Customer cost changes were estimated using information from Duke Energy's records and energy consumption data from the US Department of Energy Interruption Cost Estimation (ICE) tool. The ICE tool was used to estimate the overall business cost savings across all industries, including specific estimates for construction companies and manufacturers. The estimated impact across the remaining sectors was allocated to each industry (at the 2-digit NAICS level) based on historical energy intensity. Energy intensity was measured as the distribution of electricity absorption across industries based on the 2015 IMPLAN input-output economic model of North Carolina. Additional information is included in the appendix.

3.1 Change in normal-service reliability

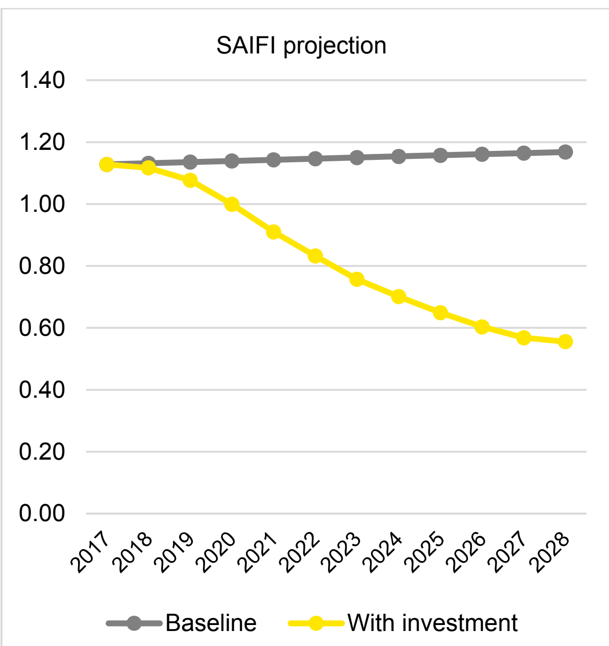
At current levels, Duke Energy's 3.2 million retail customers in North Carolina experience an estimated $1.17 billion in outage costs annually related to normal-service interruptions (non-major events). Businesses make up nearly all of this impact (98%).The annual cost is projected to grow to $1.70 billion without investment due to a projected decline in reliability using current infrastructure. With investment, these costs fall to $700 million. This approximately $1 billion reduction in outage-related costs is a benefit to businesses and households of improved electric reliability.

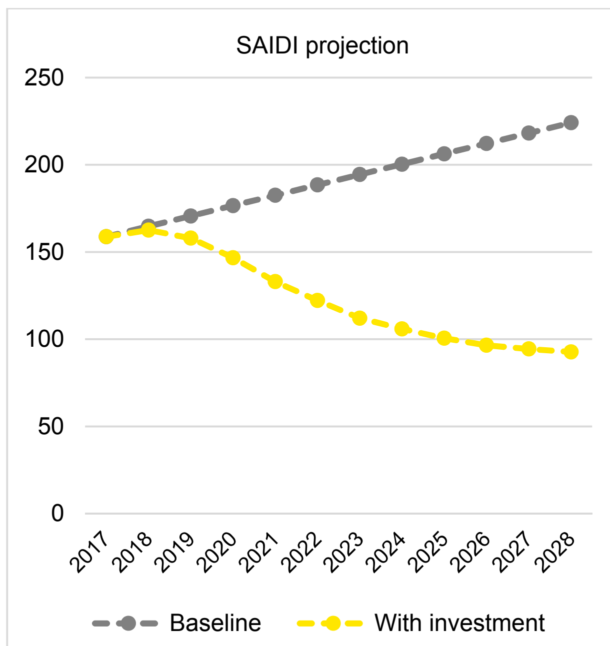
Electricity reliability is measured using two standard metrics:

- **System Average Interruption Frequency Index (SAIFI):** Total number of sustained (>5 minutes) customer interruptions / Total number of customers served
- **System Average Interruption Duration Index (SAIDI):** Total customer interruption duration (minutes) / Total number of customers served

Duke Energy estimates that Power/Forward could result in a 52% decrease in interruptions for the average North Carolina customer and a 59% reduction in the average outage time per customer, relative to projected reliability without investment (see Figures 3 and 4).

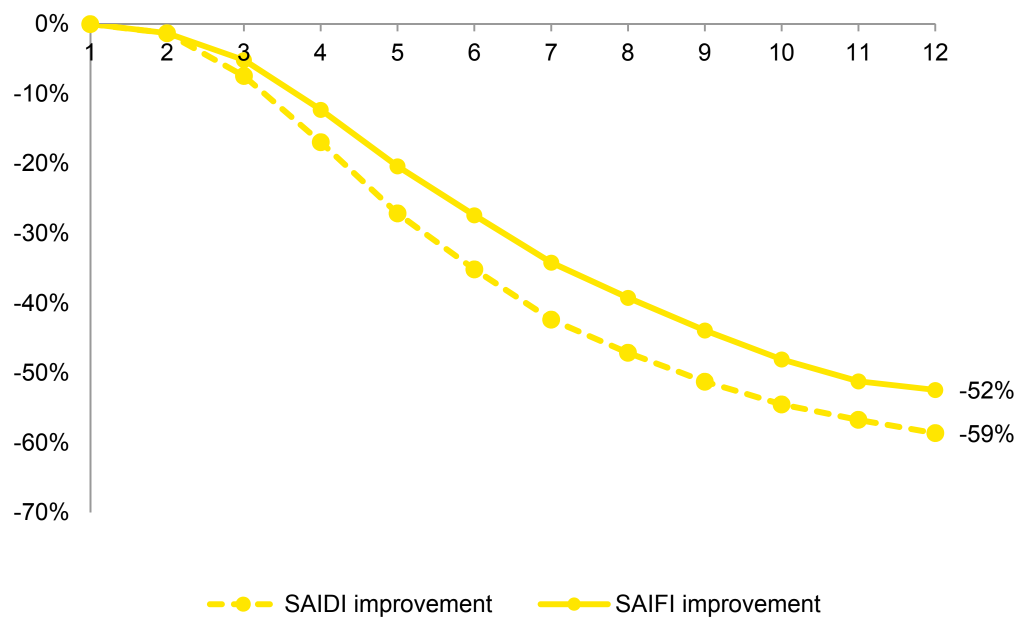
Figure 3. SAIFI and SAIDI projections, 2017-2028
Combined improvement from grid hardening, targeted undergrounding, and self-optimizing grid





Note: Excluding major events; Source: Duke Energy management.

Figure 4. SAIFI and SAIDI improvement compared to projected baseline, 2017-2028
Combined improvement from grid hardening, targeted undergrounding, and self-optimizing grid



Note: Excluding major events; Source: Duke Energy management.

3.2 Estimated average annual impact on major event days (MEDs)

The SAIFI and SAIDI projections in Section 3.1 do not consider the potential benefits related to avoided or shortened outages during major events. Clearly hurricanes, such as Matthew in 2016, are included in the impacts of major events, but there are many smaller scale multi-day events such as ice, severe thunderstorm, and wind storms that are also included in the calculation of Major Event Days (MEDs). For example, in 2016, Duke Energy customers that experienced an MED outage event(s) in North Carolina were out an average of 11.5 hours related to MEDs.

Duke Energy projects that Power/Forward grid improvements could, on average, reduce MED interruption time by 30%.

While MEDs are less common, the impacts to customers, businesses and communities are more severe. The benefit to businesses and household of reduced MEDs was estimated using the 10-year historical actuals to define an annual average customers interrupted (CI) and customer minutes interrupted (CMI) from major events. Duke Energy applied this annual average experience to project estimates of the avoided CI and CMI reductions that would be realized as a result of proposed Power/Forward grid investments. EY used this information as inputs into the ICE tool to estimate the direct static value of reliability improvements as the improved infrastructure comes online over the investment period. See Table 4.

Table 4. Estimated MED impacts, upon project completion

	Customers interrupted	Customer minutes interrupted
10-year historical average, NC	1,173,481	815,452,734
Estimated reduction (%)	33%	30%
Hypothetical MED, after project completion	789,797	567,233,923

Source: Duke Energy management.

This method only partially captures the value from the most severe events like Hurricanes Fran, Floyd, and Matthew as well as severe winter icing events like the December 2002 Ice Storm. Currently available models do not effectively capture the community impacts from these most severe events where widespread infrastructure damage may mean limited access to fuel, food, and shelter. In many cases (particularly in rural areas) these critical services are directly tied to electric infrastructure outages. An effective example to illustrate these broader benefits comes from looking at a specific analysis applied to Hurricane Matthew events and projects outcomes had proposed grid investments already been completed.

Table 5 shows a projected outage events reduction of 34% and a 30% reduction in duration from Matthew for the more heavily impacted DEP jurisdiction, with the potential to move Hurricane Matthew restoration completion from 6 days to nearly 4 days (excluding areas where flood waters prevented access). As well, DEC impacted areas were through the second day of restoration before being available to assist DEP. The 57% reduction in customers interrupted and the 45% reduction in CMI for DEC impacts from Matthew could enable those resources to be available to assist DEP a full day earlier.

Table 5. Hypothetical impacts of the project on Hurricane Matthew outages

	% Potential CI Eliminated	% Potential CMI Eliminated	% Potential Outages Eliminated
DEP NC	30%	30%	34%
DEC NC	57%	45%	32%

Source: Duke Energy management.

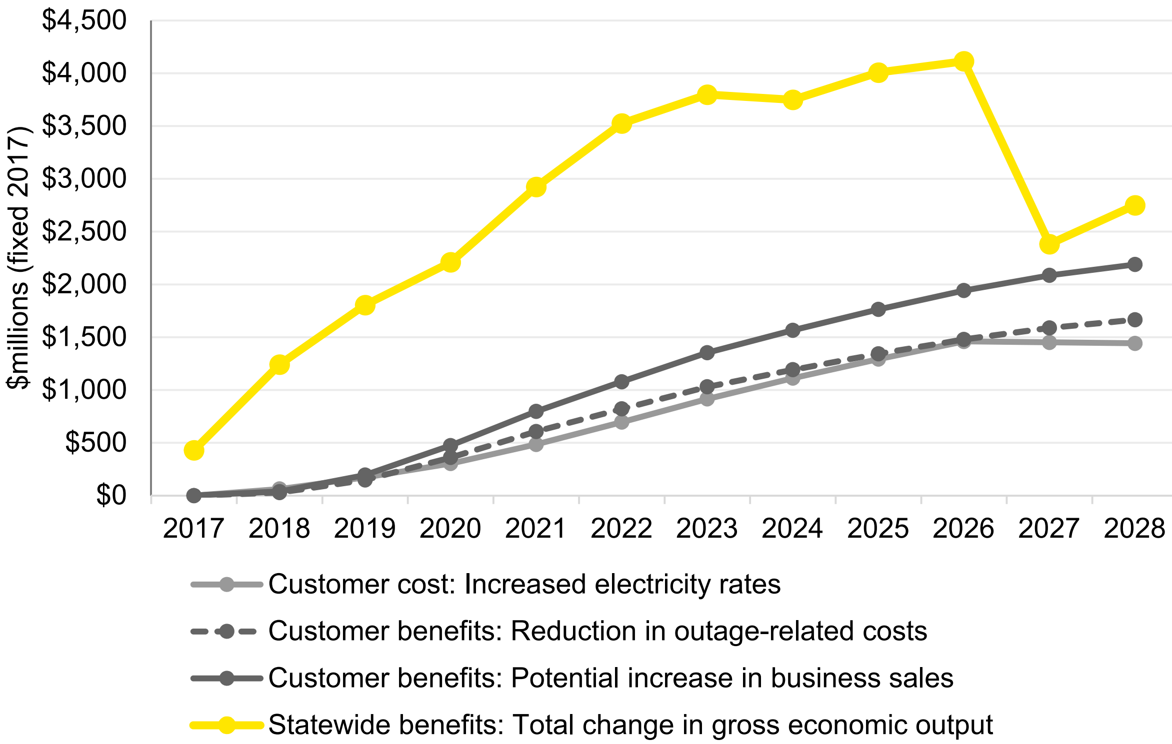
3.3 Net change in customer outage costs and electric rates

The business and household benefits grow over the investment period as Duke Energy's new infrastructure comes online. The anticipated benefit of the reliability improvement (in terms of avoided outage-related business costs) will range from $29 million in 2018 to $1.67 billion by the end of 2028, including $1 billion related to normal-service reliability and $670 million related to avoided MED outages. If these avoided costs were translated into related sales by businesses, the sales would total $2.20 billion by 2028.

These benefits will be partially offset by increased electricity rates paid by Duke Energy's customers to support the program investment. Duke Energy estimates that average retail electricity rates for North Carolina customers will increase by approximately 20% by 2026, relative to current rates. The rate increases grow along with investment and track with benefits over the period. The annual costs (incremental rate increases) will range from $62 million in 2018 to $1.44 billion by 2028.

The avoided outage costs and project investments will generate $32.93 billion in increased businesses sales (economic output). Theses statewide economic benefits are shown in Figure 5. On average, the project will generate $2.75 billion of economic output during each year of the project period, relative to the baseline state economic forecast.

Figure 5. Customer costs and benefits compared to statewide output impacts
Millions of 2017 dollars

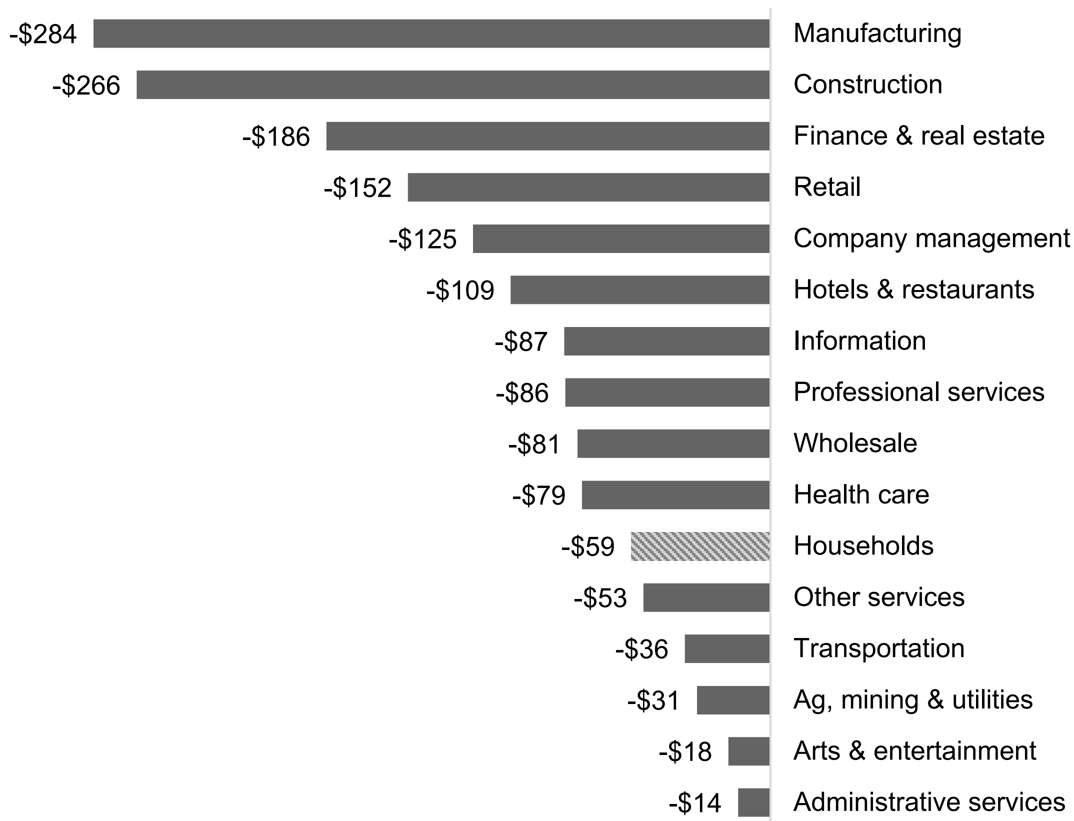


Note: Includes benefits related to normal-service and MED reliability improvements.
Source: Duke Energy management; EY analysis.

The benefits are driven by business production cost savings. According to estimates developed by the Berkeley National Laboratories for the Department of Energy (as used in the ICE tool), businesses incur a much higher cost of electricity outages than households. Manufacturers will realize 17% of the total benefit – totaling $284 million upon project completion. The remaining impact will be spread across all sectors of the economy, including households. See Figure 6.

EY estimates that industries will realize these cost saving benefits in proportion to their average electricity intensity. As shown in Figure 6, businesses in construction and manufacturing will realize the largest benefits (based on the econometric estimates underlying the ICE calculation tool). Finance and real estate will have the third largest overall benefit – primarily due to managed office buildings. The analysis estimates the average commercial & industrial (C&I) customer will receive a cumulative benefit of approximately $20,000 as a result of reliability improvements and avoided MEDs over the period (cumulative, 2018-2028).

Figure 6. Potential cost savings from reliability benefits, by sector
Annual cost savings, once fully-phased in (2028); Millions of 2017 dollars



Note: Includes cost savings related to both normal-service improvements and major event days.
Source: EY estimates based on data provided by Duke Energy; the DOE ICE tool; and the REMI economic model of North Carolina.

4. Economy-wide dynamic impact of infrastructure improvements

The economic impacts of reliability improvements will extend beyond the direct business cost reductions experienced by customers. EY estimated the dynamic economic impacts throughout the North Carolina economy using the REMI econometric model of the state.

The REMI model estimates the macroeconomic impacts of these changes in direct business and household costs into changes in statewide employment, GDP, resident income, and state and local taxes supported through purchases of intermediate goods, spending by households, and investment activity. These impacts are summarized in Table 6. As businesses realize the benefits of these cost reductions, they will support additional economic activity through incremental purchases of operating inputs and payments to employees. This activity will support up to an estimated 15,256 jobs after implementation (in 2028), including indirect and induced economic activity.

The impacts will phase in over several years as the economy adjusts. Although Figure 7 shows continuous employment growth, the incremental economic impacts related to the project (relative to the baseline) will decline over time, as the economy adjusts after the completion of the project. This analysis presents impacts over three periods: (1) mid-investment (investment year 5, 2022), (2) end of investment period (year 11, 2028), and (3) investment period total (11-year cumulative impacts).

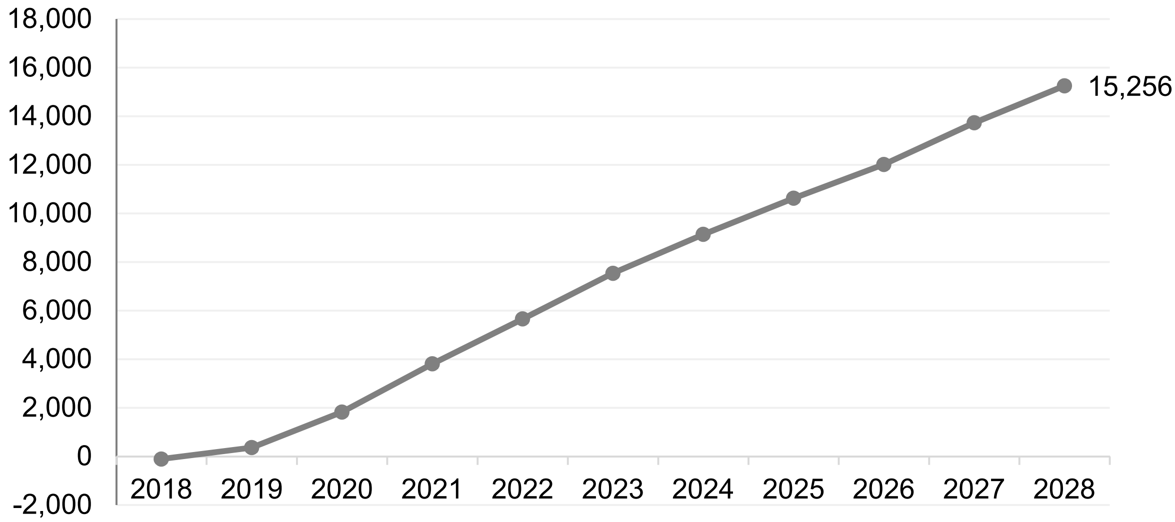
This economic activity will drive a cumulative impact of $421 million in tax revenues for state and local governments over the 11-year period. This includes $276 million of estimated state taxes paid by businesses and households. The annual tax impact will reach $89 million by the end of the investment period (2028).

Table 6. Estimated economic impacts of reliability increases, total impact
Millions of 2017 dollars

	Year 5 2022	Year 11 2028	Cumulative 11-yr. total
Employment	5,658	15,256	7,259*
Economic output	$806	$2,750	$12,905
GDP	$407	$1,434	$6,602
Labor income	$313	$981	$4,806
Private investment	$131	$431	$1,934
State taxes	$17	$59	$276
Local taxes	$9	$31	$145

*Average jobs in place in each year.
Source: Duke Energy management; EY analysis.

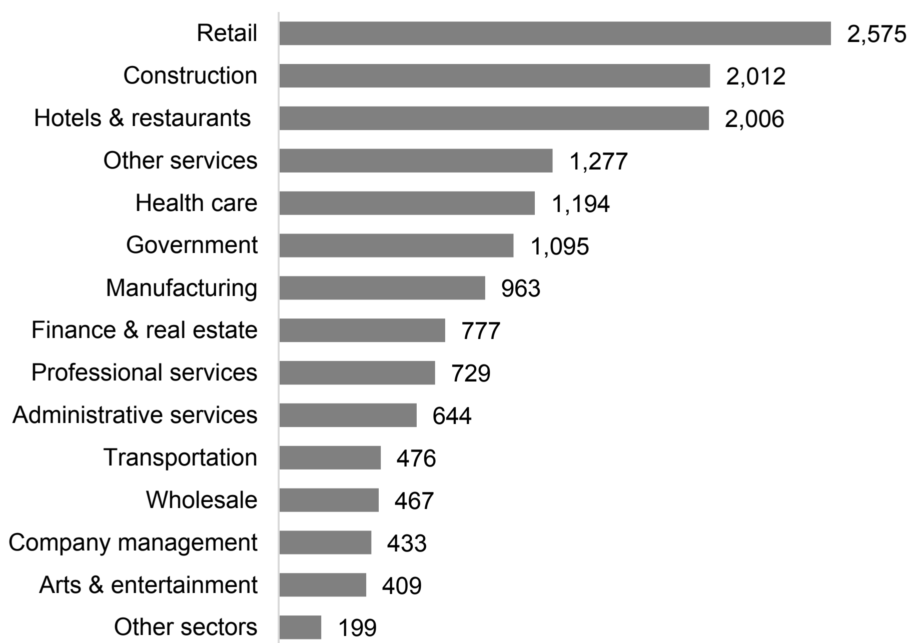
Figure 7. Estimated employment impact of reliability increases, by year



Source: EY analysis based on the REMI economic model of North Carolina.

The largest employment impacts will be in the retail sector, related to employee household demand. The construction sector will also see a significant employment impact, as result of additional investment related to the increased economic activity. See Figure 8.

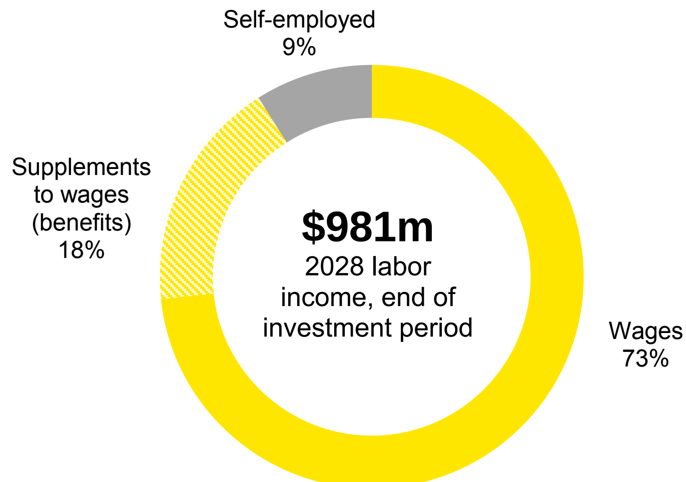
Figure 8. Employment impacts of reliability increases, by sector
2028, end of investment period



Source: EY analysis based on the REMI economic model of North Carolina.

Figures 9 and 10 illustrate the composition of the labor income and GDP impacts. Figure 9 shows that the projected increase in statewide labor income resulting from increased employment and economic activity includes cash wages earned by employees, benefits and other non-cash payments provided to employees as part of their total compensation, and earnings of self-employed workers including independent contractors. Reliability improvements will result in an estimated increase of $4.81 billion in income earned in North Carolina over the 11-year period, totaling $981 million in 2028. Wages and benefits earned by employees account for approximately 90% of this amount. These workers will earn an average of $70,000 in total compensation, including estimated wages, overtime, and benefits.[9] See Figure 9.

Figure 9. Components of total labor income from reliability increases, 2028
2017 dollars

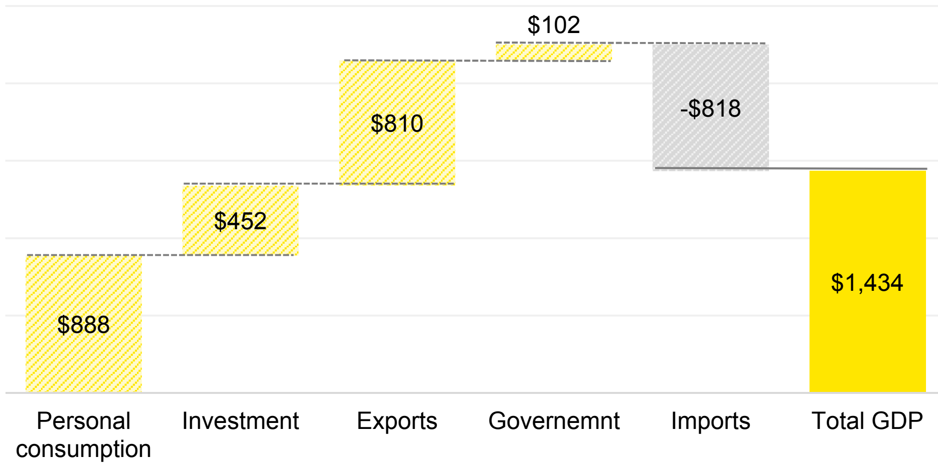


Source: EY analysis based on the REMI economic model of North Carolina.

The avoided outage costs will generate an estimated nearly $6.60 billion boost to state GDP over 11 years, generated as a result of $12.91 billion in increased businesses sales (economic output). The GDP impact is driven by personal consumption and investment activity. See Figure 10, which shows the composition of GDP, by final demand use. The change in personal consumption spending accounts for the largest share of GDP, while investment accounts for the second largest positive contribution. The higher level of income and economic activity also increases statewide imports, which is netted against other items to yield the overall $1.43 billion GDP impact in 2028.

[9] Employment represents the total number of full- and part-time employees and includes sole proprietors.

Figure 10. Components of GDP impact from reliability increases, 2028
Millions of 2017 dollars



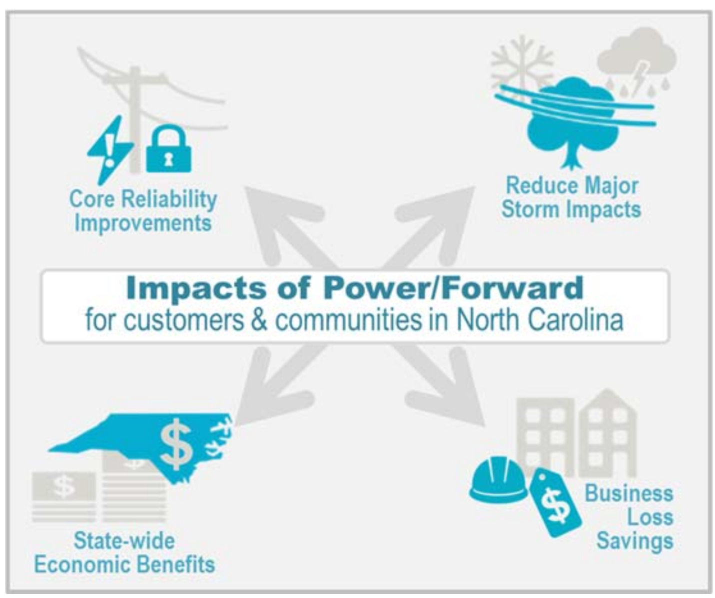
Source: EY analysis based on the REMI economic model of North Carolina.

Part 3: Conclusions – Statewide impacts of Duke Energy's Power/Forward program

As shown in this report, Duke Energy's North Carolina Power/Forward program has the potential to provide benefits in four ways.

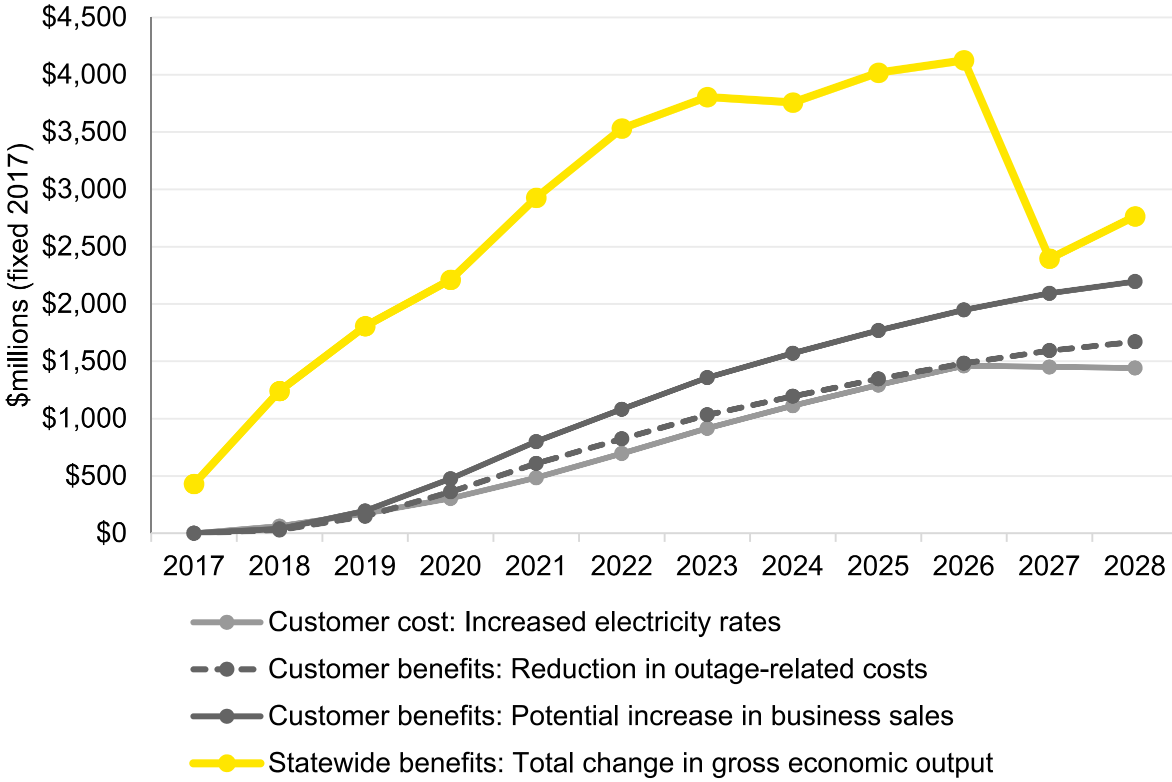
1. **Improved non-major event reliability.** The Power/Forward investments in the grid will improve reliability for Duke Energy customers during normal operations by approximately 40-60%. For both businesses and households, this means the frequency of power outages and the duration of those outages will decrease.
2. **Improved major event reliability.** As a result of the investment, Duke Energy customers will enjoy an estimated 30% fewer minutes of total outages during major events, including storms and hurricanes. These reduced outages will provide benefits to customers such as reduced food spoilage for households and reduced interruption costs for businesses. In addition, by preserving or more quickly restoring power to customers during major events, the entire state can more quickly resume normal functioning after a major event.
3. **Reduced outage-related business costs.** Reduced business costs resulting from a more reliable electric grid make North Carolina a more competitive place to do business. By 2028, the analysis shows that North Carolina businesses will save $1.7 billion per year from reduced outage-related costs. Businesses with more reliable access to electricity operate more efficiently and make North Carolina's business environment more competitive.
4. **Economic benefits.** The economic benefits arise from a more reliable electric grid and more competitive business environment as well as the jobs and spending supported by the grid investment itself. While customer rates will increase as a result of the capital spending, the economic benefits are estimated to exceed these costs. In total, our analysis shows that 19,000 jobs will be supported statewide through higher levels of economic activity associated with improved reliability and the spending associated with the plan.

The "four corners" of Duke Energy's Power/Forward program



Source: Duke Energy management.

Figure 11. Business and household benefits and costs
Millions of 2017 dollars



Note: Includes benefits related to normal-service and MED reliability improvements
Source: Duke Energy management; EY analysis.

5. Appendix: Study methodology

5.1 Estimating the temporary impacts related to capital expenditures

The estimated economic and tax contributions presented in this study are based on information regarding Duke Energy's proposed capital investments in system-wide upgrades and improvements over the next ten years, provided the client's management. The state and local economic and tax impacts related to this activity were estimated using the statewide Economic Impact Analysis for Planning (IMPLAN) input-output economic model for North Carolina, which describes relationships between businesses, households, and governments within the state. This model follows economic flows, as purchases of local goods by companies and employees support sales, jobs, and tax revenues. IMPLAN is used by the public sector as well as private-sector businesses and other researchers and is based on widely accepted methodology for estimating these types of economic linkages.

The magnitude of each economic effect is described in terms of an economic multiplier. The multipliers in the IMPLAN model are based on the Leontief matrix, which estimates the total economic requirements for every unit of direct output in a given industry using detailed inter-industry relationships documented in the input-output model. The input-output framework connects commodity supply from one industry to commodity demand by another. The multipliers estimated using this approach capture all of the upstream economic activity (or backward linkages) related to an industry's production by attaching technical coefficients to expenditures. These output coefficients (dollars of demand) are then translated into dollars of GDP and labor income and number of employees based on industry averages.

In general, estimated tax impacts are estimated based on the historical relationship between state and local tax collections (by tax type) to economic activity (measured as personal income). This ratio estimates the effective tax rates for each tax type as a share of total personal income. This approach assumes that Duke Energy employees and taxes from the indirect and induced activity will generate taxes at the statewide and countywide average effective rate on economic activity.

Limitations

The reader should be aware of the following model limitations and assumptions when interpreting the capital investment impact results:

- Indirect economic impacts were estimated based on relationships in the IMPLAN input-output model, which describe the mix of locally supplied goods and services, by industry, based on historical purchasing relationships. The IMPLAN industry models were chosen to most closely resemble the mix of activities related to the planned capital expenditures and incremental maintenance costs, but may be different in some cases.

- In general, indirect and induced tax impacts are estimated based on state averages for all industries and households. These estimates do not incorporate industry-specific tax rates, exemptions, or bases.

- The economic impacts presented in this report quantify the economic activity supported by Duke Energy's investments and purchases. In some cases, the indirect and induced jobs not be net new to the state, but are temporarily supported by Duke Energy's expenditures.

Direct state and local sales and use taxes on construction materials were estimated based on the applicable statutory tax rates (4.75% state; 2.25% average local rate), assuming 49% of construction expenditures are on taxable materials for the capital investment and 25% of incremental operations and maintenance costs are on taxable materials.

5.2 Estimating the direct impact on business costs

To estimate the direct economic impacts of increased reliability that could result from Duke Energy's infrastructure investments in North Carolina, this analysis used data from Duke Energy as inputs to the US Department of Energy's Interruption Cost Estimate (ICE) Calculator[10], which uses an econometric model to estimate the cost to businesses and households of interruptions in electrical supply. EY then allocated the cost estimates from the ICE Calculator to industry sectors at the 2-digit NAICS level based on each sector's consumption of electricity as indicated by the intermediate use table in the 2015 IMPLAN input-output economic model of North Carolina.

The ICE Calculator was developed by Nexant and the Lawrence Berkeley National Laboratory for the US Department of Energy for use by utilities and governments in understanding the economic impact of electrical grid reliability. It is based on an econometric model developed using data "from 28 customer value of service reliability studies conducted by 10 major U.S. electric utilities over the 16-year period from 1989 to 2005."[11] The underlying econometric model estimates the interruption cost for three types of customers: (1) medium and large commercial and industrial customers (C&I) defined as customers using more than 50,000 kWhs annually, (2) small C&Is defined as those using less than 50,000 kWhs annually, and (3) residential customers. For each type of C&I, interruption cost was estimated with a regression model as a function of the duration of the outage, the industry affected, and other seasonal/temporal factors. A similar approach was used for residential customers taking into account duration of the outage, demographic characteristics of the households, and temporal factors.

The primary limitations of the ICE Calculator stem from the data used to fit the underlying model. In particular, about 50% of the data available was more than 15 years old as of 2015, no data was available for the northeast or Mid-Atlantic, there was limited data available for the Great Lakes region, and the data does not include outages with duration greater than 24 hours. Another set of limitations arise from how the data was collected. Because the data was originally collected by utility companies for planning purposes, "interruption conditions described in the surveys for a given region tended to focus on periods of time when interruptions were more problematic for that region."[12] In addition, because different surveys were done at different times, there is significant multicollinearity in the data e.g. between survey year and region. Finally, the ICE Calculator is

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[10] *Interruption Cost Estimate Calculator*.
[11] Michael J. Sullivan, Josh Schellenberg, and Marshall Blundell, "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States."
[12] Ibid.

limited by its level of industry detail. The study that the ICE Calculator is based on estimates interruption impact coefficients for three broad industries: manufacturing, construction, and all other. The ICE Calculator then by default takes as an input only an aggregate number of C&Is and allocates these between sectors based on Census establishment counts.

Duke Energy provided North Carolina customer accounts by category and outage data from which EY estimated the current reliability measures (SAIFI and SIDI). These measures were estimated excluding Major Event Days (MEDs). EY then used counts of customer accounts by type and the reliability measures as inputs to the ICE Calculator, which yielded estimates of the direct economic value of reliability improvements for the construction, manufacturing, and other sectors. To refine these estimates, EY used the IMPLAN 2015 North Carolina use table to allocate the ICE Calculator's other impacts across 2-digit NAICS sectors based on each sectors' use of electricity as an input to production. In addition, a portion of the impacts related to real estate rental and services were allocated to the industries that employ those services to more accurately reflect the industries that benefit from increased electrical grid reliability.

EY accepted the default ICE settings for:

- Percentage of accounts in construction, manufacturing, and all other industries,
- Percentage of customers with backup generation and/or power conditioning equipment,
- Distribution of outages by time of day, and
- Distribution of outages by time of year.

These default settings were based on historical data for North Carolina.

5.3 Estimating the total economic impacts

This analysis estimates the indirect economic impact of improving electricity generation and distribution infrastructure in North Carolina through use of a Computable General Equilibrium (CGE) model of the state economy. In particular, the estimated direct business operating cost savings resulting from increased reliability is used as an input to a CGE economic model, developed by Regional Economic Models, Inc. ("REMI") and used under license by EY. The CGE model incorporates input-output, general equilibrium, econometric, and economic geography methodologies to estimate impacts on macroeconomic variables and estimate industry-specific results for the North Carolina economy. The REMI model estimates the reduction in business costs will impact:

- **Intermediate demand for inputs (indirect effects):** Resulting from additional purchases from suppliers to produce final goods.

- **Local consumption demand (induced effects):** Resulting from the increase in personal income and subsequent household spending.

- **Investment activity:** Demand for capital goods

- **Exports & imports:** Trade within the US and with other countries

- **Government activity:** Resulting from additional government expenditures

The input-output module of the model takes into account the inter-industry transactions within the state economy as well as the economy's interaction with buyers and sellers in other parts of the United States as well as other countries. The social accounting matrix contained in the CGE model extends this model of inter-industry dependence to transactions between industries, households, and government. In this way, the CGE model estimates economic impacts that consider the same types of direct, supplier-related, and consumption-related impacts that are estimated by users of an input-output model.

Additional features of the CGE model include:

- **Consideration of supply-side constraints.** The CGE model takes into account supply-side constraints on the economy. That is, the extra output cannot be produced in one area without taking resources away from other activities.
- **Change in prices with variation in supply and demand.** Constraints on the availability of inputs, such as skilled labor and intermediate goods, require prices to act as a rationing device. A CGE model allows prices to vary and capture the supply and demand of industry inputs.
- **Change in consumption shares.** The REMI model allows for the household budget share of goods and services to vary depending on relative prices.
- **Adjustment dynamics of market economy.** CGE models mimic the economy's adjustment process from one equilibrium to another after an economic shock. As such, the model does not provide a timeless impact, but annual changes incorporating the time path of the change in operations and the behavioural changes of businesses and consumers.

The parameters used to define structural relationships in the model are quantified through an econometric methodology. These elasticity estimates allow the behavioral sensitivity of businesses and consumers to changes in the price of goods and services to vary by industry. Examples of econometrically determined response parameters include income and price elasticities of demand for various goods, factor substitution elasticities, and export transformation elasticities. This reflects that consumers, in the example of good-specific price elasticities of demand, will be more responsive to a change in the price of some goods (e.g., luxury goods) than others (e.g., necessities).

A REMI model was selected based on its recognized credibility for simulating economic impacts. REMI models are widely used by universities, government agencies, and private research organizations, including most US state governments. Academic journal articles regarding the model equations and simulation results have been published in the American Economic Review, the Review of Economic Statistics, the Journal of Regional Science, and the International Regional Science Review.

Limitations

The reader should be aware of the following model limitations and assumptions when interpreting the reliability impact results:

- Estimates of the direct business cost reduction are based on the Department of Energy Interruption Cost Estimator (ICE) tool developed by Nexant and Lawrence Berkeley National Laboratory. While this tool is believed to contain correct information, EY does not assume any legal responsibility for the accuracy or completeness of the information.[13]
- The ICE tool is based on data and estimates describing the costs of sustained interruptions lasting up to 16 hours. It is not meant to be applied to major outages or blackouts that last longer than 16 hours. Because of this, the EY report is limited to estimated changes in annual reliability measures excluding major events. The business costs related to major event outages is likely very significant. However, since these events are relatively rare, unpredictable, and hard to measure, they were not considered for the purposes of this study.
- State and local tax impacts are estimated based on statewide averages for all industries and households. These estimates do not incorporate industry-specific tax rates, exemptions, or bases.
- This analysis does not reflect any change in rates that would accompany the capital investments to achieve these results. To the extent rates increase, the effects would be netted against the positive impacts measured in this study.

[13] Additional information on the ICE tool is included in the Appendix.

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DUKE ENERGY

BUILDING A SMARTER ENERGY FUTURE℠

Power/Forward Carolinas

Executive Technical Overview

EXECUTIVE SUMMARY

North Carolinians expect and deserve reliable, clean, sustainable and affordable energy. And Duke Energy has a proven track record of supplying and delivering energy to millions of customers. In 2016, power reliability was 99.97 percent, rates remained nearly 20 percent below the national average and our coal plant fleet continued to shrink – down by half since 2005 reducing carbon dioxide emissions by 29 percent.

But the world is changing, and so, too, are customer expectations. Everything today is digitally- and technology-based, providing consumers with more information and control than ever before. These technological and customer-driven changes have imposed different demands on the electric power grid. Individuals and businesses are increasingly demanding perfect power and with the explosive growth in the state's population, the grid is being tasked like never before to operate reliably, all of which is accelerating the aging process.

Citizens across the state are just now experiencing the effects of a grid that needs to be modernized. Outage events are trending up, the duration of events is growing and major event damage continues, leading to longer outage times. Without additional investment, approximately 30 percent of our grid will exceed its 30-year design life over the next 10 years.

Duke Energy has developed a bold 10-year plan, Power/Forward Carolinas, that will make the grid more reliable, while also making it smarter and more secure. Third-party economic evaluations of the $13 billion grid improvement plan indicate that over the 10-year implementation period, in addition to providing significant reliability and customer service improvements, Power/Forward Carolinas will stimulate approximately $33 billion in economic growth for the state of North Carolina.

About this overview

The purpose of this report is to provide an overview of the Power/Forward Carolinas grid improvement plan and highlight the benefits and value to the Duke Energy customers of North Carolina.

Contents include:

November 2017

1.0 THE NEED IS CLEAR

North Carolina customers expect more control, options and convenience when it comes to their energy experience. We rely on perfect power for everything. From routine, day-to-day activities -- like charging a cell phone -- to powering large data storage centers and high-tech manufacturing, the electric power grid has become the backbone of our state's digital economy and the electrons that flow through it are its virtual lifeblood.

But despite investing approximately $1 billion annually in preventative maintenance, reliability is declining. The grid and its components are aging, not advancing; outage events – including major weather events -- are on the rise, and North Carolina is experiencing the impacts.

Customer expectations have changed

Customers -- more than ever -- expect more options, greater reliability and value. This change in expectations has been greatly influenced by the ongoing evolution and disruption of retail markets, both online and in physical outlets, resulting from increased e-commerce, or the "Amazon Effect." Self-selecting billing and payment dates, scheduling appointments, accessing real-time data, perfect power and immediate service repairs after outages are all examples of basic services consumers expect but require technology to deliver.

A 2017 J.D. Power and Associates satisfaction study of electric utility residential customers confirms this shift in expectations, finding, among other things that:

- More customers are now going directly to their utilities' website for information, with more than one third of customers accessing website content by mobile phones or tablets.
- Customers who experience extended outage are less satisfied when the outage is caused by equipment failure [Duke Energy's fault] vs. a hurricane or auto accident.
- Customers' satisfaction increases during outage events with each additional piece of information that is provided (e.g. outage start time, cause, number of customers affected, etc.)
- Customers are more satisfied with the price they pay when they hear about rate increases and infrastructure investment, reliability and power supply.

To deliver on customer expectations, we must do more than maintain the power grid; we must make the appropriate investments to transform it, leveraging technology to modernize its operation, making it more reliable, smart and secure.

People rely on electricity more than ever to power their lives and businesses. Power is no longer a convenience nor is it a luxury.

Increasingly, all electric power customers, whether residential, industrial or commercial, rely upon electricity every minute of every day. Similar to roads and bridges serving as vital arteries for our Tar Heel state, prosperous communities and our state economy are powered by reliable electricity. Reliable power is now an absolute necessity.

At Duke Energy, we currently invest $1B annually in preventative maintenance for our reliable grid. Year-after-year, we have replaced mechanical components with mechanical components. However, the new demands on the power grid from customer expectations using digital technology and an expectation for greater reliability cannot be met without implementing our bold 10-year Power/Forward plan.

Proven industry data including System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) metrics are reflecting our power grid's experience with increased weather events and greater demands. Recent benchmarking against utility peers reveals that Duke Energy Progress and Duke Energy Carolinas are in or nearing fourth quartile performance for reliability.

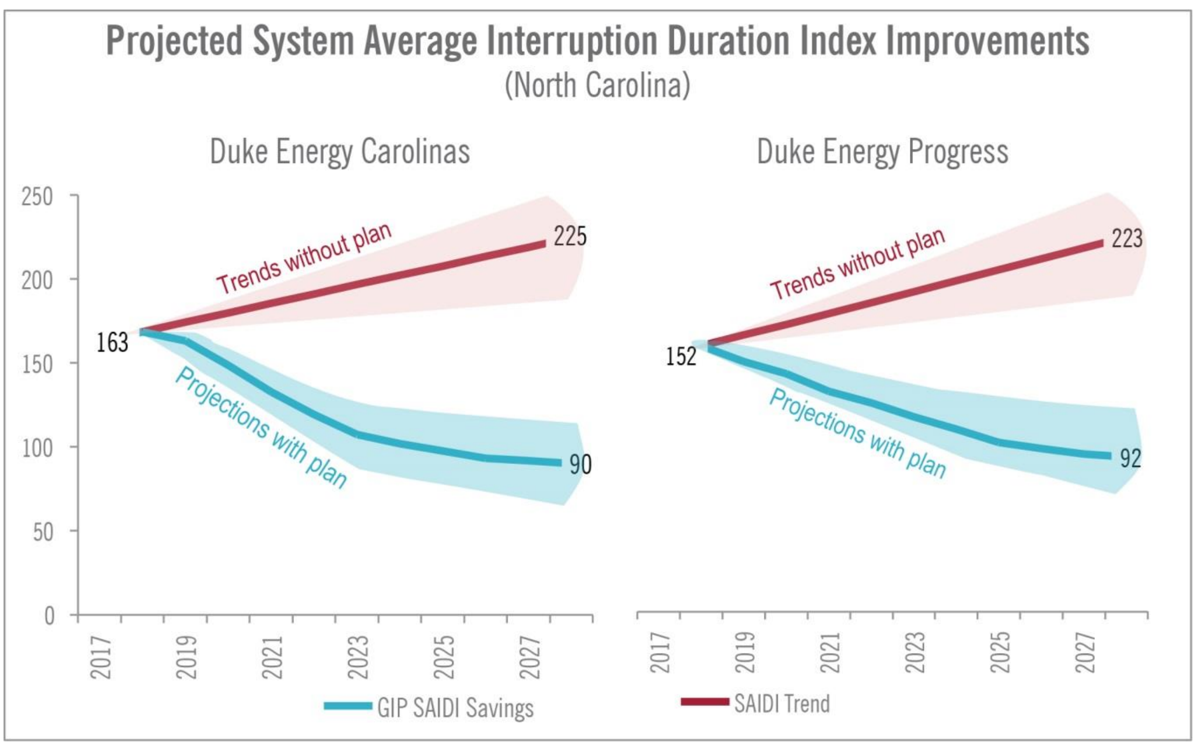


Figure 1 – 10 years of projected North Carolina SAIDI values starting with the 2017 year-end projection and ending at the 2028 year-end projection. The information charted denotes 10 years of SAIDI projections both with and without Power/Forward for DEC and DEP (NC only).

Power/Forward Carolinas will reduce the number and duration of routine outage events for customers. To determine the reliability improvements expected from Power/Forward programs, our engineers applied decades of historical data from tracking performance of power reliability programs and projected the impacts of the individual program measures found in Power/Forward. Those improvements were factored into the SAIDI and SAIFI forward-looking trend projections to produce the performance with the Power/Forward impacts (blue lines in figure 1.) To acknowledge the increasing uncertainty of these projections further out in time, we have overlaid cones of uncertainty for each reliability measure forecast. These cones of uncertainty are merely illustrative. Additional work is underway to apply even more rigorous methods to determine actual levels of forecast uncertainty.

Figure 1 clearly denotes a projected SAIDI improvement of up to 60%. The additional projections found in Appendix B illustrate similar findings for SAIFI.

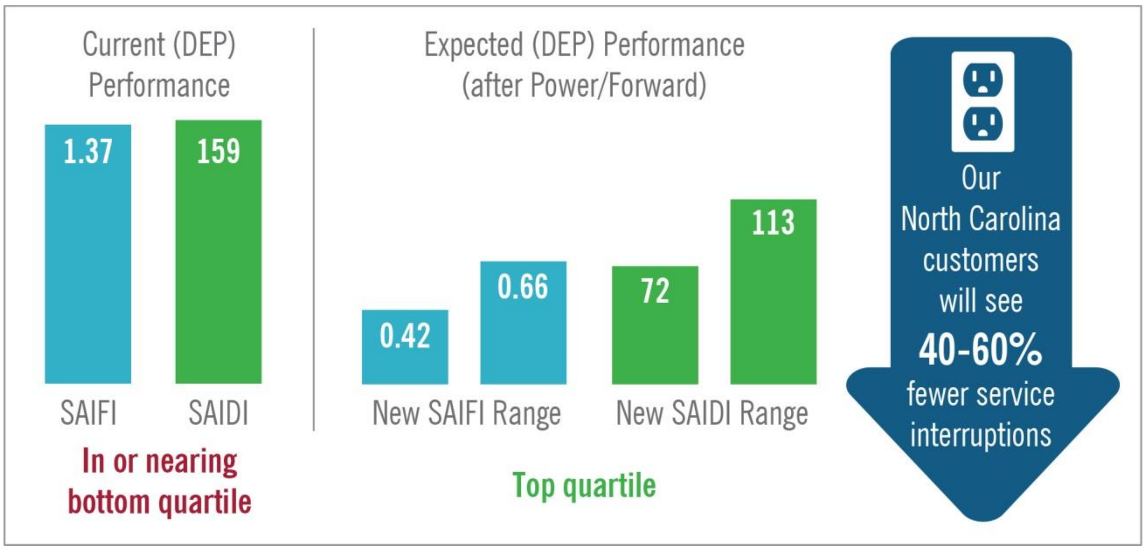


Figure 2 – This data reflects significant improvements that occur in Duke Energy Progress' SAIFI and SAIDI reliability performance measures in NC after Power/Forward is implemented. (Ranges of improved performance are based on historic load and weather information and do not reflect any impacts from changes in weather severity or customer

Similarly, Figure 2 provides a sample of the impact of Power/Forward on SAIDI and SAIFI for DEP in North Carolina. Beginning with 2016 year-end value of DEP SAIFI and SAIDI (1.37 and 159, respectively), upon full implementation of Power/Forward, Duke Energy expects to see SAIFI and SAIDI improvement in the range of 40-60%.

Interestingly, according to J.D. Power research, customers who experience a series of momentary power outages are just as unhappy as those with a sustained power outage.

To achieve fewer outages and greater reliability, businesses and households will necessarily experience an increase in rates as a result of these investments.

Here are a number of actual examples of reliability impacts across NC and our customer base:

1) According to a 2017 economic impact study performed by EY, at current grid performance levels, retail electric customers in North Carolina have approximately $1.17 billion in outage costs annually related to normal service interruptions (non-major events), with businesses making up 98% of this impact. These business losses could have represented potential costs savings and reinvestments in growth and new hiring by local North Carolina businesses.

2) An industrial customer reported actual lost profit margins of nearly $70,000 from four hours of outage time following Hurricane Irma.

3) A Materials Producer reported $3.5M loss due to a single plant interruption

Clearly, improvements from the Power/Forward Carolinas investment will result in fewer outages and blinks and provide much more reliable power for customers in North Carolina.

Severe weather events are increasing, and the threat of cyber and physical attacks on the grid are real.

Our grid is responding to an increasing number of storms. The National Weather Service has cited an 80% increase in the number of severe weather events impacting the U.S. from 2000 to 2016, which has led to an increase in major event days (MEDs). Wind and ice storms are two of the leading causes of outage conditions for our power systems, and flooding has also become an increasing concern.

Within North Carolina, we have seen the impact firsthand from such storms. Analysis of the past 10 years of North Carolina outage data shows that in an average year, nearly 1.2 million North Carolina homes and businesses are impacted. During Hurricane Matthew in 2016, North Carolina households and businesses experienced over 950 million minutes of power interruption, with some communities without power for more than six days.

A **major event day (MED)** is a day in which a major reliability event, such as a hurricane or major ice storm, causes an electric utility to shift into a "storm restoration mode" of operation in order to adequately respond. IEEE Standard 1366 statistically defines a major event day as any calendar day when SAIDI exceeds 2.5 standard deviations from the previous five year log-normal distribution of SAIDI days in a system or region.

Combined with this, the threat of cyber and physical attacks on the grid are real, and of increasing concern. According to a USA Today analysis of federal energy records, about once every four days, part of the nation's power grid is struck by a cyber or physical attack, one which could leave millions in the dark. As one of the largest investor-owned utilities in the U.S., Duke Energy is a prime target for cyber-crime. Our Power/Forward Carolinas investments are designed to mitigate the impact of major storm events, as well as to protect and defend against critical cybersecurity risks.

Technology is now available to enable a transition from a mechanical grid that is aging to a more modern, digitized grid.

Our investments in the grid help to promote North Carolina's drive for continued growth and development. However, to date, these investments have been heavily focused on replacing like-for-like assets and equipment; with an increasingly global economy and greater need for consistent, reliable power, now is the time for us to invest in newer, smart technologies to meet the needs of the future.

A large portion of North Carolina's energy grid is reaching the end of its useful life. Nearly half of many critical grid assets will have reached the end of design life within the next 10 years, including, for example, over 30% of overhead conductor in North Carolina's Duke Energy Progress (DEP) territory; for overhead transformers, this value is 57%. However, our planned strategic investments will enable us to transition to a modern, digitized grid. This includes taking advantage of increasingly sophisticated technology advancements, and replacing aging infrastructure with better and more improved grid devices and systems that will allow us to meet the needs of a global and highly digitized economy. For example, installing self-optimizing technologies will enable us to better isolate faults and much more quickly re-route power, thereby, significantly reducing the average number of customers impacted by an outage.

Other advanced enterprise system technologies allow us to remotely monitor grid heath and improve overall system operations and maintenance activities. With deployment of digital smart meters, we are able to offer our customers increased options and services, providing increased customer control of their energy usage.

Over the next 10 years, our investment in these areas and others will take advantage of new technologies to create a smarter, resilient and more secure electric power that delivers the services our customers expect and deserve.

2.0 SEVEN STRATEGIC PROGRAMS

The Power/Forward Carolinas plan is comprised of seven strategic programs. Deploying these improvement programs will enable us to better meet our customers' needs and expectations, including better managing their energy usage and reducing outage frequency and duration. It will also enable us to accelerate storm restoration, protect against physical and cyber security threat and better manage distributed energy resources (DER) and energy storage technologies.

Figure 3 – Power/Forward Carolinas seven strategic programs

Power/Forward Carolinas -- Strategic Programs, by level of investment

Targeted Underground (TUG)	Converting heavily-treed neighborhoods prone to power outages from overhead to underground construction to decrease outages, reduce momentary interruptions (blinks), improve major storm restoration time, and improve customer satisfaction.
Distribution Hardening & Resiliency	Upgrading equipment to lower system outage risk due to asset failure (hardening) and to minimize the impacts of events and improve ability to recover rapidly when events occur (resiliency). This program also addresses asset end-of-life opportunities, system design, and physical and cyber security.
Transmission Improvements	Deploying equipment upgrades, flood mitigation, physical and cyber security, and system intelligence to make a smarter, more reliable and secure transmission system.
Self-Optimizing Grid (SOG)	Applying modernization investments to build a more resilient distribution system better able to isolate problems and re-route power to minimize impacts to our customers and communities. To enable SOG functionality, circuits will have automated switches approximately every 400 customers, or 2 MW peak load, or 3 miles in circuit segment length.
Advanced Metering Infrastructure (AMI)	Deploying digital smart meters and associated communication devices to provide enhanced customer billing and payment options, detailed usage data, and energy-savings tools, as well as enhanced operational functions such as automated meter-reading, remote service connections and outage detection.
Communication Network Upgrades	Providing high-speed, high bandwidth, secure communications pathways (fiber optic and wireless) for the increasing number of smart components, sensors, and remotely activated devices on the transmission and distribution systems.
Advanced Enterprise Systems	Upgrading systems that manage grid devices, monitor equipment health, analyze data from monitoring sensors to improve system operations and maintenance activities, and enable grid self-optimizing technologies.

Estimated Program Costs and Operational Benefits

Duke Energy expects to invest $13 billion in North Carolina to implement the plan's seven strategic programs over a 10-year period. In general, our standard planning and prioritization processes will be used for Power/Forward Carolinas programs. For new transformational programs (e.g., Self-Optimizing Grid, Targeted Underground), we have developed new guidelines to provide additional guidance on the planning, prioritization and execution of these programs.

We will evaluate viable solutions, as the planning work continues annually throughout the Power/Forward Carolinas initiative, to choose the most cost-effective solution accomplishing the objectives of the program and providing the most value to customers.

Program-level cost drivers and methodologies for each of the seven strategic programs are described below with supplemental information provided in *Appendix A, Power/Forward Carolinas Cost Estimate Supplemental Information.*

The program details and cost estimates outlined below represent the initial 10-year cost estimates for Power/Forward Carolinas and are not necessarily the full population of detailed projects that will be a part of the plan. Some projects are further along in the planning lifecycle and have more detailed budgets, while others are higher-level estimates of future efforts. Each year, we will scope and budget the work for the following year, which may shift funding among programs and projects, shift projects earlier or later in the timeline, or add or remove projects as applicable based on resource availability and benefit achievement.

10 Year Power/Forward Initiative Capital Investments

Targeted Underground	$4.9 B
Distribution Hardening and Resiliency	$3.5 B
Transmission Improvements	$2.2 B
Self-Optimizing Grid	$1.2 B
Advanced Metering Infrastructure	$549 M
Communications Network Upgrades	$546 M
Advanced Enterprise Systems	$103 M
Total	**$13 B**

Table 1 – 10 year investment for North Carolina programs

Program Cost Estimate Details

Targeted Underground – ($4.9B) The bulk of this program focuses on fused tap lines that run through residential neighborhoods. For this work, total cost estimates are based on unit costs of $400K-$500K per mile to convert overhead to underground. Feeder level undergrounding, is much more costly, typically running well over $1 million per mile. These costs are based on industry benchmarking for tap line undergrounding, and the scope of approx. 10,200 miles for North Carolina. These costs include engineering and construction, along with brownfield development costs to engage and negotiate with all customers impacted. For example, the Company will employ dedicated land agents and engagement specialists to secure easements, and estimates the need to secure ~7,500 easements across the enterprise in 2018 alone.

Program	Unit	# Units	Cost/Unit	Total $M
Targeted Underground	Miles	10,220	$400-$500K	$4,893

Distribution Hardening & Resiliency – ($3.5B) This program is made up of a variety of work streams. Many programs are based on historical unit cost averages per mile or foot. Examples in this category include cable replacement (4,500 miles at approx. $150K per mile) and deteriorated conductor replacement (6,600 miles at approx. $100K per mile). Others are based on historical unit cost averages per unit upgraded. Examples in this category include transformer retrofit (351,000 at approx. $1,200 per unit) and pole replacement (24,500 poles at approx. $3,300 per pole). Several programs do not fit into either category and their costs are based on subject matter expertise. An example of this is the area of vulnerability[1] program (23 locations at approx. $5 million per area).

Transmission Improvements – ($2.2B – NC) This program is made up of a variety of transmission grid reliability programs. Equipment engineers and subject matter experts have identified specific assets that need to be replaced to ensure continued transmission resiliency and reliability. There are 35 reliability programs identified to replace various types of equipment on transmission lines and in substations. The majority of the programs are based on historical unit cost averages per unit replaced. Examples in this category include breaker replacements, substation transformer replacements, and line equipment replacements and hardening. These cost estimates are asset-based, however, work will be implemented on a substation or site basis. Other programs such as Condition-Based Monitoring (CBM), Phasor Measurement Units, Health and Risk Management (HRM) and physical/cyber security programs, are project-based and have standalone cost estimates.

[1] Area of Vulnerability is defined as "a portion or portions of the electric distribution system where the risk and/or probability of a system disturbance results in an impactful service disruption to the customer(s) and correspondingly high economic, societal, or reputational impact."

Self-Optimizing Grid – ($1.2B) Approximately 50% of the distribution circuits (~1,500) in North Carolina, serving approx. 80% of the customers, will be upgraded to Self-Optimizing Grid guidelines for switch automation, connectivity, and capacity. Average unit cost per circuit is estimated at $840K and is based on historical cost averages for similar types of work. However, the standard deviation from this average is large, with costs ranging from $200K to $2 million per circuit. Many circuits already have appropriate connectivity and capacity and will only require switch automation. Other circuits will require significant capacity upgrades and new circuit ties.

Program	# Circuits	Cost/Unit	Total $M
Self-Optimizing Grid	1,500	$840,000	$1,260

Advanced Metering Infrastructure – ($549M) These costs are based on the standalone cost estimates provided previously for AMI in the 2017 Smart Grid Technology Plan Update.

Communications Network Upgrades – ($546M) This program is made up of a variety of work streams and the costs identified are the approximate allocations for DEC North Carolina and DEP North Carolina. Some of the programs are project-based and have standalone enterprise cost estimates—for example, the Land Mobile Radio End-of-Life project (in the Mission Critical Voice Communications workstream) allocation is estimated at $55.2M in DEC and $47.6M in DEP and the Vehicle Area Network allocation is estimated at $8.0M in DEC and $4.9 in DEP. Other communications efforts have been estimated based on historical unit upgrade cost averages. For example the tower and shelter upgrades are estimated at $500K per tower and $150K per shelter, based on historical average costs. These cost estimates are refined as specific vendor costs become available. DEC and DEP plan to replace approximately 37 towers ($500K per tower) and 23 shelters ($150K per shelter) during the 10-year plan ($30M) with the remainder of the budget ($6.1M) allocated to power supply replacement where necessary.

Advanced Enterprise Systems – ($103M) These cost estimates are based on the standalone cost estimates for each enterprise systems program (e.g., Distribution Management System, Outage Management System, SCADA). Costs identified are the approximate allocations for DEC North Carolina and DEP North Carolina.

Additional Operational Benefits

Beyond the positive impacts our Power/Forward plan produces for the state, we have begun to identify additional value created from our plan in the form of cost savings for North Carolina operations. Based on the reduction in outage events resulting from our 10-year grid improvement plan, and using standard engineering calculations, we estimate approximately $42 million annually in additional benefits in the form of reliability-related operation and maintenance (O&M) savings opportunities.

These outage event reduction O&M savings include:

- vegetation management ($14.8M)
- outage restoration activities ($15.3M)
- major storm event restoration ($11.9M)

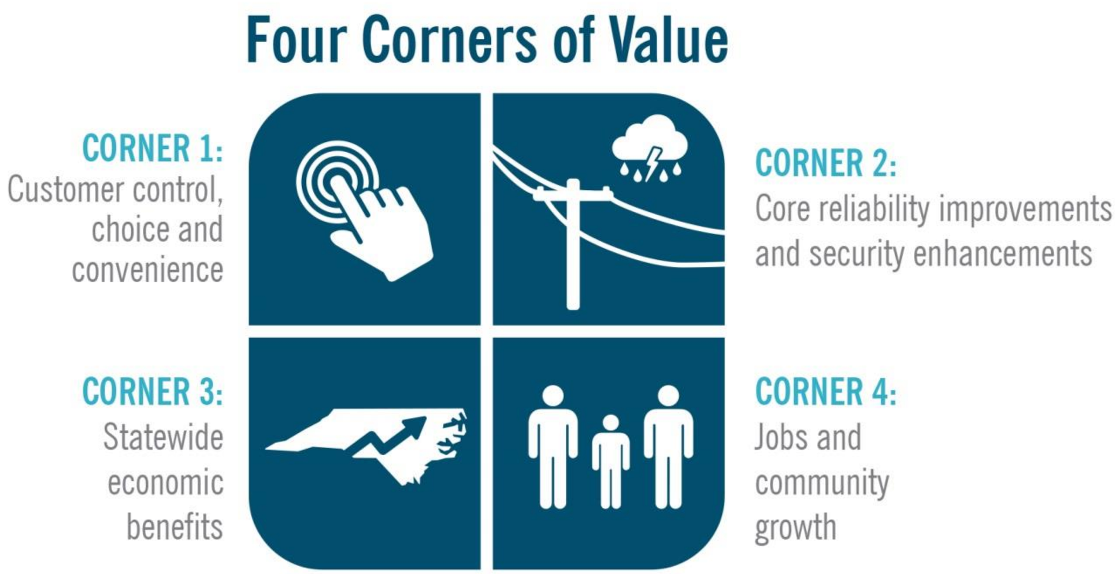
These values reflect O&M cost savings beginning in year 11 and do not include O&M cost savings resulting from our AMI program.

We anticipate additional Power/Forward plan benefits resulting from:

- Improved management of private distributed energy resources as customer adoption grows (e.g., grid-connected rooftop solar);
- Increased protection from cyber and physical security attacks;
- Improved environmental impacts from:
    - Reduced risk of oil spills and gas leaks due to applicable equipment replacements (estimated to avoid over 1300 gallons of oil spilled and 100 oil-spill events annually); this will also result in lower environmental clean-up costs (estimated to result in over $150,000 in annual savings across the Carolinas)
    - Reduced risk of avian collisions as a result of undergrounding overhead facilities (this will also result in cost reductions associated with levied fines relating to eagle and other bird impacts).

3.0 FOUR CORNERS OF VALUE

Duke Energy was born in the Carolinas, and we have proudly served our customers for more than 100 years. Our employees are deeply committed to the 3.2M households and businesses we serve. As guardians of the grid, we need to implement Power/Forward Carolinas, to move forward to provide even more options for customers through new products and services, improve core electric power reliability, drive economic growth, and develop jobs and communities. The benefits of Power/Forward Carolinas can be represented by examining the multiple ways in which value is advancing for customers and communities in North Carolina and the broader Carolinas region. We identify these areas of value, or "four corners," below.



Power/Forward Carolinas Value Proposition:

Below are several examples showing the value proposition Power/Forward will bring in each of the four corners.

Corner 1: Customer control, choice and convenience

- Access to new service and billing options like Pick Your Due Date and Usage Alerts.
- Ability for customer to see detailed usage data daily, making it easier to use energy more efficiently.
- Option to stop/start service remotely.
- Allowing for improved response times and speeds outage repairs.

Corner 2: Core reliability improvements and security enhancements[2]

- Reduction in regular-service outages by 40 – 60%
- Estimated 30% reduction in the frequency and duration of major event outages, including named storms and hurricanes
- Increased protection from cyber and physical security attacks

Table 2 shows the historic 10-year average numbers of customer interruption and minutes of interruption due to major events which are not reflected in SAIDI and SAIFI measures. Based on our analysis, the improvements implemented as part of Power/Forward would have reduced these impacts by one third.

REDUCTION IN MAJOR STORM IMPACTS	Customers interrupted (CI)	Customer Mins Interrupted (CMI)
10-year historical average, NC	1.2 million	815 million
Estimated reduction (%)	33%	30%
Power/Forward	**0.8 million**	**567 million**

Table 2 – Average annual MED events and duration anticipated in North Carolina (DEC and DEP) before and after Power Forward

Consider again the long and widespread outages stemming from Hurricane Matthew. This same analysis applied to Matthew shows a significant reduction in grid damage and associated restoration.

Table 3 illustrates that improvements implemented as part of Power/Forward would have eliminated more than 30% of the power outages experienced in Hurricane Matthew, reducing the total outage time North Carolina customers experienced (950 million minutes of interruption) by nearly 300 million minutes. This reduction allows customers to get back to work more quickly or better support their loved ones who were impacted. A fully implemented Power/Forward plan would have reduced our overall restoration from six days to four days (excluding area where flood waters prevented access).

Hurricane Matthew (2016)

North Carolina	% CI Eliminated	% CMI Eliminated	% Outages Eliminated
DEP NC	30%	30%	34%
DEC NC	57%	45%	32%

Table 3 – Number and duration of Hurricane Matthew power outages in NC that would have been avoided with Power/Forward implementation

[2] Source: EY Study, *North Carolina impacts of Duke Energy's Power/Forward Grid Improvement Program*, November 2017

Corner 3: Statewide economic benefits

- Beyond the 10 year implementation of this plan, positive economic impacts will continue to be felt across the state. According to the third-party EY study, reliability improvements will result in an additional $12.9 billion in added economic activity for North Carolina.
- By 2028, the EY analysis shows that North Carolina businesses will save $1.7 billion per year from reduced outage-related costs.
- Generation of $1.1B in state and local taxes, with an additional $421M projected from reliability improvements

Corner 4: Jobs and community growth

- Approximately 12,000 jobs created for the state of North Carolina through the Duke Energy grid investment, plus an additional 7,000 for reliability improvements

Statewide Economic Benefits – additional details

As highlighted in our discussion of Power/Forward program costs, our grid improvement plan will mean direct capital investments of more than $13 billion over the 10-year plan. This level of direct capital investment will generate $20 billion in total economic output for the state of North Carolina throughout the investment period.

Duke Energy's capital investment will generate nearly $1.1 billion in state and local tax revenues. An estimated $518 million of this will be direct taxes paid by Duke Energy, including $330 million of state and local sales taxes on electrical equipment and installation materials.

Our capital investments will also support a total of approximately 12,000 jobs across the state, with Duke Energy employing an average of 6,200 direct employees and contractors.

Combined Value for North Carolina Customers and Communities

The combined value that Power/Forward generates for our North Carolina customers and statewide is $20 billion from the capital investment and an additional $12.9 billion from reliability improvements, resulting in a cumulative impact of approximately $33 billion.

Figure 7 below charts four dimensions of economic impacts (in millions of dollars) over the 10-year plan period.

1) **Customer Cost** (light gray line) – charts the contributions of North Carolina customers for the Power/Forward investments; this line is a function of electric rate increases over time.

2) **Baseline Customer Benefit** (dotted line) – charts the value of outage-related costs our customers avoid as a result of improved grid reliability; this value is a function of the decreasing number of power interruptions and outage times.

3) **Additional Customer Benefit Opportunity** (dark line) – charts the baseline customer benefits (illustrated by the dotted line) plus the additional potential value from converting those baseline savings into additional business profits; this is both a function of improving reliability and a function of how general market forces impact individual customers' businesses over time.

4) **Statewide Benefits** (blue line) – charts the total change in gross economic output for the state; this is a function of the reinvested business savings (illustrated by additional customer benefit opportunities, dark line) as well as the new jobs and the state's increased business activity created over time as a result of our direct Power/Forward capital investments.

Note that the overall statewide benefits continue to increase throughout the investment period peak investment year (2026). While the clearly measurable economic impacts from direct capital investments end with the cessation of our direct investing, the benefits resulting from the state's modernized and more reliable grid continue beyond 2028.

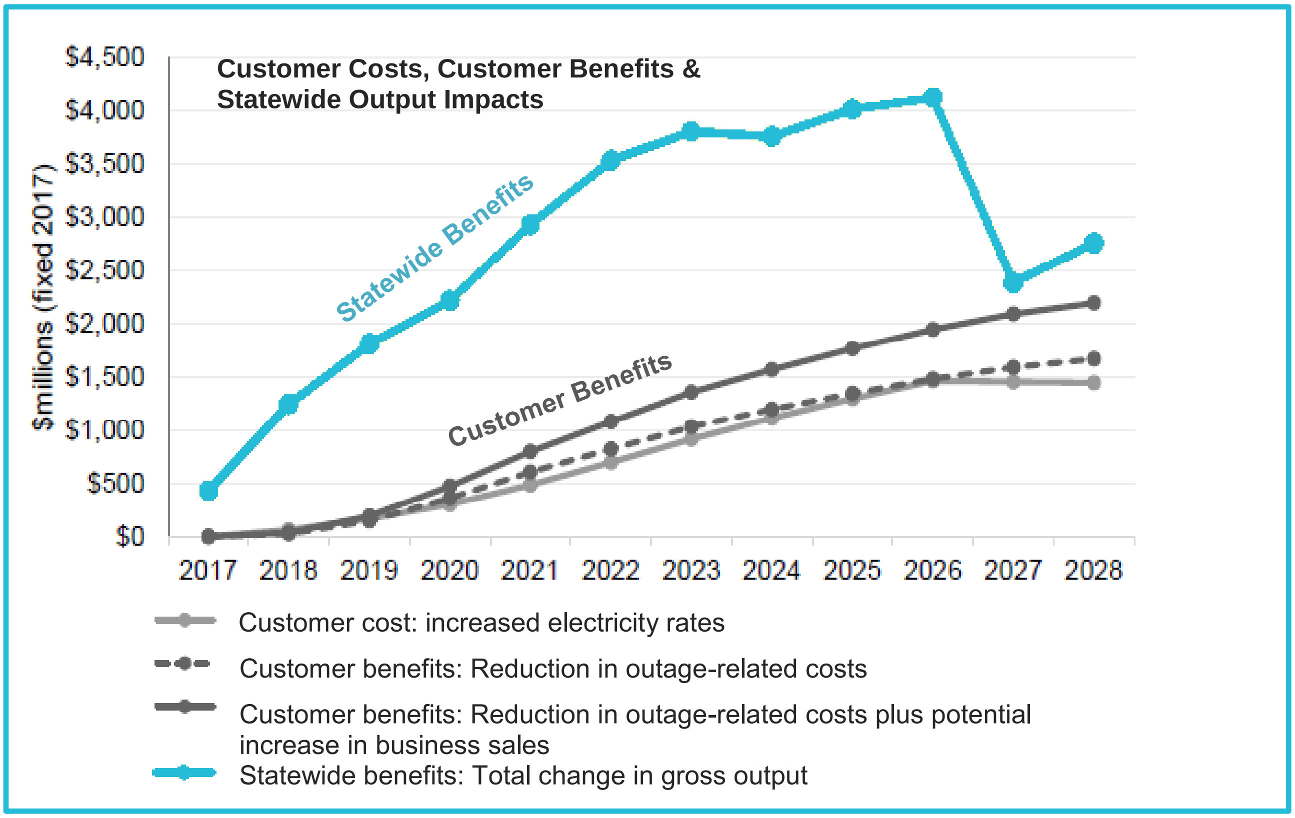


Figure 7 – Customer costs and benefits compared to statewide output impacts

The increase in costs borne by our customers associated with grid improvements (light gray line) are expected to continue until all capital investments are completed in 2026; after this point, costs will begin to fall with depreciation. The annual costs (incremental rate increases) will range from $62 million in 2018 to $1.4 billion by 2028. We anticipate reliability improvements to begin to generate avoided outage costs that could range from $29 million in 2018 to $1.7 billion by the end of 2028 (dotted line to dark gray line). If these avoided costs were then translated into new sales activity by businesses, reliability benefits could grow as high as $2.2 billion by 2028.

Thus, combining the maximum anticipated benefits from both the direct infrastructure investments and the improved reliability yields a total potential impact of approximately $33 billion for the state of North Carolina.

4.0 CONCLUSION

North Carolina needs an energy grid that is smarter, more reliable and secure to grow the economy, create jobs and enable the services consumers expect. And despite investing $1 billion annually into the state's energy grid, we need to implement Power/Forward Carolinas to advance and modernize the power grid infrastructure to position NC for future success.

Building on more than a century of service, Duke Energy's founding fathers envisioned a stronger North Carolina when they first harnessed the Catawba River for power generation leading to industrial growth across our great state. Today, we are in a similar position faced with the realities of an aging grid that in its current mechanical state will not sustain the growing expectations of our digitally-connected society.

To remain globally competitive, attract new business and serve the growing and changing expectations of our customers, North Carolina's grid must be modernized. The state's power grid is the backbone of our digital economy and the electricity flowing through its lines is the lifeblood that keeps the economy growing. We must act now and move forward together to build a stronger, more prosperous future.

This is our defining moment. Our bold plan – Power /Forward Carolinas -- positions NC and our customers for success now and for years to come.

Power/Forward Carolinas
SUPPLEMENTAL INFORMATION
(APPENDICES)

TABLE OF APPENDICES

APPENDIX A, POWER/FORWARD CAROLINAS COST ESTIMATE SUPPLEMENTAL INFORMATION

The information below is supplied as supplemental information for Power/Forward program costs for some of the programs identified in **Table A1**. The program details and cost estimates outlined below represent the initial 10-year cost estimates for Power/Forward Carolinas and are not necessarily the full population of detailed projects that will be a part of plan. Some projects are further along in the planning lifecycle to have more detailed budgets, while others are higher-level estimates of future efforts. Each year, the Company will scope and budget the work for future years, which may shift funding among programs and projects, shift projects earlier or later in the timeline, or add or remove projects as applicable based on resource availability and benefits achievement.

10-Year Power/Forward Initiative

Targeted Underground	$4.9 B
Distribution Hardening and Resiliency	$3.5 B
Transmission Improvements	$2.2 B
Self-Optimizing Grid	$1.2 B
Advanced Metering Infrastructure	$549 M
Communications Network Upgrades	$546 M
Advanced Enterprise Systems	$103 M
Total	**$13 B**

Table A1 – 10-year investment for North Carolina programs

Program level cost drivers and methodologies for each of the seven strategic programs are described in *Section 2.0 Power/Forward Program Costs*. The information below provides more granular budgeting details where appropriate.

Targeted Underground – ($4.9B) Using the budget methodology described for Targeted Underground in Section 2.0 Power/Forward Program Costs, the following budget has been developed.

Program	Unit	# Units	Cost/Unit	Total $M
Targeted Underground	Miles	10,220	$400-$500K	$4,893

COUNTY	TUG MILES
Alexander	47.85
Anson	31.28
Avery	10.77
Beaufort	13.34
Bladen	33.75
Brunswick	51.17
Buncombe	618.88
Burke	104.85
Cabarrus	120.69
Caldwell	92.23
Carteret	73.93
Caswell	26.34
Catawba	207.41
Chatham	110.92
Cherokee	49.84
Cleveland	160.75
Columbus	94.34
Craven	45.64
Cumberland	97.92
Davidson	136.20
Davie	53.39
Duplin	75.56
Durham	198.82
Edgecombe	4.80
Forsyth	433.44
Franklin	54.73
Gaston	225.48

COUNTY	TUG MILES
Graham	46.58
Granville	43.79
Greene	4.76
Guilford	424.79
Halifax	6.98
Harnett	121.29
Haywood	182.93
Henderson	345.55
Hoke	29.43
Iredell	126.07
Jackson	177.18
Johnston	125.63
Jones	8.22
Lee	126.32
Lenoir	34.39
Lincoln	97.93
McDowell	121.60
Macon	166.97
Madison	8.00
Mecklenburg	752.42
Mitchell	47.90
Montgomery	71.78
Moore	176.96
Nash	63.47
New Hanover	317.25
Onslow	54.47
Orange	102.87

COUNTY	TUG MILES
Pamlico	17.50
Pender	61.20
Person	33.01
Pitt	10.20
Polk	92.66
Randolph	242.05
Richmond	98.13
Robeson	167.86
Rockingham	167.11
Rowan	321.35
Rutherford	155.82
Sampson	65.35
Scotland	48.76
Stanly	66.26
Stokes	66.13
Surry	135.27
Swain	116.83
Transylvania	84.01
Union	131.95
Vance	73.33
Wake	610.57
Warren	24.19
Wayne	118.23
Wilkes	129.59
Wilson	8.38
Yadkin	39.37
Yancey	5.69

Totals 10,220 miles in NC

Distribution Hardening & Resiliency — ($3.5B) Using the budget methodology described for Distribution Hardening & Resiliency in Section 2.0 Power/Forward Program Costs, the following budget has been developed.

			DEC		DEP	
Program Description	**Unit**	**Cost/Unit**	**# Units**	**Total $M**	**# Units**	**Total $M**
Transformer Retrofit	Location	$1,152	7,000	$8.1	344,000	$396.3
Cable Replacement	Miles	$148,685	2,822	$419.6	1,681	$249.9
Sectionalization	Circuits	$20,000	1,008	$20.2	739	$14.8
Deteriorated Conductor Replacement / line rebuild	Miles	$100,000	3,145	$314.5	3,520	$352.0
Areas of Vulnerability	Locations	$5,000,000	15	$75.0	8	$40.0
Pole Hardening	Poles	$3,333	15,395	$51.3	9,171	$30.6
Capacity	Substations	$10,000,000	21	$210.0	6	$60.0
Live front switchgear and transformer replacement	# devices replaced	$25,000	1,248	$31.2	915	$22.9
Hazard Tree Removal		$1,000	14,400	$14.4	10,560	$10.6
Feeder Ties (for long duration outages)	Miles	$250,000	2,000	$500.0	750	$187.5
Oil-filled reclosers replacement	Reclosers	$50,000	528	$26.4	387	$19.4
Underground Riser Retrofit		$1,000	34,560	$34.6	25,344	$25.3
Electronic Recloser	Reclosers	$6,500	528	$3.4	387	$2.5
Hardening and resiliency programs requiring further engineering and scoping (e.g., structural guying, BIL uplift, physical and cyber security improvements, ampacity upgrades, etc.)				$231.2		$135.8
	10-Year NC Total		**DEC**	**$1,939.8**	**DEP**	**$1,547.5**
				Grand Total $ M	**$3,487.3**	

Transmission Improvements – ($2.75B – includes NC and SC) Using the budget methodology described for Transmission Improvements in Section 2.0 Power/Forward Program Costs, the following budget has been developed.

	DEC			DEP		
Program Description	# Units	Cost/ Unit	Total $M	# Units	Cost/Unit	Total $M
Replace T-Oil Breakers w/Gas	400	$300,000	$120.0	200	$300,000	$60.0
Replace 230kV SF6 Breakers	50	$600,000	$30.0			
Replace 500kV Breakers	17	$895,000	$15.2	6	$895,000	$5.4
Replace D-Oil Breakers	500	$125,000	$62.5	400	$125,000	$50.0
Replace CCVTs 25+ or older	300	$22,000	$6.6	700	$22,000	$15.4
Replace RTU Replacement	50	$150,000	$7.5	84	$150,000	$12.6
Replace SBC Breaker Failure Relays	145	$150,000	$21.8			
Replace Electro-mechanical Relays per Terminal	500	$300,000	$150.0	400	$300,000	$120.0
Hybrid Relay Group scheme				116	$100,000	$11.6
Replace First Gen Relays	550	$180,000	$99.0	35	$180,000	$6.3
Install new Digital Fault Recorder (DFR)	3	$250,000	$0.8	10	$250,000	$2.5
Replace Digital Fault Recorder (DFR)	15	$250,000	$3.8	23	$250,000	$5.8
Replace Line Relay Carriers/Transfer Trip	15	$400,000	$6.0	27	$400,000	$10.8
Battery Bank Replacement				300	$15,000	$4.5
Replace Type U Bushings (count per transformer)	250	$100,000	$25.0	79	$102,000	$8.1
Bushings (count per transformer)				100	$102,000	$10.2
Replace Transformers - 1 PH & 3 PH	100	$2,000,000	$200.0	100	$2,000,000	$200.0
Replace Trench Reactors				46	$119,000	$5.5
Upgrade Load Tap Changer (LTC)	15	$300,000	$4.5			
Replace Silica Carbide Arresters	2500	$24,000	$60.0	250	$22,000	$5.5
Replace Voltage Regulators - 1PH	15	$70,606	$1.1			
Replace Voltage Regulators - 3PH	10	$240,000	$2.4	71	$350,000	$24.9
Replace Cap & Pin Insulators Bus Supports & Standoffs	4000	$25,000	$100.0			
Upgrade Transformer Coolers	21	$300,000	$6.3			
Emergent Equipment Replacements	10	$20,000,000	$200.0	8	$20,000,000	$160.0
Replace Substation Circuit Switchers				70	$150,000	$10.5
Replace OB Arresters				44	$22,000	$1.0
Wood Substations, Rebuild (incremental cost of wood)				48	$1,500,000	$72.0

	DEC			DEP		
Program Description	# Units	Cost/ Unit	Total $M	# Units	Cost/Unit	Total $M
Wood Pole Replacement	5000	$25,000	$125.0	7000	$25,000	$175.0
T-Line Rebuilds (Per Mile)	150	$1,500,000	$225.0			
Substation Animal Mitigation	80	$250,000	$20,000,000	60	$250,000	$15,000,000
Remote Sectionalizing Switches	75	$500,000	$37,500,000	100	$500,000	$50,000,000
T-Line Static Replacements (Per Mile)	250	$150,000	$37.5	300	$150,000	$45.0
T-Line Str/Tower Replacements	100	$189,000	$18.9	420	$189,000	$79.4
Replace T-Line Switches	100	$250,000	$25.0	132	$250,000	$33.0
Replace Cap & Pin Insulators Switches	400	$25,000	$10.0	130	$250,000	$32.5
Replace Polymer Insulators with Porcelain (Per Mile)	56	$200,000	$11.2	200	$300,000	$60.0
Physical & Cyber Security Improvements			$185,000,000			$102,000,000
System Intelligence HRM & CBM			$30,550,000			$16,450,000
		DEC Total:	**$1,575**		**DEP Total:**	**$1,167.3**
			Grand Total $ M:	**$2,742.2**		

Self-Optimizing Grid – ($1.2B) Using the budget methodology described for Self-Optimizing Grid in Section 2.0 Power/Forward Program Costs, the following budget has been developed. On average, three to four automated switches will be used for each circuit upgraded to SOG guidelines.

Program	# Circuits	Cost/Unit	Total $M
Self-Optimizing Grid	1,500	$840,000	$1,260

			DEC		DEP	
Program Description	Unit	Cost/Unit	# Units	Total $M	# Units	Total $M
Automation	Automated Switches	$50,000	3,550	$177.5	2,100	$105.0
Capacity & Connectivity	Circuit	$650,000	960	$624.0	540	$351.0
	10-Year NC Total		**DEC**	**$801.5**	**DEP**	**$456.0**
			Grand Total $M		**$1,257.5**	

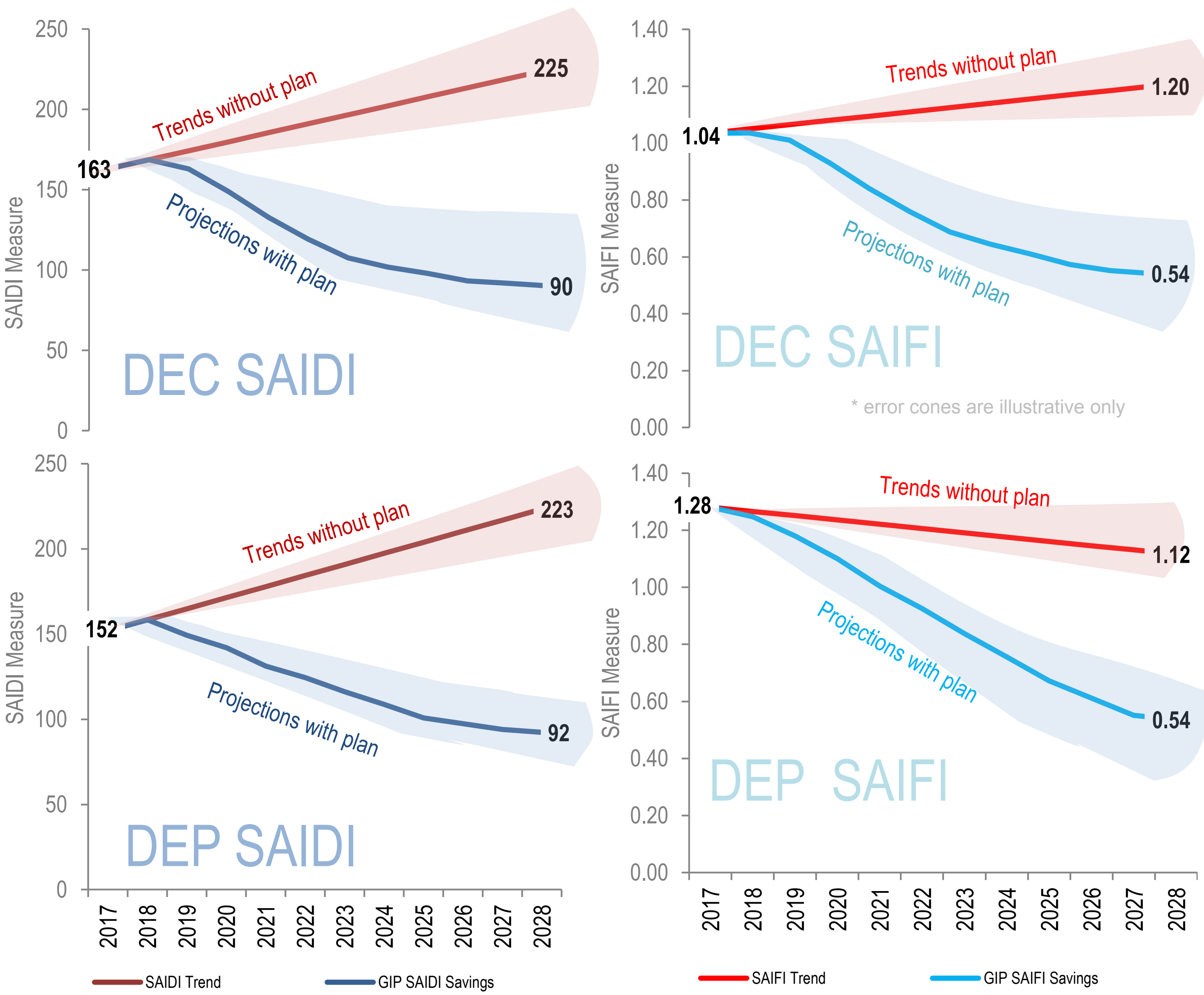
Communications Network Upgrades – – ($546M) Using the budget methodology described for Communications Network Upgrade in Section 2.0 Power/Forward Program Costs, the following budget has been developed.

Project Name	Totals $M*
Mission Critical Transport Network	258.5
Next Gen Cellular	30.9
Vehicle Area Network	10.7
Asset/Network & GIS Management	17.1
Mission Critical Voice Communications	100.8
Towers, Shelters & Power Supplies	36.3
BizWAN	3.9
GridWAN	38.3
Totals	**496.4***

* Reflects updated budget amounts

APPENDIX B, ADDITIONAL NORTH CAROLINA RELIABILITY MEASURES INFORMATION

Figures below represent the 10-year reliability measure projections for SAIDI and SAIFI for Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) in North Carolina with and without Power/Forward implementation.



About the Reliability Measures Projections

The 10-year "trends without plan" projections were developed from five years of historical non-MED outage data to ensure a sample size capable of producing an 80% confidence level. The mean value (μ) of each of the data set (DEC and DEP) was calculated and projected using linear regression techniques.

To acknowledge the increasing uncertainty of these projections the further out in time they are projected, we have overlaid cones of uncertainty for each reliability measure forecast. These cones of uncertainty are merely illustrative as we are working to apply rigorous methods to determine actual levels of forecasts uncertainty.

The 2017 starting value is a projection from the 2016 year end SAIDI and SAIFI measures for DEC and DEP.

APPENDIX C, PROJECTED IMPACTS AVOIDED DURING MAJOR STORMS

The tables below denote the forecasted customer impacts from named storms and major weather events (events that caused multi-day outages) that could have been from the past three years with Power/Forward Implementation. Customer Interruptions (CI) eliminated, Customer Minutes of Interruption (CMI) Eliminated and Outages Eliminated are shown in percentage reduction of actual event totals.

February 2014 Ice Storm

North Carolina	% CI Eliminated	% CMI Eliminated	% Outages Eliminated
DEP NC	38%	42%	43%
DEC NC	46%	53%	38%

March 2014 Ice Storm

North Carolina	% CI Eliminated	% CMI Eliminated	% Outages Eliminated
DEP NC	31%	33%	33%
DEC NC	41%	39%	27%

Winter Storm Remus (2015)

North Carolina	% CI Eliminated	% CMI Eliminated	% Outages Eliminated
DEP NC	23%	23%	31%
DEC NC	46%	44%	32%

Winter Storm Octavia (2015)

North Carolina	% CI Eliminated	% CMI Eliminated	% Outages Eliminated
DEP NC	25%	23%	37%
DEC NC	45%	43%	33%

Hurricane Hermine (2016)

North Carolina	% CI Eliminated	% CMI Eliminated	% Outages Eliminated
DEP NC	27%	25%	42%
DEC NC	NA	NA	NA

Hurricane Irma (2016)

North Carolina	% CI Eliminated	% CMI Eliminated	% Outages Eliminated
DEP NC	33%	43%	44%
DEC NC	46%	39%	26%

APPENDIX D, MEASURING THE ECONOMIC IMPACT OF RELIABILITY IMPROVEMENTS

Measuring Costs Savings Associated with Core Reliability Improvements

To estimate businesses and households cost savings associated with core reliability improvements, EY used our SAIFI and SAIDI projections for non-major events along with our North Carolina customer segment data (i.e., numbers of residential, business, and commercial customers as inputs) into the Interruption Cost Estimate Calculator (ICE) developed by the U.S. Department of Energy and Lawrence Berkeley National Laboratory.

The ICE model specifically calculates the average interruption cost for residential, business, and commercial customers for a given SAIFI/SAIDI data pair using a regression model that takes into account factors such as the duration of the outage, the industry affected, household demographics patterns, and various seasonal factors. By estimating the difference in interruption costs associated with current SAIFI/SAIDI projections with and without implementation of the Power/Forward improvements, the annual direct cost savings resulting from our proposed grid improvements can be determined.

Measuring Costs Savings Associated with Reduced Major Storm Impact

To estimate businesses and households cost savings associated with *reduced major storm impacts*, EY used the annual averages for customer interruptions (CI) and customer minutes interrupted (CMI) associated with Major Event Days (MEDs). From this, EY projected estimates of the avoided CI and CMI anticipated from our Power/Forward improvements. Again, the data was input into the DOE/LBNL ICE tool to estimate the direct cost savings as our improved infrastructure comes on line over the 10 year investment period.

Measuring Additional Statewide Economic Impacts

Note that these direct cost savings do not capture the full economic impact of our reliability improvements. When North Carolina businesses experience these cost reductions, over time they will begin to expand their economic activities through additional purchases of raw inputs and the hiring of additional employees (*state wide benefits*). To estimate this additional economic activity, the IMPLAN model was used.

Both the reinvested business loss savings and the indirect and induced economic stimulus represent new economic activity that is the result of grid reliability improvements.

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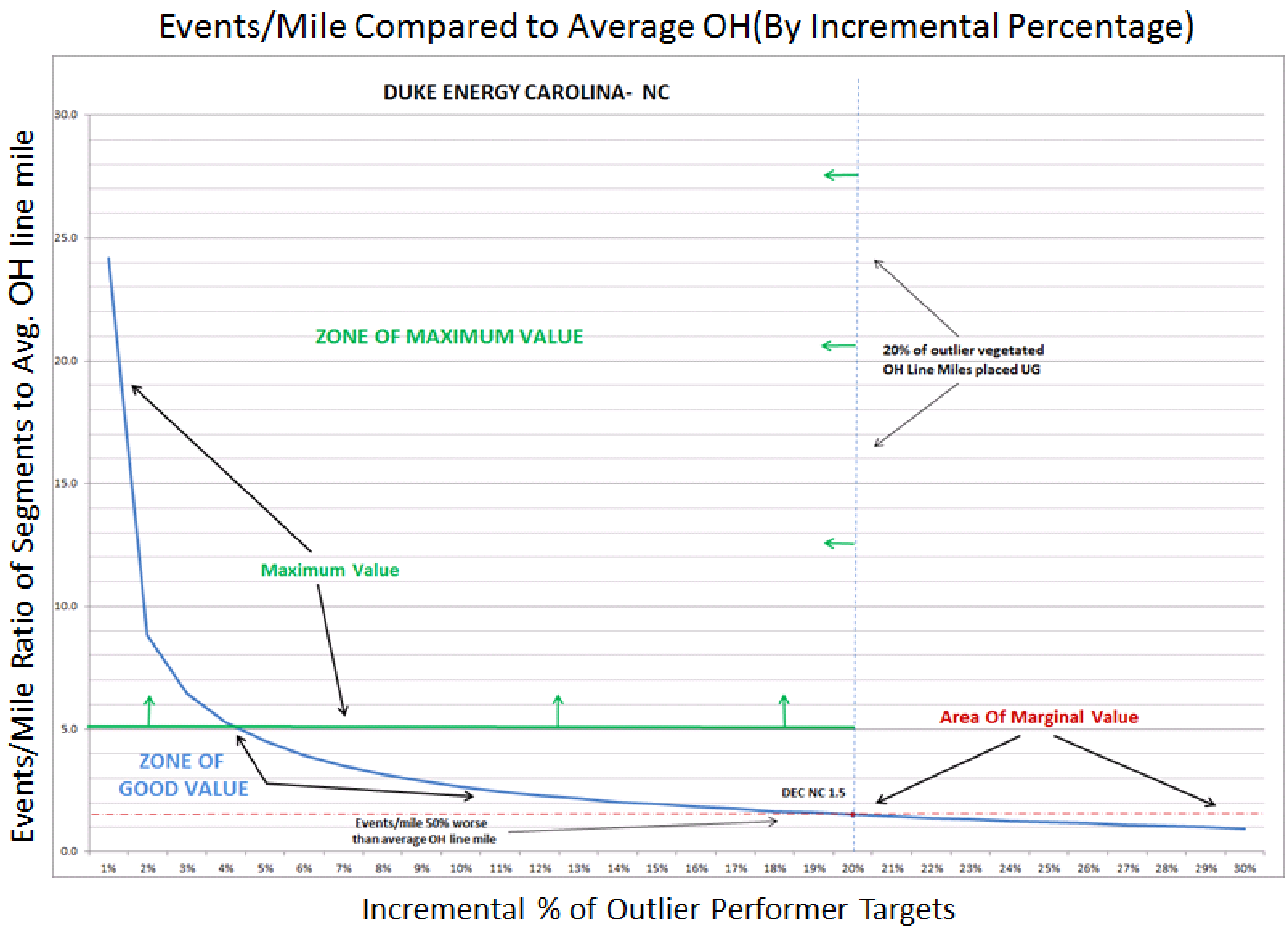
 Exhibit 3 – Tech Customers Data Request 2-9

Question #	Tech Customers 2-9
Status	Complete
Assigned To	Brown, Justin C.
Request Date	11/27/2017
Due Date	12/4/2017
Internal Witness	
Topic	Simpson Testimony
Question Detail	Please describe the approach employed by DEC to differentiate between an investment included in the traditional T&D category (i.e., within the forecast $4.5 billion budget) and an investment included in Power/Forward Carolina (i.e., within the forecast $2.9 billion budget).
Manager Reviewer	Stratton, Don T
Answer	As described in 2-7 above the Customary spend budget was set before P/F and has now been adjusted down to $3.4B to remove those items covered by P/F. Customary spend covers new customer connects, Circuit and substation capacity increases for load growth, Lighting, Restoration maintenance, Integrity programs such as pole replacement and UG cable replacements, and reliability programs. The customary $3.4B will continue to include a level of spend in all these categories as represented in the pie charts on pgs. 9 and 11 of the Simpson testimony consistent with the historical spend. P/F is incremental spend focused strictly on reliability. The scope of Power Forward includes work streams that are new and not part of routine T&D customary spend. The company will differentiate between the routine and GRR Rider installation by aligning the scope and work plans associated with each to distinct accounting code block that captures these costs separately, where practical. Many of the projects within the Transmission and Distribution "Hardening and Resiliency" or H/R work scope such as Transformer Retrofit, Deteriorated Conductor, and Circuit Sectionalization, to name a few, already exist and will continue to have a customary level of base funding. Therefore, the charges will be delineated between T&D customary and Power Forward based on a set customary spend level threshold.

 Exhibit 3 – Tech Customers Data Request 2-9

Question #	Tech Customers 2-7
Status	Complete
Assigned To	Culbreth, Melissa B
Request Date	11/27/2017
Due Date	12/4/2017
Internal Witness	
Topic	Simpson Testimony
Question Detail	Please provide a detailed breakdown of the $4.5 billion capital investment budget cited for the traditional T&D investments not including Power/Forward Carolina. What types of investment are included in that budget? Is undergrounding included? Is adding capacity to distribution circuits included?
Manager Reviewer	Stratton, Don T
Answer	The $4.5B over 5-years represented the Corporate Forecast as of 12/31/16 for T&D. The forecast at that time was prior to the announcement of Power Forward. The forecast at that time was representative of the fact that we were seeing worsening reliability trends and we needed to invest more in reliability projects and so it included $1B in Grid modernization and reliability projects. With the announcement of Power Forward, the $1B in Grid Modernization projects will be removed from the T&D Customary spending forecast. The types of investments included in the $3.4B capital budget would be very consistent with what is shown in the pie charts provided on pgs. 9 and 11 in the Simpson testimony. The $3.4B includes capacity increases to distribution circuits and T/D substations for load growth. It does not include any amount of spending for undergrounding.


Events/Mile Compared to Average OH(By Incremental Percentage)
DUKE ENERGY CAROLINA- NC
ZONE OF MAXIMUM VALUE
20% of outlier vegetated
OH Line Miles placed UG
Maximum Value
Area Of Marginal Value
ZONE OF
GOOD VALUE
DEC NC 1.5
Events/mile 50% worse
than average OH line mile
Events/Mile Ratio of Segments to Avg. OH line mile
30.0
25.0
20.0
15.0
10.0
5.0
0.0
1% 2% 3% 4% 5% 6% 7% 8% 9% 10% 11% 12% 13% 14% 15% 16% 17% 18% 19% 20% 21% 22% 23% 24% 25% 26% 27% 28% 29% 30%
Incremental % of Outlier Performer Targets

DEC Distribution Poles: Current Status

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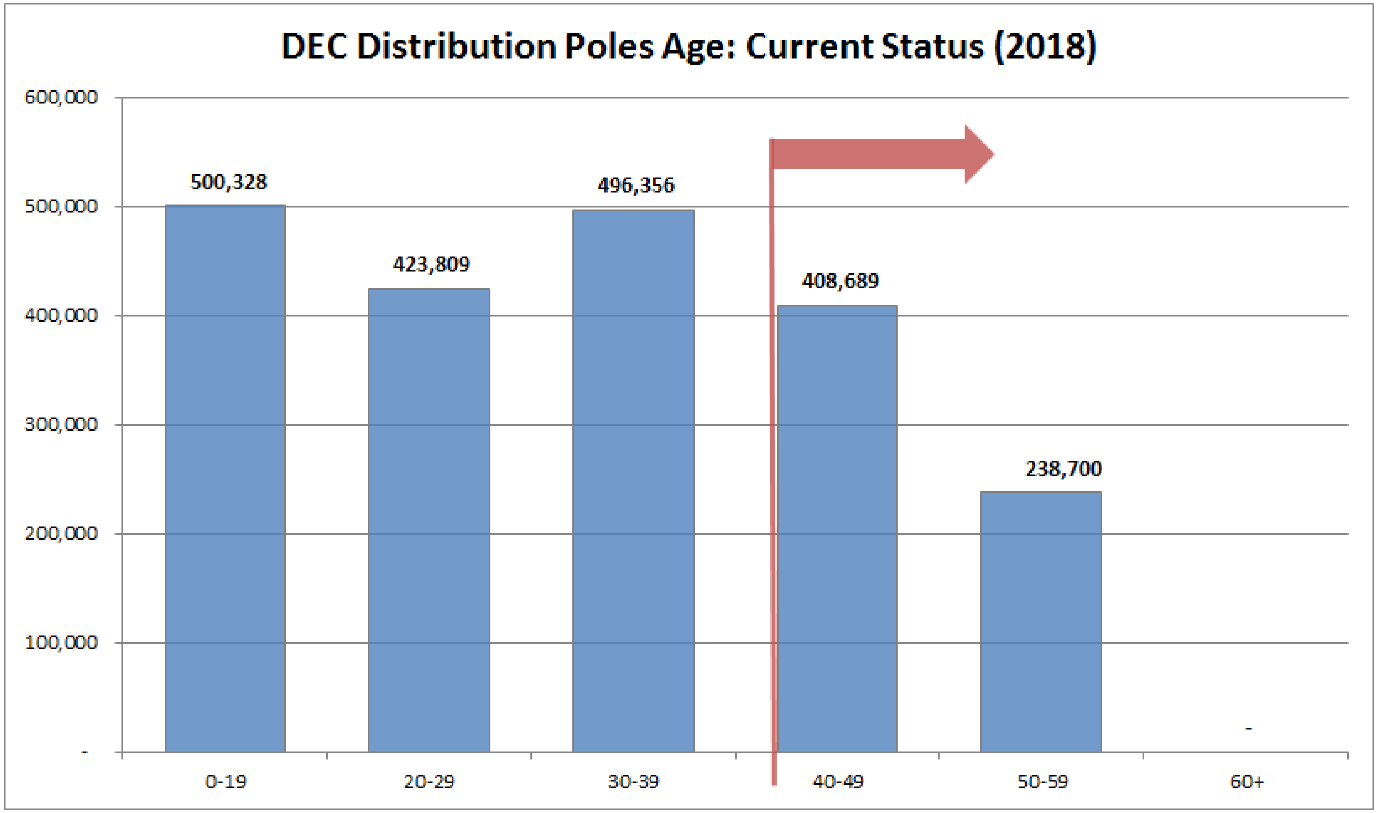
- Values represented in the chart and table below are for DEC, which includes a portion of SC
- Values based on an expected useful life of 40 years



Expected Useful
Life: 40 yrs

DEC Distribution Poles Current Status (2018)		
Age Range	Pole Count	% of Total
0-19	500,328	24.2%
20-29	423,809	20.5%
30-39	496,356	24.0%
40-49	408,689	19.8%
50-59	238,700	11.5%
60+	-	0.0%

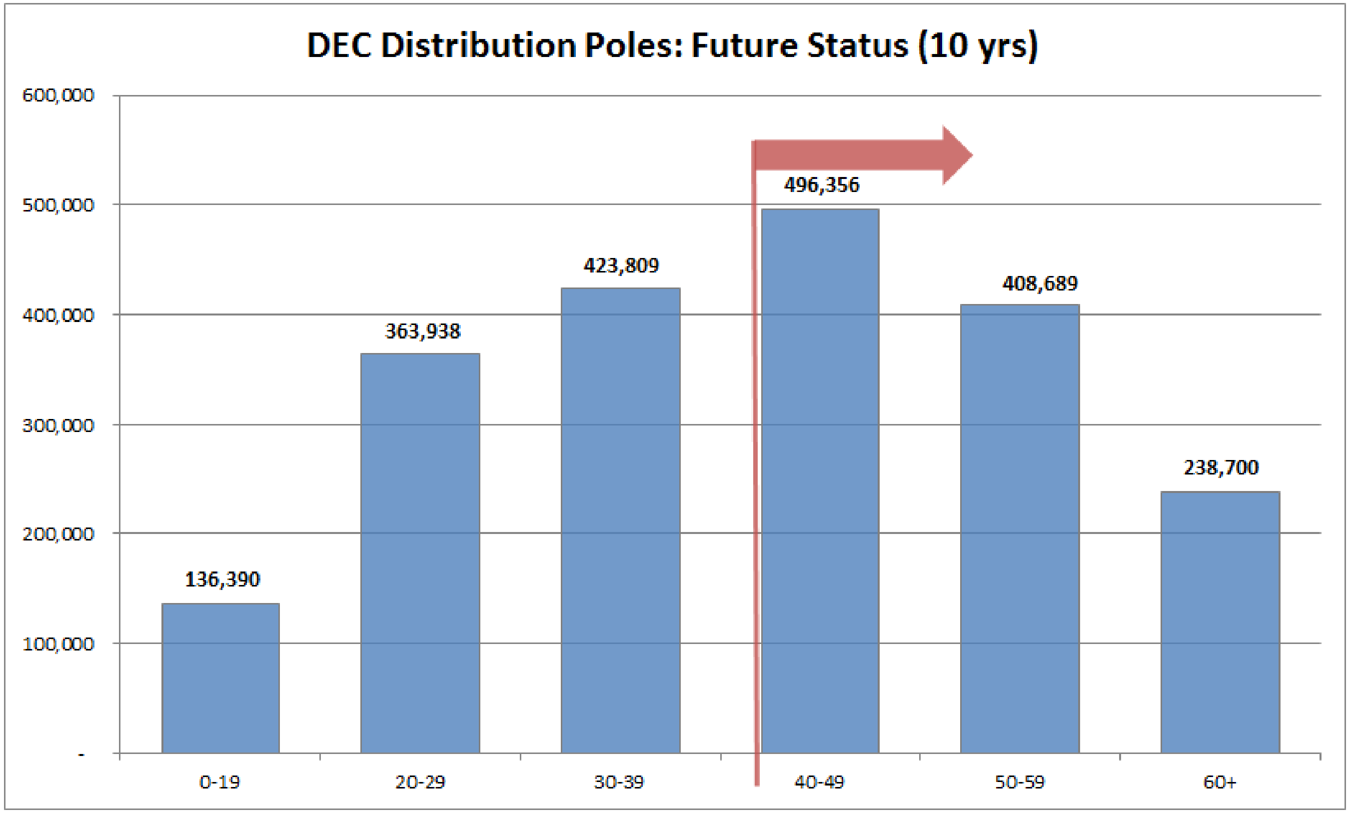
- Over 31% of DEC's distribution poles are now at or beyond their expected useful life.

Source: Asset counts and deployment dates provided by Asset Accounting as of 12/2016.

DEC Distribution Poles: Future Status: 10 yrs

DUKE ENERGY.

- Values represented in the chart and table below are for DEC, which includes a portion of SC
- Values based on an expected useful life of 40 years



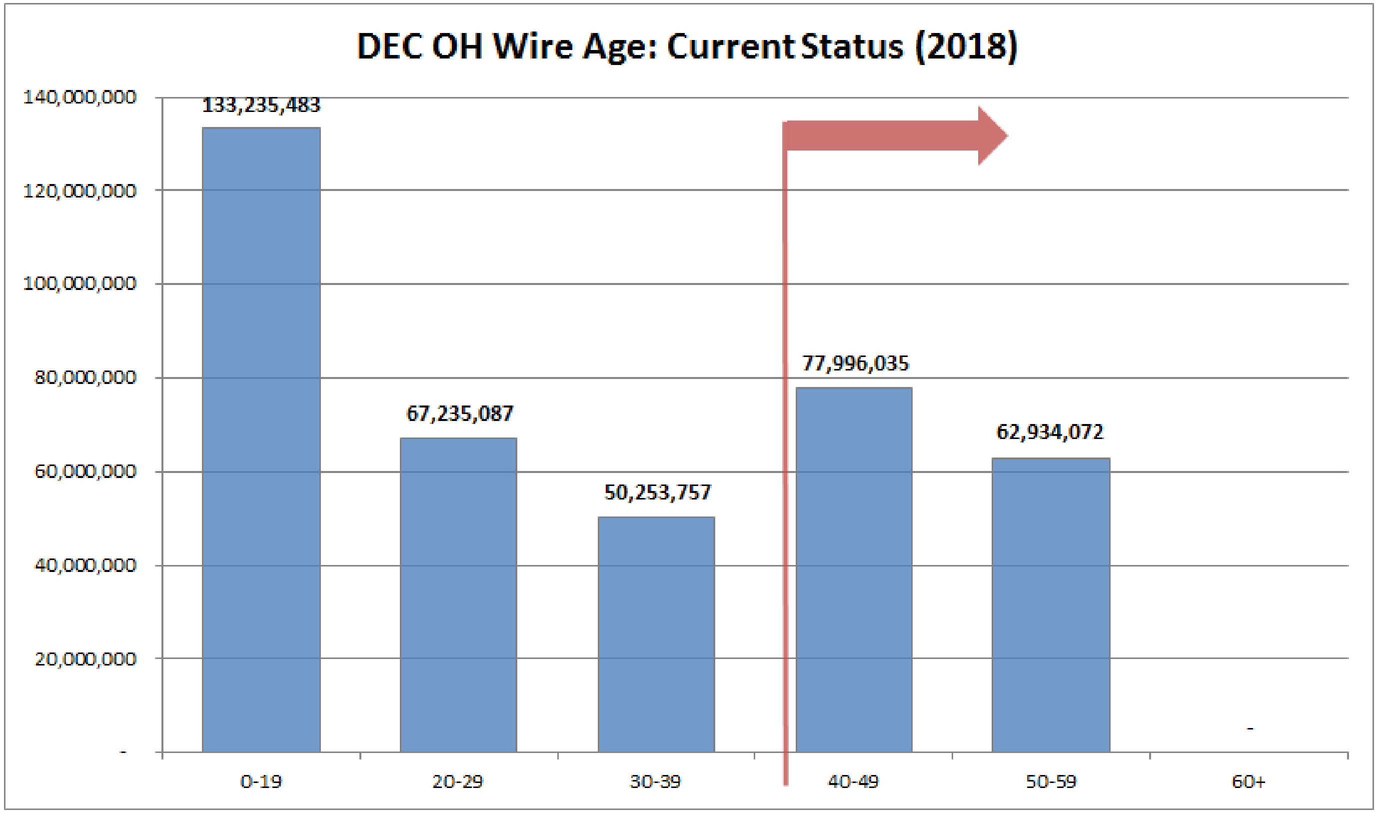
Expected Useful
Life: 40 yrs

DEC Distribution Poles Future Status (10 yrs)		
Age Range	Pole Count	% of Total
0-19	136,390	6.6%
20-29	363,938	17.6%
30-39	423,809	20.5%
40-49	496,356	24.0%
50-59	408,689	19.8%
60+	238,700	11.5%

- Over 55% of DEC's distribution poles will be at or beyond their expected useful life in 10 years, assuming no replacements.

DEC Distribution Overhead Conductor: Current Status

- Values represented in the chart and table below are for DEC, which includes a portion of SC
- Values based on an expected useful life of OH conductor of 40 years



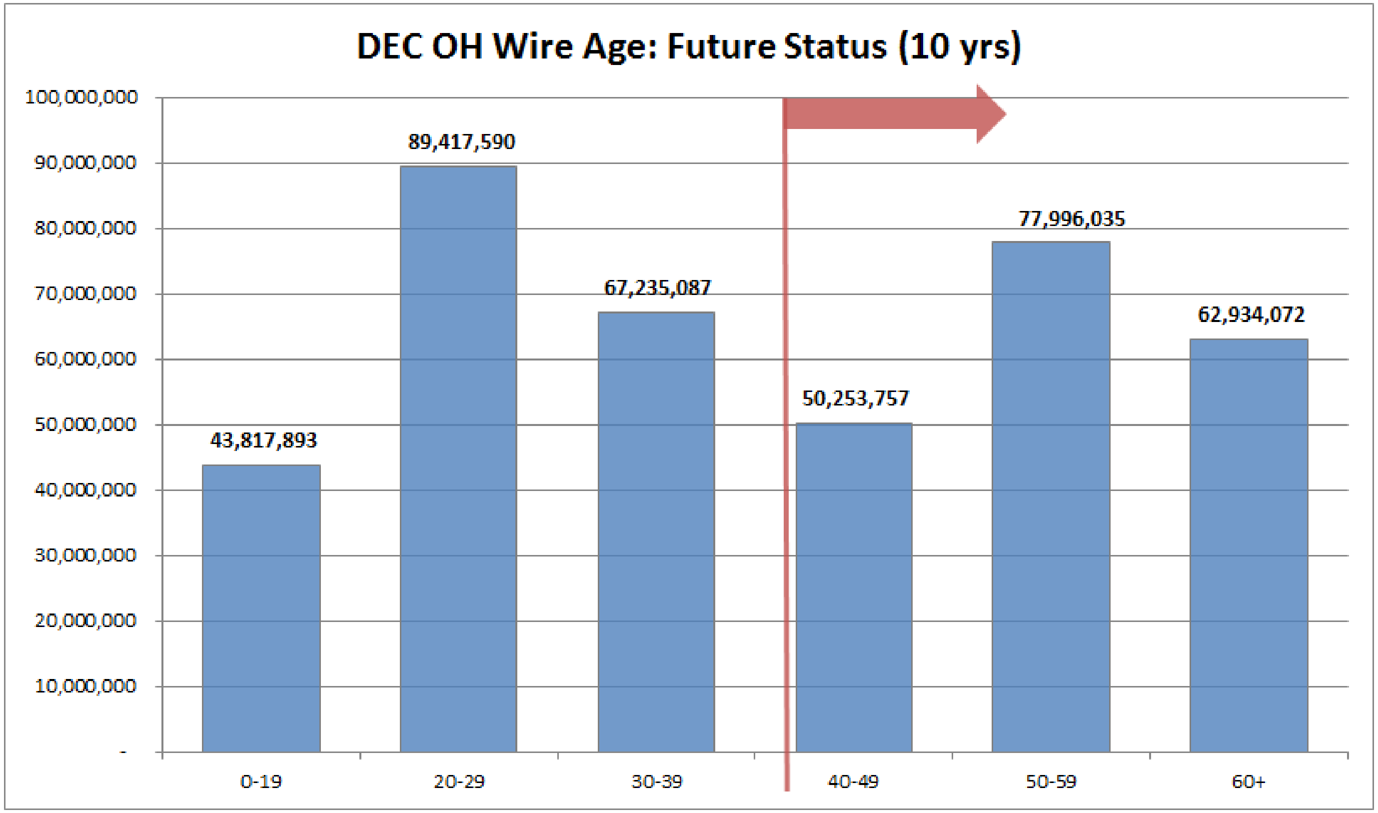
Expected Useful
Life: 40 yrs

DEC OH Wire Current Status (2018)		
Age Range	Asset Count	% of Total
0-19	133,235,483	34.0%
20-29	67,235,087	17.2%
30-39	50,253,757	12.8%
40-49	77,996,035	19.9%
50-59	62,934,072	16.1%
60+	-	0.0%

- Over 36% of DEC's distribution overhead conductor wire are now at or beyond their expected useful life.

DEC Distribution Overhead Conductor : Future Status: 10 yrs

- Values represented in the chart and table below are for DEC, which includes a portion of SC
- Values based on an expected useful life of OH conductor of 40 years



Expected Useful
Life: 40 yrs

DEC OH Wire Future Status (10 yrs)		
Age Range	Asset Count	% of Total
0-19	43,817,893	11.2%
20-29	89,417,590	22.8%
30-39	67,235,087	17.2%
40-49	50,253,757	12.8%
50-59	77,996,035	19.9%
60+	62,934,072	16.1%

- Over 48% of DEC's distribution overhead conductor wire will be at or beyond their expected useful life in 10 years, assuming no replacements.

Source: Asset counts and deployment dates provided by Asset Accounting as of 12/2016.

DEC Distribution OH Transformers: Current Status

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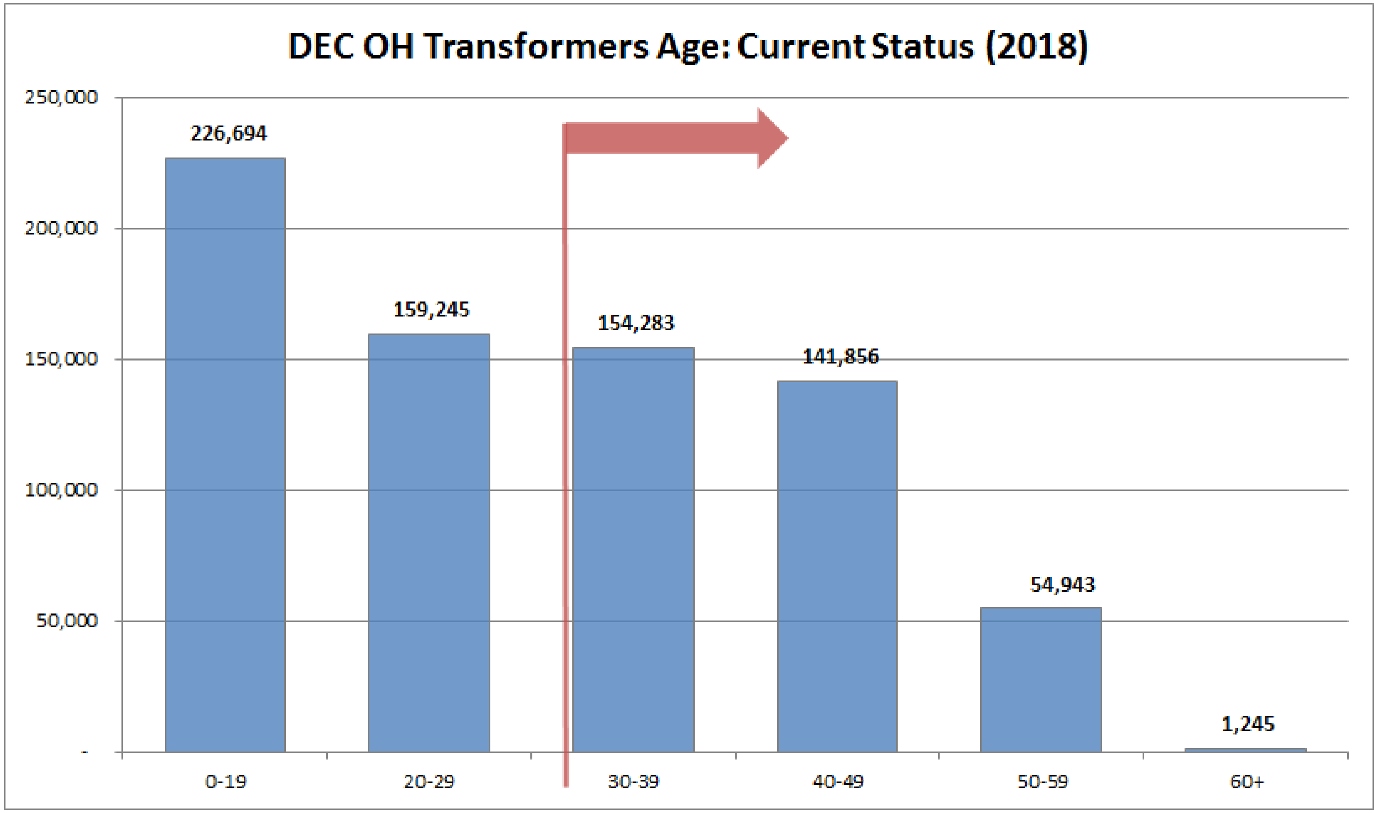
- Values represented in the chart and table below are for DEC, which includes a portion of SC
- Values based on an expected useful life of OH transformer of 30 years



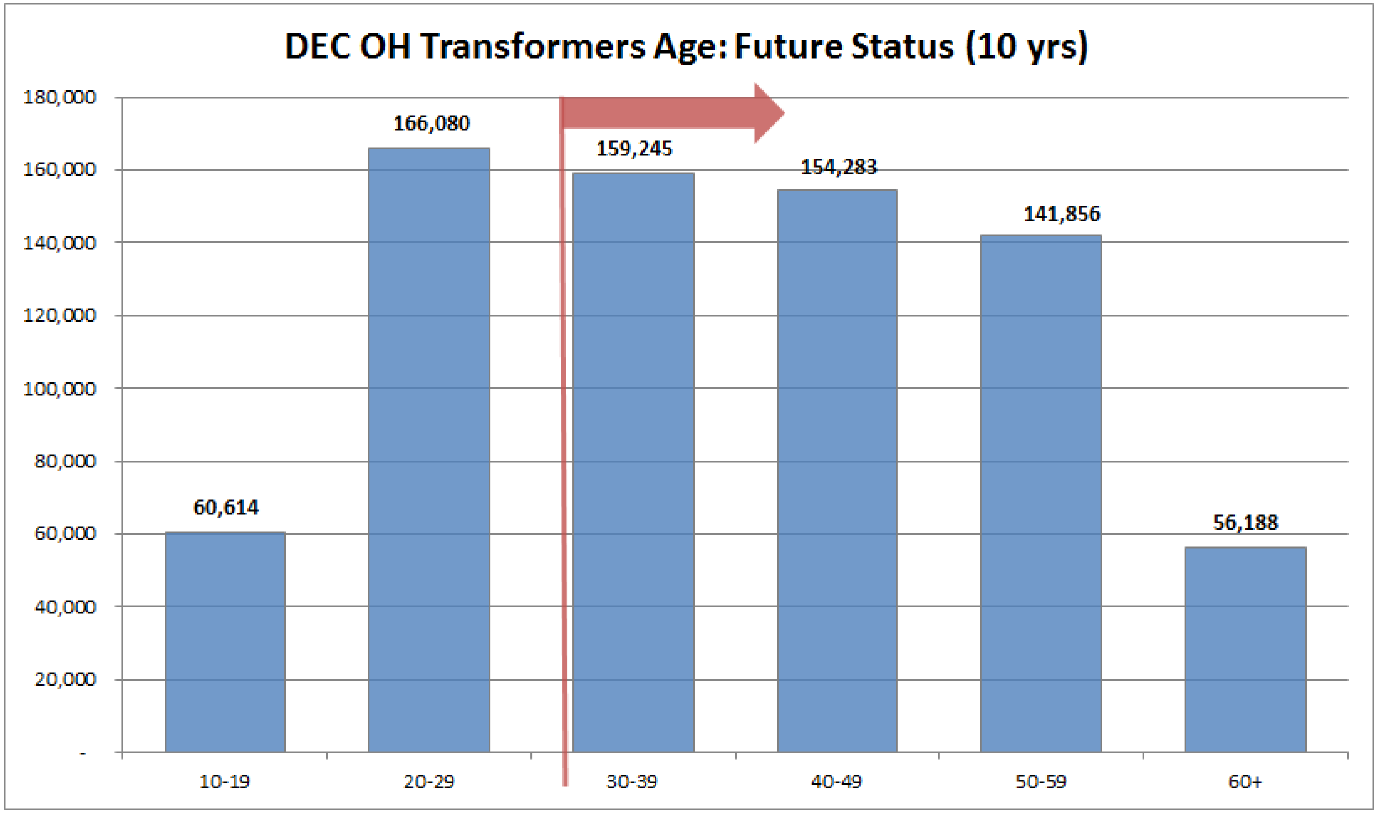
Expected Useful
Life: 30 yrs

DEC OH Transformer Current Status (2018)		
Age Range	Asset Count	% of Total
0-19	226,694	30.7%
20-29	159,245	21.6%
30-39	154,283	20.9%
40-49	141,856	19.2%
50-59	54,943	7.4%
60+	1,245	0.2%

- Over 47% of DEC's distribution overhead transformers are now at or beyond their expected useful life.

DEC Distribution OH Transformers: Future Status: 10 yrs

- Values represented in the chart and table below are for DEC, which includes a portion of SC
- Values based on an expected useful life of OH transformer of 30 years



Expected Useful Life: 30 yrs

DEC OH Transformers Future Status (10 yrs)		
Age Range	Asset Count	% of Total
10-19	60,614	8.2%
20-29	166,080	22.5%
30-39	159,245	21.6%
40-49	154,283	20.9%
50-59	141,856	19.2%
60+	56,188	7.6%

- Over 69% of DEC's distribution overhead transformers will be at or beyond their expected useful life in 10 years, assuming no replacements.

DEC Distribution UG Transformers: Current Status

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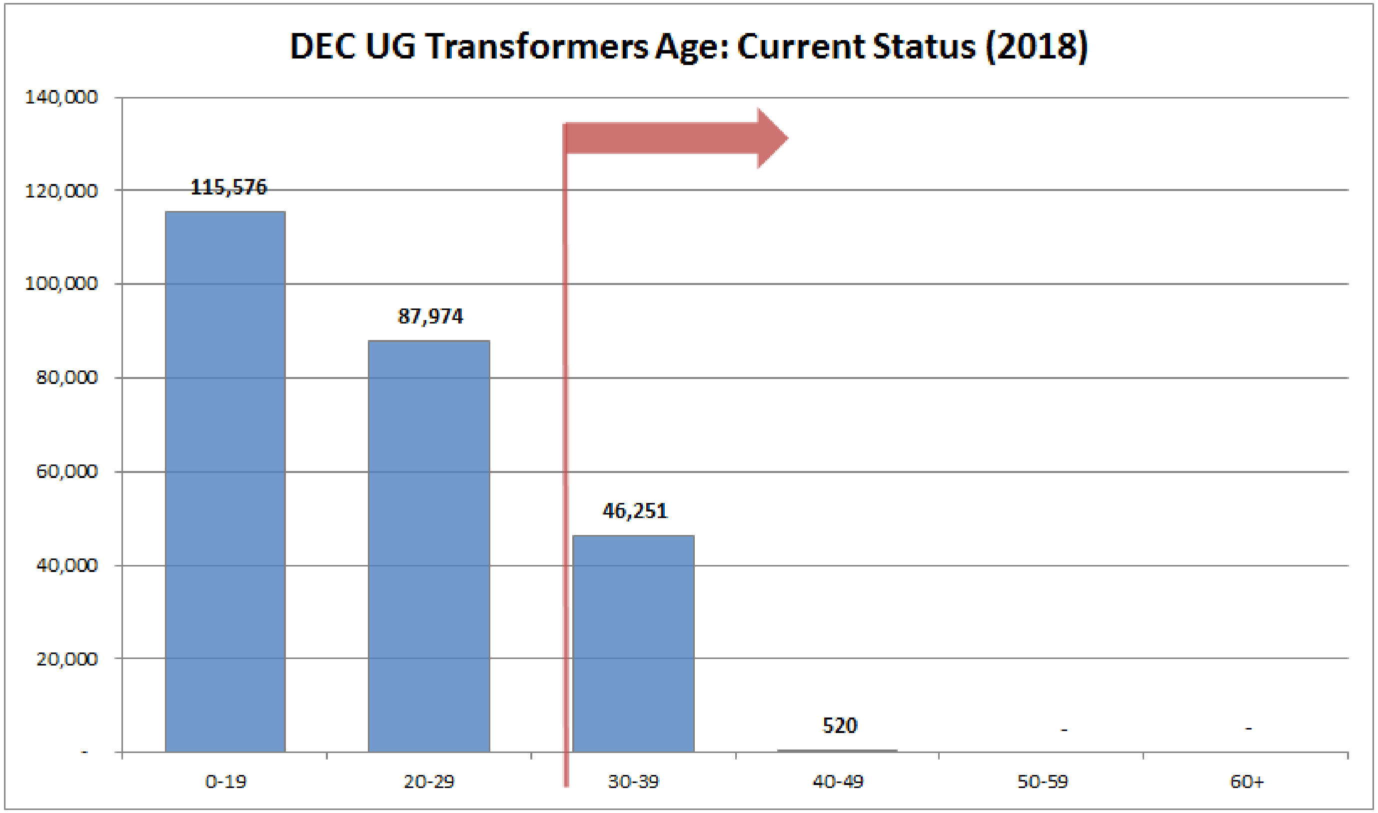
- Values represented in the chart and table below are for DEC, which includes a portion of SC
- Values based on an expected useful life of UG transformer of 30 years



Expected Useful
Life: 30 yrs

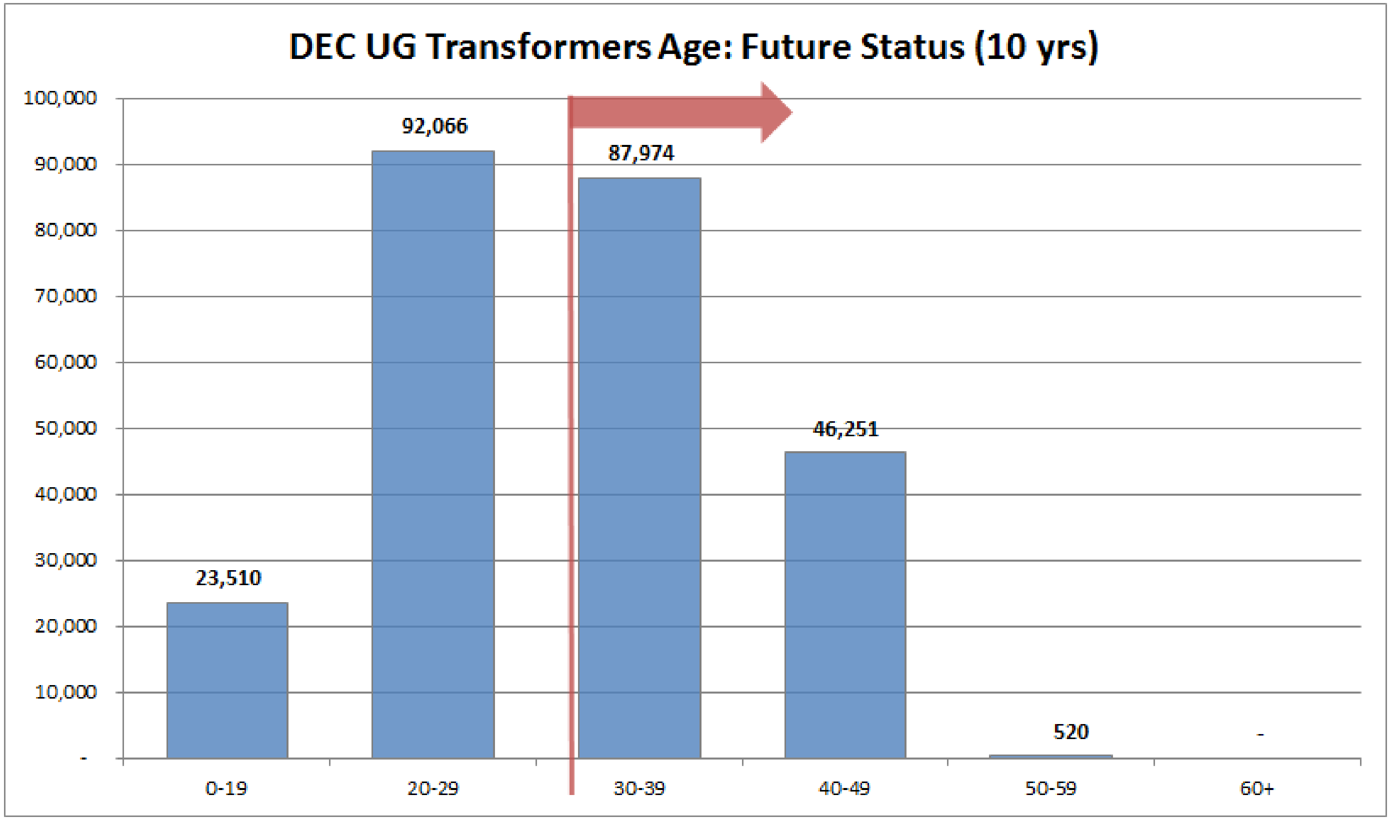
DEC UG Transformer Current Status (2018)		
Age Range	Asset Count	% of Total
0-19	115,576	46.2%
20-29	87,974	35.1%
30-39	46,251	18.5%
40-49	520	0.2%
50-59	-	0.0%
60+	-	0.0%

- Over 18% of DEC's distribution underground transformers are now at or beyond their expected useful life.

Source: Asset counts and deployment dates provided by Asset Accounting as of 12/2016.

DEC Distribution UG Transformers: Future Status: 10 yrs

- Values represented in the chart and table below are for DEC, which includes a portion of SC
- Values based on an expected useful life of UG transformer of 30 years



Expected Useful
Life: 30 yrs

DEC UG Transformers Future Status (10 yrs)		
Age Range	Asset Count	% of Total
0-19	23,510	9.4%
20-29	92,066	36.8%
30-39	87,974	35.1%
40-49	46,251	18.5%
50-59	520	0.2%
60+	-	0.0%

- Over 53% of DEC's distribution underground transformers will be at or beyond their expected useful life in 10 years, assuming no replacements.

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Electric Grid Improvements Concept Assessment

July 6, 2015

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Background and Objectives

Background

In a Frederick Poll survey, 74% of respondents indicated being in favor of making Smart Grid investment a priority. Additionally, one-third indicated they would be willing to pay higher electric rates to fund an investment in Smart Grid technology.

Carolina Delivery Operations wants to better understand customer perceptions of and reactions to Smart Grid investments, as well as reactions to the cost implications.

Objectives

The purpose of this research is to address the following business objectives:

- Evaluate the appeal of upgrading electric grid technology to Duke Energy's Carolinas Residential Customers
- Determine their reactions to potential monthly bill increases for these upgrades

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Methodology

- Bellomy Research conducted a total of 1,247 online surveys among Duke Energy Carolinas residential customers. Respondents included a representative sample of 1,000 Duke Energy Carolinas residential customers (840 in NC and 160 in SC), plus an additional 247 SC customers so differences in reactions between NC and SC customers could be assessed.
- The sample was provided by Duke Energy and included each customer's average monthly electric bill.
- They were then presented with the Electric Grid Improvements Concept and evaluated it on five key attributes with no pricing displayed.
- Following the concept evaluation, customers indicated how reasonable they thought it would be if their monthly bill increased as a result of the Electric Grid Improvements. Respondents were equally divided into two groups for this pricing exercise. Half were presented with proposed monthly bill increases of 1%, 2% and 3%. The other half were presented with customized dollar amounts that represented 1%, 2% and 3% of their average monthly bill.
- All respondents first evaluated the middle price level (2%, or the dollar equivalent of their monthly bill).
  - Depending on their response, they then either evaluated the higher or lower increase.
- Respondents provided further reactions to of the concept, per se, by highlighting words or phrases of the concept that they liked or disliked.

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Electric Grid Improvement Concept

Electric Grid Improvements

Duke Energy is beginning major upgrades to its electric grid that will greatly improve electric service to customers in North Carolina and South Carolina. These enhancements will:

- Significantly reduce the number of power outages by:
  - Putting troublesome overhead circuits underground
  - Connecting more circuits together to provide backup routes so there is more than one route for power to your home or business
  - Increasing automation on the system
- Make most outages that do occur much shorter, with power often automatically restored in minutes
- Reduce greenhouse gas emissions by:
  - Making it easier to connect renewable energy sources such as solar and wind to the electric grid
  - Improving the efficiency of the system

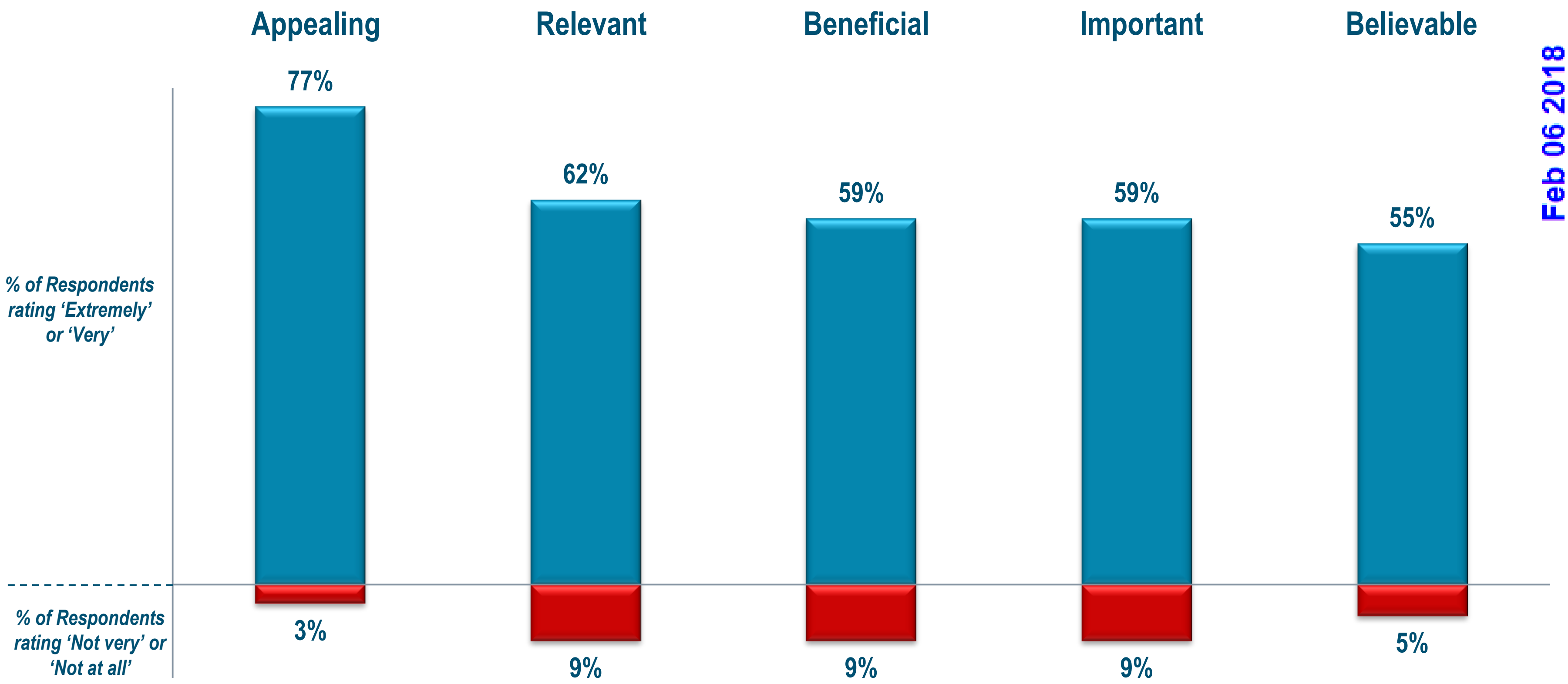
This work will begin in 2016 and continue over the next 15 years.

Executive Summary

- Initial reactions to the electric grid improvements concept/description was relatively positive among Carolinas residential customers. Before any indication of potential cost implications:
  - Over 75% found it “Extremely” or “Very Appealing,” while only 3% rated it unfavorably.
  - Over half rated the concept “Extremely” or “Very” positively across four other attributes, with unfavorable ratings from fewer than 10% of respondents.
- At the baseline/middle price point, over 40% of Carolinas customers felt the idea left them feeling more favorable about the company.
  - Customers rated price increases related to the electric grid improvements more favorably when presented as a dollar-increase to their monthly bill than when it was communicated as a percentage increase.
- The phrases in the concept description that resonated most with customers were related to putting overhead circuits underground, reducing outages, and making the system more efficient.
- The top descriptors of the Electric Grid Improvements Concept indicate that customers view it as a positive step, but think the improvements should have already occurred.

Concept Assessment – Before Cost Implications
Total Carolinas Residential Customers

- Over three-fourths of respondents rated the Electric Grid Improvements Concept as 'Extremely' or 'Very' Appealing, and more than half said it was Relevant, Beneficial, Important and Believable.
- Very few customers rated this concept unfavorably.
- There were no meaningful differences in Concept ratings between NC and SC customers.



Total (n=1000)
Q4 How **appealing** do you find the idea of these Electric Grid Improvements, as described in what you just read? Q5: How **believable** is this description of Electric Grid Improvements? Q6: How **relevant** are these Electric Grid Improvements to you, personally? Q7: How **beneficial** are these Electric Grid Improvements to you, personally? Q8: How **important** are these Electric Grid Improvements to you, personally?

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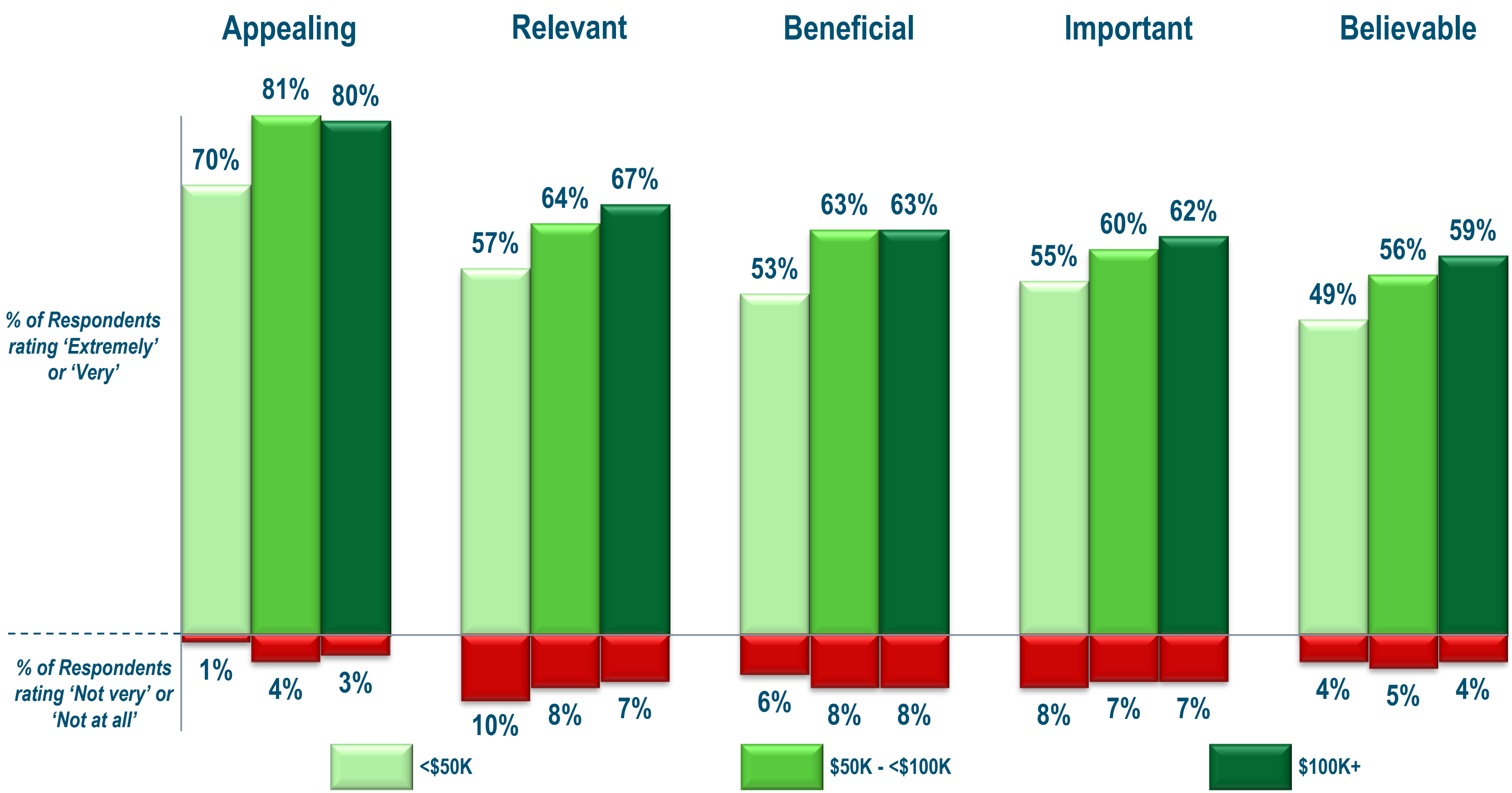
Concept Assessment – Before Cost Implications
By Household Income

- The electric grid improvements concept generated the highest interest among customers with household incomes greater than $50,000.



<$50K (n=178); $50K - <$100K (n=336); $100K+ (n=249)
Q4 How **appealing** do you find the idea of these Electric Grid Improvements, as described in what you just read? Q5: How **believable** is this description of Electric Grid Improvements? Q6: How **relevant** are these Electric Grid Improvements to you, personally? Q7: How **beneficial** are these Electric Grid Improvements to you, personally? Q8: How **important** are these Electric Grid Improvements to you, personally?

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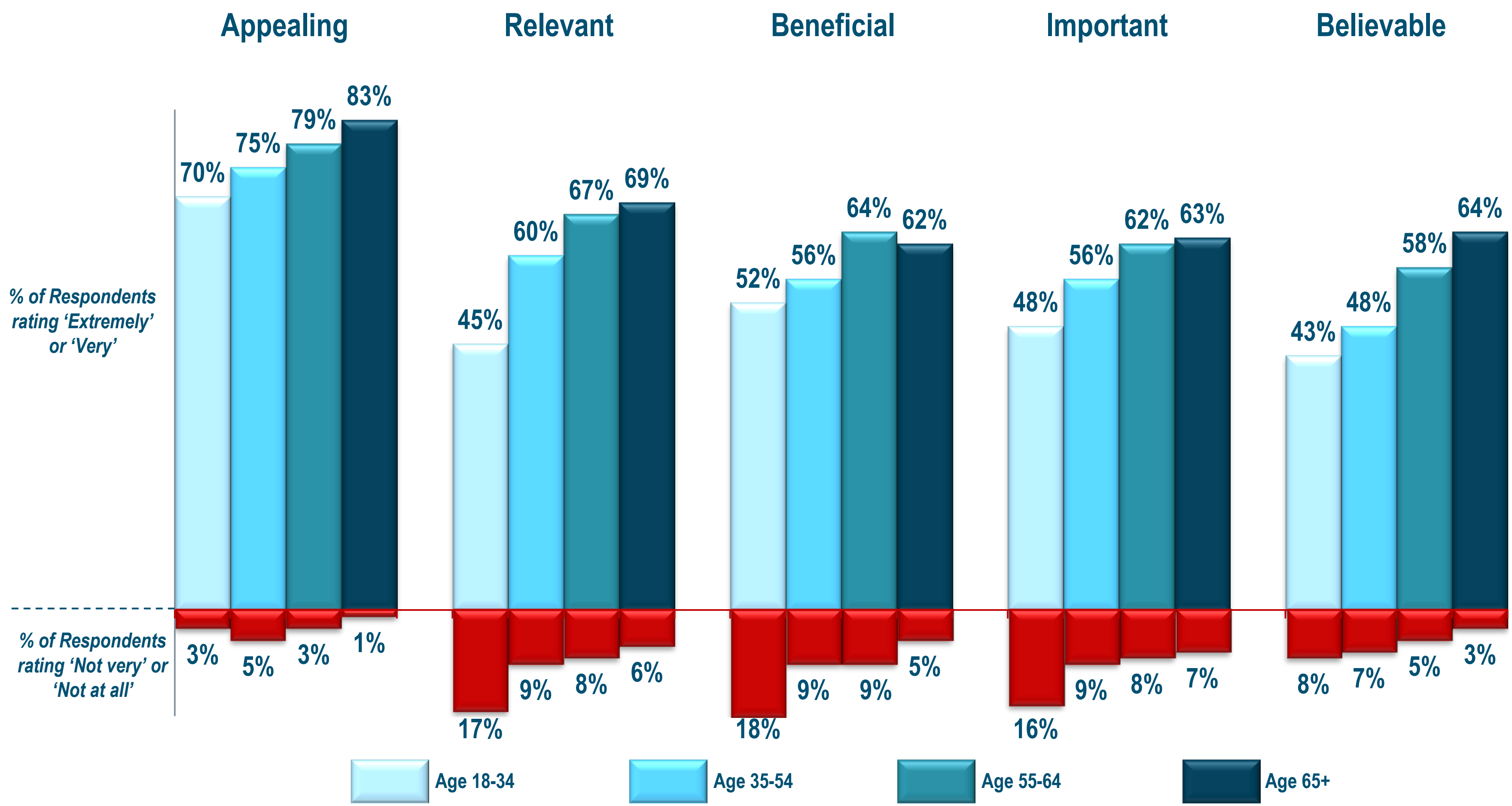
Concept Assessment – Before Cost Implications
By Age

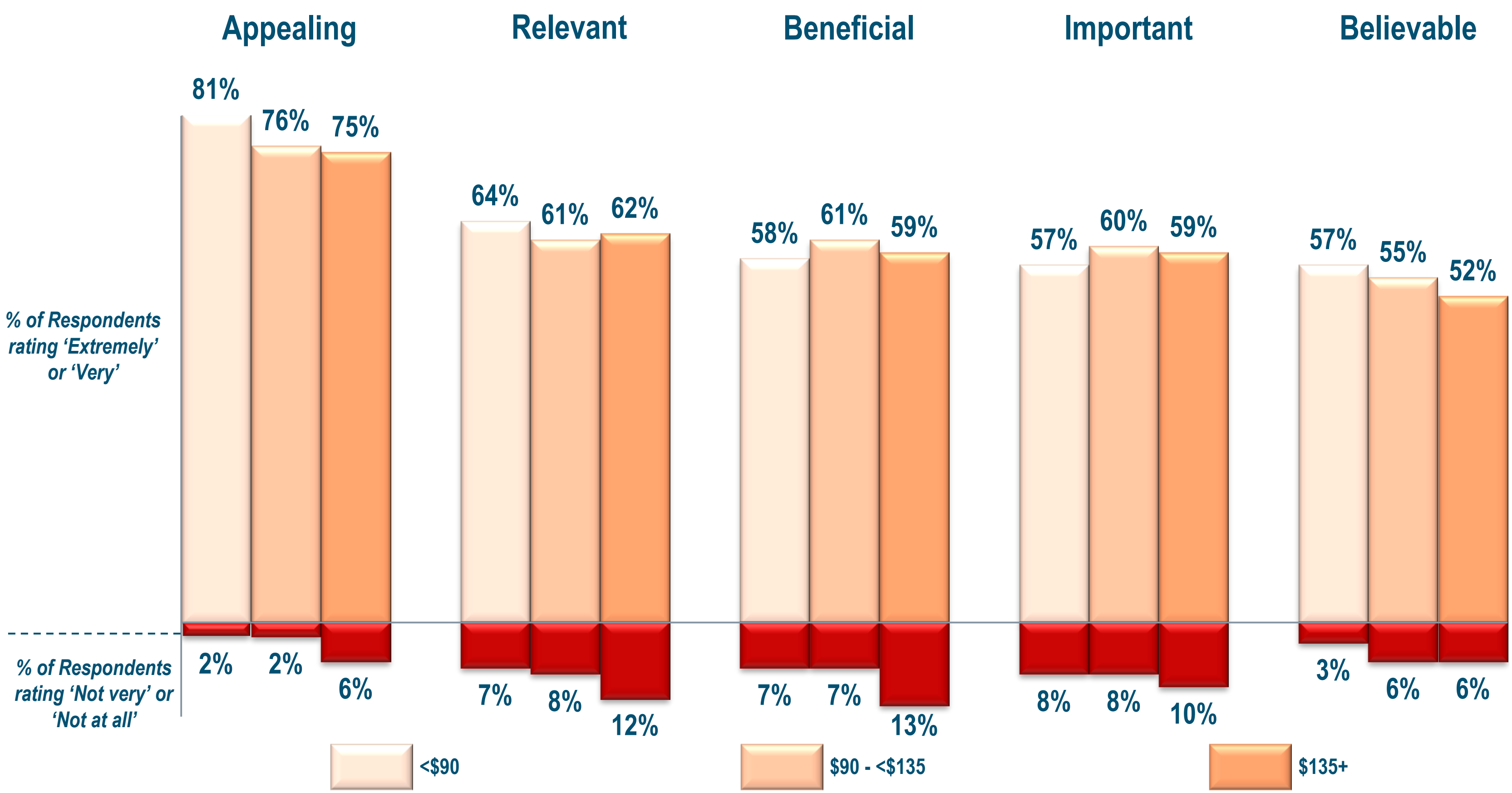
- As respondent age increased, so did ratings of the Electric Grid Improvements Concept.
- Respondents between the ages of 18 and 34 were least likely to find the concept Relevant, Beneficial and Important.



Age 18-34 (n=106); Age 35-54 (n=372); Age 55-64 (n=252); Age 65+ (n=270)
Q4 How **appealing** do you find the idea of these Electric Grid Improvements, as described in what you just read? Q5: How **believable** is this description of Electric Grid Improvements? Q6: How **relevant** are these Electric Grid Improvements to you, personally? Q7: How **beneficial** are these Electric Grid Improvements to you, personally? Q8: How **important** are these Electric Grid Improvements to you, personally?

Concept Assessment – Before Cost Implications
By Average Monthly Electric Bill

- Concept Appeal, Relevance and Believability were slightly higher among respondents with the lowest average monthly electric bill.



<$90 (n=352); $90 - <$135 (n=321); $135+ (n=327)

Q4 How **appealing** do you find the idea of these Electric Grid Improvements, as described in what you just read? Q5: How **believable** is this description of Electric Grid Improvements? Q6: How **relevant** are these Electric Grid Improvements to you, personally? Q7: How **beneficial** are these Electric Grid Improvements to you, personally? Q8: How **important** are these Electric Grid Improvements to you, personally?

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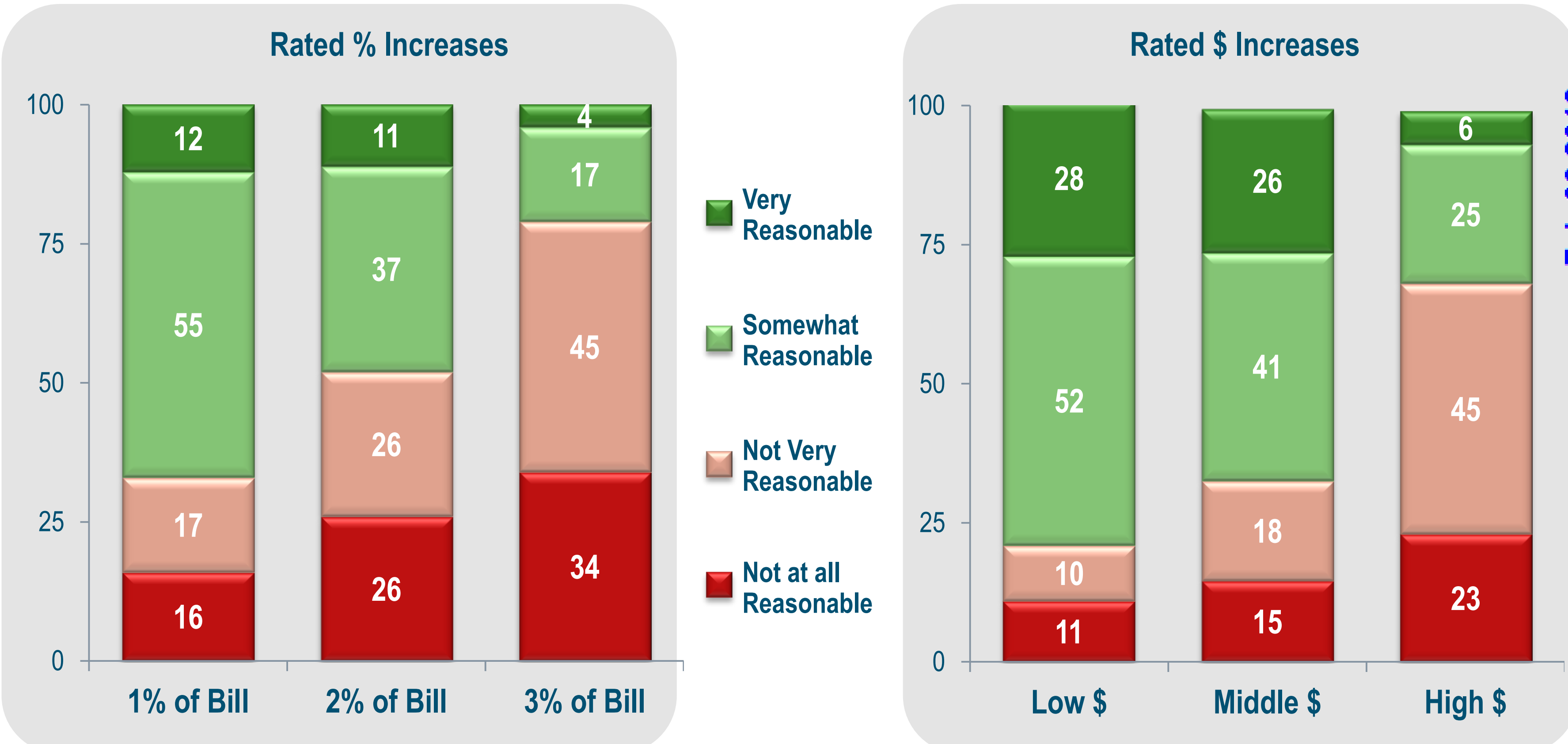
Assessment of Monthly Bill Increases
Total Carolinas Residential Customers

- Respondents were more likely to find a monthly bill increase reasonable if the increase was presented in a dollar amount than if it was presented as a percentage of their monthly bill.
- The highest bill increase (% or $) was found to be ‘Not Very’ or ‘Not at all’ Reasonable by the majority of respondents.



Respondents rating $ increases (n=500); Respondents rating % increases (n=500)
Q9/Q14/Q16. How reasonable do you think it would be if the proposed Electric Grid Improvements increased your average monthly bill by about [PRICE]?

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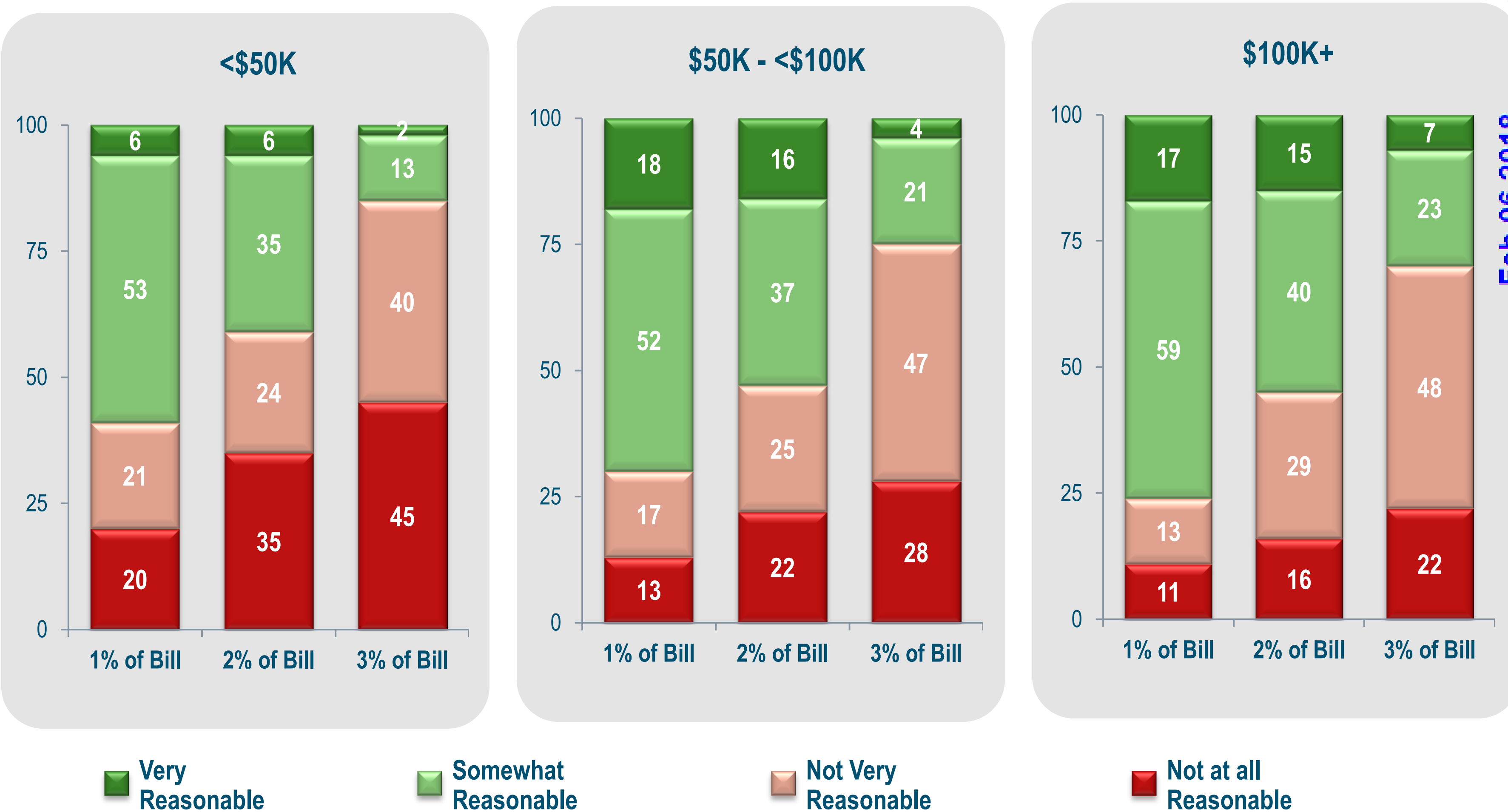
Assessment of Monthly Bill Increases (Expressed as %)
By Household Income

- Customers with higher household incomes were more likely to say a percentage increase in their monthly bill would be ‘Very’ or ‘Somewhat’ Reasonable.



	Very Reasonable	Somewhat Reasonable	Not Very Reasonable	Not at all Reasonable
<$50K: 1% of Bill	6	53	21	20
<$50K: 2% of Bill	6	35	24	35
<$50K: 3% of Bill	2	13	40	45
$50K - <$100K: 1% of Bill	18	52	17	13
$50K - <$100K: 2% of Bill	16	37	25	22
$50K - <$100K: 3% of Bill	4	21	47	28
$100K+: 1% of Bill	17	59	13	11
$100K+: 2% of Bill	15	40	29	16
$100K+: 3% of Bill	7	23	48	22

Respondents rating % increases: <$50K (n=100); $50K - <$100K (n=163); $100K+ (n=112)
Q9/Q14/Q16. How reasonable do you think it would be if the proposed Electric Grid Improvements increased your average monthly bill by about [PRICE]?

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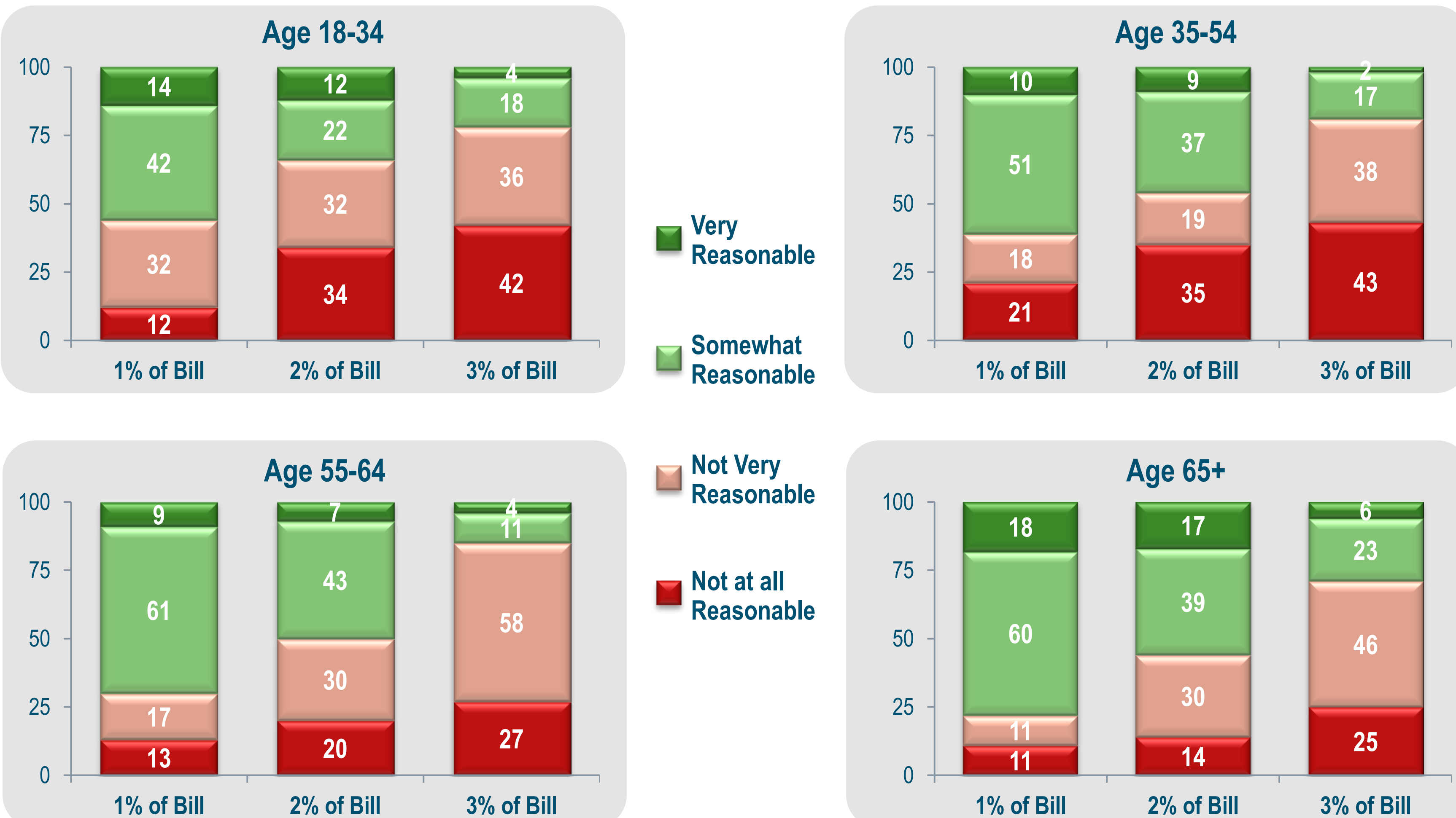
Assessment of Monthly Bill Increases (Expressed as %) By Age

- Older customers were more likely to say a percentage increase in their monthly bill would be 'Very' or 'Somewhat' Reasonable.



Respondents rating % increases: Age 18-34 (n=50); Age 35-54 (n=195); Age 55-64 (n=115); Age 65+ (n=140)
Q9/Q14/Q16. How reasonable do you think it would be if the proposed Electric Grid Improvements increased your average monthly bill by about [PRICE]?

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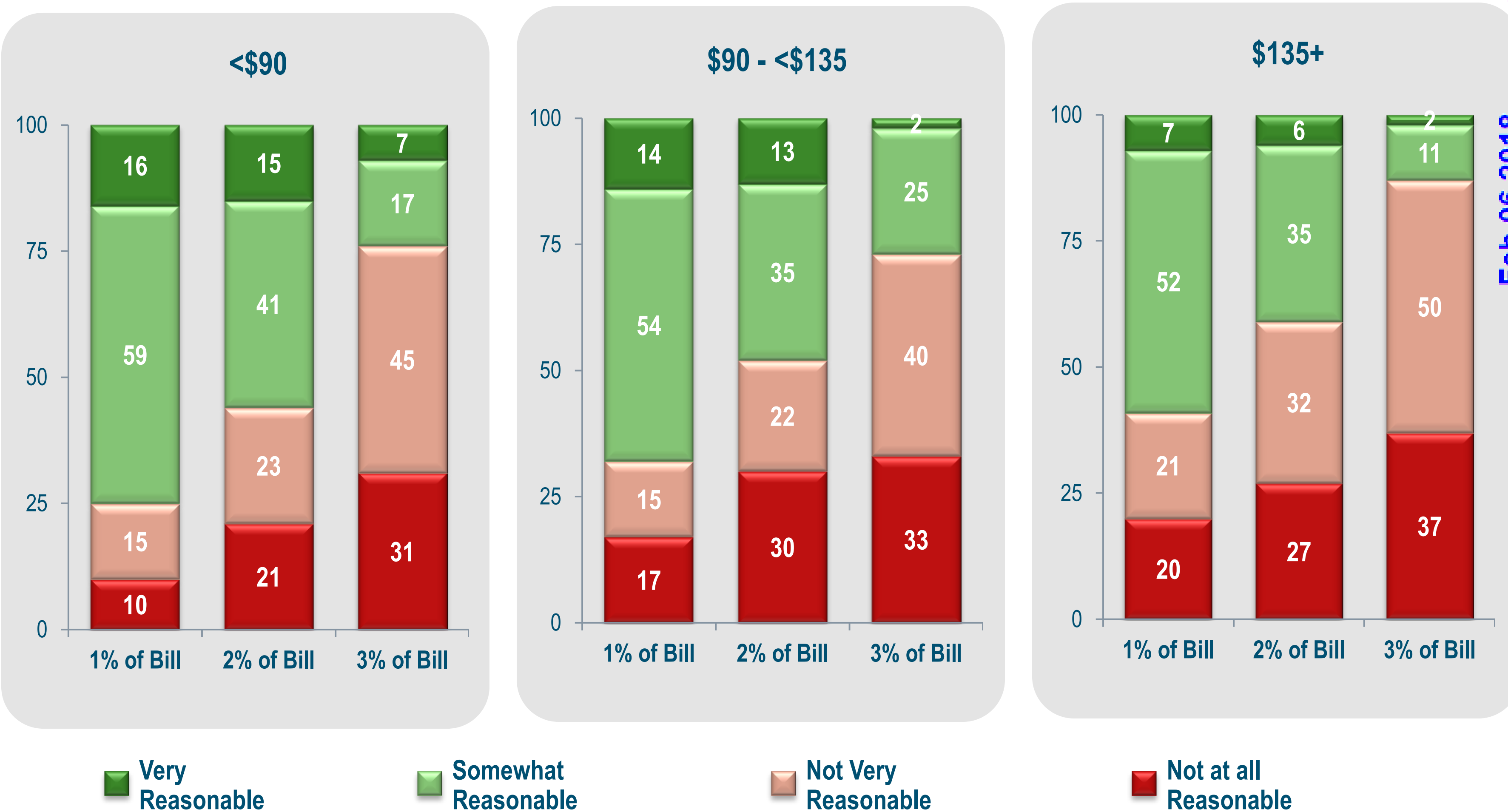
Assessment of Monthly Bill Increases (Expressed as %)
By Average Monthly Electric Bill

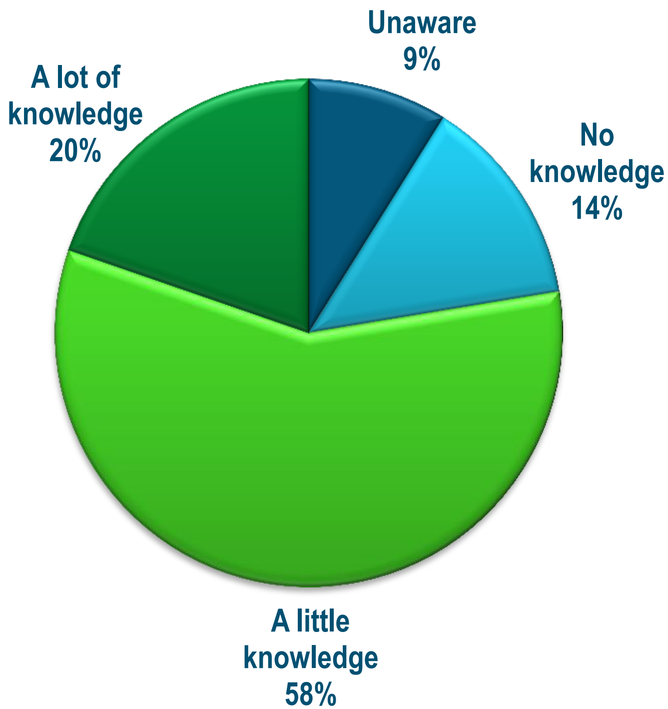
- Customers with larger monthly electric bills were least likely to say a percentage increase in their monthly bill would be ‘Very’ or ‘Somewhat’ Reasonable

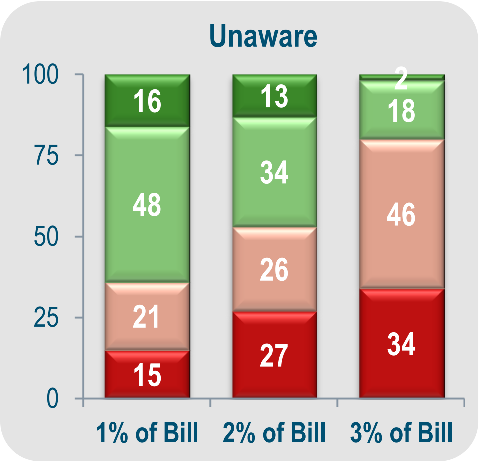


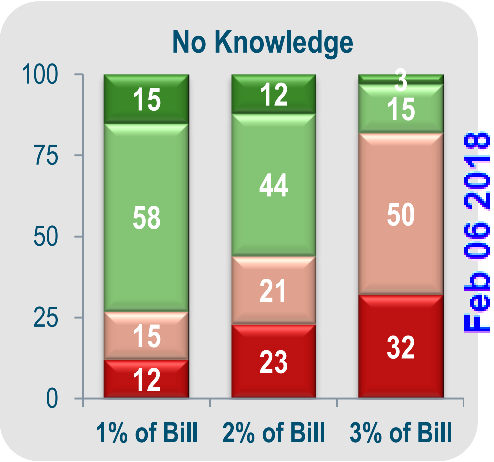
Respondents rating % increases: <$90 (n=174); $90 - <$135 (n=162); $135+ (n=164)
Q9/Q14/Q16. How reasonable do you think it would be if the proposed Electric Grid Improvements increased your average monthly bill by about [PRICE]?

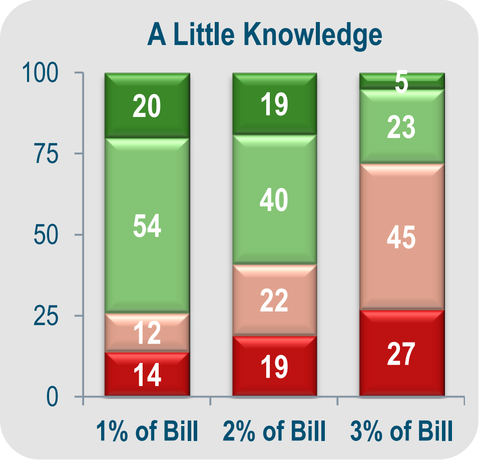
Familiarity with the Term “Electric Grid”

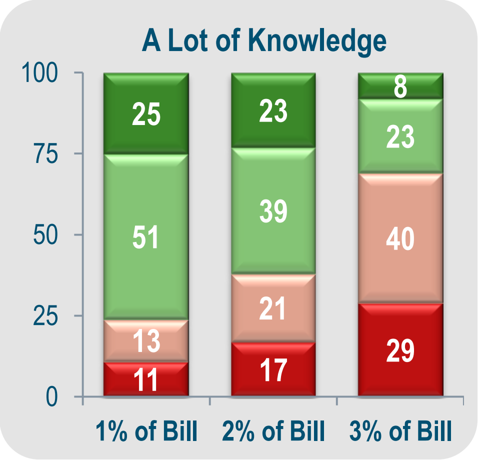
- Almost all customers were aware of the term ‘Electric Grid,’ and most said they have at least a little knowledge of what the term means.
- Customers with at least some knowledge of the term ‘Electric Grid’ were more likely to say a monthly bill increase would be reasonable.











Total (n=1000)
Q3: Sometimes the wires and other equipment used to distribute electricity to homes and businesses are referred to as the “**Electric Grid**.“ How familiar are you with this terminology?

Effect on Favorability toward Duke Energy
Total Carolinas Residential Customers

- Over 40% of respondents said the electric grid improvements concept left them feeling 'More Favorable' about Duke Energy, while only 13% said they were left feeling 'Less Favorable.'

Customer Quotes:

Because you want to make me pay for maintenance of your system.

I don't want to have to foot the cost for something I don't necessarily need. Energy is expensive enough as it is.

Improvements should reduce costs, not increase them.

It seems to solve most of our power problems. It's green.

Duke Energy is being proactive to plan for the future.

An improved electric grid offers greater availability and shorter outages would always make Duke Energy look good..

I want outage free service. Even if it costs more.

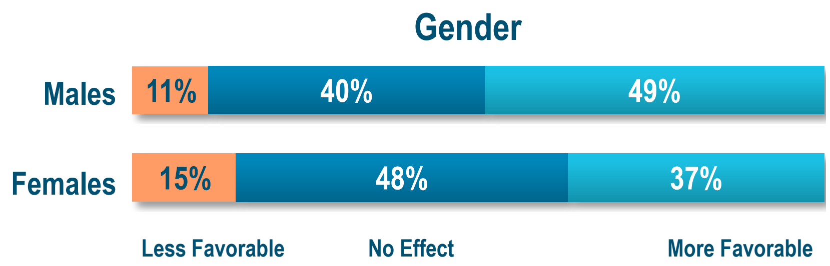
I feel Duke Energy is taking the lead with this technology that most certainly will be needed in the near future. I applaud them for this.

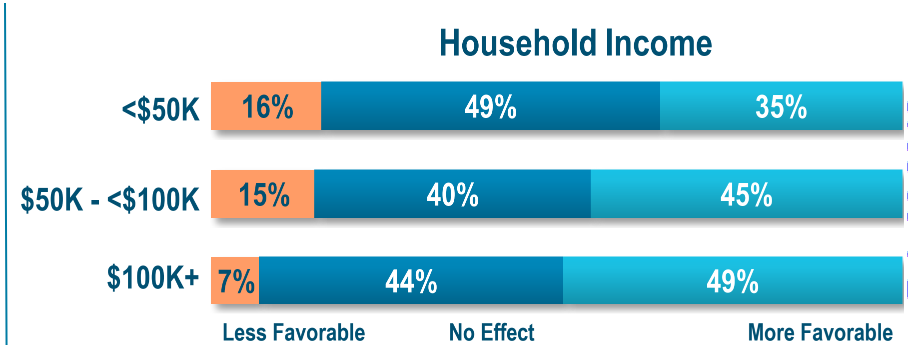
I would like to have fewer outages and less downtime, as well as more options for energy generation.

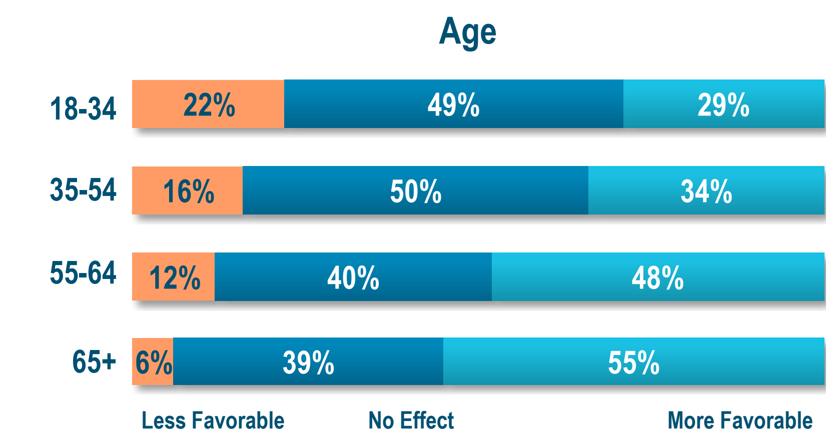
Total (n=1000)
Q12: Would you say the proposed Electric Grid Improvements would leave you feeling MORE favorable about **[INSERT COMPANY]**, LESS favorable, or have no effect?

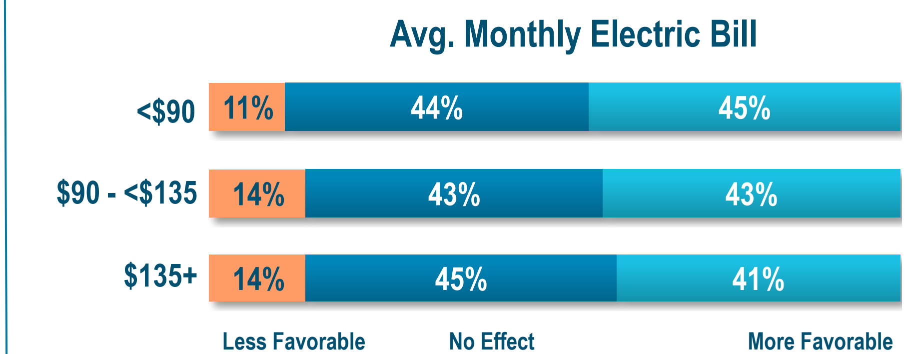
Effect on Favorability toward Duke Energy
Demographic Subgroups

- The Electric Grid Improvement idea was more likely to improve favorability of Duke Energy among male customers than female customers.
- Similar to overall appeal of the concept, a higher percentage of older customers and those with higher incomes were left with a more positive favorability toward the company after being exposed to this improvement concept.









Males (n=507), Females (n=493); Age 18-34 (n=106); Age 35-54 (n=372); Age 55-64 (n=252); Age 65+ (n=270); <$50K (n=178); $50K - <$100K (n=336); $100K+ (n=249); <$90 (n=352); $90 - <$135 (n=321); $135+ (n=327)

Q12: Would you say the proposed Electric Grid Improvements would leave you feeling MORE favorable about **[INSERT COMPANY]**, LESS favorable, or have no effect?

Electric Grid Improvement Concept
Top Phrases Liked

Electric Grid Improvements

Duke Energy is beginning major upgrades to its electric grid that will greatly improve electric service[15%] to customers in North Carolina and South Carolina. These enhancements will:

- Significantly[15%] **reduce the number of power outages[42%]** by:
  - **Putting troublesome overhead circuits underground[57%]**
  - **Connecting more circuits together[33%]** to **provide backup routes [24%]** so **there is more than one route for power to your home or business[30%]**
  - **Increasing automation on the system[26%]**
- **Make most outages that do occur much shorter[49%]** , with **power often automatically restored in minutes[34%]**
- **Reduce greenhouse gas emissions[35%]** by:
  - Making it easier[20%] to **connect renewable energy sources[38%]** such as solar[19%] and wind[17%] to the electric grid
  - **Improving the efficiency of the system[48%]**

This work will begin in 2016 and continue over the next 15 years

Total (n=1000)
Note: phrases selected by less than 10% of respondents are not displayed in green font.

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Electric Grid Improvement Concept
Top Phrases Disliked

Electric Grid Improvements

Duke Energy is beginning major upgrades to its electric grid that will greatly improve electric service to customers in North Carolina and South Carolina. These enhancements will:

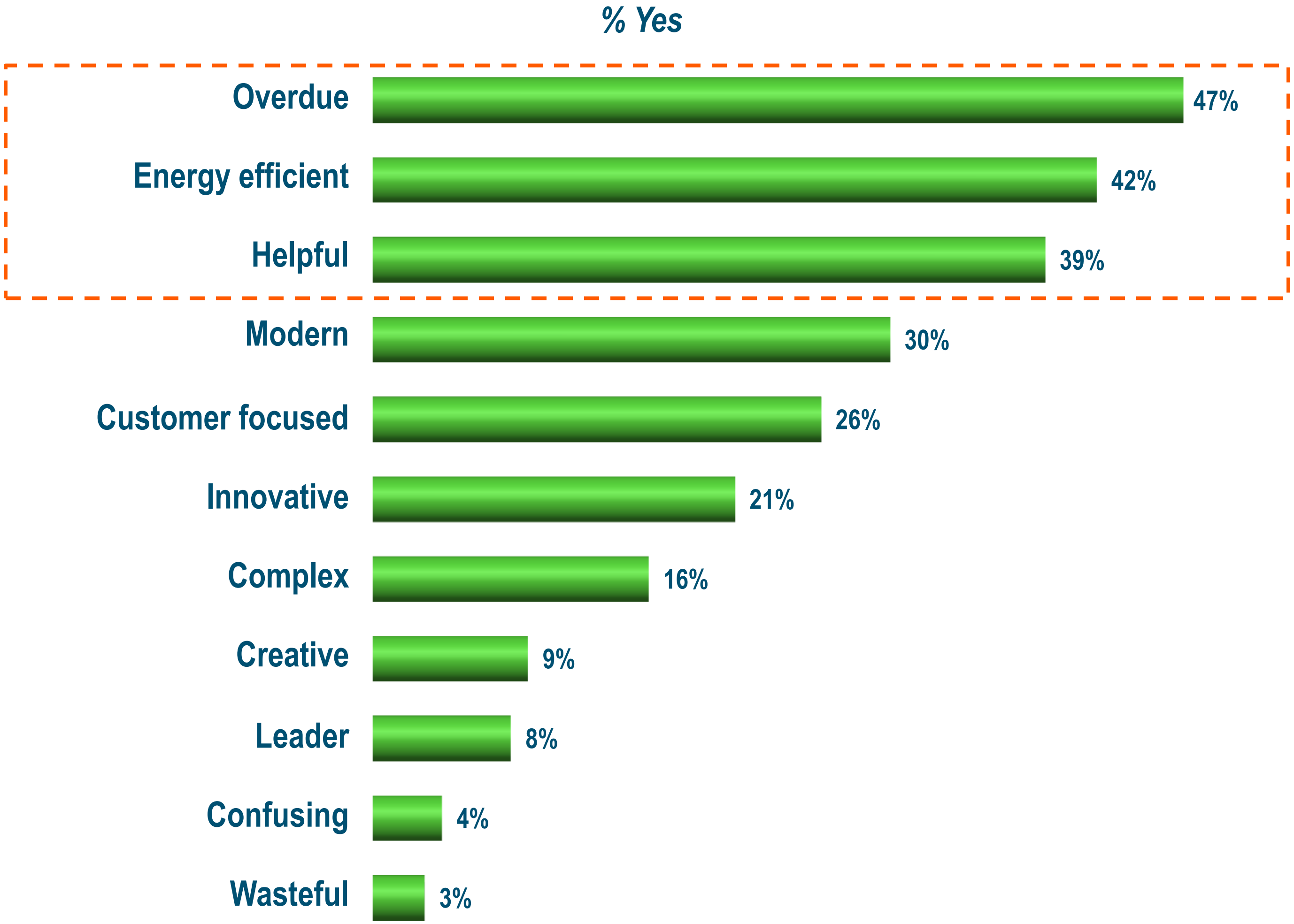
- Significantly reduce the number of power outages by:
  - Putting troublesome overhead circuits underground
  - Connecting more circuits together to provide backup routes so there is more than one route for power to your home or business
  - Increasing automation on the system[7%]
- Make most outages that do occur much shorter, with power often automatically restored in minutes
- Reduce greenhouse gas emissions[5%] by:
  - Making it easier to connect renewable energy sources[4%] such as solar and wind to the electric grid
  - Improving the efficiency of the system

This work will begin in 2016[3%] and **continue over the next 15 years[20%]**.

Total (n=1000)
Note: phrases selected by less than 3% of respondents are not displayed in red font.

Concept Descriptors
Total Carolinas Residential Customers

- Most-selected descriptors of the electric grid improvements concept indicate that customers view it as a positive step, but think the improvements should have already occurred.



Total Respondents n=1000
Q20: Which, if any, of these words or phrases describe your perceptions of Duke Energy's Electric Grid Improvements?

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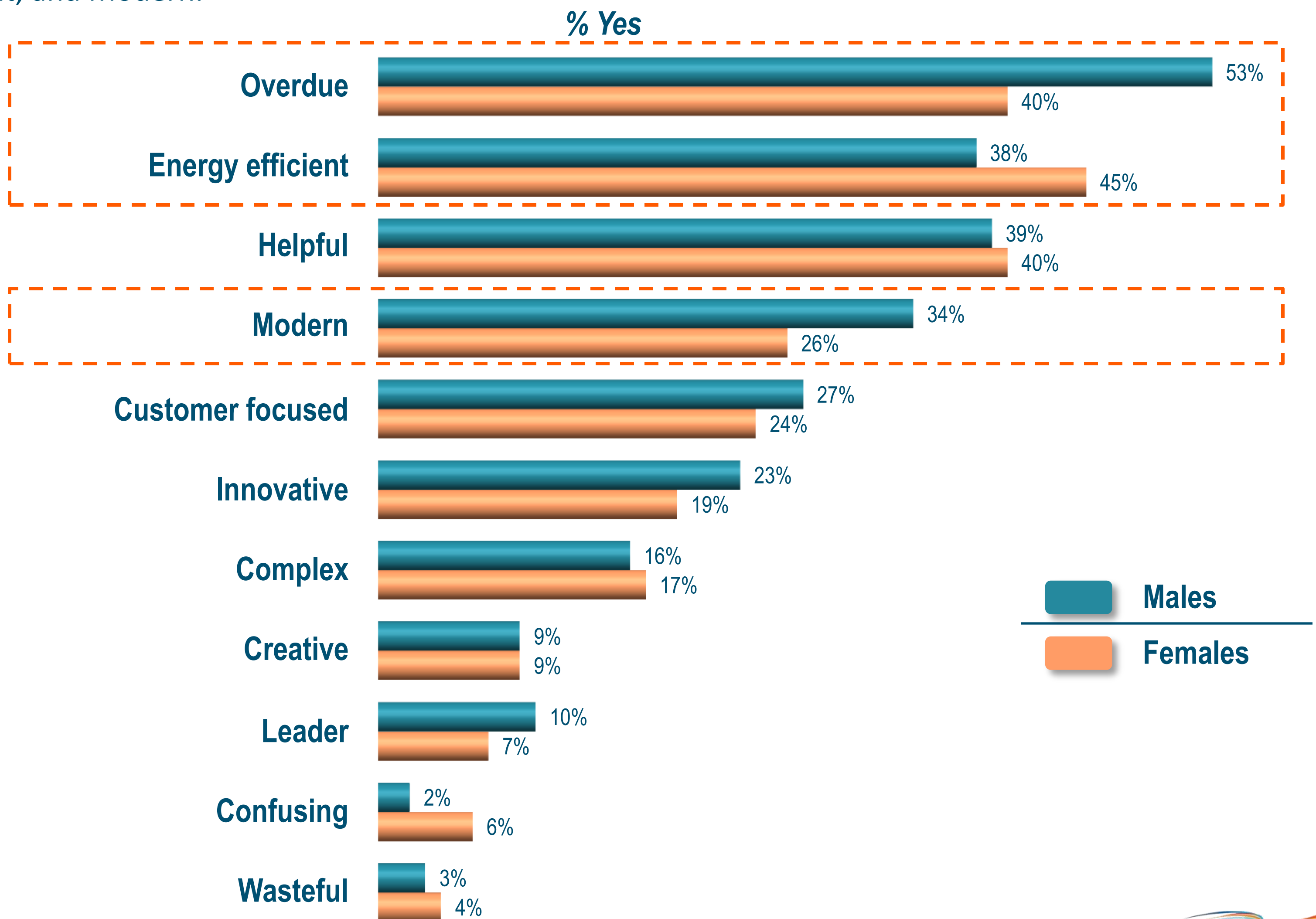
Concept Descriptors
By Gender

- Males and females perceived the concept differently on three of the top five descriptors: Overdue, Energy Efficient, and Modern.



Males (n=507), Females (n=493)

Q20: Which, if any, of these words or phrases describe your perceptions of Duke Energy's Electric Grid Improvements?

Duke Energy embarks on a 10-year initiative to strengthen North Carolina's energy grid

April 12, 2017

- **Power/Forward Carolinas initiative will result in nearly 14,000 new jobs and more than $1 billion in taxes to benefit communities**
- **$13 billion in improvements will provide customers an electric grid that is smarter, more reliable and more secure**

CHARLOTTE, N.C. -- Duke Energy today announced Power/Forward Carolinas -- a $13 billion, 10-year project to

Related Stories

Duke Energy to pass savings from new federal tax law to North Carolina customers

Duke Energy renews contract with biomass energy producer in North Carolina

modernize the state's electric system.

These upgrades will harden the system against storms and outages; make it safer and more resilient against cyber-attacks and physical threats; help expand renewable energy; generate jobs and stimulate economic growth.

It will also give 7 million people in North Carolina more information to manage their energy use.

"Safely powering the lives of hard-working families and maintaining the vitality of our communities are our most important responsibilities," said David Fountain, Duke Energy's North Carolina president. "When we improve our energy infrastructure, we not only improve power quality and reliability for everyone, but we help grow our economy and create jobs while keeping energy at a reasonable price."

Duke Energy's 10-year modernization plan for NC will result in:

- Additional bill-lowering tools designed to help customers reduce their energy costs
- An average of 13,900 jobs each year
- $10.4 billion in salaries and wages
- Almost $800 million in state taxes and $550 million in local taxes
- A total economic output of $21.5 billion over the 10 years

Modernizing the electric system
Meeting the demands of today's technological and customer-driven changes to North Carolina's grid — the sixth-largest in the nation — is becoming more challenging. Duke Energy's Power/Forward Carolinas initiative will help the company better serve its customers with focused investments that:

- Move targeted power lines underground to help reduce outages;
- enhance grid technologies to self-identify problems and reroute power, decreasing outage numbers and duration;

Duke Energy proposes two additional renewable energy programs for North Carolina customers

Related Tags

North Carolina

- advance smart metering infrastructure to enable more bill-lowering tools;
- protect against physical and cyber-security threats and keep the grid safe; and
- support the sustainable growth of renewable energy and emerging technologies.

"We must embrace a forward-thinking approach to building a smarter energy future for North Carolina," Fountain said. "We have been working hard to generate cleaner, smarter electricity, and now we must invest to make the system that delivers that energy even smarter."

For more information on Duke Energy's Power/Forward Carolinas plan to build a smarter energy future, visit www.duke-energy.com/our-company/future.

About Duke Energy
Headquartered in Charlotte, N.C., Duke Energy is one of the largest energy holding companies in the United States. Its Electric Utilities and Infrastructure business unit serves approximately 7.5 million customers located in six states in the Southeast and Midwest. The company's Gas Utilities and Infrastructure business unit distributes natural gas to approximately 1.6 million customers in the Carolinas, Ohio, Kentucky and Tennessee. Its Commercial Renewables business unit operates a growing renewable energy portfolio across the United States.

Duke Energy is a Fortune 125 company traded on the New York Stock Exchange under the symbol DUK. More information about the company is available at duke-energy.com.

The Duke Energy News Center serves as a multimedia resource for journalists and features news releases, helpful links, photos and videos. Hosted by Duke Energy, illumination is an online destination for stories about people, innovations, and community and environmental topics. It also offers glimpses into the past and insights into the future of energy.

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