Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276
Guyton Direct Exhibit 6
Distribution Program Summaries

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Capacity

Program purpose
Capacity upgrades and improvements enhance reliability of service for our new and existing customers, and support load growth from traditional loads. Additionally, the upgrades support transportation electrification and integration of distributed energy resources (DERs), such as rooftop solar and battery storage.
Timeline for construction
Refer to the MYRP Project List for project-specific timelines. At the program level, construction is planned from December 2020 to December 2026.
Estimated in-service date
Refer to the MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from January 2024 to December 2026.
Program description
Capacity work is driven by customer load growth, including the expansion of electric vehicles and other distributed technologies. **Retail substation upgrades** focus on work needed within the retail substations that serve distribution customers. Work includes installation of transformers, substation upgrades, and extension of transmission lines to new substation property. Improvements like transformer upgrades increase the capacity available at that substation to meet current and future customer demand for electricity. **Distribution system capacity upgrades** focus on work needed to add capacity on distribution lines. Improvements include new distribution lines and equipment (e.g., regulators, reclosers) or upgrades to existing equipment to increase the maximum current that can be delivered. The use of advanced data analysis, like Morecast and the Advanced Distribution Planning (ADP) toolsets, help to forecast locations where capacity upgrades are most needed. As demand for electricity increases, either from customer growth or installation of large quantities of distributed energy resources, it increases pressure on the system from the points of use upstream to the substation. Upgrading the lines to a larger conductor by replacing conductors, adding a new circuit, or transferring some load to an adjacent circuit, can help better distribute electricity and provide a reliable experience for all customer needs. This improvement program will drive planners to choose the best and most cost-effective solution for targeted line upgrades to enable sustainable customer load growth and expansion of distributed resources.

The picture below represents an actual retail substation. It acts as the interconnection between the transmission and distribution systems.

The picture above represents an actual distribution line. These lines take the power from the substations and deliver it to our customers as well as enable two-way power flow to support DERs.

Projected costs (including capital and O&M expenditure)
Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan '24-Dec '24	Jan '25-Dec '25	Jan '26-Dec '26	Total
Capital Costs	$157.4M	$205.9M	$164.5M	**$527.8M**
O&M Costs (installation only)	$3.1M	$2.6M	$2.5M	**$8.2M**

Grid capabilities enabled	HB951 Policy Considerations addressed
Capacity • Address changing customer demand by equipping circuits with the capacity needed to meet increasing load • Promote DER adoption by enabling two-way power flow	• Encourages utility-scale renewable energy and storage • Encourages DERs • Encourages beneficial electrification, including electric vehicles • Promotes resilience and security of the electric grid • Maintains adequate levels of reliability and customer service

Capacity

Customer Benefits

Is the Program required by law?	
No.	
Explanation of need for proposed expenditure	
As customer growth expands and becomes concentrated in some areas, it is important that we ensure our system is ready to support that growth. In addition, the expansion of distributed technologies like battery storage and electric vehicle charging will add increased demands on lines and equipment that are nearing capacity or that were not built with these technologies in mind. Expanding the capacity of the lines and substations, and in some cases, distributing load to other lines can help support growth and expand distributed technologies while maintaining high reliability for new and existing customers.	
Benefits created for customers	
Benefit	**Description**
Improved reliability	Reduce potential outages due to overloaded conductors and equipment associated with DER penetration and customer load growth. Upgrades will also help improve resiliency by allowing for additional switching scenarios to address outages and high demand scenarios.
Improved resiliency	Higher capacity lines improve voltage quality and make it easier to troubleshoot outages and restore service. Additional capacity and connectivity can also support self-healing networks in the area to lessen the duration and impact of outages on the system.
Expand solar and renewables	Strategically upgrading capacity supports more efficient DER connections.

Distribution Automation

Program purpose
The Distribution Automation program focuses on modernizing single use fuses with devices capable of intelligently resetting themselves for reuse, restoring power faster for customers and eliminating unnecessary use of resources (labor, fuel, inventory, etc.) to reset them. The program seeks to improve reliability and minimize customer interruption when an outage occurs, turning what would have been a sustained outage into a momentary blink.
Timeline for construction
Refer to the MYRP Project List for project-specific timelines. At the program level, construction is planned from December 2020 to December 2026.
Estimated in-service date
Refer to the MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from January 2024 to December 2026.
Program description
The Distribution Automation program replaces single use fuses on a distribution line with automated lateral devices, which effectively operate comparable to small reclosers. Currently, distribution line fuses are designed to open in the event of a fault, resulting in a sustained outage. Line fuses are one-operation devices, meaning that once a fuse interrupts a fault, the fuse melts and must be manually replaced. Most interruptions on the distribution grid are temporary, such as a tree limb falling on a power line before falling to the ground. But due to the use of fuses, those temporary faults often become sustained outages. The new, automated lateral device (ALD) will open during the temporary fault, but then resets and attempts to close and restore power after a short period of time. If the fault source is cleared, power is restored without manual intervention. The ALD is capable of attempting self-restoration multiple times. If the fault source is sustained, the ALD opens to protect the circuit until a manual repair can be completed to the line. Larger reclosing devices on our lines can sense faults downstream of line fuses and typically open and reclose in an attempt to clear faults without a sustained outage. In these instances, a large portion of customers will still experience a momentary outage. By introducing the ALD, in most cases, the remaining customers on the circuit will not see a momentary outage like they typically do today. Historically, lateral devices designed to de-energize and re-energize the line to clear faults without an outage were only available in sizes designed to serve larger load segments of our distribution system. With the availability of ALDs, however, reclosing capability can be applied to smaller segments of the circuit traditionally protected by fuses.

The Fuse Replacement program focuses on segments of the distribution system where line protection is less robust and where it is likely that even a temporary fault will result in a fuse melting and a sustained outage. These upgrades will provide benefits to help reduce both sustained and momentary outages.

Figure 1: The pictures below respresent two possible ALDs that can be used in this program.

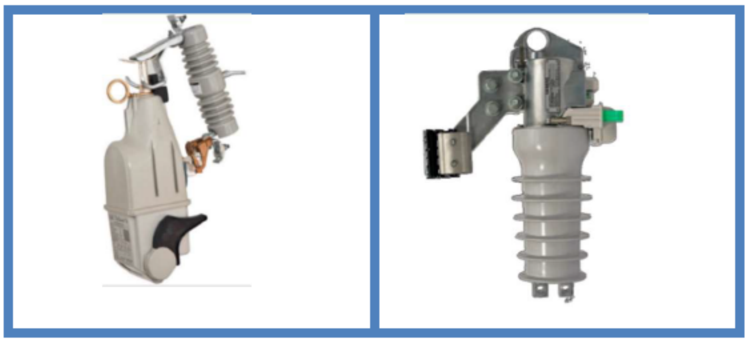
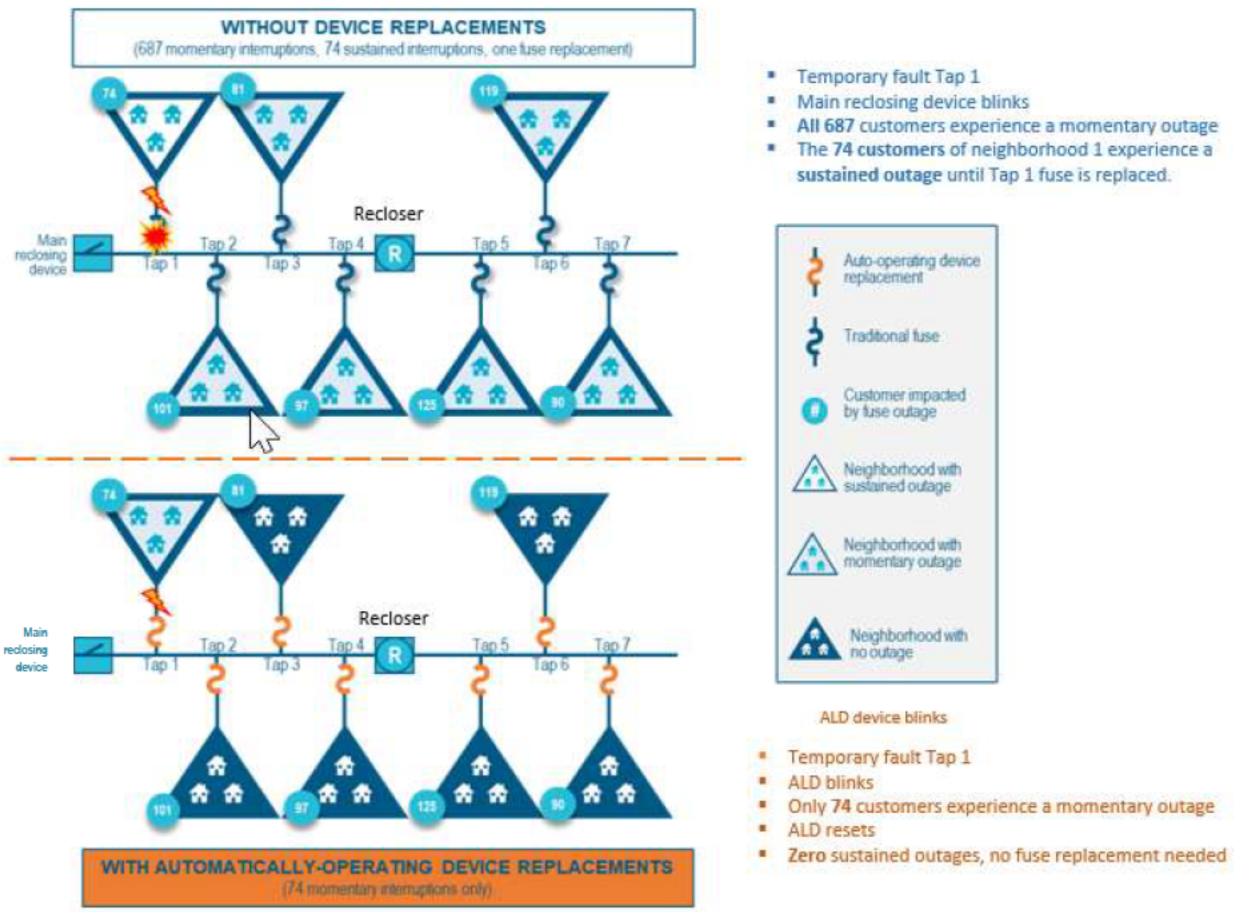


Figure 2: The schematic below represents a pre- and post-program example. Currently, when a fault occurs beyond a fuse, it's possible that the upstream reclosing device blinks affecting many customers plus the fuse melts with a sustained outage. Future state with an automated lateral device, the fault is isolated, affecting only the customers on the lateral/tap with a momentary blink in most cases.


WITHOUT DEVICE REPLACEMENTS
(687 momentary interruptions, 74 sustained interruptions, one fuse replacement)
Recloser
Main reclosing device
Tap 1
Tap 2
Tap 3
Tap 4
Tap 5
Tap 6
Tap 7
74
81
119
101
97
125
90
Temporary fault Tap 1
Main reclosing device blinks
All 687 customers experience a momentary outage
The 74 customers of neighborhood 1 experience a sustained outage until Tap 1 fuse is replaced.
Auto-operating device replacement
Traditional fuse
Customer impacted by fuse outage
Neighborhood with sustained outage
Neighborhood with momentary outage
Neighborhood with no outage
ALD device blinks
Temporary fault Tap 1
ALD blinks
Only 74 customers experience a momentary outage
ALD resets
Zero sustained outages, no fuse replacement needed
WITH AUTOMATICALLY-OPERATING DEVICE REPLACEMENTS
(74 momentary interruptions only)

Projected costs (including capital and O&M expenditure)
Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan ’24-Dec ‘24	Jan ’25-Dec ‘25	Jan ’26-Dec ‘26	Total
Capital costs	$15.0M	$8.1M	$5.3M	**$28.4M**
O&M costs (installation only)	$.3M	$.1M	$.1M	**$.5M**

Grid capabilities enabled	HB951 Policy Considerations addressed
Reliability • Improve resiliency by increasing grid strength and ability to rapidly restore power • Promote DER adoption by providing consistent power flow.	• Encourages DERS • Encourages beneficial electrification, including electric vehicles • Maintains adequate levels of reliability and customer service • Promotes resilience and security of the electric grid

Distribution Automation

Cost Benefit Analysis

Is the Program required by law?
No.

Explanation of need for proposed expenditure
When a fault occurs on a distribution line equipped with traditional fuse protection, the fuse activation typically results in an extended outage for customers until the fuse is manually replaced. The Fuse Replacement program modernizes single-use fuses with devices capable of intelligently resetting themselves for reuse, helping turn a sustained outage into a momentary blink. This smart technology also helps to eliminate unnecessary use of resources (labor, fuel, inventory, etc.) to reset the fuse, helping improve operational efficiency.

Financial Cost-Benefit Analysis	
Total NPV Costs	**$24.9M**
Total NPV Benefits	**$67.0M**
Net value of Program	**$42.1M**
Benefit to Cost Ratio (BCR)	**2.7**

Description of Benefits

Benefit Category	**Description**
Improve reliability and resiliency	Reduction in customer interruptions benefits all customers where applied, including potential critical need customers. Instead of an extended outage, customers now experience only a momentary outage when clearing a temporary fault.

Distribution Hardening & Resiliency: Laterals

Program purpose

This distribution work improves reliability by targeting lateral sections of an overhead power line, also known as tap lines, identified as a risk for failure, which could lead to a disruptive, unplanned outage. Identifying improvement opportunities in advance of an outage provides the opportunity to engage with customers to complete the work in a way that minimizes disruptions and strengthens the grid against unplanned interruptions of service.

Timeline for construction

Refer to the MYRP Project List for project-specific timelines. At the program level, construction is planned from December 2023 to December 2026.

Estimated in-service date

Refer to the MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from January 2024 to December 2026.

Program description

This work is focused on the lateral sections, also known as tap lines, which branch from the main feeder lines and feed neighborhoods, businesses, and commercial/industrial customers. Targeted work is identified through a data-driven approach based on factors such as historical data and observed condition of the line. Risk factors that are considered when identifying candidates for this program are power lines that have a history of prior outages due to deteriorated wire, evidence of prior damage (fraying, multiple splices, pitting etc.), and small wire that has been identified with a steel core that presents a risk of deterioration.

This work includes replacing at-risk steel core conductor with new all-aluminum segments of conductor, which is extremely corrosion resistant, and increasing the size in some cases, to accommodate more load. These improvements will help to improve reliability on the line, deliver a better experience for customers and support the high level of performance needed to grow distributed technologies in the area.

Projected costs (including capital and O&M expenditure)

Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan '24-Dec '24	Jan '25-Dec '25	Jan '26-Dec '26	Total
Capital costs	$70.0M	$135.6M	$230.9M	**$436.5M**
O&M costs (installation only)	$1.3M	$2.5M	$4.2M	**$8.0M**

Grid capabilities enabled	HB951 Policy Considerations addressed
Reliability • Improved resiliency by increasing grid strength and ability to rapidly restore power • Promote DER adoption by providing consistent power flow	• Maintains adequate levels of reliability and customer service • Encourages DER • Encourages beneficial electrification, including electric vehicles.

Distribution Hardening & Resiliency: (Laterals)

Cost Benefit Analysis

Is the program required by law?	
No.	
Explanation of need for proposed expenditure	
Duke Energy has an obligation to provide reliable service to customers in every community that we serve. Proactively replacing and upgrading damaged, deteriorated, or at-risk lateral distribution lines that can lead to unplanned outages is essential for providing safe and reliable service to customers and supports the reliable expansion of distributed resources.	
Financial Cost-Benefit Analysis	
Total NPV Costs	**$361.5M**
Total NPV Benefits	**$898.5M**
Net value of Program	**$536.9M**
Benefit to Cost Ratio (BCR)	**2.5**

Description of Benefits	
Benefit Category	**Description**
Improved reliability	Eliminate the risk of overhead conductor failures by upgrading the size and quality of the wire. This improvement will help increase reliability for customers served by the line.
Improved resiliency	More robust design and construction standards can help to avoid outages, but also help crews restore power faster in these areas. Upgrades that help shorten outages can also free up line and tree crews sooner to help with outage restoration in other areas. Provides a consistent power flow to support DER adoption.
Outage cost avoidance	Fewer and shorter outages resulting from grid strengthening work help avoid recurring trips to the same locations to restore power after severe weather and can also make line and tree crews available faster to assist with power restoration in other areas.
Improved customer experience	Improving the overall reliability of the line, increasing the resiliency of the line, and decreasing restoration times improves the overall customer experience and establishes an operational environment that is more resilient and more conducive to distributed technologies in that area.

Distribution Hardening & Resiliency: Public Interference

Program purpose

This distribution work improves reliability by targeting the company's most outage-prone overhead backbone power line sections that are statistically impacted most by outages and damage from vehicle accidents and other public interference events. Using advanced data analytics, design teams will identify the appropriate hardening and resiliency solution to reduce the number of outages experienced by customers.

Timeline for construction

Refer to the MYRP Project List for project-specific timelines. At the program level, construction is planned from June 2022 to December 2026.

Estimated in-service date

Refer to the MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from February 2024 to December 2026.

Program description

Public interference outages, typically cars hitting overhead power line poles, are outside of the company's control. When these accidents occur, it often results in a long-duration outage due to the severity of the damage caused by the incident. Historical outage data is used to identify the locations where vehicles have been prone to strike poles.

Criteria for consideration in the selection of targeted communities include:

- Service location (i.e., lines must be located on three-phase portions of the circuit)
- Frequency of outages from vehicle accidents

Lines targeted will receive a custom solution which may include undergrounding of the overhead line, relocating the line, or changing the design of the infrastructure at the location of the repeat occurrences.

Projected costs (including capital and O&M expenditure)

Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan '24-Dec '24	Jan '25-Dec '25	Jan '26-Dec '26	Total
Capital costs	$11.8M	$39.7M	$44.6M	**$96.1M**
O&M costs (installation only)	$.2M	$.7M	$.8M	**$1.7M**

Grid capabilities enabled	HB951 Policy Considerations addressed
Reliability: • Improved resiliency by increasing grid strength and ability to rapidly restore power • Promote DER adoption by providing consistent power flow	• Maintains adequate levels of reliability and customer service • Encourages DER • Encourages beneficial electrification, including electric vehicles.

Distribution Hardening & Resiliency: Public Interference

Cost Benefit Analysis

Is the program required by law?	
No.	
Explanation of need for proposed expenditure	
Duke Energy has experienced an increasing number of public interference outages in recent years in many parts of its service area. This Distribution Hardening and Resiliency program will improve overall reliability in locations proven to be vulnerable to outages caused by public interference. Addressing areas with outlier outage performance improves reliability, increases public safety, and lowers maintenance and restoration costs for all customers.	
Financial Cost-Benefit Analysis	
Total NPV Costs	**$80.3M**
Total NPV Benefits	**$99.9M**
Net value of Program	**$19.6M**
Benefit to Cost Ratio (BCR)	**1.2**
Description of Benefits	
Benefit Category	**Description**
Improved reliability	A stronger grid is more resistant to outages from public interference. Reducing the risk of outages on overhead lines improves reliability and provides a better experience for customers.
Improved resiliency	More robust design and construction standards helps avoid outages and reduces the need for crews to return to the same outage-prone areas. Provides stable power flow to support DER adoption.
Outage cost avoidance	Fewer and shorter outages resulting from grid strengthening work helps avoid recurring trips to the same locations to restore power.
Improved customer experience	Improving the overall reliability of the line, increasing the resiliency of the line, and decreasing restoration times improves the overall customer experience and establishes an operational environment that is more conducive to distributed technologies in that area.

Distribution Hardening & Resiliency: Storm

Program purpose

These distribution improvements strengthen the grid in areas vulnerable to severe weather, and in other high-impact areas. Assets will be engineered to better withstand high winds and impacts from snow and ice to help reduce outages and restoration time in areas prone to physical damage during severe storms. Strengthening the grid in these areas improves reliability and can also help free up resources faster to assist with outage restoration in other areas.

Timeline for construction

Refer to the MYRP Project List for project-specific timelines. At the program level, construction is planned from June 2022 to December 2026.

Estimated in-service date

Refer to the MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from January 2024 to December 2026.

Program description

The distribution grid across North Carolina was historically built to withstand the typical weather types that are most commonly experienced in the state (e.g., winter storms, an occasional tropical system, summer afternoon thunderstorms). Increasingly, though, we are seeing a rise in frequency and severity of outages in many parts of the state. This trend can become even more pronounced in areas that are more exposed to these extreme conditions.

Distribution hardening and resiliency improvements are targeted to locations of the distribution grid that have been identified, through analysis of historical outage data, as being more vulnerable to outage impacts from extreme weather events. Examples are poles and wires in heavily vegetated areas that experience impacts from downed trees, or areas where an outage could potentially impact essential services or large numbers of customers for an extended period of time.

Poles and wires in these areas are being replaced with an upgraded, more robust standard that includes larger poles, shorter spans, and additional guy wiring which helps provide a hardened, more reliable grid during extreme weather events. A construction comparable to Grade B & NESC 250B-D loading for solutioning will be applied to the targeted circuit segments. The grades of construction (B/C/N) determine the different safety factors for design, with Grade B providing the highest margin of safety. For example, Grade B is required for spans crossing limited access highways, railroads, and waterways. NESC 250B-D defines required wind and ice loading for design.

Projected costs (including capital and O&M expenditure) *Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC*				
DEC NC	**Jan '24-Dec '24**	**Jan '25-Dec '25**	**Jan '26-Dec '26**	**Total**
Capital costs	$3.4M	$16.3M	$31.6M	**$51.3M**
O&M costs (installation only)	$.06M	$.3M	$.6M	**$.9M**

Grid capabilities enabled	**HB951 Policy Considerations addressed**
Reliability • Improved resiliency by increasing grid strength and ability to rapidly restore power • Promote DER adoption by providing consistent power flow	• Promotes resilience and security of the electric grid • Maintains adequate levels of reliability and customer service • Encourages DERs • Encourages beneficial electrification, including electric vehicles

Distribution Hardening & Resiliency: Storm

Cost Benefit Analysis

Is the program required by law?
No.

Explanation of need for proposed expenditure
Storms have increased in frequency and severity over the last decade. Historical data demonstrates that some areas are more vulnerable to the impacts of outages from severe weather than others. Smart, targeted investments in these areas can help to reduce outage impacts on communities and customers in areas prone to extreme weather and keep essential services available when customers depend on them most.

Financial Cost-Benefit Analysis	
Total NPV Costs	**$41.8M**
Total NPV Benefits	**$167.9M**
Net value of Program	**$126.1M**
Benefit to Cost Ratio (BCR)	**4.0**

Description of Benefits	
Benefit Category	**Description**
Improved reliability	A stronger grid is more resistant to power outages from severe weather. This helps reduce the frequency of long-duration power outages caused by storms.
Improved resiliency	More robust design and construction standards in storm-vulnerable areas can help to avoid outages, but also help crews restore power faster in these areas. Upgrades that help shorten outages can also free up line and tree crews sooner to help with outage restoration in other areas. Provides more stable power flow to support DER adoption.
Outage cost avoidance	Fewer and shorter outages resulting from grid strengthening work helps avoid recurring trips to the same locations to restore power after severe weather and can also make line and tree crews available faster to assist with power restoration in other areas.
Improved customer experience	Improving the overall reliability of the line, increasing the resiliency of the line, and decreasing restoration times improves the overall customer experience and establishes an operational

	environment that is more resilient and more conducive to distributed technologies in that area.

Energy Storage

Program purpose

The Energy Storage program expands Duke Energy's fleet of flexible battery storage systems to enable cleaner energy options. It addresses existing reliability challenges on the distribution system, improving reliability and resiliency by avoiding outages and speeding restoration for groups of distribution customers or single community-critical customers. The program does so while providing benefits to the bulk electric system as it transitions from legacy generation types to more renewable resources in support of the Carbon Plan.

Timeline for construction

Refer to MYRP Project List for project-specific timelines. At the program level, construction is planned from late 2023 through September 2025.

Estimated in-service date

Refer to MYRP Project List for project-specific dates. Initial in-service is expected to occur between June 2024 and September 2025.

Program description

Projected costs (including capital and O&M expenditure)

Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan '24-Dec '24	Jan '25-Dec '25	Jan '26-Dec '26	Total
Reliability	$21M	$55M	$0M	**$76M**
Critical Customer	$7.5M	$0M	$0M	**$7.5M**
Total Capital costs	$28.5M	$55M	$0M	**$83.5M**
O&M Costs (installation only)	$0M	$0M	$0M	**$0M**

Grid capabilities enabled

Reliability

- Promote DER adoption by providing consistent power flow

Capacity

- Promote DER adoption by enabling 2-way power flow capability in more circuits
- Address changing demand by outfitting circuits with capacity to meet increasing load

Automation & Communication

- Promote DER adoption by enabling more efficient resource management

HB951 Policy Considerations addressed

- Encourages utility-scale renewable energy and storage
- Encourages DERs
- Maintains adequate levels of reliability and customer service

Energy Storage

Customer Benefits

Is the Program required by law?	
No. However, standalone battery energy storage is included in the Carbon Plan's near-term action plan, as filed in compliance with the Energy Solutions for North Carolina Act.	
Explanation of need for proposed expenditure	
The Energy Storage program addresses long-standing reliability challenges with cost-effective applications of a maturing technology, while providing benefits to the bulk electric system without construction of new carbon-emitting resources.	
Financial Cost-Benefit Analysis	
Total NPV Costs	**$66.8M**
Total NPV Benefits	**$62.9M**
Net value of Program	**($3.9M)**
Benefit to Cost Ratio	**0.94**

Other Qualitative Benefits	
Benefit	**Description**
Improved Reliability and Resiliency	Reliability microgrids improve service reliability, resulting in saved customer expenses such as spoiled food, lost home office productivity, lost business revenue and backup generator fuel purchase which are a direct result of unplanned utility interruptions caused by vegetation, wildlife, and vehicle accidents.
Basic Services	Reliability microgrids include volunteer fire departments, TV broadcasting stations, cell towers, gas stations, medical practice, schools, and grocery sales. Improving reliability for these customers and reducing service outages increases the safety of the communities they serve.
Solution Scaling	Deployment of multiple reliability microgrid projects builds confidence in microgrids as available "tools in the toolbox" for solving other/future operational and engineering challenges.
Community Safety	Critical customer microgrids help ensure that the continuation of fundamental community services provided by organizations such as hospitals. As such, the benefits created by electric service reliability improvements are enjoyed by a

	large variety and number of customers in the utility service territory.
New Customer Solutions	By deploying early critical customer projects, Duke Energy can continue offering innovative solutions, like microgrids, as options for customers with needs for high electric service reliability and ability to share project costs and benefits.
Sustainability	Benefits to the bulk electric system such as capacity, regulation and contingency reserves have traditionally been performed by carbon-emitting generation resources. Replacing carbon-emitting resources with assets that have nearly zero direct emissions helps reduce emissions and deliver positive environmental benefits to the state.
Interconnection Study Process Improvements	Engineering assessments of the projects' impacts to the existing transmission and distribution systems are constantly being improved across the Carolinas. Challenges solved during execution of these initial projects will enable faster, more efficient, more predictable outcomes when studies are performed for future projects.
Organizational Experience (Design/Ops)	Duke Energy teams in the Carolinas have not yet operated battery energy storage projects at this scale. Battery use cases explored in the DEC MYRP energy storage portfolio will refine future ideation/construction/operation processes and enable more effective designs and more efficient operations when repeated for future similar projects.
Cost-effective implementation	Sourcing of materials and labor for battery engineering, procurement, and construction is more effective when a group of projects can be solicited rather than individual/single projects. A programmatic approach will likely result in better outcomes in terms of cost, material certainty, and schedule predictability. These outcomes can help improve service and deliver cost savings to customers.

Hazard Tree Removal Program

Program purpose

The Vegetation Management Capital Hazard Tree program identifies and takes down dead, structurally unsound, dying, diseased, leaning, or otherwise defective trees from outside the maintained right-of-way that could strike electrical lines or equipment on the distribution system. Reliability is maintained or improved by minimizing interruptions from tree-caused outages.

Timeline for construction

Refer to the MYRP Project List for project-specific timelines. At the program level, work is planned throughout the MYRP period from July 2023 to December 2026.

Estimated in-service date

Refer to the MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from August 2023 to December 2026. This is based on the understanding that vegetation capital blankets are placed in service monthly.

Program description

All hazard trees are identified by a qualified Duke Energy representative per industry best management practices. Any tree found to present an *extreme risk to infrastructure and failure is imminent* is designated for immediate mitigation. A Duke Energy program manager assigns remaining identified trees to a supplier for property owner/customer notification and consent for pending work (for trees in unmaintained areas, tree mitigation may proceed if supplier made a good faith effort to contact owner but was unsuccessful). As schedule and mobilization allows, suppliers cut down trees following property owner/customer notification.

Projected costs (including capital and O&M expenditure)

Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Aug ‘23-Dec ‘24	Jan ’25-Dec ‘25	Jan ’26-Dec ‘26	Total
Capital costs	$35.8M	$21.5M	$19.5M	**$76.8M**
O&M costs (installation only)	$0	$0	$0	**$0**

Grid capabilities enabled	HB951 Policy Considerations addressed
Reliability & Resiliency • Improved reliability through a better protected grid that can better resist vegetation-based outages • Improved resiliency by removal of hazard trees that can cause extensive damage to distribution infrastructure and result in longer outage restorations • Improved power flow consistency and efficiency through fewer vegetation-related outages, which supports the level of reliability needed to promote greater adoption of distributed energy resources	• Encourages DERs • Encourages beneficial electrification, including electric vehicles • Promotes resilience and security of the electric grid • Maintains adequate levels of reliability and customer service

Hazard Tree Removal Program

Customer Benefits

Is the Program required by law?
No.

Explanation of need for proposed expenditure
Trees are one of the leading causes of power outages, and damage to the grid from trees outside of the right-of-way can cause more frequent and longer power outages due to damage these trees can cause. The purpose of the program is to improve reliability by identifying and taking down dead, structurally unsound, dying, diseased, leaning, or otherwise defective trees from outside the maintained right-of-way that could strike electrical lines or equipment of the distribution system. Reliability is improved by minimizing interruptions from tree-caused outages.

Description of Benefits	
Benefit Category	**Description**
Improve reliability and resiliency	Managing trees and other vegetation to improve reliability and make the grid more resistant to vegetation-related outages.

Infrastructure Integrity

Program purpose
The Infrastructure Integrity program seeks to continually improve and ensure a safe and reliable electrical energy delivery system through identification and mitigation of risk factors such as end-of-service equipment, technology obsolescence, and removal of damaged in-service distribution equipment such as capacitors, regulators, reclosers, and other line equipment. Proactively identifying and planning these improvement opportunities can minimize impacts to customers, turn potential emergency outage response into a planned replacement, strengthen the overall grid against unplanned interruptions of service, and support the increased grid capabilities being implemented to promote DER adoption.
Timeline for construction
Refer to the MYRP Project List for project-specific timelines. At the program level, construction is planned from December 2020 to December 2026.
Estimated in-service date
Refer to the MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from January 2024 to December 2026.
Program description
As more automation is added to the system from grid improvements to improve reliability and support DER, the historical system integrity norms are changing to consider the dependency of distribution customer reliability on two-way power flow. Programs that were historically in place to address known risk factors are now evolving to support more devices on the system, changes in device operations due to power intermittency, and newer technologies that deliver new capabilities and challenges for the grid. Examples of infrastructure integrity work include: • Asset replacement – Inspection-based programs including poles. • Oil mitigation – hydraulic-to-solid dielectric replacement, and replacement of live-front/end-of-life transformers. • Greenhouse gas mitigation – replacement of SF6 switchgear with solid dielectric. • Technological obsolescence – replacement of recloser control panels nearing end of life. • System operability to serve dynamic power flows – replacing non-communicating hydraulic reclosers with new remote-accessible solid dielectric units. • Major outage root cause studies. This work coincides with other distribution improvement work scheduled at the substation or circuit to optimize crew travel, maximize switching procedure utilization, and improve traffic control zone utilization.

Projected costs (including capital and O&M expenditure)
Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan '24-Dec '24	Jan '25-Dec '25	Jan '26-Dec '26	Total
Capital costs	222.9M	$121.5M	$103M	**$447.4M**
O&M costs (installation only)	$4M	$2.2M	$1.9M	**$8.1M**

Grid capabilities enabled	HB951 Policy Considerations addressed
Reliability • Improve resiliency by increasing grid strength and ability to rapidly restore power • Promote DER adoption by providing consistent power flow	• Encourages DERs • Encourages beneficial electrification, including electric vehicles • Promotes resilience and security of the electric grid • Maintains adequate levels of reliability and customer service

Infrastructure Integrity

Customer Benefits

Is the program required by law?
No.

Explanation of need for proposed expenditure
Equipment that is damaged or nearing its end of service is at a higher risk of failure that could lead to an extended power outage. Proactively upgrading or replacing at-risk distribution equipment is a key step to delivering the power quality and service that customers expect. These infrastructure integrity improvements also support changing customer expectations and will ultimately enhance access to cleaner renewable energy resources on the grid.

Benefits created for customers	
Benefit	**Description**
Improved reliability	Sustaining the integrity of the infrastructure through data-informed replacements will lead to a more reliable power quality experience for customers.
Improved resiliency	Sustaining infrastructure integrity makes it easier to troubleshoot outages and restore service quicker.
Improve the customer experience	Coordinating infrastructure improvements with other planned work helps optimize crew travel, maximizes planned outage and switching procedures, and improves traffic control zone utilization on substation projects.

Integrated Volt VAR Control (IVVC)

Program purpose
Integrated Volt-Var Control (IVVC) establishes control of distribution equipment in substations and on distribution lines to optimize delivery voltages and power factors on the distribution grid. DEC will dynamically operate IVVC in the form of Conservation Voltage Reduction (CVR) which reduces energy (MWh's) and saves fuel, while reducing Duke Energy's carbon footprint. By installing modern sensing and control devices, as well as integrating them into the Distribution Management System, IVVC helps improve distribution system operational efficiency.
Timeline for construction
Refer to the MYRP Project List for project-specific timelines. At the program level, construction is planned from February 2024 to December 2026.
Estimated in-service date
Refer to MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from August 2024 to December 2026
Program description
Integrated Voltage/VAR Control (IVVC) is the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid. This allows the distribution system to operate as efficiently as possible without violating load and voltage constraints, while supporting the reactive power needs of the bulk power system. Historically, communication with and control of substation voltage regulation, substation capacitors, and distribution line voltage regulators on the DEC system is minimal. Additionally, distribution line capacitors have had communications, but not remote-control capabilities. The IVVC program installs communications and control infrastructure including substation voltage regulator control replacement, substation capacitor control replacement, distribution line voltage regulator control replacement, distribution line capacitor replacement, medium voltage sensors, and two-way communications implementation into these substation and distribution line devices. New distribution line voltage regulator and capacitor additions are installed where necessary. A conceptual view of IVVC is presented below in **Figure 1**.

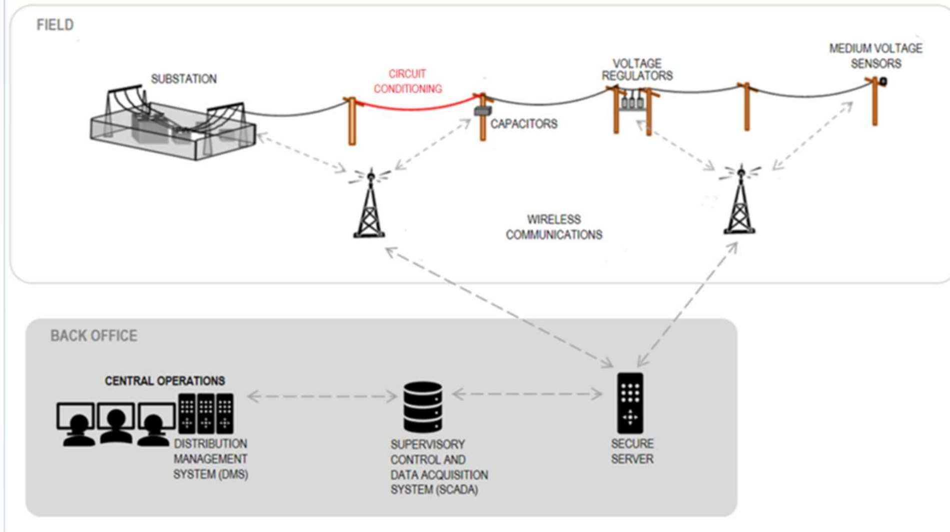


Figure 1: Conceptual View of Integrated Volt/VAR Control (IVVC).

IVVC can dynamically optimize the control of substation and distribution devices, resulting in a flattening of the voltage profile across an entire circuit, starting at the substation and continuing out to the farthest endpoint on that circuit. This flattening of the voltage profile is accomplished by circuit conditioning, such as phase balancing, and by integrating substation and distribution line voltage regulators and capacitors into the Distribution Management System (DMS), with two-way communications, automating their operation. The DMS continuously monitors the conditions on the controlled circuits and maintains the desired voltage profile. Once the system is operating with a relatively flat voltage profile across an entire circuit, the resulting circuit voltage at the substation can then be operated at a lower overall level. Lowering the circuit voltage, through conservation voltage reduction (CVR), at the substation results in a reduction of system loading, creating the benefit of decreased generation. CVR supports voltage reduction and energy conservation. This provides fuel savings to customers and reduced emissions from the avoided generation.

IVVC provides increased visibility into the status and condition of substation and field devices such as capacitor banks, voltage regulators, and transformer load-tap changers. This added visibility and enhanced voltage control will help manage the integration of distributed energy resources (i.e., solar) by providing foundational capability to respond to intermittency.

DEC's 2024-2026 MYRP includes circuits that will receive both VRM and IVVC improvements. Technologies implemented in VRM further enhance IVVC by extending optimized Volt/VAR control into supporting greater DER integration. When developing IVVC/VRM scopes, DEC will make sure that IVVC and VRM circuit work is truly complementary and not redundant. This will be accomplished by conducting the IVVC and VRM analysis sequentially and combining the implementation scopes at the circuit level.

Projected costs (including capital and O&M expenditure)
Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan '24-Dec '24	Jan '25-Dec '25	Jan '26-Dec '26	Total
Capital costs	$25.5M	$37.2M	$33.6M	**$96.3M**
O&M costs (installation only)	$.5M	$.7M	$.6M	**$1.8M**

Grid capabilities enabled	HB951 Policy Considerations addressed
Voltage Regulation • More efficient grid due to lower line losses and reduced reactive power • Less generation fuel consumed and lower emissions due to grid efficiencies • Integrated control of capacitor banks provides greater ability to reduce reactive power, resulting in less apparent load on the system • Optimized control of volt/VAR devices provides foundational capability to respond to intermittency	• Encourages peak load reduction or efficient use of the system • Encourages utility-scale renewable energy and storage • Encourages DERs • Encourages beneficial electrification, including electric vehicles • Promotes resilience and updated security of the electric grid • Maintains adequate levels of reliability and customer service

Integrated Voltage Var Control

Cost Benefit Analysis

Is the Program required by law?	
No.	
Explanation of need for proposed expenditure	
Conservation Voltage Reduction (CVR) supports voltage reduction and energy conservation. IVVC can dynamically optimize the control of substation and distribution devices, enabling distribution system to operate in CVR mode, that results in a reduction of system loading, creating the benefit of decreased generation. This provides fuel savings to customers and reduced emissions from the avoided generation. The IVVC program deploys technology that enables CVR mode, and installs devices that improve power quality to all customers by helping maintain voltage levels within acceptable ANSI standard voltage limitations as the load changes with future increased penetrations of DER.	
Financial Cost-Benefit Analysis	
Total NPV Costs	**$540.2M**
Total NPV Benefits	**$842.6M**
Net value of Program	**$302.4M**
Benefit to Cost Ratio (BCR)	**1.6**

Description of Benefits

Benefit Category	**Description**
Fuel Savings	IVVC reduces energy (MWh's) consumptions and saves fuel. Fuel savings are passed directly to customers.
Carbon reduction	Lower carbon emissions from reduced generation due to reduced energy (MWh's) consumption and improved grid efficiencies.
Improves voltage experience for customers	Integrated Volt/VAR Control maintains proper voltage levels to customers by keeping voltages in the proper range.
Expands solar and renewables	Optimized control of Volt/VAR devices improves the grid's ability to respond to intermittency
Improve Grid Efficiency	More efficient grid due to lower line losses and reduced reactive power. Integrated sensing and control deployed in IVVC helps improve distribution system operation efficiency.

Long Duration Interruption

Program purpose
This distribution work relocates segments of main overhead feeder lines in hard-to-access areas to improve accessibility for utility trucks. Improving crew accessibility reduces restoration time for outages in difficult to reach areas and increases worker safety. Moving these line segments to road-accessible locations that are more easily maintained can also help reduce the risk of an outage, improving overall reliability for customers in these areas and can also help free up resources faster to assist with outage restoration in other areas.

Timeline for construction
Refer to the MYRP Project List for project-specific timelines. At the program level, construction is planned from July 2022 to December 2026.

Estimated in-service date
Refer to the MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from January 2024 to December 2026.

Program description
Targeted areas for this program are radial distribution lines that serve entire communities or large groups of customers, as well as inaccessible line segments (i.e., off road, swamps, mountain gorges, extreme terrain, etc.). The areas targeted for improvement experience consistently higher-than-average outage durations and reduced power reliability and customer satisfaction. During extreme weather events, vegetation, erosion, and flooding can create challenges and potentially unsafe conditions for restoration crews trying to restore power, resulting in longer outage times. Addressing these challenges typically involves relocating the lines to road fronts which may require more line miles. Road accessibility helps improve the customer experience and provides positive benefits to the overall power restoration process as it allows more efficient access to lines and equipment from the road right of way.

Projected costs (including capital and O&M expenditure)
Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	**Jan '24-Dec '24**	**Jan '25-Dec '25**	**Jan '26-Dec '26**	**Total**
Capital costs	$6.4M	$5.0M	$11.7M	**$23.1M**
O&M costs (installation only)	$.2M	$.2M	$.4M	**$.8M**

Grid capabilities enabled	HB951 Policy Considerations addressed
Reliability • Improved resiliency by increasing grid strength and ability to rapidly restore power • Promote DER adoption by providing consistent power flow	• Promotes resilience and security of the electric grid • Maintains high levels of reliability and improves customer service • Encourages DERs • Encourages beneficial electrification, including electric vehicles.

Long Duration Interruption

Cost Benefit Analysis

Is the program required by law?
No.

Explanation of need for proposed expenditure
Power restoration is more challenging in hard-to-reach areas when outages occur, creating a potential for longer restorations and increased outage time. Long-duration outages have a negative impact on overall system reliability and customer satisfaction. This challenge is increasingly true as more customers work and attend school remotely and rely on electricity for daily functional and productivity needs. The lines targeted for this long-duration interruption improvement are experiencing above-average outage durations that would benefit from relocating the line to an area more accessible by utility trucks and crews.

Financial Cost-Benefit Analysis	
Total NPV Costs	**$19.7M**
Total NPV Benefits	**$320.2M**
Net value of Program	**$300.5M**
Benefit to Cost Ratio (BCR)	**16.3**

Description of Benefits	
Benefit Category	**Description**
Improved reliability	Strategically relocating outage-prone line segments to more accessible and maintainable locations helps reduce outage risk.
Improved resilience	Relocating the feeder segment to a more accessible and maintainable right of way helps improve resiliency by reducing outages and promoting faster responses when outages do occur.
Reduced outage costs	Relocating these feeder segments from hard-to-reach locations to more maintainable areas helps reduce outages and avoids the need for more specialized and expensive equipment and crew labor needed to repair outages.
Improved customer experience	Improving the overall reliability of the line, increasing the resiliency of the line, and decreasing restoration times improve the overall customer experience and establishes an operational environment that is more resilient and more conducive to distributed technologies in that area.

Self-Optimizing Grid

Program purpose
The Self-Optimizing Grid (SOG) program, also known as the smart-thinking grid, redesigns key portions of the distribution system and transforms it into a dynamic self-healing network to improve system reliability and resiliency, restore outages faster, and manage the dynamic two-way power flows that expansion of distributed energy resources (DER) will bring.
Timeline for construction
Refer to the MYRP Project List for project-specific timelines. At the program level, construction is planned from December 2020 to December 2026.
Estimated in-service date
Refer to the MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from January 2024 to December 2026.
Program description
SOG uses self-healing technology to improve grid reliability and resiliency. To detect potential faults in real time, the system uses sensors, switches, and controls. The self-healing system can automatically detect power outages, quickly isolate the problem, and reroute power to restore service to customers as quickly as possible. This smart, self-healing technology can reduce the number of customers affected by an outage by up to 75% and can often restore power in less than a minute. This system can even detect issues before a customer reports a power outage. The SOG work executed during the three-year MYRP is expected to save annually, 127,000 customer interruptions (CI) and over 25 million customer minutes interrupted (CMI). The SOG program converts circuits into switchable segments in order to minimize the number of customers affected by sustained outages, expands the capacity to support an integrated grid, and ensures the necessary connectivity to allow for rerouting options. The added capacity, smart switching capability, and connectivity necessary for SOG also enables the two-way power flow needed to support more rooftop solar, battery storage, electric vehicles, and microgrids – technologies that will increasingly power the lives of customers and move the state of North Carolina towards a cleaner energy future for all customers. The SOG program consists of three (3) major components: capacity, connectivity, and automation. **SOG Capacity** focuses on expanding substation and distribution line capacity to allow for two-way power flow. Increased line capacity through the SOG program reduces line losses and enables DER hosting capabilities. **SOG Connectivity** creates tie points between circuits to allow two-way power flow for automatic reconfiguration. **SOG Automation** provides intelligence and control for the Self-Optimizing Grid. Automation projects enable the grid to dynamically reconfigure around trouble and better manage local DER.

Figure 1

Figure 1 shows a Smart Grid system that is composed of intelligent equipment, advanced communication equipment, and distributed energy resources. The figure shows two distribution circuits which are fully optimized that allow power to be fully rerouted in the event of an outage.

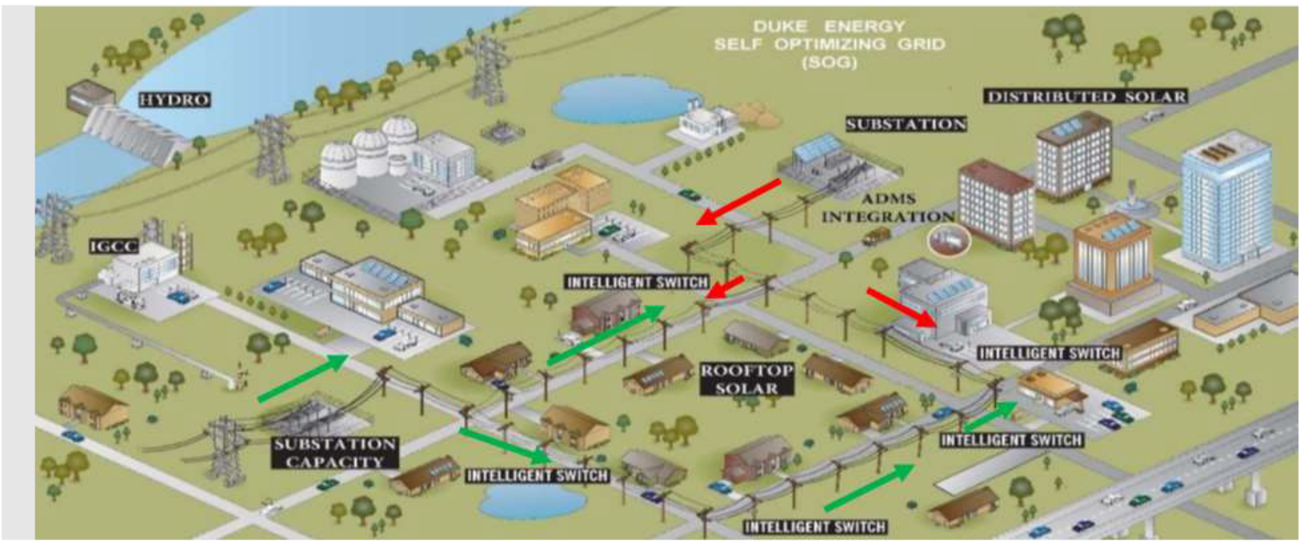


Figure 2

Figure 2 demonstrates how most current state circuits have line segments with a high customer count and do not have two-way power flow capabilities. Therefore, a system fault that results in an outage can impact many customers.

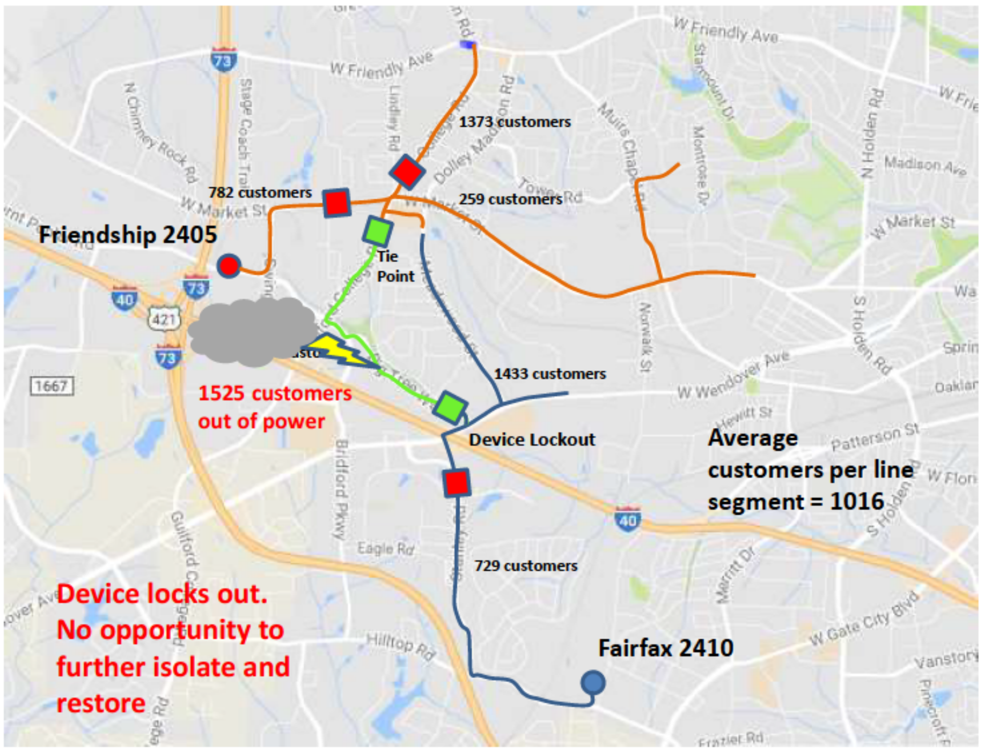
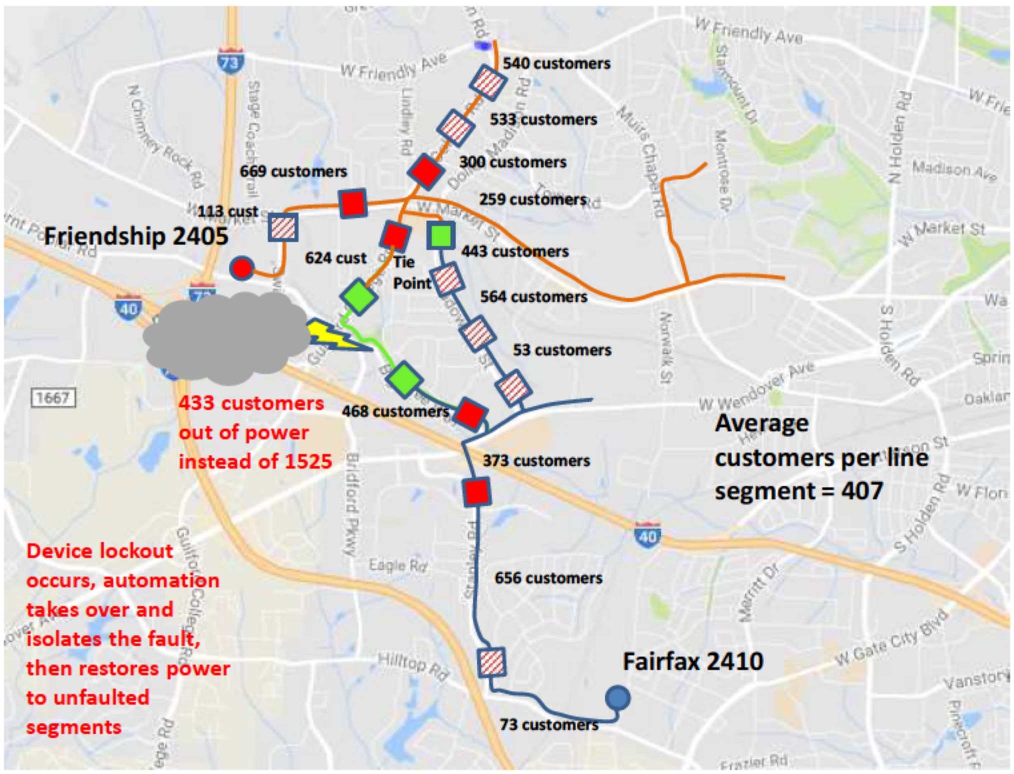


Figure 3

Figure 3 demonstrates the future state under the SOG program in which a circuit with additional segmentation devices and interconnectivity to adjacent circuits allows the system to isolate faults to a small portion of the circuit while all other customers do not experience an outage.



Projected costs (including capital and O&M expenditure)

Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan '24-Dec '24	Jan '25-Dec '25	Jan '26-Dec '26	Total
Capital costs	$127.8M	$58.4M	$84.6M	**$270.8M**
O&M costs (installation only)	$1.8M	$.8M	$1.2M	**$3.8M**

Grid capabilities enabled

Reliability

- Improve resiliency to increase grid strength and ability to rapidly restore power

Capacity

- Promote DER adoption by enabling 2-way power flow capability in more circuits
- Address changing demand by outfitting circuits with capacity to meet increasing load

Automation & Communication

- Improve resiliency by detecting faults and rerouting power to self-heal, reducing impact from outages
- Promote DER adoption by enabling more efficient resource management

HB951 Policy Considerations addressed

- Encourages DERs
- Encourages beneficial electrification, including electric vehicles
- Promotes resilience and security of the electric grid
- Maintains adequate levels of reliability and customer service

Self-Optimizing Grid

Cost Benefit Analysis

Is the Program required by law?		
No.		
Explanation of need for proposed expenditure		
The current grid has limited ability to reroute or rapidly restore power, and limited ability to optimize for the growing penetrations of distributed energy resources (DER). The SOG program was established to foundationally address both issues. This smart-thinking grid technology functions as an integrated network with increased capacity, automated switching capabilities and support for two-way power flow. SOG can help to reduce outage impacts, improve reliability and resiliency, and enhance the customer experience. The deployment of SOG brings additional benefits including improved line efficiency along with DER and EV readiness.		
Financial Cost-Benefit Analysis		
Total NPV Costs		**$238.4M**
Total NPV Benefits		**$1,348.5M**
Net value of Program		**$1,110.1M**
Benefit to Cost Ratio (BCR)		**5.7**
Description of Benefits		
Benefit Category	**Description**	
Improve reliability and resiliency	SOG creates a network of interconnected circuits that are split into smaller automatically switchable segments that can isolate faults and reconfigure to greatly reduce the number of customers affected by sustained outages. The program also reduces the number of outages, decreases the duration of outages when they do occur, and helps restore power in a matter of minutes.	
Expand solar and renewables	SOG creates a network of interconnected circuits with more capacity and support for two-way power flow which accommodates more renewable energy resources.	

Targeted Undergrounding

Program purpose

The Targeted Undergrounding (TUG) program improves reliability by strategically identifying the company's most outage prone overhead power line sections and relocating them underground to reduce the number of outages experienced by customers.

Timeline for construction

Refer to the MYRP Project List for project-specific timelines. At the program level, construction is planned from October 2021 to December 2026.

Estimated in-service date

Refer to the MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from January 2024 to December 2026.

Program description

This program uses data analytics to identify overhead line segments with an unusually high frequency of historical outages and places those segments underground.

Criteria for consideration and selection of targeted communities includes:

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

Projected costs (including capital and O&M expenditure)

Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan '24-Dec '24	Jan '25-Dec '25	Jan '26-Dec '26	Total
Capital costs	$38.4M	$67.1M	$88.2M	**193.7M**
O&M costs (installation only)	$.02M	$.05M	$.06M	**$.1M**

Grid capabilities enabled

Reliability

- Improved resiliency by increasing grid strength and ability to rapidly restore power
- Promote DER adoption by providing consistent power flow

HB951 Policy Considerations addressed

- Encourages DERs
- Encourages beneficial electrification, including electric vehicles
- Promotes resilience and security of the electric grid
- Maintains adequate levels of reliability and customer service

Targeted Undergrounding

Cost Benefit Analysis

Is the program required by law?
No.

Explanation of need for proposed expenditure
While the overall electric grid is very reliable, some segments of overhead power lines experience an unusually high number of outages, resulting in decreased customer satisfaction. When these segments of lines fail, they cause problems for customers directly served by them as well as customers upstream. Lines targeted to be moved underground are typically the most resource-intensive parts of the grid to repair after a major storm. Due to the frequent interruptions, equipment on these line segments can experience shortened equipment life and additional equipment-related service interruptions by being exposed to the frequent overcurrent from the faults. The TUG program eliminates exposure to the elements that commonly cause outage events on the overhead portion of the grid. Converting overhead outage prone parts of the system to underground enables us to restore service more quickly and cost effectively for all customers. Addressing areas with outlier outage performance improves service while lowering maintenance and restoration costs for all customers.

Financial cost-benefit analysis	
Total NPV Costs	**$159.1M**
Total NPV Benefits	**$487.0M**
Net value of Program	**$327.9M**
Benefit to Cost Ratio (BCR)	**3.1**

Description of Benefits	
Benefit Category	**Description**
Improved reliability	By undergrounding the overhead wires, the exposure to failures above ground will be eliminated and will lead to an improved reliability experience for customers on that line.
Improved resiliency	Improved system resiliency by reducing repeated trips to the same line segments during storms and outage events, freeing up resources faster to restore power to other customers. Provides stable flow for DER adoption.
Reduced outage costs	Overhead conductor that is converted to underground will not require vegetation maintenance costs to maintain the right of way.

Improved customer experience	Improving the overall reliability of the line, increasing the resiliency of the line, and decreasing restoration times improves the overall customer experience and establishes an operational environment that is more resilient and more conducive to distributed technologies in that area.

Voltage Regulation & Management

Program purpose
The Voltage Regulation and Management (VRM) improvement program will modernize the grid by installing devices that will improve voltage management and power quality for all customers, while supporting the growth of distributed energy resources (DER).
Timeline for construction
Refer to the MYRP Project List for project-specific timelines. At the program level, construction is planned from February 2024 to December 2026.
Estimated in-service date
Refer to MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from August 2024 to December 2026.
Program description
Currently, the electrical distribution systems are designed and operated based on the assumption of centralized generation, with one-way power flow from the distribution substation to end-use customers. With the increasing penetration of DERs, reverse power flow could occur through the distribution system. Significant reverse power flow may cause operational issues for the distribution system, including over-voltage on the distribution feeder. This program establishes control of equipment on the distribution grid to optimize delivery voltages to customers and to prepare for two-way power flows on the grid. The Voltage Regulation Management (VRM) program will improve the grid's ability to address intermittency and fluctuations caused by DERs and to enable DER adoption and improve power quality to customers. There are three levels of the VRM program that will be applied to circuits depending on the projected level of DER penetration (informed by Integrated System Operations Planning (ISOP) and Morecast data) on the circuit. These projects range from minor equipment for circuits with light forecasted DER penetration to major equipment for circuits with heavier forecasted DER penetration. The first level will install voltage regulators on circuits, which help maintain a constant voltage level to create more "regulation zones". These zones improve the voltage management on the circuit by addressing high-end voltage conditions and reducing intermittency caused by solar DER sites. This also improves power quality for customers by maintaining voltage levels within ANSI standard voltage limits. These regulators will have new modernized microprocessor-based controls capable of two-way power flow and communications for remote monitoring, control, and data acquisition, as well as integration to the centralized Distribution Management System. The number of regulators being installed on a circuit will be proportional to the forecasted DER enablement on the circuit. For example, in **Figure 1** below, two new line voltage regulators (the yellow dots) are installed to create three voltage regulation zones.

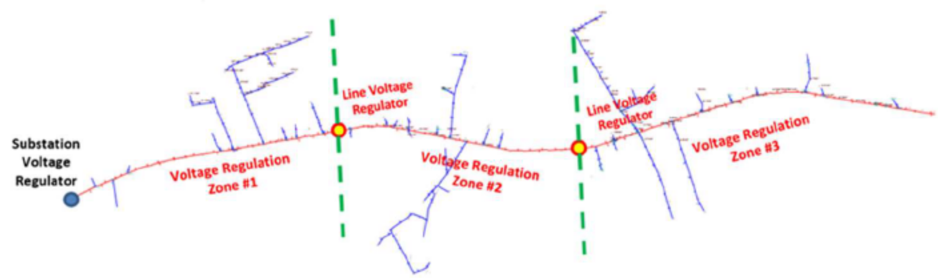


Figure 1: Illustration of voltage "Regulation Zones" on an example circuit (*for conceptual purposes only*).

The second level of the VRM program will install new distribution line capacitors on circuits. The capacitors will help improve voltage management and allow electricity to be distributed more efficiently across the distribution circuits by automatically adjusting the reactive power on the circuits. Capacitors complement the voltage regulators and help maintain the proper voltage levels for customers in each regulation zone. The capacitors will also be equipped with digital microprocessor-based controls capable of two-way communications to the centralized Distribution Management System. Real time communications to the capacitors will ensure the devices are operating properly under all load conditions. The controls will provide remote operation and monitoring functionality that will improve power quality to customers. Sensors will be installed at each new capacitor bank to continuously monitor the flow of power. The sensors can also provide real-time fault detection and location information.

Level 3 includes higher levels of DER penetration will require more specialized equipment like power electronic devices to handle the large and rapid voltage fluctuations that come with intermittent sunshine caused by cloud movement. These devices better equip the distribution system to manage power quality issues associated with increasing DER penetration. Power electronics devices also reduce voltage regulator and capacitor operations on a distribution circuit with high levels of DER.

The current system is limited in its ability to manage and integrate DERs. Investments in VRM will help transition the current grid to the grid of the future with two-way power flow capabilities. As distributed energy resources, such as rooftop solar and electric vehicles, reach deeper levels of penetration, it is essential to automatically manage and maintain proper voltage levels for customers. The implementation of modern, advanced voltage regulators, capacitors, and power electronic technologies based on ISOP modeling of customer DER growth enables effective voltage management under dynamic conditions and keeps pace with customer expectations.

In DEC, MYRP 2024-2026 includes circuits that will receive both VRM and IVVC improvements. Technologies implemented in VRM further enhance IVVC by extending optimized Volt/VAR control into supporting greater DER integration. When developing IVVC/VRM scopes, Duke Energy will make sure that IVVC and VRM circuit work is truly complementary and not redundant . This will be accomplished by doing the IVVC and VRM analysis sequentially and combining the implementation scopes at the circuit level.

Projected costs (including capital and O&M expenditure)
Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan '24-Dec '24	Jan '25-Dec '25	Jan '26-Dec '26	Total
Capital costs	$26.2M	$40.6M	$32.9M	**$99.7M**
O&M costs (installation only)	$.5M	$.8M	$.6M	**$1.9M**

Grid capabilities enabled	HB951 Policy Considerations addressed
Voltage Regulation • Promote DER adoption by regulating and stabilizing voltage levels to protect customers from disruptive supply spikes or sags • Improve resiliency by reducing intermittency / fluctuations from DER power supply	• Encourages peak load reduction or efficient use of the system • Encourages utility-scale renewable energy and storage • Encourages DERs • Encourages beneficial electrification, including electric vehicles • Promotes resilience and updated security of the electric grid • Maintains adequate levels of reliability and customer service

Voltage Regulation & Management

Customer Benefits

Is the Program required by law?	
No.	
Explanation of need for proposed expenditure	
Distributed Energy Resources (DER) and electric vehicles (EV) are expected to have a significant impact on the distribution system around voltage and reactive power (VAR) support. The distribution system is rapidly becoming more dynamic with two-way power flows driving the need for additional VAR and voltage management capabilities, compared to the current state. The Voltage Regulation and Management Program will modernize the grid and improve voltage management to customers based on the predicted DER penetration for each circuit, with the goal of being proactive instead of reactive. A programmatic approach to place devices will be effective for voltage and Var support. Optimized control of Volt/Var devices improves the grid's ability to respond to intermittency. The devices installed in this program will improve power quality to all customers by helping maintain voltage levels within acceptable ANSI standard voltage limitations as the load changes with future increased penetrations of DER.	
Benefits created for customers	
Benefit	**Description**
Improves voltage experience for customers	Advanced technologies help maintain proper voltage levels to customers by keeping voltages in the proper range. Additionally, integrating advanced equipment on the grid helps reduce power quality issues associated with increasing DER penetration.
Expands solar and renewables	Increasing the level of distributed energy resources that can be accommodated on the distribution grid reduces the need to curtail or issue moratoriums on customer-owned interconnections.
Gives customers more options and control	Increasing the grid's ability to integrate more renewables and electric vehicles provides customers more options to meet their individual needs.
Transforms the grid to prepare for a cleaner, lower-carbon future	Technologies that enable two-way power flows for increased DER on the grid will allow more customers to interconnect clean forms of renewable generation. This capability helps North Carolina continue to be

	attractive to businesses with environmental commitments.

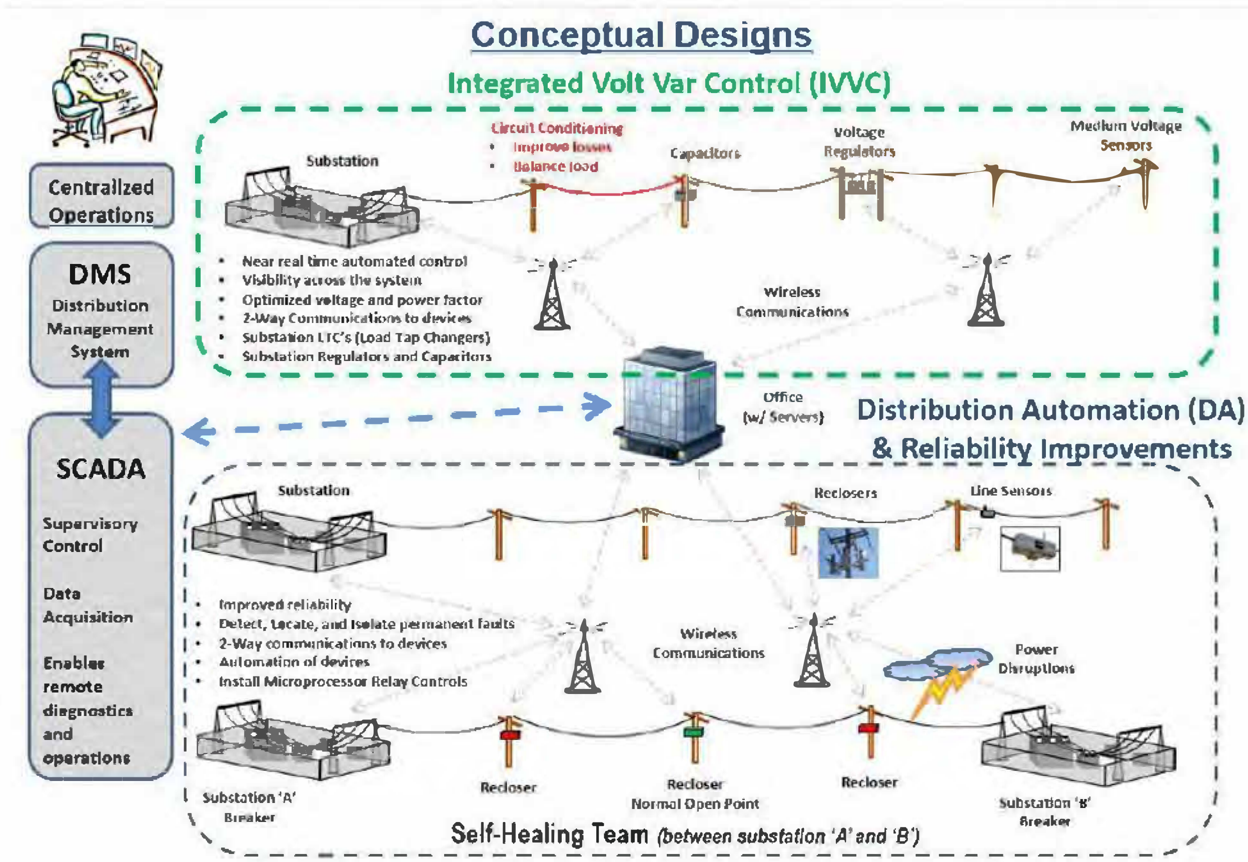
Distribution Program Summaries
Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Table of Contents

Advanced Distribution Management System (ADMS)

Project purpose
The Advanced Distribution Management System (ADMS) program is deploying a single software platform that will consolidate the existing Outage Management System (OMS), Distribution Management System (DMS) and Supervisory Control and Data Acquisition (SCADA) System. The platform allows grid operators to perform control room functions from a single application rather than multiple applications from different vendors, allowing operators to monitor grid performance and manage outages from a single pane. Operators will also be able to use the consolidated platform to perform switching operations, manage Integrated Volt/Var Control (IVVC) and troubleshoot field devices. The ADMS will also provide a smart foundation that can support advanced capabilities such as Closed Loop Fault Isolation and Service Restoration (CLFISR), Advanced Fault Location (AFL), Conservation Voltage Reduction (CVR), and Distributed Energy Resources (DER) dispatch.
Timeline for construction
Refer to MYRP Project List for project-specific timelines. At the program level, construction is planned from July 2022 to March of 2024.
Estimated in-service date
Refer to MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from December 2024 to March 2026.
Project description
The **Advanced Distribution Management System (ADMS)** is the centralized distribution monitoring and control system that harnesses information from across the grid to increase automation, optimize system performance and improve reliability for customers. This smart system orchestrates and manages technologies such as Self-Optimizing Grid (SOG) automation projects, smart switches, and distributed energy resources. The ADMS project consolidates existing SCADA, DMS and OMS systems into a single platform to improve operational efficiency and flexibility by standardizing grid operations, increasing situational awareness and control through real-time data from thousands of points across the grid, providing improved IT system reliability, and reducing human performance risk. The ADMS system also provides the ability to manage voltage in near real time to optimize the grid and support the two-way power flows needed to enable more renewables and distributed resources. ADMS supports a variety of current and future capabilities, including: **Closed Loop Fault Isolation and Service Restoration (CLFISR)** minimizes outage impacts by automatically identifying a fault and selecting a switching plan to isolate the fault and restore power to as many customers as possible in moments. Like other advanced applications, this self-healing

system relies on an accurate digital model of the grid to support analyses and quickly evaluate solutions to restore service to customers.



Distribution System Demand Response (DSDR) conversion to Continuous Voltage Reduction (CVR) mode -
In 2014, Duke Energy Progress implemented Distribution System Demand Response (DSDR) to achieve peak voltage reduction across the utility's distribution system. Because the substation, distribution, telecommunications, and IT infrastructure were put in place as part of the original DSDR implementation, the current project focuses on the distribution management upgrades required to support various operational modes, including the current DSDR mode and CVR mode, as well as Self-optimizing Grid and other distribution automation capabilities. Through this project, the company will enable an approximate 2% distribution system voltage reduction resulting in energy conservation that translates into an approximate 400,000 Mwh annual reduction.

Automatic Fault Location (AFL) uses smart devices on the grid to more precisely locate faults, such as a tree or tree limb, on a line. The project will upgrade distribution management capabilities to analyze grid device data in real time and provide more accurate fault locations to direct crews and restore power faster.

The **DER Dispatch** project will deliver new software and processes to help operators monitor and manage transmission and distribution-connected distributed resources such as solar and battery storage. Current processes and tools only provide operators with a rudimentary ability to shed large blocks of solar generation in emergency conditions to meet power control reliability standards. The proposed solution will account for energy delivered by each DER location, track curtailments, and balance energy management from these resources based on economic, contractual, and other considerations. Improving the way these resources are managed will help support more distributed resources at both the distribution and bulk power level, provide better communications to suppliers, and deliver cleaner options and lower carbon solutions to customers.

Projected costs (including capital and O&M expenditure)
Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan '24 – Dec '24	Jan '25 – Dec '25	Jan '26 – Dec '26	Total
Capital costs	$82.6M	$21.1M	-	**$103.7M**
O&M costs (installation only)	$.4M	$.2M	-	**$.6M**

Grid capabilities enabled	HB951 Policy Considerations addressed
Reliability: • Promote DER adoption by providing consistent power flow *Automation & Communication* • Improve resiliency by detecting faults and rerouting power to self-heal, reducing impact from outages • Promote DER adoption by enabling more efficient resource management *Voltage Regulation* • Promote DER adoption by optimizing voltage levels to protect customers from disruptive supply spikes or sags • Improve resiliency by reducing intermittency / fluctuations from DER power supply *Capacity* • Promote DER adoption by enabling two-way power flow capability in more circuits	• Encourages peak load reduction or efficient use of the system • Encourages utility-scale renewable energy and storage • Encourages DERs • Encourages beneficial electrification, including electric vehicles • Promotes resilience and security of the electric grid • Maintains adequate levels of reliability and customer service • Promotes rate designs that yield peak load reduction or beneficial load-shaping

DUKE ENERGY.

Advanced Distribution Management System (ADMS)
Customer Benefits

Is the project / program required by law?
No

Explanation of need for proposed expenditure
Resiliency improvements and infrastructure support for cleaner energy options and distributed technology will depend heavily on smart monitoring and control technologies to support his dynamic and increasingly automated grid. The ADMS system can manage data from 1.2 million data points, analyze that data and control devices in the field to support self-healing outage restoration, manage battery storage and distributed technologies, and actively manage renewable energy systems on the grid. The increased situational awareness and automation capabilities the ADMS brings will help to avoid or shorten outage time; locate faults and power quality issues on the system faster; better protect the grid from potential threats and suspicious activity; and enable faster responses to incidents like animal interference, cars hitting poles and other public activities.

Benefits created for customers *[Describe benefits in the context of the overall filing narrative, which could include the following]*

Benefit	Description
Improved reliability	Standardization and consolidation of the ADMS platform will drive a more consistent customer experience, improved monitoring and communications during outage events, and enable advanced capabilities like fault location and self-healing capabilities to reduce customer outage impacts.
Voltage optimization and efficiency	DSDR/CVR Project will improve distribution voltage efficiencies and reduce overall energy consumption by customers and support better voltage quality and reliability.
Affordability	DSDR/CVR will create power delivery efficiencies by regulating voltage at the lower end of the reliable range, which helps reduce overall consumption without sacrificing voltage quality. Reduced consumption helps lower fuel costs, which can generate savings for customers.
Sustainable growth of renewables and distributed resources	DER dispatch tools support the increased integration of renewables and battery storage on the transmission and distribution grid, which also helps provide cleaner energy options to customers and achieve carbon reduction goals.

Land Mobile Radio (LMR)

Project purpose

This work upgrades the existing, end-of-service Land Mobile Radio (LMR) systems in each Duke Energy region with a common enhanced, reliable, and interoperable communications system. The LMR network is a key component of Duke Energy's private communication infrastructure used by transmission and distribution teams to more effectively dispatch field resources; improve grid management and increase customer satisfaction through reliable service and restoration of power in a variety of operating conditions.

Timeline for construction

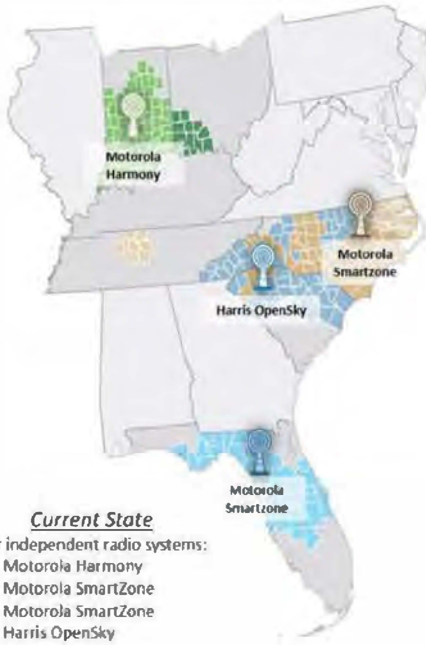
Refer to MYRP Project List for project-specific timelines. At the program level, construction is planned from
March 2022 – March 2025.

Estimated in-service date

Refer to MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from January 2024 – December 2024.

Project description

The LMR network architecture provides higher resiliency and availability when other forms of communication services are challenged (e.g., commercial cellular networks and other leased services) for field, dispatch center and grid management resources. LMR enables the Advanced Distribution Management System (ADMS) and Distribution Control Center's (DCC) vision of being able to control and dispatch from any location to any resource at any time during emergency type of events.



Current State

Four independent radio systems:
1. Motorola Harmony
2. Motorola SmartZone
3. Motorola SmartZone
4. Harris OpenSky

Future State

Harris P25 - Single, interoperable, enterprise-wide radio system with redundant cores in each region. New system is also scalable for future expansion, if necessary

Projected costs (including capital and O&M expenditure)
Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan '24 – Dec '24	Jan '25 – Dec '25	Jan '26 – Dec '26	Total
Capital costs	$80M	-	-	$80M
O&M costs (installation only)	-	-	-	-

Grid capabilities enabled

Reliability:
- Improved reliability and resiliency by providing a common platform and critical private communication infrastructure to dispatch crews and manage the grid to restore power faster when outages occur.

Automation & Communication
- Advanced communication capabilities to power grid improvements and system that enable and promote efficient management of distributed energy resources.

HB951 Policy Considerations addressed
- Promotes resilience and security of the electric grid
- Maintains adequate levels of reliability and customer service

Land Mobile Radio (LMR)
Customer Benefits

Is the project / program required by law?
No
Explanation of need for proposed expenditure
Duke Energy requires a reliable internal communication solution that is available for mission critical operational purposes 24/7. A mission-critical communication system managed and maintained by Duke Energy ensures that the assets receive the highest priority to maintain mission critical voice communications. Upgrading the existing system moves Duke Energy to an industry standard P25 communication protocol and ensures OEM support and security patching.
Benefits created for customers *[Describe benefits in the context of the overall filing narrative, which could include the following]*

Benefit	Description
Improved reliability	Redundancy within the core communications network is a critical part of delivering the reliable service quality that customers expect during normal operations and during storm restoration to ensure the safety of equipment, personnel, and the public.
Improved personnel safety	The company can respond more quickly to emergency alerts received from LMR radio user personnel in distress, or those unable to communicate through other communications channels.
Improved resiliency	Interoperability between regions for both field and dispatch center resources enables dispatch from any location to any resource at any time during emergency type events. Additionally, the LMR network supports disaster recovery and business continuity plans by using utility-grade standards and is available when other forms of communication are not available (e.g., commercial cellular networks).
Improved public safety	A communication system managed and maintained by Duke Energy ensures that our crews receive the highest priority mission critical communications to support public safety in the event of a natural disaster, including events associated with normal and high-water power plant operations.
Sustained growth of renewables and distributed resources	Renewable resources are dispatched utilizing LMR which helps provide cleaner energy options to customers and achieve carbon reduction goals

Towers, Shelters & Power Supplies (TSPS)

Program purpose
The Towers, Shelters & Power Supplies (TSPS) improvement program evaluates opportunities to address infrastructure nearing end of service and to construct new communications towers for microwave (MW) transport, Land Mobile Radio (LMR) systems and other strategic high-capacity edge wireless technologies. The program helps reduce operations and maintenance costs at sites where Duke Energy currently leases tower space by evaluating continued lease costs vs. ownership costs. Duke Energy owns and leases communication towers in each region for its microwave transport network and various private wireless systems for mission critical voice communications, and communications to field devices for monitoring, control and/or data collection. In addition, each tower site incorporates a backup power supply system consisting of batteries and generators that allow communications to continue through challenging operating periods such as ice storms and hurricanes.
Timeline for construction
Refer to MYRP Project List for project-specific timelines. At the program level, construction is planned from December 2023 – September 2026
Estimated in-service date
Refer to the MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from December 2023 -September 2026

DUKE ENERGY.

Program description

Each component of TSPS is continually evaluated to create a prioritized upgrade and replacement schedule, based on key characteristics such as age, condition, maintenance history, risk, capacity to support growth, impact to grid operations, and potential to offset costs for sites where Duke Energy leases tower space. Approximately 14 TSPS sites are planned to be completed between 2023 and 2026.

Newly constructed towers are designed and built to meet the latest ANSI/TIA tower structure standards for existing wireless infrastructure while providing added capacity for future growth. Backup power systems are also evaluated for age and capacity to ensure they can meet the resiliency requirements for a utility communications network.

Power supplies are located at all tower/shelter and strategic telecom locations to provide the operational availability and resiliency required for a utility communications network. Battery systems provide the primary source of power to operate the telecom hardware housed in the shelter at the site. Batteries are charged by the electric service to the site. The electric service is backed up by a generator with automatic transfer capabilities. Generally, batteries will supply a minimum of 8 hours of standby time in the event electric service is interrupted and a generator fails to run. A generator's fuel supply will support a minimum run time of 7 days.

Projected costs (including capital and O&M expenditure)

Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan ' 24 – Dec '24	Jan '25 – Dec '25	Jan '26 – Dec '26	Total
Capital costs	$7.7M	$9.2M	$8.7M	**$25.6M**
O&M costs (installation only)	-	-	-	-

Grid capabilities enabled

Reliability and resiliency

- Improved reliability by improving communication capabilities to better manage the grid and ensure efficient operations.
- Improved resiliency through improved communication resilience to coordinate essential restoration

HB951 Policy Considerations addressed

- Encourages peak load reduction or efficient use of the system
- Encourages DERs
- Encourages beneficial electrification, including electric vehicles
- Promotes resilience and security of the electric grid
- Maintains adequate levels of reliability and customer service

activities, helping restore power faster after outage events. • Upgraded communication technologies to support improved grid management and efficiency. *Automation & Communication* • Improved resiliency by detecting faults and rerouting power to self-heal, reducing impact from outages • Provided advanced communication and control technologies to support the two-way power flow needed to expand distributed energy resources. *Voltage Regulation* • Optimized voltage levels to encourage the adoption of DER while protecting customers from disruptive supply spikes or sags • Improved resiliency by reducing intermittency / fluctuations from DER power supply *Capacity* • Expanded capacity to support the two-way power flow needed to sustainably enable expanded DER adoption.	

Towers, Shelters & Power Supplies (TSPS)

Customer Benefits

Is the program required by law?
No
Explanation of need for proposed expenditure
TSPS are key Duke Energy communications assets that enable highly reliable private wireless communications systems to support mission critical operations 24/7. Private mission-critical communications infrastructure managed and maintained by Duke Energy ensures that grid control systems and field assets receive the highest priority to support grid integrity, and reliability.
Benefits created for customers *[Describe benefits in the context of the overall filing narrative, which could include the following]*

Benefit	Description
Duke Energy tower designs align to ANSI/TIA tower structural standards	Ensures maximum survivability for structures based on critical guidance regarding load requirements and design criteria. Designed with margin to support future growth in the use of wireless technologies.
Improved Reliability	Ensures proper level of tower structural integrity, shelters that provide a protected environment for electronics, and availability of standby power during challenging operating periods such as ice storms and hurricanes
Provide reliable communications for normal and event operations	Communications infrastructure managed and maintained by Duke Energy helps ensure that we operate at the highest levels of availability to maintain mission critical communications 24/7.

Mission Critical Transport (MCT)

Program purpose

Mission Critical Transport (MCT) strategically upgrades and incorporates the backbone infrastructure needed for high-speed, reliable, sustainable, interoperable communications for grid devices and personnel including the use of high-capacity private fiber routes.

Timeline for construction

Refer to Master Project List for project-specific timelines. At the program level, construction is planned from December 2023 – September 2026

Estimated in-service date

Refer to Master Project List for project-specific dates. At the program level, individual location in-service dates range from December 2023 - September 2026

Program description

MCT strategically evaluates and upgrades communications high-capacity fiber infrastructure required for high-speed, reliable, sustainable, and interoperable communications for grid devices and personnel.

Current fiber routes are continually evaluated and identified to create a prioritized replacement schedule for potentially at-risk routes, based on key characteristics such as age, condition, maintenance history, risk, and capacity to support growth, and impact to grid operations.

The scope of MCT also includes strategic fiber construction for new private routes to replace leased circuits, increase capacity, and/or improve security, reliability, and resiliency leveraging transmission line rebuild projects where and when possible.

Projected costs (including capital and O&M expenditure)

Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan '24 – Dec 24	Jan '25 – Dec '25	Jan '26 – Dec '26	Total
Capital costs	-	$21.1M	$8.7M	**$29.8M**
O&M costs (Installation only)	-	-	-	-

Grid capabilities enabled

Reliability and resiliency

- Improved reliability by improving communication capabilities to better manage the grid and ensure efficient operations.
- Improved resiliency through improved communication resilience to coordinate essential restoration activities, helping

HB951 Policy Considerations addressed

- Encourages peak load reduction or efficient use of the system
- Encourages DERs
- Encourages beneficial electrification, including electric vehicles
- Promotes resilience and security of the electric grid

restore power faster after outage events. • Upgraded communication technologies to support improved grid management and efficiency. Automation & Communication • Improved resiliency by detecting faults and rerouting power to self-heal, reducing impact from outages • Provided advanced communication and control technologies to support the two-way power flow needed to expand distributed energy resources.	• Maintains adequate levels of reliability and customer service

Mission Critical Transport (MCT)
Customer Benefits

Program required by law?	
No	
Explanation of need for proposed expenditure	
Mission Critical Transport (MCT) is a key Duke Energy communications asset that enables very reliable high speed and high-capacity private communications to support mission critical operations 24/7. Mission Critical Transport infrastructure managed and maintained by Duke Energy ensures that grid control systems and field assets receive the highest priority to support grid integrity and reliability.	
Benefits created for customers	
Benefit	**Description**
Duke Energy fiber designs align to Telecommunications Industry standards	Ensures maximum capacity based on grid control and customer system needs regarding bandwidth and latency requirements. Designed with margin to support future growth.
Improved Reliability	Ensures reliable high capacity and secure core infrastructure to enable high speed, low latency grid operations during normal, as well as challenging operating periods such as ice storms and hurricanes
Provide reliable communications for normal and event operations	Communications infrastructure managed and maintained by Duke Energy ensures that we operate at the highest levels of availability to maintain mission critical communications 24/7.
Supports remote operations of renewable energy assets	Mission Critical Transport infrastructure provides a platform for wireless technologies that enables resilient communications for renewable energy control and management

Corporate Facilities

Program purpose

Operations centers are the workplace for customer delivery, transmission, lighting, and fleet staff that support the electric grid's construction and maintenance. They are also hubs for material storage, service vehicles and even crew staging and operations during storms. These facilities are being updated to meet the needs of growing towns and cities, as well as support the significant grid improvements taking place to better serve customers and achieve Duke Energy's cleaner energy and carbon goals.

Timeline for construction

Planning and design for the projects within this program started in the first quarter of 2022. Construction of these facility updates will occur through the summer/fall of 2026, with individual operation centers completing construction and entering service throughout this period.

Estimated in-service date

Refer to Master Project List for project-specific in-service dates. At the program level, individual location in-service dates range from October 2023 to June 2026

Program description

DEC-NC

Matthews New Ops Center

A new operations center in Matthews will replace an existing facility that has reached its end of service. The existing facility has storm damage, and the team has outgrown the space. With grid improvement work underway in the area, the building space and acreage is not sufficient to support needs. The new facility, located at a different location, will better serve operational needs in the area going forward.

Little Rock Ops Center Land

The purpose of this land purchase is to secure the location for the new Charlotte operations center that will support the southern region of the city.

Little Rock Operations Center-New Center

Although this new facility is not due to force from the airport, their continued growth has long hindered the operation at this center. The airport has future plans that may include expansion in our space, so this replacement will well position our teams for success whenever that challenge occurs.

Hickory Ops Center Renovation

This work will improve the space for the betterment of employees that support grid maintenance activities that help to ensure continued reliability of service to customers in the area.

Elkin Ops Renovation
This work will improve the space for the betterment of employees that support grid maintenance activities that help to ensure continued reliability of service to customers in the area.

Lewisville Ops Center Renovation
Operations Centers are the workplace for customer delivery, transmission, lighting, and fleet staff that support the grid's maintenance and expansion, but they are also the hubs for material storage and service vehicle placement. As the towns and cities throughout the DEC region have grown and transformed, the operations centers must be well positioned to provide the needs of the workforce that directly support customers.

Fairfax Garage Renovation
Operations Centers are the workplace for customer delivery, transmission, lighting, and fleet staff that support the grid's maintenance and expansion, but they are also the hubs for material storage and service vehicle placement. As the towns and cities throughout the DEC region have grown and transformed, the operations centers must be well positioned to provide the needs of the workforce that directly support customers.

Burlington Ops Center Renovation
Operations Centers are the workplace for customer delivery, transmission, lighting, and fleet staff that support the grid's maintenance and expansion, but they are also the hubs for material storage and service vehicle placement. As the towns and cities throughout the DEC region have grown and transformed, the operations centers must be well positioned to provide the needs of the workforce that directly support customers.

Fairfax Ops Roof Replacement
Replacing the roof of this facility will greatly extend the life of the building and protect the health and well being of occupants.

Hendersonville Ops Center Renovation
Operations Centers are the workplace for customer delivery, transmission, lighting, and fleet staff that support the grid's maintenance and expansion, but they are also the hubs for material storage and service vehicle placement. As the towns and cities throughout the DEC region have grown and transformed, the operations centers must be well positioned to provide the needs of the workforce that directly support customers.

Spindale Ops Center Renovation
Operations Centers are the workplace for customer delivery, transmission, lighting, and fleet staff that support the grid's maintenance and expansion, but they are also the hubs for material storage and service vehicle placement. As the towns and cities throughout the DEC region have grown and transformed, the operations centers must be well positioned to provide the needs of the workforce that directly support customers.

Wentworth New Ops Center
Operations Centers are the workplace for customer delivery, transmission, lighting, and fleet staff that support the grid's maintenance and expansion, but they are also the hubs for material storage and service vehicle placement. As the towns and cities throughout the DEC region have grown and transformed, the operations centers must be well positioned to provide the needs of the workforce that directly support customers.

Rural Hall Ops Center Renovation
Operations Centers are the workplace for customer delivery, transmission, lighting, and fleet staff that support the grid's maintenance and expansion, but they are also the hubs for material storage and service vehicle placement. As the towns and cities throughout the DEC region have grown and transformed, the operations centers must be well positioned to provide the needs of the workforce that directly support customers.

Mooresville Ops Center Renovation
Operations Centers are the workplace for customer delivery, transmission, lighting, and fleet staff that support the grid's maintenance and expansion, but they are also the hubs for material storage and service vehicle placement. As the towns and cities throughout the DEC region have grown and transformed, the operations centers must be well positioned to provide the needs of the workforce that directly support customers.

Salisbury Ops Center Renovation
Operations Centers are the workplace for customer delivery, transmission, lighting, and fleet staff that support the grid's maintenance and expansion, but they are also the hubs for material storage and service vehicle placement. As the towns and cities throughout the DEC region have grown and transformed, the operations centers must be well positioned to provide the needs of the workforce that directly support customers.

Fairfax Bldg Renovation
Operations Centers are the workplace for customer delivery, transmission, lighting, and fleet staff that support the grid's maintenance and expansion, but they are also the hubs for material storage and service vehicle placement. As the towns and cities throughout the DEC region have grown and transformed, the operations centers must be well positioned to provide the needs of the workforce that directly support customers.

Projected costs (including capital and O&M expenditure)
Note: Timing for costs based on in-service dates for associated projects

DEC NC	Jan '24 – Dec '24	Jan '25 – Dec '25	Jan '26 – Dec '26	Total
Capital costs	$56.4M	$22.8M	$45.6M	$124.8M
O&M costs	$.42K	$.23K	$0.38K	$1.03M

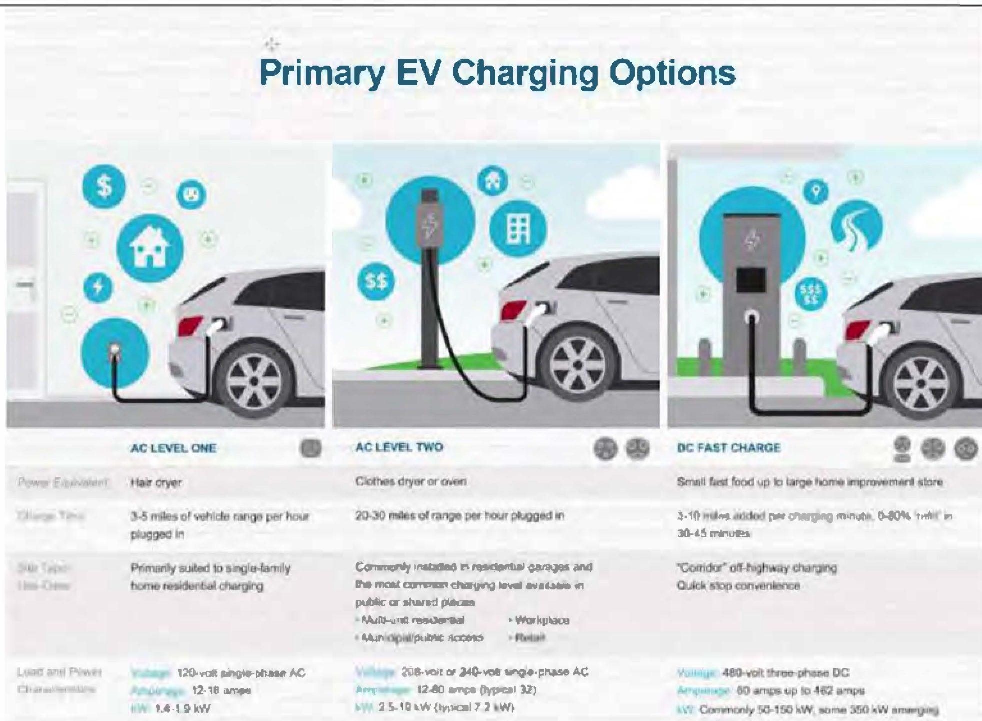
Grid capabilities enabled	HB951 Policy Considerations addressed
• *N/A*	• Promotes resilience and security of the electric grid • Maintains adequate levels of reliability and customer service

Corporate Facilities
Customer Benefits

Is the project / program required by law?	
No	
Explanation of need for proposed expenditure	
As towns and cities throughout the Duke Energy Progress region continue to grow, the operations centers that serve them must be updated or constructed to meet workforce and supply needs in the service of customers.	
Benefits created for customers *[Describe benefits in the context of the overall filing narrative, which could include the following]*	
Benefit	**Description**
Improved recovery times	By improving the location and capabilities of its operations centers, the company can more efficiently respond to outages and restore power faster to customers.
Readiness for grid modernization	Operations centers must have sufficient indoor and outdoor spaces to support crews and materials working to improve the electric grid, increase reliability and resiliency, and ready the grid for cleaner energy options and a lower carbon future.

Electrification Charging Infrastructure

Program purpose
This project will provide necessary charging stations for both Duke Energy facilities and as required for home charging for Duke Energy vehicles. These charging stations are essential to achieve our 2030 corporate goal of converting 100% of light duty vehicles to electric and 50% of the combined fleet of medium-duty, heavy-duty, and off-road vehicles to EVs, plug in hybrids or other zero-carbon alternatives by 2030.
Timeline for construction
Refer to Master Project List for project-specific timelines. At the program level, construction is planned from August 2023 to August 2026.
Estimated in-service date
Refer to Master Project List for project-specific dates. At the program level, individual location in-service dates range from October 2023 to September 2026.
Program description
- Scope of project: Installation of Level 2 and Level 3 charging stations distributed across Duke Energy facilities and home charging locations as required in support of electrification of internal Fleet assets - Project / program justification: Charging stations are required to meet enterprise electrification goal for 2030 - Technology details (how it works): Charging stations will be a mix of network and non-network chargers as well as varying Levels (see below) as needed to gather necessary data in support of carbon-reduction goals and reporting.



Projected costs (including capital and O&M expenditure)
Note: Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

DEC NC	Jan '24 – Dec '24	Jan '25 – Dec '25	Jan '26 – Dec '26	Total
Capital costs	$6.1M	$6.8M	$4.2M	**$17.1M**
O&M costs (installation only)	-	-	-	-

Grid capabilities enabled	HB951 Policy Considerations addressed
• Network chargers enable charging in off peak • Identification of forecasted additional load requirements/load impact in support of electrification charging infrastructure	• Encourages peak load reduction or efficient use of the system • Encourages utility-scale renewable energy and storage • Encourages energy efficiency • Encourages beneficial electrification, including electric vehicles

Electrification Charging Infrastructure
Customer Benefits

Is the Program required by law?	
No	
Explanation of need for proposed expenditure	
This project will provide necessary charging stations for both Duke Energy facilities and as required for home charging for Duke Energy vehicles. These charging stations are essential to achieve our 2030 corporate goal of converting 100% of light duty vehicles to electric and 50% of the combined fleet of medium-duty, heavy-duty, and off-road vehicles to EVs, plug in hybrids or other zero-carbon alternatives by 2030.	
Benefits created for customers *[Describe benefits in the context of the overall filing narrative, which could include the following]*	
Benefit	**Description**
More control over consumption	Leveraging network chargers to charge in off peak
Carbon reduction	Support electrification of Fleet
Reduction in fuel costs	Overall reduction in fuel costs and fuel consumption

AREA/PROJECT/PROGRAM	Distribution Automation: Fuse Replacement - 8
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2022	2023	2024	2025	2026	2027	2028	2029	2030
		0	1	2	3	4	5	6	7	8
COSTS										
Program Capital Costs	$ 22,006,794	$ 1,346,625	$ 9,630,976	$ 8,691,821	$ 3,516,405	$ 1,363,964	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 2,239,140	$ 137,016	$ 979,929	$ 884,372	$ 357,786	$ 138,780	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 24,245,934	$ 1,483,641	$ 10,610,905	$ 9,576,193	$ 3,874,191	$ 1,502,744	$ -	$ -	$ -	$ -
Program O&M Costs	$ 485,707	$ 29,721	$ 212,563	$ 191,835	$ 77,610	$ 30,104	$ -	$ -	$ -	$ -
Total Program Costs	$ 24,731,641	$ 1,513,362	$ 10,823,468	$ 9,768,029	$ 3,951,801	$ 1,532,847	$ -	$ -	$ -	$ -
On-Going Maintenance	$ 162,480	$ -	$ -	$ -	$ 6,552	$ 10,014	$ 12,275	$ 12,582	$ 12,896	$ 13,219
Total On-Going Costs	$ 162,480	$ -	$ -	$ -	$ 6,552	$ 10,014	$ 12,275	$ 12,582	$ 12,896	$ 13,219
OPERATIONAL BENEFITS										
N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CUSTOMER BENEFITS										
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 377,946	$ -	$ -	$ -	$ 14,546	$ 22,789	$ 28,632	$ 29,348	$ 30,082	$ 30,834
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 7,337,940	$ -	$ -	$ -	$ 282,407	$ 442,448	$ 555,902	$ 569,799	$ 584,044	$ 598,645
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Momentary Outage Benefits (Non-MED) - Residential Customers	$ 8,675,255	$ -	$ -	$ -	$ 333,875	$ 523,082	$ 657,213	$ 673,643	$ 690,484	$ 707,747
Avoided Momentary Outage Benefits (Non-MED) - Small C&I Customers	$ 50,587,528	$ -	$ -	$ -	$ 1,946,906	$ 3,050,221	$ 3,832,369	$ 3,928,179	$ 4,026,383	$ 4,127,043
Avoided Momentary Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Customer Benefits	$ 66,978,669	$ -	$ -	$ -	$ 2,577,733	$ 4,038,539	$ 5,074,116	$ 5,200,969	$ 5,330,993	$ 5,464,268
COMBINED COSTS AND BENEFITS										
Total PV of Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total PV of Customer Benefits	$ 66,978,669	$ -	$ -	$ -	$ 2,577,733	$ 4,038,539	$ 5,074,116	$ 5,200,969	$ 5,330,993	$ 5,464,268
Total PV of Combined Benefits	$ 66,978,669	$ -	$ -	$ -	$ 2,577,733	$ 4,038,539	$ 5,074,116	$ 5,200,969	$ 5,330,993	$ 5,464,268
Total PV Program and On-Going Costs	$ 24,894,120	$ 1,513,362	$ 10,823,468	$ 9,768,029	$ 3,958,352	$ 1,542,861	$ 12,275	$ 12,582	$ 12,896	$ 13,219
Combined NPV of Program	$ 42,084,548	$ (1,513,362)	$ (10,823,468)	$ (9,768,029)	$ (1,380,619)	$ 2,495,678	$ 5,061,841	$ 5,188,387	$ 5,318,097	$ 5,451,050
Ratio of NPV Benefits to NPV Costs	2.7									
Cumulative Net Benefits (Payback Period)		$ (1,513,362)	$ (12,336,831)	$ (22,104,859)	$ (23,485,478)	$ (20,989,801)	$ (15,927,959)	$ (10,739,572)	$ (5,421,474)	$ 29,575

AREA/PROJECT/PROGRAM	Distribution Automation: Fuse Replacement - 8
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	YEAR								
		2031	2032	2033	2034	2035	2036	2037	2038	2039
		9	10	11	12	13	14	15	16	17
COSTS										
Program Capital Costs	$ 22,006,794	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 2,239,140	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 24,245,934	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 485,707	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	$ 24,731,641	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
On-Going Maintenance	$ 162,480	$ 13,549	$ 13,888	$ 14,235	$ 14,591	$ 14,956	$ 15,330	$ 15,713	$ 16,106	$ 16,508
Total On-Going Costs	$ 162,480	$ 13,549	$ 13,888	$ 14,235	$ 14,591	$ 14,956	$ 15,330	$ 15,713	$ 16,106	$ 16,508
OPERATIONAL BENEFITS										
N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CUSTOMER BENEFITS										
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 377,946	$ 31,604	$ 32,395	$ 33,204	$ 34,035	$ 34,885	$ 35,758	$ 36,652	$ 37,568	$ 38,507
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 7,337,940	$ 613,612	$ 628,952	$ 644,676	$ 660,793	$ 677,312	$ 694,245	$ 711,601	$ 729,391	$ 747,626
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Momentary Outage Benefits (Non-MED) - Residential Customers	$ 8,675,255	$ 725,440	$ 743,576	$ 762,166	$ 781,220	$ 800,750	$ 820,769	$ 841,288	$ 862,320	$ 883,878
Avoided Momentary Outage Benefits (Non-MED) - Small C&I Customers	$ 50,587,528	$ 4,230,219	$ 4,335,974	$ 4,444,374	$ 4,555,483	$ 4,669,370	$ 4,786,104	$ 4,905,757	$ 5,028,401	$ 5,154,111
Avoided Momentary Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Customer Benefits	$ 66,978,669	$ 5,600,875	$ 5,740,897	$ 5,884,419	$ 6,031,530	$ 6,182,318	$ 6,336,876	$ 6,495,298	$ 6,657,680	$ 6,824,122
COMBINED COSTS AND BENEFITS										
Total PV of Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total PV of Customer Benefits	$ 66,978,669	$ 5,600,875	$ 5,740,897	$ 5,884,419	$ 6,031,530	$ 6,182,318	$ 6,336,876	$ 6,495,298	$ 6,657,680	$ 6,824,122
Total PV of Combined Benefits	$ 66,978,669	$ 5,600,875	$ 5,740,897	$ 5,884,419	$ 6,031,530	$ 6,182,318	$ 6,336,876	$ 6,495,298	$ 6,657,680	$ 6,824,122
Total PV Program and On-Going Costs	$ 24,894,120	$ 13,549	$ 13,888	$ 14,235	$ 14,591	$ 14,956	$ 15,330	$ 15,713	$ 16,106	$ 16,508
Combined NPV of Program	$ 42,084,548	$ 5,587,326	$ 5,727,009	$ 5,870,184	$ 6,016,939	$ 6,167,362	$ 6,321,546	$ 6,479,585	$ 6,641,575	$ 6,807,614
Ratio of NPV Benefits to NPV Costs	2.7									
Cumulative Net Benefits (Payback Period)		$ 5,616,901	$ 11,343,910	$ 17,214,094	$ 23,231,033	$ 29,398,395	$ 35,719,942	$ 42,199,527	$ 48,841,102	$ 55,648,716

AREA/PROJECT/PROGRAM	Distribution Automation: Fuse Replacement - 8
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2040	2041	2042	2043	2044	2045	2046	2047	2048
		18	19	20	21	22	23	24	25	26
COSTS										
Program Capital Costs	$ 22,006,794	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 2,239,140	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 24,245,934	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 485,707	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	$ 24,731,641	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
On-Going Maintenance	$ 162,480	$ 16,921	$ 17,344	$ 17,778	$ 18,222	$ 18,678	$ 19,145	$ 19,623	$ 20,114	$ 20,617
Total On-Going Costs	$ 162,480	$ 16,921	$ 17,344	$ 17,778	$ 18,222	$ 18,678	$ 19,145	$ 19,623	$ 20,114	$ 20,617
OPERATIONAL BENEFITS										
N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CUSTOMER BENEFITS										
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 377,946	$ 39,470	$ 40,456	$ 41,468	$ 42,505	$ 43,567	$ 44,656	$ 45,773	$ 46,917	$ 48,090
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 7,337,940	$ 766,317	$ 785,475	$ 805,112	$ 825,239	$ 845,870	$ 867,017	$ 888,693	$ 910,910	$ 933,683
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Momentary Outage Benefits (Non-MED) - Residential Customers	$ 8,675,255	$ 905,975	$ 928,625	$ 951,840	$ 975,636	$ 1,000,027	$ 1,025,028	$ 1,050,654	$ 1,076,920	$ 1,103,843
Avoided Momentary Outage Benefits (Non-MED) - Small C&I Customers	$ 50,587,528	$ 5,282,964	$ 5,415,038	$ 5,550,414	$ 5,689,174	$ 5,831,403	$ 5,977,188	$ 6,126,618	$ 6,279,784	$ 6,436,778
Avoided Momentary Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Customer Benefits	$ 66,978,669	$ 6,994,725	$ 7,169,594	$ 7,348,833	$ 7,532,554	$ 7,720,868	$ 7,913,890	$ 8,111,737	$ 8,314,530	$ 8,522,394
COMBINED COSTS AND BENEFITS										
Total PV of Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total PV of Customer Benefits	$ 66,978,669	$ 6,994,725	$ 7,169,594	$ 7,348,833	$ 7,532,554	$ 7,720,868	$ 7,913,890	$ 8,111,737	$ 8,314,530	$ 8,522,394
Total PV of Combined Benefits	$ 66,978,669	$ 6,994,725	$ 7,169,594	$ 7,348,833	$ 7,532,554	$ 7,720,868	$ 7,913,890	$ 8,111,737	$ 8,314,530	$ 8,522,394
Total PV Program and On-Going Costs	$ 24,894,120	$ 16,921	$ 17,344	$ 17,778	$ 18,222	$ 18,678	$ 19,145	$ 19,623	$ 20,114	$ 20,617
Combined NPV of Program	$ 42,084,548	$ 6,977,804	$ 7,152,249	$ 7,331,056	$ 7,514,332	$ 7,702,190	$ 7,894,745	$ 8,092,114	$ 8,294,417	$ 8,501,777
Ratio of NPV Benefits to NPV Costs	2.7									
Cumulative Net Benefits (Payback Period)		$ 62,626,520	$ 69,778,769	$ 77,109,825	$ 84,624,157	$ 92,326,348	$ 100,221,093	$ 108,313,207	$ 116,607,623	$ 125,109,400

AREA/PROJECT/PROGRAM	Distribution Automation: Fuse Replacement - 8
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2049	2050	2051	2052	TOTAL
		27	28	29	30	
COSTS						
Program Capital Costs	$ 22,006,794	$ -	$ -	$ -	$ -	$ 24,549,791
Program Capital Contingency Costs	$ 2,239,140	$ -	$ -	$ -	$ -	$ 2,497,883
Total Program Capital Costs	$ 24,245,934	$ -	$ -	$ -	$ -	$ 27,047,674
Program O&M Costs	$ 485,707	$ -	$ -	$ -	$ -	$ 541,833
Total Program Costs	$ 24,731,641	$ -	$ -	$ -	$ -	$ 27,589,507
On-Going Maintenance	$ 162,480	$ 21,132	$ 21,660	$ 22,202	$ 22,757	$ 458,605
Total On-Going Costs	$ 162,480	$ 21,132	$ 21,660	$ 22,202	$ 22,757	$ 458,605
OPERATIONAL BENEFITS						
N/A	$ -	$ -	$ -	$ -	$ -	$ -
Total Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -
CUSTOMER BENEFITS						
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 377,946	$ 49,292	$ 50,525	$ 51,788	$ 53,082	$ 1,068,425
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 7,337,940	$ 957,025	$ 980,950	$ 1,005,474	$ 1,030,611	$ 20,743,829
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -
						$ -
Avoided Momentary Outage Benefits (Non-MED) - Residential Customers	$ 8,675,255	$ 1,131,439	$ 1,159,725	$ 1,188,718	$ 1,218,436	$ 24,524,320
Avoided Momentary Outage Benefits (Non-MED) - Small C&I Customers	$ 50,587,528	$ 6,597,698	$ 6,762,640	$ 6,931,706	$ 7,104,999	$ 143,007,295
Avoided Momentary Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -
						$ -
Total Customer Benefits	$ 66,978,669	$ 8,735,454	$ 8,953,840	$ 9,177,686	$ 9,407,128	$ 189,343,869
COMBINED COSTS AND BENEFITS						
Total PV of Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -
Total PV of Customer Benefits	$ 66,978,669	$ 8,735,454	$ 8,953,840	$ 9,177,686	$ 9,407,128	$ 189,343,869
Total PV of Combined Benefits	$ 66,978,669	$ 8,735,454	$ 8,953,840	$ 9,177,686	$ 9,407,128	$ 189,343,869
Total PV Program and On-Going Costs	$ 24,894,120	$ 21,132	$ 21,660	$ 22,202	$ 22,757	$ 28,048,113
Combined NPV of Program	$ 42,084,548	$ 8,714,321	$ 8,932,180	$ 9,155,484	$ 9,384,371	$ 161,295,756
Ratio of NPV Benefits to NPV Costs	2.7					
Cumulative Net Benefits (Payback Period)		$ 133,823,722	$ 142,755,901	$ 151,911,385	$ 161,295,756	$ 322,591,513

Duke Energy Caro North Carolina Combined DEC Self Optimized Grid (SOG) Years 2022-2026

Sources

	Units		NPV (calculated)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
				0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Benefits			$ 1,348,548,964		$ -	$ 32,946,491	$ 53,000,401	$ 73,909,834	$ 98,392,575	$ 101,123,903	$ 103,987,398	$ 107,005,525	$ 110,063,374	$ 113,047,541	$ 115,989,703	$ 119,105,893	$ 122,169,651	$ 125,480,274	$ 128,799,426	$ 132,047,421	$ 135,357,785
Costs			$ 238,449,118	$ 10,852,690	$ 93,708,996	$ 79,158,559	$ 63,180,311	$ 15,877,496	$ 441,822	$ 452,868	$ 464,190	$ 475,794	$ 487,689	$ 499,881	$ 512,378	$ 525,188	$ 538,318	$ 551,775	$ 565,570	$ 579,709	$ 594,202
Net			**$ 1,110,099,846**	**$ (10,852,690)**	**$ (93,708,996)**	**$ (46,212,069)**	**$ (10,179,910)**	**$ 58,032,338**	**$ 97,950,753**	**$ 100,671,035**	**$ 103,523,208**	**$ 106,529,731**	**$ 109,575,684**	**$ 112,547,660**	**$ 115,477,325**	**$ 118,580,705**	**$ 121,631,333**	**$ 124,928,499**	**$ 128,233,857**	**$ 131,467,712**	**$ 134,763,583**
BCR			5.7																		
COSTS																					
PROGRAM COSTS (Full & Partial SOG)																					
Switch Automatic	$		$ 207,825,872	$ 9,708,281	$ 83,811,062	$ 70,653,549	$ 56,240,986	$ 13,831,329													
Contingency	$		$ 21,144,576	$ 987,738	$ 8,527,087	$ 7,188,419	$ 5,722,059	$ 1,407,224													
Implementation O&M			$ 3,353,874	$ 156,671	$ 1,352,535	$ 1,140,200	$ 907,612	$ 223,209													
Total Program Cos	$		**$ 232,324,322**	**$ 10,852,690**	**$ 93,690,684**	**$ 78,982,168**	**$ 62,870,656**	**$ 15,461,762**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ON-GOING COSTS (Full & Partial SOG)																					
On-going O&M	$		$ 6,124,796		$ 18,311	$ 176,392	$ 309,655	$ 415,734	$ 441,822	$ 452,868	$ 464,190	$ 475,794	$ 487,689	$ 499,881	$ 512,378	$ 525,188	$ 538,318	$ 551,775	$ 565,570	$ 579,709	$ 594,202
Total On-going O&	$		**$ 6,124,796**		**$ 18,311**	**$ 176,392**	**$ 309,655**	**$ 415,734**	**$ 441,822**	**$ 452,868**	**$ 464,190**	**$ 475,794**	**$ 487,689**	**$ 499,881**	**$ 512,378**	**$ 525,188**	**$ 538,318**	**$ 551,775**	**$ 565,570**	**$ 579,709**	**$ 594,202**
TOTAL COSTS																					
Program Costs	$		$ 232,324,322	$ 10,852,690	$ 93,690,684	$ 78,982,168	$ 62,870,656	$ 15,461,762	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
On-going Costs	$		$ 6,124,796	$ -	$ 18,311	$ 176,392	$ 309,655	$ 415,734	$ 441,822	$ 452,868	$ 464,190	$ 475,794	$ 487,689	$ 499,881	$ 512,378	$ 525,188	$ 538,318	$ 551,775	$ 565,570	$ 579,709	$ 594,202
Total Cost	$		**$ 238,449,118**	**$ 10,852,690**	**$ 93,708,996**	**$ 79,158,559**	**$ 63,180,311**	**$ 15,877,496**	**$ 441,822**	**$ 452,868**	**$ 464,190**	**$ 475,794**	**$ 487,689**	**$ 499,881**	**$ 512,378**	**$ 525,188**	**$ 538,318**	**$ 551,775**	**$ 565,570**	**$ 579,709**	**$ 594,202**
BENEFITS																					
RELIABILITY																					
CI Savings	outages					46,929	71,166	96,701	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987
CMI Savings	min					9,181,046	14,533,892	19,867,082	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033
Typical Duration	hr					3.26	3.40	3.42	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39
Residential Custom	%					86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%
Small C&I Custome	%					11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%
Large C&I Custome	%					2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%
Residential Outage	$/outage					$ 12	$ 12	$ 13	$ 13	$ 13	$ 13	$ 14	$ 14	$ 15	$ 15	$ 15	$ 16	$ 16	$ 16	$ 17	$ 17
Small C&I Outage \	$/outage					$ 2,107	$ 2,239	$ 2,307	$ 2,342	$ 2,401	$ 2,461	$ 2,522	$ 2,585	$ 2,650	$ 2,716	$ 2,784	$ 2,854	$ 2,925	$ 2,998	$ 3,073	$ 3,150
Large C&I Outage \	$/outage					$ 19,753	$ 20,867	$ 21,479	$ 21,839	$ 22,385	$ 22,945	$ 23,518	$ 24,106	$ 24,709	$ 25,327	$ 25,960	$ 26,609	$ 27,274	$ 27,956	$ 28,655	$ 29,371
Residential Moment	$/momentary					$ 6	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 8	$ 8	$ 8	$ 8	$ 8	$ 9	$ 9	$ 9	$ 9
Small C&I Momenta	$/momentary					$ 564	$ 578	$ 592	$ 607	$ 622	$ 638	$ 654	$ 670	$ 687	$ 704	$ 721	$ 739	$ 758	$ 777	$ 796	$ 816
Large C&I Momenta	$/momentary					$ 7,340	$ 7,523	$ 7,712	$ 7,904	$ 8,102	$ 8,304	$ 8,512	$ 8,725	$ 8,943	$ 9,167	$ 9,396	$ 9,631	$ 9,871	$ 10,118	$ 10,371	$ 10,630
Momentary Outage	momentaries					46,929	71,166	96,701	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987
Customer Avoided	$		$ 9,050,691	$ -	$0	$ 217,601	$ 361,566	$ 507,494	$ 671,434	$ 688,220	$ 705,426	$ 723,061	$ 741,138	$ 759,666	$ 778,658	$ 798,124	$ 818,078	$ 838,529	$ 859,493	$ 880,980	$ 903,005
Customer Avoided	$		$ 341,174,591	$ -	$0	$ 8,223,817	$ 13,622,565	$ 19,115,970	$ 25,310,244	$ 25,943,000	$ 26,591,575	$ 27,256,364	$ 27,937,774	$ 28,636,218	$ 29,352,123	$ 30,085,926	$ 30,838,075	$ 31,609,026	$ 32,399,252	$ 33,209,233	$ 34,039,464
Customer Avoided	$		$ 534,348,840	$ -	$0	$ 12,866,393	$ 21,340,701	$ 29,948,947	$ 39,641,049	$ 40,632,075	$ 41,647,877	$ 42,689,074	$ 43,756,300	$ 44,850,208	$ 45,971,463	$ 47,120,750	$ 48,298,768	$ 49,506,238	$ 50,743,894	$ 52,012,491	$ 53,312,803
Customer Avoided	$		**$ 884,574,122**		**$ -**	**$ 21,307,811**	**$ 35,324,832**	**$ 49,572,411**	**$ 65,622,727**	**$ 67,263,295**	**$ 68,944,877**	**$ 70,668,499**	**$ 72,435,212**	**$ 74,246,092**	**$ 76,102,244**	**$ 78,004,801**	**$ 79,954,921**	**$ 81,953,794**	**$ 84,002,638**	**$ 86,102,704**	**$ 88,255,272**
Customer Avoided I	$		$ 10,116,251	$ -	$0	$ 257,495	$ 400,243	$ 557,450	$ 750,339	$ 769,098	$ 788,325	$ 808,033	$ 828,234	$ 848,940	$ 870,164	$ 891,918	$ 914,216	$ 937,071	$ 960,498	$ 984,510	$ 1,009,123
Customer Avoided I	$		$ 117,980,661	$ -	$0	$ 3,003,028	$ 4,667,825	$ 6,501,249	$ 8,750,825	$ 8,969,595	$ 9,193,835	$ 9,423,681	$ 9,659,273	$ 9,900,755	$ 10,148,274	$ 10,401,981	$ 10,662,030	$ 10,928,581	$ 11,201,795	$ 11,481,840	$ 11,768,886
Customer Avoided I	$		$ 298,906,296	$ -	$0	$ 7,608,231	$ 11,826,025	$ 16,471,041	$ 22,170,384	$ 22,724,644	$ 23,292,760	$ 23,875,079	$ 24,471,956	$ 25,083,755	$ 25,710,849	$ 26,353,620	$ 27,012,461	$ 27,687,772	$ 28,379,966	$ 29,089,465	$ 29,816,702
Customer Avoided	$		**$ 427,003,208**		**$ -**	**$ 10,868,753**	**$ 16,894,092**	**$ 23,529,740**	**$ 31,671,548**	**$ 32,463,337**	**$ 33,274,921**	**$ 34,106,794**	**$ 34,959,463**	**$ 35,833,450**	**$ 36,729,286**	**$ 37,647,518**	**$ 38,588,706**	**$ 39,553,424**	**$ 40,542,260**	**$ 41,555,816**	**$ 42,594,712**
CAPACITY SAVINGS																					
Capacity Savings fr	MW			0	0	12	12	12	12	12	13	13	13	13	13	13	14	14	14	14	14
Capacity Value	$/kW				$ -	$ 63	$ 63	$ 64	$ 66	$ 67	$ 70	$ 74	$ 76	$ 82	$ 86	$ 87	$ 87	$ 90	$ 92	$ 96	$ 98
Capacity Savings	$		**$ 14,100,459**		**$ -**	**$ 763,526**	**$ 774,853**	**$ 788,921**	**$ 811,511**	**$ 831,155**	**$ 881,798**	**$ 936,342**	**$ 981,128**	**$ 1,069,384**	**$ 1,130,820**	**$ 1,173,227**	**$ 1,191,639**	**$ 1,256,742**	**$ 1,298,631**	**$ 1,366,742**	**$ 1,417,138**
ENERGY SAVINGS																					
Capacity factor for e	-				0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
Energy Savings fro	MWh				0	428	429	431	433	436	440	446	452	457	462	472	477	488	493	501	507
Energy Value	$/MWh				$ 16	$ 15	$ 14	$ 14	$ 14	$ 14	$ 14	$ 15	$ 15	$ 15	$ 16	$ 19	$ 20	$ 23	$ 25	$ 25	$ 26
Energy Savings (N	$		**$ 122,763**		**$ -**	**$ 6,400**	**$ 6,096**	**$ 6,129**	**$ 6,095**	**$ 6,165**	**$ 6,277**	**$ 6,575**	**$ 6,586**	**$ 6,955**	**$ 7,452**	**$ 8,778**	**$ 9,628**	**$ 11,105**	**$ 12,177**	**$ 12,594**	**$ 13,102**
ENVIRONMENTAL BENEFITS																					
Value: SOx	$/ton					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Value: NOx	$/ton					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Value: CO2	$/ton					$ -	$ 5	$ 10	$ 15	$ 20	$ 25	$ 30	$ 35	$ 40	$ 45	$ 50	$ 55	$ 60	$ 65	$ 70	$ 75
Energy: SOx reduct	ton/MWh					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Energy: NOx reduct	ton/MWh					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Energy: CO2 reduct	ton/MWh					0.25	0.25	0.24	0.24	0.24	0.23	0.23	0.22	0.22	0.21	0.22	0.21	0.22	0.23	0.22	0.21
Environmental Bene	$		$ 67,114			$ -	$ 528	$ 1,037	$ 1,527	$ 2,100	$ 2,503	$ 3,099	$ 3,493	$ 3,972	$ 4,370	$ 5,147	$ 5,613	$ 6,528	$ 7,389	$ 7,658	$ 7,888
Environmental Be	$		**$ 67,114**		**$ -**	**$ -**	**$ 528**	**$ 1,037**	**$ 1,527**	**$ 2,100**	**$ 2,503**	**$ 3,099**	**$ 3,493**	**$ 3,972**	**$ 4,370**	**$ 5,147**	**$ 5,613**	**$ 6,528**	**$ 7,389**	**$ 7,658**	**$ 7,888**
Peak Shaving Ben	$		**$ 14,290,336**		**$ -**	**$ 769,926**	**$ 781,477**	**$ 796,086**	**$ 819,133**	**$ 839,420**	**$ 890,578**	**$ 946,016**	**$ 991,206**	**$ 1,080,311**	**$ 1,142,643**	**$ 1,187,152**	**$ 1,206,880**	**$ 1,274,376**	**$ 1,318,198**	**$ 1,386,995**	**$ 1,438,129**
DER ENABLEMENT																					
Forecasted PV (Ann	MW	Total NC (DEC & DEP)				56	56	56	43	37	39	41	41	41	41	42	43	43	44	44	45
Forecasted PV (Cu	MW	Total NC (DEC & D	PV Forecast from Net Meter Data		145	201	257	312	355	392	431	472	513	554	596	637	680	724	767	812	857
PV scaling factor (S	-	Total NC (DEC & DEP)				4%	11%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Limit (without SOG)	MW	Total NC (DEC & DEP)				310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310
Limit (with SOG)	MW	Total NC (DEC & DEP)				522	522	522	522	522	522	522	522	522	522	522	522	522	522	522	522
PV derate factor for	-	Total NC (DEC & DEP)				19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%
PV Enablement	MW	Total NC (DEC & DEP)				0	0	0	9	17	25	33	41	43	43	43	43	43	43	43	43
Energy Savings	MWh/MW	Total NC (DEC & DEP)				1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936
DER Enablement: (	$	DEC NC = 60% of	$ 3,961,373	$ -	0	$ -	$ -	$ 2,976.59	$ 68,157.89	$ 127,319.85	$ 197,282.65	$ 276,418.26	$ 358,645.70	$ 402,385.21	$ 420,840.17	$ 427,480.72	$ 429,521.58	$ 443,344.98	$ 452,834.44	$ 469,403.00	$ 480,672.10
DER Enablement: E	$	DEC NC = 60% of	$ 9,551,438	$ -	0	$ -	$ -	$ 6,724.02	$ 148,862.48	$ 274,608.66	$ 408,388.23	$ 564,419.83	$ 700,015.97	$ 760,955.53	$ 806,482.79	$ 930,056.76	$ 1,009,104.08	$ 1,139,181.95	$ 1,234,739.15	$ 1,257,752.93	$ 1,292,273.60
DER Enablement: E	$	DEC NC = 60% of	$ 9,416,133	$ -	0	$ -	$ -	$ 1,896	$ 62,147	$ 155,922	$ 271,351	$ 443,378	$ 618,830	$ 724,348	$ 788,207	$ 908,885	$ 980,519	$ 1,116,154	$ 1,248,757	$ 1,274,750	$ 1,296,727
DER/PV Enableme	$		**$ 22,685,424**		**$ -**	**$ -**	**$ -**	**$ 11,597**	**$ 279,167**	**$ 557,851**	**$ 877,022**	**$ 1,284,217**	**$ 1,677,492**	**$ 1,887,688**	**$ 2,015,530**	**$ 2,266,423**	**$ 2,419,144**	**$ 2,698,681**	**$ 2,936,331**	**$ 3,001,906**	**$ 3,069,673**
TOTAL BENEFITS																					
Customer Avoide	$		$ 884,574,122	$ -	$ -	$ 21,307,811	$ 35,324,832	$ 49,572,411	$ 65,622,727	$ 67,263,295	$ 68,944,877	$ 70,668,499	$ 72,435,212	$ 74,246,092	$ 76,102,244	$ 78,004,801	$ 79,954,921	$ 81,953,794	$ 84,002,638	$ 86,102,704	$ 88,255,272
Customer Avoide	$		$ 427,003,208	$ -	$ -	$ 10,868,753	$ 16,894,092	$ 23,529,740	$ 31,671,548	$ 32,463,337	$ 33,274,921	$ 34,106,794	$ 34,959,463	$ 35,833,450	$ 36,729,286	$ 37,647,518	$ 38,588,706	$ 39,553,424	$ 40,542,260	$ 41,555,816	$ 42,594,712
Peak Shaving Be	$		$ 14,286,210	$ -	$ -	$ 769,926	$ 781,477	$ 796,086	$ 819,133	$ 839,420	$ 890,578	$ 946,016	$ 991,206	$ 1,080,311	$ 1,142,643	$ 1,187,152	$ 1,206,880	$ 1,274,376	$ 1,318,198	$ 1,386,995	$ 1,438,129
DER/PV Enabler	$		$ 22,685,424	$ -	$ -	$ -	$ -	$ 11,597	$ 279,167	$ 557,851	$ 877,022	$ 1,284,217	$ 1,677,492	$ 1,887,688	$ 2,015,530	$ 2,266,423	$ 2,419,144	$ 2,698,681	$ 2,936,331	$ 3,001,906	$ 3,069,673
Total Benefits	$	$ -	**$ 1,348,548,964**		**$ -**	**$ 32,946,491**	**$ 53,000,401**	**$ 73,909,834**	**$ 98,392,575**	**$ 101,123,903**	**$ 103,987,398**	**$ 107,005,525**	**$ 110,063,374**	**$ 113,047,541**	**$ 115,989,703**	**$ 119,105,893**	**$ 122,169,651**	**$ 125,480,274**	**$ 128,799,426**	**$ 132,047,421**	**$ 135,357,785**

Duke Energy Caro North Carolina Combined DEC Self O
Sources

		2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	
	Units	18	19	20	21	22	23	24	25	26	27	28	29	30	TOTAL
Benefits		$ 138,803,164	$ 142,368,914	$ 146,008,382	$ 149,712,056	$ 153,541,608	$ 157,486,047	$ 161,375,788	$ 165,507,271	$ 169,704,931	$ 173,975,824	$ 178,191,030	$ 182,592,858	$ 187,128,852	$ 3,778,823,919
Costs		$ 609,057	$ 624,283	$ 639,890	$ 655,888	$ 672,285	$ 689,092	$ 706,319	$ 723,977	$ 742,077	$ 760,629	$ 779,644	$ 799,135	$ 819,114	$ 267,836,137
Net		**$ 138,194,107**	**$ 141,744,631**	**$ 145,368,491**	**$ 149,056,168**	**$ 152,869,323**	**$ 156,796,955**	**$ 160,669,469**	**$ 164,783,294**	**$ 168,962,854**	**$ 173,215,196**	**$ 177,411,385**	**$ 181,793,722**	**$ 186,309,738**	**$ 3,510,987,781**
BCR															
COSTS															
PROGRAM COSTS (Full & Partial SO(															
Switch Automatic	$														$ 224,536,926
Contingency	$														$ 22,844,789
Implementation O&M															
Total Program Co:	$	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 247,381,715
ON-GOING COSTS (Full & Partial SO(															
On-going O&M	$	$ 609,057	$ 624,283	$ 639,890	$ 655,888	$ 672,285	$ 689,092	$ 706,319	$ 723,977	$ 742,077	$ 760,629	$ 779,644	$ 799,135	$ 819,114	$ 16,830,867
Total On-going O&	$	**$ 609,057**	**$ 624,283**	**$ 639,890**	**$ 655,888**	**$ 672,285**	**$ 689,092**	**$ 706,319**	**$ 723,977**	**$ 742,077**	**$ 760,629**	**$ 779,644**	**$ 799,135**	**$ 819,114**	**$ 16,830,867**
TOTAL COSTS															
Program Costs	$	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 251,005,270
On-going Costs	$	$ 609,057	$ 624,283	$ 639,890	$ 655,888	$ 672,285	$ 689,092	$ 706,319	$ 723,977	$ 742,077	$ 760,629	$ 779,644	$ 799,135	$ 819,114	$ 16,830,867
Total Cost	$	**$ 609,057**	**$ 624,283**	**$ 639,890**	**$ 655,888**	**$ 672,285**	**$ 689,092**	**$ 706,319**	**$ 723,977**	**$ 742,077**	**$ 760,629**	**$ 779,644**	**$ 799,135**	**$ 819,114**	**$ 267,836,137**
BENEFITS															
RELIABILITY															
CI Savings	*outages*	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	
CMI Savings	*min*	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	25,793,033	
Typical Duration	*hr*	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	
Residential Custom	*%*	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	86.4%	
Small C&I Custome	*%*	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	
Large C&I Custome	*%*	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	
Residential Outage	*$/outage*	$ 18	$ 18	$ 19	$ 19	$ 20	$ 20	$ 21	$ 21	$ 22	$ 22	$ 23	$ 23	24	
Small C&I Outage \	*$/outage*	$ 3,228	$ 3,309	$ 3,392	$ 3,477	$ 3,564	$ 3,653	$ 3,744	$ 3,838	$ 3,934	$ 4,032	$ 4,133	$ 4,236	4,342	
Large C&I Outage \	*$/outage*	$ 30,106	$ 30,858	$ 31,630	$ 32,420	$ 33,231	$ 34,062	$ 34,913	$ 35,786	$ 36,681	$ 37,598	$ 38,538	$ 39,501	40,489	
Residential Moment	*$/momentary*	$ 9	$ 10	$ 10	$ 10	$ 10	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12	$ 12	13	
Small C&I Momenta	*$/momentary*	$ 837	$ 858	$ 879	$ 901	$ 923	$ 947	$ 970	$ 994	$ 1,019	$ 1,045	$ 1,071	$ 1,098	1,125	
Large C&I Momenta	*$/momentary*	$ 10,896	$ 11,169	$ 11,448	$ 11,734	$ 12,027	$ 12,328	$ 12,636	$ 12,952	$ 13,276	$ 13,608	$ 13,948	$ 14,297	14,654	
Momentary Outage:	*momentaries*	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	126,987	
Customer Avoided (	$	$ 925,580	$ 948,719	$ 972,437	$ 996,748	$ 1,021,667	$ 1,047,208	$ 1,073,389	$ 1,100,223	$ 1,127,729	$ 1,155,922	$ 1,184,820	$ 1,214,441	1,244,802	
Customer Avoided (	$	$ 34,890,451	$ 35,762,712	$ 36,656,780	$ 37,573,199	$ 38,512,529	$ 39,475,343	$ 40,462,226	$ 41,473,782	$ 42,510,626	$ 43,573,392	$ 44,662,727	$ 45,779,295	46,923,777	
Customer Avoided (	$	$ 54,645,623	$ 56,011,764	$ 57,412,058	$ 58,847,359	$ 60,318,543	$ 61,826,507	$ 63,372,170	$ 64,956,474	$ 66,580,386	$ 68,244,895	$ 69,951,018	$ 71,699,793	73,492,288	
Customer Avoidec	$	**$ 90,461,654**	**$ 92,723,195**	**$ 95,041,275**	**$ 97,417,307**	**$ 99,852,740**	**$ 102,349,058**	**$ 104,907,785**	**$ 107,530,479**	**$ 110,218,741**	**$ 112,974,210**	**$ 115,798,565**	**$ 118,693,529**	**121,660,867**	
Customer Avoided I	$	$ 1,034,351	$ 1,060,210	$ 1,086,715	$ 1,113,883	$ 1,141,730	$ 1,170,273	$ 1,199,530	$ 1,229,519	$ 1,260,256	$ 1,291,763	$ 1,324,057	$ 1,357,158	1,391,087	
Customer Avoided I	$	$ 12,063,108	$ 12,364,686	$ 12,673,803	$ 12,990,648	$ 13,315,415	$ 13,648,300	$ 13,989,507	$ 14,339,245	$ 14,697,726	$ 15,065,169	$ 15,441,799	$ 15,827,844	16,223,540	
Customer Avoided I	$	$ 30,562,120	$ 31,326,173	$ 32,109,327	$ 32,912,060	$ 33,734,862	$ 34,578,233	$ 35,442,689	$ 36,328,756	$ 37,236,975	$ 38,167,900	$ 39,122,097	$ 40,100,149	41,102,653	
Customer Avoidec	$	**$ 43,659,579**	**$ 44,751,069**	**$ 45,869,846**	**$ 47,016,592**	**$ 48,192,006**	**$ 49,396,807**	**$ 50,631,727**	**$ 51,897,520**	**$ 53,194,958**	**$ 54,524,832**	**$ 55,887,953**	**$ 57,285,151**	**58,717,280**	
CAPACITY SAVINGS															
Capacity Savings fr	*MW*	15	15	15	15	16	16	16	16	17	17	17	17	17	
Capacity Value	*$/kW*	$ 102	$ 103	$ 104	$ 105	$ 107	$ 110	$ 112	$ 115	$ 118	$ 121	$ 121	$ 121	121	
Capacity Savings	$	**$ 1,496,071**	**$ 1,554,218**	**$ 1,580,372**	**$ 1,608,603**	**$ 1,672,382**	**$ 1,734,574**	**$ 1,796,529**	**$ 1,892,930**	**$ 1,964,335**	**$ 2,024,867**	**$ 2,050,736**	**$ 2,067,142**	**$ 2,083,679**	**$ 40,199,995**
ENERGY SAVINGS															
Capacity factor for (	-	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	
Energy Savings fror	*MWh*	515	528	533	539	547	554	560	577	584	588	596	601	605	
Energy Value	*$/MWh*	$ 26	$ 28	$ 29	$ 31	$ 32	$ 33	$ 34	$ 35	$ 35	$ 36	$ 37	$ 38	38	
Energy Savings (I*	$	**$ 13,530**	**$ 14,630**	**$ 15,674**	**$ 16,633**	**$ 17,435**	**$ 18,363**	**$ 19,200**	**$ 20,033**	**$ 20,734**	**$ 21,301**	**$ 22,116**	**$ 22,575**	**$ 23,107**	**$ 377,445**
ENVIRONMENTAL BENEFITS															
Value: SOx	*$/ton*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	
Value: NOx	*$/ton*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	
Value: CO2	*$/ton*	$ 80	$ 85	$ 90	$ 95	$ 100	$ 105	$ 110	$ 115	$ 120	$ 125	$ 130	$ 135	140	
Energy: SOx reduct	*ton/MWh*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Energy: NOx reduct	*ton/MWh*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Energy: CO2 reduct	*ton/MWh*	0.20	0.20	0.20	0.20	0.20	0.20	0.19	0.19	0.19	0.19	0.18	0.18	0.18	
Environmental Bene	$	$ 8,353	$ 9,017	$ 9,658	$ 10,240	$ 10,993	$ 11,821	$ 11,717	$ 12,799	$ 13,591	$ 14,199	$ 14,064	$ 14,671	$ 15,439	$ 219,415
Environmental Be	$	**$ 8,353**	**$ 9,017**	**$ 9,658**	**$ 10,240**	**$ 10,993**	**$ 11,821**	**$ 11,717**	**$ 12,799**	**$ 13,591**	**$ 14,199**	**$ 14,064**	**$ 14,671**	**$ 15,439**	**$ 219,415**
Peak Shaving Ben	$	**$ 1,517,954**	**$ 1,577,865**	**$ 1,605,704**	**$ 1,635,476**	**$ 1,700,810**	**$ 1,764,758**	**$ 1,827,446**	**$ 1,925,763**	**$ 1,998,660**	**$ 2,060,368**	**$ 2,086,916**	**$ 2,104,388**	**$ 2,122,225**	**$ 40,796,855**
DER ENABLEMENT															
Forecasted PV (Ani	*MW*	45	45	45	46	46	47	49	49	49	51	51	53	55	
Forecasted PV (Cu	*MW*	901	946	992	1,038	1,084	1,131	1,180	1,229	1,278	1,329	1,380	1,433	1,488	
PV scaling factor (S	-	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	
Limit (without SOG)	*MW*	310	310	310	310	310	310	310	310	310	310	310	310	310	
Limit (with SOG)	*MW*	522	522	522	522	522	522	522	522	522	522	522	522	522	
PV derate factor for	-	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	
PV Enablement	*MW*	43	43	43	43	43	43	43	43	43	43	43	43	43	
Energy Savings	*MWh/MW*	1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936	1,936	
DER Enablement: (	$	$ 499,381.57	$ 506,455.94	$ 510,024.22	$ 513,637.82	$ 525,966.22	$ 538,592.31	$ 551,520.59	$ 564,759.19	$ 578,315.57	$ 592,197.36	$ 592,197.36	$ 592,197.36	$ 592,197.36	$ 11,714,726
DER Enablement: E	$	$ 1,313,286.17	$ 1,386,329.90	$ 1,470,880.52	$ 1,544,424.54	$ 1,594,454.49	$ 1,657,992.53	$ 1,714,026.07	$ 1,738,040.45	$ 1,775,062.61	$ 1,811,584.47	$ 1,857,111.73	$ 1,880,625.80	$ 1,909,643.17	$ 32,187,028
DER Enablement: E	$	$ 1,351,309	$ 1,424,000	$ 1,510,653	$ 1,584,619	$ 1,675,630	$ 1,778,839	$ 1,743,284	$ 1,850,709	$ 1,939,194	$ 2,012,633	$ 1,968,288	$ 2,036,966	$ 2,126,639	$ 32,894,634
DER/PV Enableme	$	**$ 3,163,977**	**$ 3,316,785**	**$ 3,491,557**	**$ 3,642,681**	**$ 3,796,051**	**$ 3,975,424**	**$ 4,008,831**	**$ 4,153,509**	**$ 4,292,572**	**$ 4,416,415**	**$ 4,417,597**	**$ 4,509,790**	**$ 4,628,479**	**$ 76,796,389**
TOTAL BENEFITS															
Customer Avoide	$	$ 90,461,654	$ 92,723,195	$ 95,041,275	$ 97,417,307	$ 99,852,740	$ 102,349,058	$ 104,907,785	$ 107,530,479	$ 110,218,741	$ 112,974,210	$ 115,798,565	$ 118,693,529	$ 121,660,867	$ 2,469,391,534
Customer Avoide	$	$ 43,659,579	$ 44,751,069	$ 45,869,846	$ 47,016,592	$ 48,192,006	$ 49,396,807	$ 50,631,727	$ 51,897,520	$ 53,194,958	$ 54,524,832	$ 55,887,953	$ 57,285,151	$ 58,717,280	$ 1,191,839,141
Peak Shaving Be	$	$ 1,517,954	$ 1,577,865	$ 1,605,704	$ 1,635,476	$ 1,700,810	$ 1,764,758	$ 1,827,446	$ 1,925,763	$ 1,998,660	$ 2,060,368	$ 2,086,916	$ 2,104,388	$ 2,122,225	$ 40,796,855
DER/PV Enabler	$	$ 3,163,977	$ 3,316,785	$ 3,491,557	$ 3,642,681	$ 3,796,051	$ 3,975,424	$ 4,008,831	$ 4,153,509	$ 4,292,572	$ 4,416,415	$ 4,417,597	$ 4,509,790	$ 4,628,479	$ 76,796,389
Total Benefits	$	**$ 138,803,164**	**$ 142,368,914**	**$ 146,008,382**	**$ 149,712,056**	**$ 153,541,608**	**$ 157,486,047**	**$ 161,375,788**	**$ 165,507,271**	**$ 169,704,931**	**$ 173,975,824**	**$ 178,191,030**	**$ 182,592,858**	**$ 187,128,852**	**$ 3,778,823,919**

AREA/PROJECT/PROGRAM	**Distribution H&R Lateral - 7a**
PERIOD:	**2024-2026**
REGULATORY JURISDICTION:	**DEC**
STATE:	**NC**

	NPV of COST/BENEFIT STREAM	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
		0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
COSTS										
Program Capital Costs	$ 319,677,077	$ 799,642	$ 50,301,228	$ 134,260,745	$ 128,432,855	$ 60,878,918	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 35,073,081	$ 87,732	$ 5,518,754	$ 14,730,296	$ 14,090,894	$ 6,679,275	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 354,750,158	$ 887,374	$ 55,819,982	$ 148,991,041	$ 142,523,749	$ 67,558,193	$ -	$ -	$ -	$ -
Program O&M Costs	$ 6,797,936	$ 17,004	$ 1,069,656	$ 2,855,056	$ 2,731,126	$ 1,294,591	$ -	$ -	$ -	$ -
Total Program Costs	$ 361,548,093	$ 904,378	$ 56,889,638	$ 151,846,097	$ 145,254,875	$ 68,852,784	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS										
Avoided Outage Benefits	$ 9,487,387	$ -	$ -	$ -	$ 120,307	$ 353,080	$ 749,347	$ 768,080	$ 787,282	$ 806,965
Total Operational Benefits	$ 9,487,387	$ -	$ -	$ -	$ 120,307	$ 353,080	$ 749,347	$ 768,080	$ 787,282	$ 806,965
CUSTOMER BENEFITS										
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 471,647	$ -	$ -	$ -	$ 5,700	$ 17,145	$ 37,297	$ 38,230	$ 39,186	$ 40,165
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 11,134,278	$ -	$ -	$ -	$ 134,550	$ 404,754	$ 880,489	$ 902,501	$ 925,064	$ 948,190
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Momentary Outage Benefits (Non-MED & MED) - Residential Customers	$ 20,786,747	$ -	$ -	$ -	$ 251,193	$ 755,641	$ 1,643,797	$ 1,684,892	$ 1,727,015	$ 1,770,190
Avoided Momentary Outage Benefits (Non-MED & MED) - Small C&I Customers	$ 242,425,193	$ -	$ -	$ -	$ 2,929,537	$ 8,812,650	$ 19,170,768	$ 19,650,037	$ 20,141,288	$ 20,644,820
Avoided Momentary Outage Benefits (Non-MED & MED) - Medium & Large C&I Custo	$ 614,188,938	$ -	$ -	$ -	$ 7,422,040	$ 22,327,021	$ 48,569,514	$ 49,783,751	$ 51,028,345	$ 52,304,054
Total Customer Benefits	$ 889,006,803	$ -	$ -	$ -	$ 10,743,020	$ 32,317,210	$ 70,301,865	$ 72,059,412	$ 73,860,897	$ 75,707,420
COMBINED COSTS AND BENEFITS										
Total PV of Operational Benefits	$ 9,487,387	$ -	$ -	$ -	$ 120,307	$ 353,080	$ 749,347	$ 768,080	$ 787,282	$ 806,965
Total PV of Customer Benefits	$ 889,006,803	$ -	$ -	$ -	$ 10,743,020	$ 32,317,210	$ 70,301,865	$ 72,059,412	$ 73,860,897	$ 75,707,420
Total PV of Combined Benefits	$ 898,494,190	$ -	$ -	$ -	$ 10,863,327	$ 32,670,291	$ 71,051,212	$ 72,827,492	$ 74,648,180	$ 76,514,384
Total PV Program and On-Going Costs	$ 361,548,093	$ 904,378	$ 56,889,638	$ 151,846,097	$ 145,254,875	$ 68,852,784	$ -	$ -	$ -	$ -
Combined NPV of Program	$ 536,946,097	$ (904,378)	$ (56,889,638)	$ (151,846,097)	$ (134,391,548)	$ (36,182,493)	$ 71,051,212	$ 72,827,492	$ 74,648,180	$ 76,514,384
Ratio of NPV Benefits to NPV Costs	2.5									
Cumulative Net Benefits (Payback Period)		$ (904,378)	$ (57,794,016)	$ (209,640,113)	$ (344,031,661)	$ (380,214,154)	$ (309,162,942)	$ (236,335,450)	$ (161,687,270)	$ (85,172,886)

AREA/PROJECT/PROGRAM	**Distribution H&R Lateral - 7a**
PERIOD:	**2024-2026**
REGULATORY JURISDICTION:	**DEC**
STATE:	**NC**

	NPV of COST/BENEFIT STREAM	YEAR								
		2031	2032	2033	2034	2035	2036	2037	2038	2039
		9	10	11	12	13	14	15	16	17
COSTS										
Program Capital Costs	$ 319,677,077	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 35,073,081	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 354,750,158	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 6,797,936	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	$ 361,548,093	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS										
Avoided Outage Benefits	$ 9,487,387	$ 827,139	$ 847,817	$ 869,013	$ 890,738	$ 913,006	$ 935,831	$ 959,227	$ 983,208	$ 1,007,788
Total Operational Benefits	$ 9,487,387	$ 827,139	$ 847,817	$ 869,013	$ 890,738	$ 913,006	$ 935,831	$ 959,227	$ 983,208	$ 1,007,788
CUSTOMER BENEFITS										
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 471,647	$ 41,169	$ 42,199	$ 43,254	$ 44,335	$ 45,443	$ 46,579	$ 47,744	$ 48,937	$ 50,161
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 11,134,278	$ 971,895	$ 996,192	$ 1,021,097	$ 1,046,624	$ 1,072,790	$ 1,099,610	$ 1,127,100	$ 1,155,278	$ 1,184,160
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Momentary Outage Benefits (Non-MED & MED) - Residential Customers	$ 20,786,747	$ 1,814,445	$ 1,859,806	$ 1,906,301	$ 1,953,959	$ 2,002,808	$ 2,052,878	$ 2,104,200	$ 2,156,805	$ 2,210,725
Avoided Momentary Outage Benefits (Non-MED & MED) - Small C&I Customers	$ 242,425,193	$ 21,160,941	$ 21,689,965	$ 22,232,214	$ 22,788,019	$ 23,357,719	$ 23,941,662	$ 24,540,204	$ 25,153,709	$ 25,782,552
Avoided Momentary Outage Benefits (Non-MED & MED) - Medium & Large C&I Custo	$ 614,188,938	$ 53,611,655	$ 54,951,947	$ 56,325,745	$ 57,733,889	$ 59,177,236	$ 60,656,667	$ 62,173,084	$ 63,727,411	$ 65,320,596
Total Customer Benefits	$ 889,006,803	$ 77,600,105	$ 79,540,108	$ 81,528,610	$ 83,566,826	$ 85,655,996	$ 87,797,396	$ 89,992,331	$ 92,242,139	$ 94,548,193
COMBINED COSTS AND BENEFITS										
Total PV of Operational Benefits	$ 9,487,387	$ 827,139	$ 847,817	$ 869,013	$ 890,738	$ 913,006	$ 935,831	$ 959,227	$ 983,208	$ 1,007,788
Total PV of Customer Benefits	$ 889,006,803	$ 77,600,105	$ 79,540,108	$ 81,528,610	$ 83,566,826	$ 85,655,996	$ 87,797,396	$ 89,992,331	$ 92,242,139	$ 94,548,193
Total PV of Combined Benefits	$ 898,494,190	$ 78,427,244	$ 80,387,925	$ 82,397,623	$ 84,457,564	$ 86,569,003	$ 88,733,228	$ 90,951,558	$ 93,225,347	$ 95,555,981
Total PV Program and On-Going Costs	$ 361,548,093	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Combined NPV of Program	$ 536,946,097	$ 78,427,244	$ 80,387,925	$ 82,397,623	$ 84,457,564	$ 86,569,003	$ 88,733,228	$ 90,951,558	$ 93,225,347	$ 95,555,981
Ratio of NPV Benefits to NPV Costs	2.5									
Cumulative Net Benefits (Payback Period)		$ (6,745,642)	$ 73,642,283	$ 156,039,906	$ 240,497,469	$ 327,066,472	$ 415,799,700	$ 506,751,258	$ 599,976,605	$ 695,532,586

AREA/PROJECT/PROGRAM	**Distribution H&R Lateral - 7a**
PERIOD:	**2024-2026**
REGULATORY JURISDICTION:	**DEC**
STATE:	**NC**

	NPV of COST/BENEFIT STREAM	2040	2041	2042	2043	2044	2045	2046	2047	2048
		18	19	20	21	22	23	24	25	26
COSTS										
Program Capital Costs	$ 319,677,077	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 35,073,081	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 354,750,158	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 6,797,936	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	$ 361,548,093	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS										
Avoided Outage Benefits	$ 9,487,387	$ 1,032,983	$ 1,058,807	$ 1,085,278	$ 1,112,410	$ 1,140,220	$ 1,168,725	$ 1,197,943	$ 1,227,892	$ 1,258,589
Total Operational Benefits	$ 9,487,387	$ 1,032,983	$ 1,058,807	$ 1,085,278	$ 1,112,410	$ 1,140,220	$ 1,168,725	$ 1,197,943	$ 1,227,892	$ 1,258,589
CUSTOMER BENEFITS										
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 471,647	$ 51,415	$ 52,700	$ 54,018	$ 55,368	$ 56,752	$ 58,171	$ 59,625	$ 61,116	$ 62,644
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 11,134,278	$ 1,213,763	$ 1,244,108	$ 1,275,210	$ 1,307,091	$ 1,339,768	$ 1,373,262	$ 1,407,594	$ 1,442,783	$ 1,478,853
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Momentary Outage Benefits (Non-MED & MED) - Residential Customers	$ 20,786,747	$ 2,265,993	$ 2,322,643	$ 2,380,709	$ 2,440,227	$ 2,501,232	$ 2,563,763	$ 2,627,857	$ 2,693,553	$ 2,760,892
Avoided Momentary Outage Benefits (Non-MED & MED) - Small C&I Customers	$ 242,425,193	$ 26,427,116	$ 27,087,793	$ 27,764,988	$ 28,459,113	$ 29,170,591	$ 29,899,856	$ 30,647,352	$ 31,413,536	$ 32,198,874
Avoided Momentary Outage Benefits (Non-MED & MED) - Medium & Large C&I Custo	$ 614,188,938	$ 66,953,611	$ 68,627,451	$ 70,343,137	$ 72,101,716	$ 73,904,259	$ 75,751,865	$ 77,645,662	$ 79,586,803	$ 81,576,473
Total Customer Benefits	$ 889,006,803	$ 96,911,898	$ 99,334,695	$ 101,818,063	$ 104,363,514	$ 106,972,602	$ 109,646,917	$ 112,388,090	$ 115,197,792	$ 118,077,737
COMBINED COSTS AND BENEFITS										
Total PV of Operational Benefits	$ 9,487,387	$ 1,032,983	$ 1,058,807	$ 1,085,278	$ 1,112,410	$ 1,140,220	$ 1,168,725	$ 1,197,943	$ 1,227,892	$ 1,258,589
Total PV of Customer Benefits	$ 889,006,803	$ 96,911,898	$ 99,334,695	$ 101,818,063	$ 104,363,514	$ 106,972,602	$ 109,646,917	$ 112,388,090	$ 115,197,792	$ 118,077,737
Total PV of Combined Benefits	$ 898,494,190	$ 97,944,881	$ 100,393,503	$ 102,903,340	$ 105,475,924	$ 108,112,822	$ 110,815,642	$ 113,586,033	$ 116,425,684	$ 119,336,326
Total PV Program and On-Going Costs	$ 361,548,093	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Combined NPV of Program	$ 536,946,097	$ 97,944,881	$ 100,393,503	$ 102,903,340	$ 105,475,924	$ 108,112,822	$ 110,815,642	$ 113,586,033	$ 116,425,684	$ 119,336,326
Ratio of NPV Benefits to NPV Costs	2.5									
Cumulative Net Benefits (Payback Period)		$ 793,477,467	$ 893,870,969	$ 996,774,310	$ 1,102,250,233	$ 1,210,363,055	$ 1,321,178,697	$ 1,434,764,730	$ 1,551,190,415	$ 1,670,526,741

AREA/PROJECT/PROGRAM	Distribution H&R Lateral - 7a
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2049	2050	2051	2052	TOTAL
		27	28	29	30	
COSTS						
Program Capital Costs	$ 319,677,077	$ -	$ -	$ -	$ -	$ 374,673,388
Program Capital Contingency Costs	$ 35,073,081	$ -	$ -	$ -	$ -	$ 41,106,951
Total Program Capital Costs	$ 354,750,158	$ -	$ -	$ -	$ -	$ 415,780,339
Program O&M Costs	$ 6,797,936	$ -	$ -	$ -	$ -	$ 7,967,433
Total Program Costs	$ 361,548,093	$ -	$ -	$ -	$ -	$ 423,747,772
	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS						
Avoided Outage Benefits	$ 9,487,387	$ 1,290,054	$ 1,322,305	$ 1,355,363	$ 1,389,247	$ 27,458,645
Total Operational Benefits	$ 9,487,387	$ 1,290,054	$ 1,322,305	$ 1,355,363	$ 1,389,247	$ 27,458,645
CUSTOMER BENEFITS						
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 471,647	$ 64,210	$ 65,815	$ 67,461	$ 69,147	$ 1,365,988
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 11,134,278	$ 1,515,824	$ 1,553,720	$ 1,592,563	$ 1,632,377	$ 32,247,208
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -
						$ -
Avoided Momentary Outage Benefits (Non-MED & MED) - Residential Customers	$ 20,786,747	$ 2,829,915	$ 2,900,663	$ 2,973,179	$ 3,047,509	$ 60,202,787
Avoided Momentary Outage Benefits (Non-MED & MED) - Small C&I Customers	$ 242,425,193	$ 33,003,846	$ 33,828,942	$ 34,674,666	$ 35,541,532	$ 702,114,292
Avoided Momentary Outage Benefits (Non-MED & MED) - Medium & Large C&I Custo	$ 614,188,938	$ 83,615,885	$ 85,706,282	$ 87,848,939	$ 90,045,163	$ 1,778,820,201
						$ -
Total Customer Benefits	$ 889,006,803	$ 121,029,680	$ 124,055,422	$ 127,156,808	$ 130,335,728	$ 2,574,750,476
COMBINED COSTS AND BENEFITS						
Total PV of Operational Benefits	$ 9,487,387	$ 1,290,054	$ 1,322,305	$ 1,355,363	$ 1,389,247	$ 27,458,645
Total PV of Customer Benefits	$ 889,006,803	$ 121,029,680	$ 124,055,422	$ 127,156,808	$ 130,335,728	$ 2,574,750,476
Total PV of Combined Benefits	$ 898,494,190	$ 122,319,734	$ 125,377,728	$ 128,512,171	$ 131,724,975	$ 2,602,209,121
Total PV Program and On-Going Costs	$ 361,548,093	$ -	$ -	$ -	$ -	$ 423,747,772
Combined NPV of Program	$ 536,946,097	$ 122,319,734	$ 125,377,728	$ 128,512,171	$ 131,724,975	$ 2,178,461,349
Ratio of NPV Benefits to NPV Costs	2.5					
Cumulative Net Benefits (Payback Period)		$ 1,792,846,475	$ 1,918,224,203	$ 2,046,736,374	$ 2,178,461,349	$ 4,356,922,698

AREA/PROJECT/PROGRAM	Distribution H&R Public Int. - 7c
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2022	2023	2024	2025	2026	2027
		0	1	2	3	4	5
COSTS							
Program Capital Costs	$ 71,083,834	$ 431,505	$ 14,618,638	$ 28,913,803	$ 29,479,475	$ 9,143,253	$ -
Program Capital Contingency Costs	$ 7,717,138	$ 46,846	$ 1,587,056	$ 3,138,995	$ 3,200,406	$ 992,627	$ -
Total Program Capital Costs	$ 78,800,972	$ 478,350	$ 16,205,695	$ 32,052,798	$ 32,679,881	$ 10,135,880	$ -
Program O&M Costs	$ 1,507,044	$ 9,148	$ 309,929	$ 613,000	$ 624,993	$ 193,846	$ -
Total Program Costs	**$ 80,308,016**	**$ 487,499**	**$ 16,515,623**	**$ 32,665,798**	**$ 33,304,874**	**$ 10,329,725**	**$ -**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS							
Avoided Outage Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Operational Benefits	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
CUSTOMER BENEFITS							
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 1,527,692	$ -	$ -	$ -	$ 14,190	$ 63,112	$ 120,615
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 34,332,625	$ -	$ -	$ -	$ 318,910	$ 1,418,347	$ 2,710,654
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 64,086,067	$ -	$ -	$ -	$ 595,284	$ 2,647,519	$ 5,059,769
Total Customer Benefits	**$ 99,946,384**	**$ -**	**$ -**	**$ -**	**$ 928,384**	**$ 4,128,978**	**$ 7,891,039**
COMBINED COSTS AND BENEFITS							
Total PV of Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total PV of Customer Benefits	$ 99,946,384	$ -	$ -	$ -	$ 928,384	$ 4,128,978	$ 7,891,039
Total PV of Combined Benefits	**$ 99,946,384**	**$ -**	**$ -**	**$ -**	**$ 928,384**	**$ 4,128,978**	**$ 7,891,039**
Total PV Program and On-Going Costs	**$ 80,308,016**	**$ 487,499**	**$ 16,515,623**	**$ 32,665,798**	**$ 33,304,874**	**$ 10,329,725**	**$ -**
Combined NPV of Program	**$ 19,638,369**	**$ (487,499)**	**$ (16,515,623)**	**$ (32,665,798)**	**$ (32,376,490)**	**$ (6,200,748)**	**$ 7,891,039**
Ratio of NPV Benefits to NPV Costs	**1.2**						

AREA/PROJECT/PROGRAM	Distribution H&R Public Int. - 7c
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2028	2029	2030	2031	2032	2033	2034
		6	7	8	9	10	11	12
COSTS								
Program Capital Costs	$ 71,083,834	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 7,717,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 78,800,972	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 1,507,044	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	**$ 80,308,016**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS								
Avoided Outage Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Operational Benefits	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
CUSTOMER BENEFITS								
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 1,527,692	$ 123,631	$ 126,722	$ 129,890	$ 133,137	$ 136,465	$ 139,877	$ 143,374
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 34,332,625	$ 2,778,420	$ 2,847,881	$ 2,919,078	$ 2,992,055	$ 3,066,856	$ 3,143,528	$ 3,222,116
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 64,086,067	$ 5,186,263	$ 5,315,920	$ 5,448,818	$ 5,585,038	$ 5,724,664	$ 5,867,781	$ 6,014,476
Total Customer Benefits	**$ 99,946,384**	**$ 8,088,315**	**$ 8,290,523**	**$ 8,497,786**	**$ 8,710,230**	**$ 8,927,986**	**$ 9,151,186**	**$ 9,379,965**
COMBINED COSTS AND BENEFITS								
Total PV of Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total PV of Customer Benefits	$ 99,946,384	$ 8,088,315	$ 8,290,523	$ 8,497,786	$ 8,710,230	$ 8,927,986	$ 9,151,186	$ 9,379,965
Total PV of Combined Benefits	**$ 99,946,384**	**$ 8,088,315**	**$ 8,290,523**	**$ 8,497,786**	**$ 8,710,230**	**$ 8,927,986**	**$ 9,151,186**	**$ 9,379,965**
Total PV Program and On-Going Costs	**$ 80,308,016**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Combined NPV of Program	**$ 19,638,369**	**$ 8,088,315**	**$ 8,290,523**	**$ 8,497,786**	**$ 8,710,230**	**$ 8,927,986**	**$ 9,151,186**	**$ 9,379,965**
Ratio of NPV Benefits to NPV Costs	**1.2**							

AREA/PROJECT/PROGRAM	Distribution H&R Public Int. - 7c
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	YEAR						
		2035	2036	2037	2038	2039	2040	2041
		13	14	15	16	17	18	19
COSTS								
Program Capital Costs	$ 71,083,834	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 7,717,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 78,800,972	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 1,507,044	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	**$ 80,308,016**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS								
Avoided Outage Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Operational Benefits	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
CUSTOMER BENEFITS								
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 1,527,692	$ 146,958	$ 150,632	$ 154,398	$ 158,258	$ 162,214	$ 166,270	$ 170,427
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 34,332,625	$ 3,302,669	$ 3,385,235	$ 3,469,866	$ 3,556,613	$ 3,645,528	$ 3,736,667	$ 3,830,083
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 64,086,067	$ 6,164,837	$ 6,318,958	$ 6,476,932	$ 6,638,856	$ 6,804,827	$ 6,974,948	$ 7,149,321
Total Customer Benefits	**$ 99,946,384**	**$ 9,614,464**	**$ 9,854,826**	**$ 10,101,197**	**$ 10,353,727**	**$ 10,612,570**	**$ 10,877,884**	**$ 11,149,831**
COMBINED COSTS AND BENEFITS								
Total PV of Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total PV of Customer Benefits	$ 99,946,384	$ 9,614,464	$ 9,854,826	$ 10,101,197	$ 10,353,727	$ 10,612,570	$ 10,877,884	$ 11,149,831
Total PV of Combined Benefits	**$ 99,946,384**	**$ 9,614,464**	**$ 9,854,826**	**$ 10,101,197**	**$ 10,353,727**	**$ 10,612,570**	**$ 10,877,884**	**$ 11,149,831**
Total PV Program and On-Going Costs	**$ 80,308,016**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Combined NPV of Program	**$ 19,638,369**	**$ 9,614,464**	**$ 9,854,826**	**$ 10,101,197**	**$ 10,353,727**	**$ 10,612,570**	**$ 10,877,884**	**$ 11,149,831**
Ratio of NPV Benefits to NPV Costs	**1.2**							

AREA/PROJECT/PROGRAM	Distribution H&R Public Int. - 7c
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2042	2043	2044	2045	2046	2047	2048
		20	21	22	23	24	25	26
COSTS								
Program Capital Costs	$ 71,083,834	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 7,717,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 78,800,972	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 1,507,044	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	**$ 80,308,016**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS								
Avoided Outage Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Operational Benefits	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
CUSTOMER BENEFITS								
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 1,527,692	$ 174,687	$ 179,054	$ 183,531	$ 188,119	$ 192,822	$ 197,642	$ 202,584
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 34,332,625	$ 3,925,835	$ 4,023,981	$ 4,124,581	$ 4,227,695	$ 4,333,388	$ 4,441,722	$ 4,552,765
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 64,086,067	$ 7,328,054	$ 7,511,256	$ 7,699,037	$ 7,891,513	$ 8,088,801	$ 8,291,021	$ 8,498,296
Total Customer Benefits	**$ 99,946,384**	**$ 11,428,577**	**$ 11,714,291**	**$ 12,007,149**	**$ 12,307,327**	**$ 12,615,010**	**$ 12,930,386**	**$ 13,253,645**
COMBINED COSTS AND BENEFITS								
Total PV of Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total PV of Customer Benefits	$ 99,946,384	$ 11,428,577	$ 11,714,291	$ 12,007,149	$ 12,307,327	$ 12,615,010	$ 12,930,386	$ 13,253,645
Total PV of Combined Benefits	**$ 99,946,384**	**$ 11,428,577**	**$ 11,714,291**	**$ 12,007,149**	**$ 12,307,327**	**$ 12,615,010**	**$ 12,930,386**	**$ 13,253,645**
Total PV Program and On-Going Costs	**$ 80,308,016**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Combined NPV of Program	**$ 19,638,369**	**$ 11,428,577**	**$ 11,714,291**	**$ 12,007,149**	**$ 12,307,327**	**$ 12,615,010**	**$ 12,930,386**	**$ 13,253,645**
Ratio of NPV Benefits to NPV Costs	**1.2**							

AREA/PROJECT/PROGRAM	Distribution H&R Public Int. - 7c
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2049	2050	2051	2052
		27	28	29	30
COSTS					
Program Capital Costs	$ 71,083,834	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 7,717,138	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 78,800,972	$ -	$ -	$ -	$ -
Program O&M Costs	$ 1,507,044	$ -	$ -	$ -	$ -
Total Program Costs	**$ 80,308,016**	**$ -**	**$ -**	**$ -**	**$ -**
	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS					
Avoided Outage Benefits	$ -	$ -	$ -	$ -	$ -
Total Operational Benefits	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
CUSTOMER BENEFITS					
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 1,527,692	$ 207,648	$ 212,839	$ 218,160	$ 223,614
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 34,332,625	$ 4,666,585	$ 4,783,249	$ 4,902,830	$ 5,025,401
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 64,086,067	$ 8,710,754	$ 8,928,523	$ 9,151,736	$ 9,380,529
Total Customer Benefits	**$ 99,946,384**	**$ 13,584,987**	**$ 13,924,611**	**$ 14,272,726**	**$ 14,629,545**
COMBINED COSTS AND BENEFITS					
Total PV of Operational Benefits	$ -	$ -	$ -	$ -	$ -
Total PV of Customer Benefits	$ 99,946,384	$ 13,584,987	$ 13,924,611	$ 14,272,726	$ 14,629,545
Total PV of Combined Benefits	**$ 99,946,384**	**$ 13,584,987**	**$ 13,924,611**	**$ 14,272,726**	**$ 14,629,545**
Total PV Program and On-Going Costs	**$ 80,308,016**	**$ -**	**$ -**	**$ -**	**$ -**
Combined NPV of Program	**$ 19,638,369**	**$ 13,584,987**	**$ 13,924,611**	**$ 14,272,726**	**$ 14,629,545**
Ratio of NPV Benefits to NPV Costs	**1.2**				

AREA/PROJECT/PROGRAM	**Distribution H&R Storm - 7b**
PERIOD:	**2024-2026**
REGULATORY JURISDICTION:	**DEC**
STATE:	**NC**

	NPV of COST/BENEFIT STREAM	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
		0	**1**	**2**	**3**	**4**	**5**	**6**
COSTS								
Program Capital Costs	$ 36,974,775	$ -	$ 4,002,757	$ 13,664,601	$ 15,077,677	$ 11,235,699	$ -	$ -
Program Capital Contingency Costs	$ 4,067,225	$ -	$ 440,303	$ 1,503,106	$ 1,658,544	$ 1,235,927	$ -	$ -
Total Program Capital Costs	$ 41,042,000	$ -	$ 4,443,060	$ 15,167,707	$ 16,736,221	$ 12,471,626	$ -	$ -
Program O&M Costs	$ 791,975	$ -	$ 85,736	$ 292,687	$ 322,954	$ 240,661	$ -	$ -
Total Program Costs	**$ 41,833,976**	**$ -**	**$ 4,528,797**	**$ 15,460,394**	**$ 17,059,175**	**$ 12,712,287**	**$ -**	**$ -**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS								
Avoided Outage Benefits	$ 2,201,659	$ -	$ -	$ -	$ 11,560	$ 67,571	$ 175,923	$ 180,321
Total Operational Benefits	**$ 2,201,659**	**$ -**	**$ -**	**$ -**	**$ 11,560**	**$ 67,571**	**$ 175,923**	**$ 180,321**
CUSTOMER BENEFITS								
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 451,898	$ -	$ -	$ -	$ 2,260	$ 13,542	$ 36,137	$ 37,041
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 12,215,374	$ -	$ -	$ -	$ 61,095	$ 366,046	$ 976,838	$ 1,001,259
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 20,927,566	$ -	$ -	$ -	$ 104,669	$ 627,115	$ 1,673,533	$ 1,715,372
Avoided Sustained Outage Benefits (MED) - Residential Customers	$ 1,463,999	$ -	$ -	$ -	$ 7,322	$ 43,870	$ 117,073	$ 120,000
Avoided Sustained Outage Benefits (MED) - Small C&I Customers	$ 56,279,522	$ -	$ -	$ -	$ 281,482	$ 1,686,470	$ 4,500,555	$ 4,613,069
Avoided Sustained Outage Benefits (MED) - Medium & Large C&I Customers	$ 74,405,811	$ -	$ -	$ -	$ 372,141	$ 2,229,642	$ 5,950,076	$ 6,098,828
Total Customer Benefits	**$ 165,744,170**	**$ -**	**$ -**	**$ -**	**$ 828,971**	**$ 4,966,685**	**$ 13,254,213**	**$ 13,585,568**
COMBINED COSTS AND BENEFITS								
Total PV of Operational Benefits	$ 2,201,659	$ -	$ -	$ -	$ 11,560	$ 67,571	$ 175,923	$ 180,321
Total PV of Customer Benefits	$ 165,744,170	$ -	$ -	$ -	$ 828,971	$ 4,966,685	$ 13,254,213	$ 13,585,568
Total PV of Combined Benefits	**$ 167,945,829**	**$ -**	**$ -**	**$ -**	**$ 840,530**	**$ 5,034,255**	**$ 13,430,136**	**$ 13,765,889**
Total PV Program and On-Going Costs	**$ 41,833,976**	**$ -**	**$ 4,528,797**	**$ 15,460,394**	**$ 17,059,175**	**$ 12,712,287**	**$ -**	**$ -**
Combined NPV of Program	**$ 126,111,853**	**$ -**	**$ (4,528,797)**	**$ (15,460,394)**	**$ (16,218,645)**	**$ (7,678,032)**	**$ 13,430,136**	**$ 13,765,889**
Ratio of NPV Benefits to NPV Costs	**4.0**							
Cumulative Net Benefits (Payback Period)		$ -	$ (4,528,797)	$ (19,989,191)	$ (36,207,835)	$ (43,885,867)	$ (30,455,732)	$ (16,689,843)

AREA/PROJECT/PROGRAM	Distribution H&R Storm - 7b
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2029	2030	2031	2032	2033	2034	2035
		7	8	9	10	11	12	13
COSTS								
Program Capital Costs	$ 36,974,775	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 4,067,225	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 41,042,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 791,975	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	**$ 41,833,976**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS								
Avoided Outage Benefits	$ 2,201,659	$ 184,829	$ 189,450	$ 194,186	$ 199,041	$ 204,017	$ 209,117	$ 214,345
Total Operational Benefits	**$ 2,201,659**	**$ 184,829**	**$ 189,450**	**$ 194,186**	**$ 199,041**	**$ 204,017**	**$ 209,117**	**$ 214,345**
CUSTOMER BENEFITS								
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 451,898	$ 37,967	$ 38,916	$ 39,889	$ 40,886	$ 41,908	$ 42,956	$ 44,030
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 12,215,374	$ 1,026,290	$ 1,051,947	$ 1,078,246	$ 1,105,202	$ 1,132,832	$ 1,161,153	$ 1,190,182
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 20,927,566	$ 1,758,256	$ 1,802,212	$ 1,847,268	$ 1,893,449	$ 1,940,786	$ 1,989,305	$ 2,039,038
Avoided Sustained Outage Benefits (MED) - Residential Customers	$ 1,463,999	$ 123,000	$ 126,075	$ 129,227	$ 132,457	$ 135,769	$ 139,163	$ 142,642
Avoided Sustained Outage Benefits (MED) - Small C&I Customers	$ 56,279,522	$ 4,728,396	$ 4,846,605	$ 4,967,771	$ 5,091,965	$ 5,219,264	$ 5,349,746	$ 5,483,489
Avoided Sustained Outage Benefits (MED) - Medium & Large C&I Customers	$ 74,405,811	$ 6,251,299	$ 6,407,581	$ 6,567,771	$ 6,731,965	$ 6,900,264	$ 7,072,771	$ 7,249,590
Total Customer Benefits	**$ 165,744,170**	**$ 13,925,207**	**$ 14,273,337**	**$ 14,630,171**	**$ 14,995,925**	**$ 15,370,823**	**$ 15,755,094**	**$ 16,148,971**
COMBINED COSTS AND BENEFITS								
Total PV of Operational Benefits	$ 2,201,659	$ 184,829	$ 189,450	$ 194,186	$ 199,041	$ 204,017	$ 209,117	$ 214,345
Total PV of Customer Benefits	$ 165,744,170	$ 13,925,207	$ 14,273,337	$ 14,630,171	$ 14,995,925	$ 15,370,823	$ 15,755,094	$ 16,148,971
Total PV of Combined Benefits	**$ 167,945,829**	**$ 14,110,036**	**$ 14,462,787**	**$ 14,824,357**	**$ 15,194,966**	**$ 15,574,840**	**$ 15,964,211**	**$ 16,363,316**
Total PV Program and On-Going Costs	**$ 41,833,976**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Combined NPV of Program	**$ 126,111,853**	**$ 14,110,036**	**$ 14,462,787**	**$ 14,824,357**	**$ 15,194,966**	**$ 15,574,840**	**$ 15,964,211**	**$ 16,363,316**
Ratio of NPV Benefits to NPV Costs	**4.0**							
Cumulative Net Benefits (Payback Period)		$ (2,579,806)	$ 11,882,981	$ 26,707,338	$ 41,902,303	$ 57,477,143	$ 73,441,354	$ 89,804,670

AREA/PROJECT/PROGRAM	Distribution H&R Storm - 7b
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	YEAR 2036	2037	2038	2039	2040	2041	2042
		14	15	16	17	18	19	20
COSTS								
Program Capital Costs	$ 36,974,775	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 4,067,225	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 41,042,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 791,975	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	**$ 41,833,976**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS								
Avoided Outage Benefits	$ 2,201,659	$ 219,704	$ 225,196	$ 230,826	$ 236,597	$ 242,512	$ 248,575	$ 254,789
Total Operational Benefits	**$ 2,201,659**	**$ 219,704**	**$ 225,196**	**$ 230,826**	**$ 236,597**	**$ 242,512**	**$ 248,575**	**$ 254,789**
CUSTOMER BENEFITS								
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 451,898	$ 45,131	$ 46,259	$ 47,415	$ 48,601	$ 49,816	$ 51,061	$ 52,338
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 12,215,374	$ 1,219,937	$ 1,250,435	$ 1,281,696	$ 1,313,738	$ 1,346,582	$ 1,380,246	$ 1,414,752
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 20,927,566	$ 2,090,014	$ 2,142,264	$ 2,195,821	$ 2,250,716	$ 2,306,984	$ 2,364,659	$ 2,423,775
Avoided Sustained Outage Benefits (MED) - Residential Customers	$ 1,463,999	$ 146,208	$ 149,863	$ 153,610	$ 157,450	$ 161,386	$ 165,421	$ 169,557
Avoided Sustained Outage Benefits (MED) - Small C&I Customers	$ 56,279,522	$ 5,620,576	$ 5,761,091	$ 5,905,118	$ 6,052,746	$ 6,204,065	$ 6,359,166	$ 6,518,146
Avoided Sustained Outage Benefits (MED) - Medium & Large C&I Customers	$ 74,405,811	$ 7,430,830	$ 7,616,601	$ 7,807,016	$ 8,002,191	$ 8,202,246	$ 8,407,302	$ 8,617,484
Total Customer Benefits	**$ 165,744,170**	**$ 16,552,695**	**$ 16,966,513**	**$ 17,390,676**	**$ 17,825,442**	**$ 18,271,079**	**$ 18,727,856**	**$ 19,196,052**
COMBINED COSTS AND BENEFITS								
Total PV of Operational Benefits	$ 2,201,659	$ 219,704	$ 225,196	$ 230,826	$ 236,597	$ 242,512	$ 248,575	$ 254,789
Total PV of Customer Benefits	$ 165,744,170	$ 16,552,695	$ 16,966,513	$ 17,390,676	$ 17,825,442	$ 18,271,079	$ 18,727,856	$ 19,196,052
Total PV of Combined Benefits	**$ 167,945,829**	**$ 16,772,399**	**$ 17,191,709**	**$ 17,621,502**	**$ 18,062,039**	**$ 18,513,590**	**$ 18,976,430**	**$ 19,450,841**
Total PV Program and On-Going Costs	**$ 41,833,976**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Combined NPV of Program	**$ 126,111,853**	**$ 16,772,399**	**$ 17,191,709**	**$ 17,621,502**	**$ 18,062,039**	**$ 18,513,590**	**$ 18,976,430**	**$ 19,450,841**
Ratio of NPV Benefits to NPV Costs	**4.0**							
Cumulative Net Benefits (Payback Period)		$ 106,577,069	$ 123,768,778	$ 141,390,280	$ 159,452,319	$ 177,965,909	$ 196,942,339	$ 216,393,180

AREA/PROJECT/PROGRAM	**Distribution H&R Storm - 7b**
PERIOD:	**2024-2026**
REGULATORY JURISDICTION:	**DEC**
STATE:	**NC**

	NPV of COST/BENEFIT STREAM	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**
		21	**22**	**23**	**24**	**25**	**26**	**27**
COSTS								
Program Capital Costs	$ 36,974,775	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 4,067,225	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 41,042,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 791,975	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	**$ 41,833,976**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS								
Avoided Outage Benefits	$ 2,201,659	$ 261,159	$ 267,688	$ 274,380	$ 281,239	$ 288,270	$ 295,477	$ 302,864
Total Operational Benefits	**$ 2,201,659**	**$ 261,159**	**$ 267,688**	**$ 274,380**	**$ 281,239**	**$ 288,270**	**$ 295,477**	**$ 302,864**
CUSTOMER BENEFITS								
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 451,898	$ 53,646	$ 54,987	$ 56,362	$ 57,771	$ 59,215	$ 60,696	$ 62,213
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 12,215,374	$ 1,450,121	$ 1,486,374	$ 1,523,534	$ 1,561,622	$ 1,600,662	$ 1,640,679	$ 1,681,696
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 20,927,566	$ 2,484,370	$ 2,546,479	$ 2,610,141	$ 2,675,395	$ 2,742,279	$ 2,810,836	$ 2,881,107
Avoided Sustained Outage Benefits (MED) - Residential Customers	$ 1,463,999	$ 173,795	$ 178,140	$ 182,594	$ 187,159	$ 191,838	$ 196,634	$ 201,549
Avoided Sustained Outage Benefits (MED) - Small C&I Customers	$ 56,279,522	$ 6,681,099	$ 6,848,127	$ 7,019,330	$ 7,194,813	$ 7,374,683	$ 7,559,050	$ 7,748,027
Avoided Sustained Outage Benefits (MED) - Medium & Large C&I Customers	$ 74,405,811	$ 8,832,922	$ 9,053,745	$ 9,280,088	$ 9,512,090	$ 9,749,893	$ 9,993,640	$ 10,243,481
Total Customer Benefits	**$ 165,744,170**	**$ 19,675,953**	**$ 20,167,852**	**$ 20,672,048**	**$ 21,188,850**	**$ 21,718,571**	**$ 22,261,535**	**$ 22,818,073**
COMBINED COSTS AND BENEFITS								
Total PV of Operational Benefits	$ 2,201,659	$ 261,159	$ 267,688	$ 274,380	$ 281,239	$ 288,270	$ 295,477	$ 302,864
Total PV of Customer Benefits	$ 165,744,170	$ 19,675,953	$ 20,167,852	$ 20,672,048	$ 21,188,850	$ 21,718,571	$ 22,261,535	$ 22,818,073
Total PV of Combined Benefits	**$ 167,945,829**	**$ 19,937,112**	**$ 20,435,540**	**$ 20,946,428**	**$ 21,470,089**	**$ 22,006,841**	**$ 22,557,012**	**$ 23,120,937**
Total PV Program and On-Going Costs	**$ 41,833,976**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Combined NPV of Program	**$ 126,111,853**	**$ 19,937,112**	**$ 20,435,540**	**$ 20,946,428**	**$ 21,470,089**	**$ 22,006,841**	**$ 22,557,012**	**$ 23,120,937**
Ratio of NPV Benefits to NPV Costs	**4.0**							
Cumulative Net Benefits (Payback Period)		$ 236,330,292	$ 256,765,832	$ 277,712,260	$ 299,182,348	$ 321,189,189	$ 343,746,202	$ 366,867,139

AREA/PROJECT/PROGRAM	Distribution H&R Storm - 7b
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2050	2051	2052	TOTAL
		28	29	30	
COSTS					
Program Capital Costs	$ 36,974,775	$ -	$ -	$ -	$ 43,980,734
Program Capital Contingency Costs	$ 4,067,225	$ -	$ -	$ -	$ 4,837,881
Total Program Capital Costs	$ 41,042,000	$ -	$ -	$ -	$ 48,818,615
Program O&M Costs	$ 791,975	$ -	$ -	$ -	$ 942,038
Total Program Costs	**$ 41,833,976**	**$ -**	**$ -**	**$ -**	**$ 49,760,653**
	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS					
Avoided Outage Benefits	$ 2,201,659	$ 310,435	$ 318,196	$ 326,151	$ 6,414,416
Total Operational Benefits	**$ 2,201,659**	**$ 310,435**	**$ 318,196**	**$ 326,151**	**$ 6,414,416**
CUSTOMER BENEFITS					
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 451,898	$ 63,768	$ 65,362	$ 66,997	$ 1,317,167
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 12,215,374	$ 1,723,738	$ 1,766,832	$ 1,811,003	$ 35,604,739
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 20,927,566	$ 2,953,135	$ 3,026,963	$ 3,102,637	$ 60,998,582
					$ -
Avoided Sustained Outage Benefits (MED) - Residential Customers	$ 1,463,999	$ 206,588	$ 211,753	$ 217,047	$ 4,267,189
Avoided Sustained Outage Benefits (MED) - Small C&I Customers	$ 56,279,522	$ 7,941,727	$ 8,140,271	$ 8,343,777	$ 164,040,624
Avoided Sustained Outage Benefits (MED) - Medium & Large C&I Customers	$ 74,405,811	$ 10,499,568	$ 10,762,057	$ 11,031,109	$ 216,874,191
Total Customer Benefits	**$ 165,744,170**	**$ 23,388,525**	**$ 23,973,238**	**$ 24,572,569**	**$ 483,102,492**
COMBINED COSTS AND BENEFITS					
Total PV of Operational Benefits	$ 2,201,659	$ 310,435	$ 318,196	$ 326,151	$ 6,414,416
Total PV of Customer Benefits	$ 165,744,170	$ 23,388,525	$ 23,973,238	$ 24,572,569	$ 483,102,492
Total PV of Combined Benefits	**$ 167,945,829**	**$ 23,698,961**	**$ 24,291,435**	**$ 24,898,721**	**$ 489,516,908**
Total PV Program and On-Going Costs	**$ 41,833,976**	**$ -**	**$ -**	**$ -**	**$ 49,760,653**
Combined NPV of Program	**$ 126,111,853**	**$ 23,698,961**	**$ 24,291,435**	**$ 24,898,721**	**$ 439,756,255**
Ratio of NPV Benefits to NPV Costs	**4.0**				
Cumulative Net Benefits (Payback Period)		$ 390,566,100	$ 414,857,534	$ 439,756,255	$ 879,512,510

AREA/PROJECT/PROGRAM	Long Duration Interruption (LDI) - 10
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2022	2023	2024	2025	2026	2027	2028
		0	1	2	3	4	5	6
COSTS								
Program Capital Costs	$ 17,157,123	$ 17,216	$ 6,608,495	$ 4,225,860	$ 4,165,292	$ 4,861,677	$ -	$ -
Program Capital Contingency Costs	$ 1,858,473	$ 1,865	$ 715,837	$ 457,748	$ 451,188	$ 526,621	$ -	$ -
Total Program Capital Costs	$ 19,015,596	$ 19,081	$ 7,324,332	$ 4,683,608	$ 4,616,480	$ 5,388,298	$ -	$ -
Program O&M Costs	$ 683,560	$ 686	$ 263,290	$ 168,363	$ 165,950	$ 193,695	$ -	$ -
Total Program Costs	**$ 19,699,156**	**$ 19,767**	**$ 7,587,622**	**$ 4,851,972**	**$ 4,782,430**	**$ 5,581,993**	**$ -**	**$ -**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS								
Avoided Outage Benefits	$ 203,202	$ -	$ -	$ -	$ 4,439	$ 7,879	$ 15,903	$ 16,300
Avoided Vegetation Management Benefits	$ 508,006	$ -	$ -	$ -	$ 11,097	$ 19,699	$ 39,757	$ 40,751
Total Operational Benefits	**$ 711,208**	**$ -**	**$ -**	**$ -**	**$ 15,536**	**$ 27,578**	**$ 55,660**	**$ 57,051**
CUSTOMER BENEFITS								
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 1,694,870	$ -	$ -	$ -	$ 35,296	$ 64,221	$ 132,855	$ 136,177
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 48,047,743	$ -	$ -	$ -	$ 1,000,591	$ 1,820,606	$ 3,766,309	$ 3,860,467
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 80,920,778	$ -	$ -	$ -	$ 1,685,169	$ 3,066,218	$ 6,343,121	$ 6,501,699
Avoided Sustained Outage Benefits (MED) - Residential Customers	$ 2,079,379	$ -	$ -	$ -	$ 43,303	$ 78,791	$ 162,996	$ 167,071
Avoided Sustained Outage Benefits (MED) - Small C&I Customers	$ 81,901,508	$ -	$ -	$ -	$ 1,705,593	$ 3,103,379	$ 6,419,997	$ 6,580,497
Avoided Sustained Outage Benefits (MED) - Medium & Large C&I Customers	$ 104,854,765	$ -	$ -	$ -	$ 2,183,593	$ 3,973,115	$ 8,219,230	$ 8,424,710
Total Customer Benefits	**$ 319,499,044**	**$ -**	**$ -**	**$ -**	**$ 6,653,544**	**$ 12,106,331**	**$ 25,044,508**	**$ 25,670,621**
COMBINED COSTS AND BENEFITS								
Total PV of Operational Benefits	$ 711,208	$ -	$ -	$ -	$ 15,536	$ 27,578	$ 55,660	$ 57,051
Total PV of Customer Benefits	$ 319,499,044	$ -	$ -	$ -	$ 6,653,544	$ 12,106,331	$ 25,044,508	$ 25,670,621
Total PV of Combined Benefits	**$ 320,210,253**	**$ -**	**$ -**	**$ -**	**$ 6,669,080**	**$ 12,133,909**	**$ 25,100,168**	**$ 25,727,672**
Total PV Program and On-Going Costs	**$ 19,699,156**	**$ 19,767**	**$ 7,587,622**	**$ 4,851,972**	**$ 4,782,430**	**$ 5,581,993**	**$ -**	**$ -**
Combined NPV of Program	**$ 300,511,097**	**$ (19,767)**	**$ (7,587,622)**	**$ (4,851,972)**	**$ 1,886,650**	**$ 6,551,916**	**$ 25,100,168**	**$ 25,727,672**
Ratio of NPV Benefits to NPV Costs	**16.3**							
Cumulative Net Benefits (Payback Period)		$ (19,767)	$ (7,607,389)	$ (12,459,361)	$ (10,572,711)	$ (4,020,795)	$ 21,079,373	$ 46,807,045

AREA/PROJECT/PROGRAM	Long Duration Interruption (LDI) - 10
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2029	2030	2031	2032	2033	2034	2035
		7	8	9	10	11	12	13
COSTS								
Program Capital Costs	$ 17,157,123	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 1,858,473	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 19,015,596	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 683,560	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	**$ 19,699,156**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS								
Avoided Outage Benefits	$ 203,202	$ 16,708	$ 17,126	$ 17,554	$ 17,993	$ 18,442	$ 18,903	$ 19,376
Avoided Vegetation Management Benefits	$ 508,006	$ 41,770	$ 42,814	$ 43,884	$ 44,981	$ 46,106	$ 47,259	$ 48,440
Total Operational Benefits	**$ 711,208**	**$ 58,478**	**$ 59,940**	**$ 61,438**	**$ 62,974**	**$ 64,548**	**$ 66,162**	**$ 67,816**
CUSTOMER BENEFITS								
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 1,694,870	$ 139,581	$ 143,071	$ 146,648	$ 150,314	$ 154,072	$ 157,923	$ 161,871
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 48,047,743	$ 3,956,978	$ 4,055,903	$ 4,157,300	$ 4,261,233	$ 4,367,764	$ 4,476,958	$ 4,588,882
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 80,920,778	$ 6,664,241	$ 6,830,848	$ 7,001,619	$ 7,176,659	$ 7,356,076	$ 7,539,978	$ 7,728,477
Avoided Sustained Outage Benefits (MED) - Residential Customers	$ 2,079,379	$ 171,248	$ 175,529	$ 179,917	$ 184,415	$ 189,025	$ 193,751	$ 198,595
Avoided Sustained Outage Benefits (MED) - Small C&I Customers	$ 81,901,508	$ 6,745,010	$ 6,913,635	$ 7,086,476	$ 7,263,638	$ 7,445,229	$ 7,631,359	$ 7,822,143
Avoided Sustained Outage Benefits (MED) - Medium & Large C&I Customers	$ 104,854,765	$ 8,635,328	$ 8,851,211	$ 9,072,492	$ 9,299,304	$ 9,531,787	$ 9,770,081	$ 10,014,333
Total Customer Benefits	**$ 319,499,044**	**$ 26,312,386**	**$ 26,970,196**	**$ 27,644,451**	**$ 28,335,562**	**$ 29,043,951**	**$ 29,770,050**	**$ 30,514,301**
COMBINED COSTS AND BENEFITS								
Total PV of Operational Benefits	$ 711,208	$ 58,478	$ 59,940	$ 61,438	$ 62,974	$ 64,548	$ 66,162	$ 67,816
Total PV of Customer Benefits	$ 319,499,044	$ 26,312,386	$ 26,970,196	$ 27,644,451	$ 28,335,562	$ 29,043,951	$ 29,770,050	$ 30,514,301
Total PV of Combined Benefits	**$ 320,210,253**	**$ 26,370,864**	**$ 27,030,136**	**$ 27,705,889**	**$ 28,398,536**	**$ 29,108,500**	**$ 29,836,212**	**$ 30,582,118**
Total PV Program and On-Going Costs	**$ 19,699,156**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Combined NPV of Program	**$ 300,511,097**	**$ 26,370,864**	**$ 27,030,136**	**$ 27,705,889**	**$ 28,398,536**	**$ 29,108,500**	**$ 29,836,212**	**$ 30,582,118**
Ratio of NPV Benefits to NPV Costs	**16.3**							
Cumulative Net Benefits (Payback Period)		$ 73,177,909	$ 100,208,045	$ 127,913,934	$ 156,312,471	$ 185,420,970	$ 215,257,183	$ 245,839,300

AREA/PROJECT/PROGRAM	Long Duration Interruption (LDI) - 10
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	YEAR						
		2036	2037	2038	2039	2040	2041	2042
		14	15	16	17	18	19	20
COSTS								
Program Capital Costs	$ 17,157,123	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 1,858,473	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 19,015,596	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 683,560	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	**$ 19,699,156**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS								
Avoided Outage Benefits	$ 203,202	$ 19,860	$ 20,357	$ 20,866	$ 21,388	$ 21,922	$ 22,470	$ 23,032
Avoided Vegetation Management Benefits	$ 508,006	$ 49,651	$ 50,892	$ 52,165	$ 53,469	$ 54,806	$ 56,176	$ 57,580
Total Operational Benefits	**$ 711,208**	**$ 69,512**	**$ 71,249**	**$ 73,031**	**$ 74,856**	**$ 76,728**	**$ 78,646**	**$ 80,612**
CUSTOMER BENEFITS								
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 1,694,870	$ 165,918	$ 170,066	$ 174,318	$ 178,676	$ 183,143	$ 187,721	$ 192,414
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 48,047,743	$ 4,703,604	$ 4,821,194	$ 4,941,724	$ 5,065,267	$ 5,191,898	$ 5,321,696	$ 5,454,738
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 80,920,778	$ 7,921,689	$ 8,119,731	$ 8,322,724	$ 8,530,793	$ 8,744,062	$ 8,962,664	$ 9,186,731
Avoided Sustained Outage Benefits (MED) - Residential Customers	$ 2,079,379	$ 203,560	$ 208,649	$ 213,865	$ 219,211	$ 224,692	$ 230,309	$ 236,067
Avoided Sustained Outage Benefits (MED) - Small C&I Customers	$ 81,901,508	$ 8,017,697	$ 8,218,139	$ 8,423,593	$ 8,634,183	$ 8,850,037	$ 9,071,288	$ 9,298,070
Avoided Sustained Outage Benefits (MED) - Medium & Large C&I Customers	$ 104,854,765	$ 10,264,692	$ 10,521,309	$ 10,784,342	$ 11,053,950	$ 11,330,299	$ 11,613,556	$ 11,903,895
Total Customer Benefits	**$ 319,499,044**	**$ 31,277,159**	**$ 32,059,088**	**$ 32,860,565**	**$ 33,682,079**	**$ 34,524,131**	**$ 35,387,234**	**$ 36,271,915**
COMBINED COSTS AND BENEFITS								
Total PV of Operational Benefits	$ 711,208	$ 69,512	$ 71,249	$ 73,031	$ 74,856	$ 76,728	$ 78,646	$ 80,612
Total PV of Customer Benefits	$ 319,499,044	$ 31,277,159	$ 32,059,088	$ 32,860,565	$ 33,682,079	$ 34,524,131	$ 35,387,234	$ 36,271,915
Total PV of Combined Benefits	**$ 320,210,253**	**$ 31,346,670**	**$ 32,130,337**	**$ 32,933,596**	**$ 33,756,936**	**$ 34,600,859**	**$ 35,465,880**	**$ 36,352,527**
Total PV Program and On-Going Costs	**$ 19,699,156**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Combined NPV of Program	**$ 300,511,097**	**$ 31,346,670**	**$ 32,130,337**	**$ 32,933,596**	**$ 33,756,936**	**$ 34,600,859**	**$ 35,465,880**	**$ 36,352,527**
Ratio of NPV Benefits to NPV Costs	**16.3**							
Cumulative Net Benefits (Payback Period)		$ 277,185,971	$ 309,316,308	$ 342,249,904	$ 376,006,839	$ 410,607,698	$ 446,073,579	$ 482,426,106

AREA/PROJECT/PROGRAM	Long Duration Interruption (LDI) - 10
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2043	2044	2045	2046	2047	2048	2049
		21	22	23	24	25	26	27
COSTS								
Program Capital Costs	$ 17,157,123	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 1,858,473	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 19,015,596	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 683,560	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	**$ 19,699,156**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS								
Avoided Outage Benefits	$ 203,202	$ 23,608	$ 24,198	$ 24,803	$ 25,423	$ 26,059	$ 26,710	$ 27,378
Avoided Vegetation Management Benefits	$ 508,006	$ 59,020	$ 60,495	$ 62,007	$ 63,558	$ 65,147	$ 66,775	$ 68,445
Total Operational Benefits	**$ 711,208**	**$ 82,627**	**$ 84,693**	**$ 86,810**	**$ 88,981**	**$ 91,205**	**$ 93,485**	**$ 95,823**
CUSTOMER BENEFITS								
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 1,694,870	$ 197,225	$ 202,155	$ 207,209	$ 212,389	$ 217,699	$ 223,142	$ 228,720
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 48,047,743	$ 5,591,107	$ 5,730,884	$ 5,874,156	$ 6,021,010	$ 6,171,536	$ 6,325,824	$ 6,483,970
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 80,920,778	$ 9,416,399	$ 9,651,809	$ 9,893,104	$ 10,140,432	$ 10,393,942	$ 10,653,791	$ 10,920,136
Avoided Sustained Outage Benefits (MED) - Residential Customers	$ 2,079,379	$ 241,968	$ 248,018	$ 254,218	$ 260,573	$ 267,088	$ 273,765	$ 280,609
Avoided Sustained Outage Benefits (MED) - Small C&I Customers	$ 81,901,508	$ 9,530,522	$ 9,768,785	$ 10,013,005	$ 10,263,330	$ 10,519,913	$ 10,782,911	$ 11,052,484
Avoided Sustained Outage Benefits (MED) - Medium & Large C&I Customers	$ 104,854,765	$ 12,201,493	$ 12,506,530	$ 12,819,193	$ 13,139,673	$ 13,468,165	$ 13,804,869	$ 14,149,991
Total Customer Benefits	**$ 319,499,044**	**$ 37,178,713**	**$ 38,108,181**	**$ 39,060,886**	**$ 40,037,408**	**$ 41,038,343**	**$ 42,064,301**	**$ 43,115,909**
COMBINED COSTS AND BENEFITS								
Total PV of Operational Benefits	$ 711,208	$ 82,627	$ 84,693	$ 86,810	$ 88,981	$ 91,205	$ 93,485	$ 95,823
Total PV of Customer Benefits	$ 319,499,044	$ 37,178,713	$ 38,108,181	$ 39,060,886	$ 40,037,408	$ 41,038,343	$ 42,064,301	$ 43,115,909
Total PV of Combined Benefits	**$ 320,210,253**	**$ 37,261,341**	**$ 38,192,874**	**$ 39,147,696**	**$ 40,126,388**	**$ 41,129,548**	**$ 42,157,787**	**$ 43,211,732**
Total PV Program and On-Going Costs	**$ 19,699,156**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Combined NPV of Program	**$ 300,511,097**	**$ 37,261,341**	**$ 38,192,874**	**$ 39,147,696**	**$ 40,126,388**	**$ 41,129,548**	**$ 42,157,787**	**$ 43,211,732**
Ratio of NPV Benefits to NPV Costs	**16.3**							
Cumulative Net Benefits (Payback Period)		$ 519,687,447	$ 557,880,321	$ 597,028,017	$ 637,154,405	$ 678,283,953	$ 720,441,740	$ 763,653,472

AREA/PROJECT/PROGRAM	Long Duration Interruption (LDI) - 10
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2050	2051	2052	TOTAL
		28	29	30	
COSTS					
Program Capital Costs	$ 17,157,123	$ -	$ -	$ -	$ 19,878,540
Program Capital Contingency Costs	$ 1,858,473	$ -	$ -	$ -	$ 2,153,259
Total Program Capital Costs	$ 19,015,596	$ -	$ -	$ -	$ 22,031,799
Program O&M Costs	$ 683,560	$ -	$ -	$ -	$ 791,985
Total Program Costs	**$ 19,699,156**	**$ -**	**$ -**	**$ -**	**$ 22,823,784**
	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS					
Avoided Outage Benefits	$ 203,202	$ 28,062	$ 28,764	$ 29,483	$ 585,006
Avoided Vegetation Management Benefits	$ 508,006	$ 70,156	$ 71,910	$ 73,707	$ 1,462,516
Total Operational Benefits	**$ 711,208**	**$ 98,218**	**$ 100,674**	**$ 103,190**	**$ 2,047,522**
CUSTOMER BENEFITS					
Avoided Sustained Outage Benefits (Non-MED) - Residential Customers	$ 1,694,870	$ 234,438	$ 240,299	$ 246,307	$ 4,883,868
Avoided Sustained Outage Benefits (Non-MED) - Small C&I Customers	$ 48,047,743	$ 6,646,069	$ 6,812,221	$ 6,982,526	$ 138,452,412
Avoided Sustained Outage Benefits (Non-MED) - Medium & Large C&I Customers	$ 80,920,778	$ 11,193,139	$ 11,472,968	$ 11,759,792	$ 233,178,008
					$ -
Avoided Sustained Outage Benefits (MED) - Residential Customers	$ 2,079,379	$ 287,624	$ 294,815	$ 302,185	$ 5,991,855
Avoided Sustained Outage Benefits (MED) - Small C&I Customers	$ 81,901,508	$ 11,328,796	$ 11,612,016	$ 11,902,316	$ 236,004,040
Avoided Sustained Outage Benefits (MED) - Medium & Large C&I Customers	$ 104,854,765	$ 14,503,741	$ 14,866,334	$ 15,237,992	$ 302,145,208
Total Customer Benefits	**$ 319,499,044**	**$ 44,193,807**	**$ 45,298,652**	**$ 46,431,118**	**$ 920,655,392**
COMBINED COSTS AND BENEFITS					
Total PV of Operational Benefits	$ 711,208	$ 98,218	$ 100,674	$ 103,190	$ 2,047,522
Total PV of Customer Benefits	$ 319,499,044	$ 44,193,807	$ 45,298,652	$ 46,431,118	$ 920,655,392
Total PV of Combined Benefits	**$ 320,210,253**	**$ 44,292,025**	**$ 45,399,325**	**$ 46,534,309**	**$ 922,702,914**
Total PV Program and On-Going Costs	**$ 19,699,156**	**$ -**	**$ -**	**$ -**	**$ 22,823,784**
Combined NPV of Program	**$ 300,511,097**	**$ 44,292,025**	**$ 45,399,325**	**$ 46,534,309**	**$ 899,879,131**
Ratio of NPV Benefits to NPV Costs	**16.3**				
Cumulative Net Benefits (Payback Period)		$ 807,945,497	$ 853,344,822	$ 899,879,131	$ 1,799,758,261

AREA/PROJECT/PROGRAM	Targeted Underground (TUG) - 11
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2022	2023	2024	2025	2026	2027	2028	2029	2030
		0	1	2	3	4	5	6	7	8
COSTS										
Program Capital Costs	$ 143,222,365	$ 28,642	$ 36,777,966	$ 54,853,284	$ 49,153,637	$ 25,423,961	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 15,754,460	$ 3,151	$ 4,045,576	$ 6,033,861	$ 5,406,900	$ 2,796,636	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 158,976,825	$ 31,793	$ 40,823,542	$ 60,887,145	$ 54,560,537	$ 28,220,597	$ -	$ -	$ -	$ -
Program O&M Costs	$ 114,741	$ 23	$ 29,464	$ 43,945	$ 39,379	$ 20,368	$ -	$ -	$ -	$ -
Total Program Costs	$ 159,091,566	$ 31,816	$ 40,853,007	$ 60,931,090	$ 54,599,916	$ 28,240,965	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS										
Avoided Outage Benefits	$ 4,238,784	$ -	$ -	$ -	$ 65,898	$ 181,158	$ 332,475	$ 340,787	$ 349,307	$ 358,039
Avoided Vegetation Management Benefits	$ 4,238,784	$ -	$ -	$ -	$ 65,898	$ 181,158	$ 332,475	$ 340,787	$ 349,307	$ 358,039
Total Operational Benefits	$ 8,477,567	$ -	$ -	$ -	$ 131,796	$ 362,316	$ 664,950	$ 681,574	$ 698,613	$ 716,078
CUSTOMER BENEFITS										
Avoided Sustained Outage Benefits (Non-MED/MED) - Residential Customers	$ 504,276	$ -	$ -	$ -	$ 7,473	$ 21,056	$ 39,610	$ 40,600	$ 41,615	$ 42,656
Avoided Sustained Outage Benefits (Non-MED/MED) - Small C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Sustained Outage Benefits (Non-MED/MED) - Medium & Large C&I Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Momentary Outage Benefits (Non-MED/MED) - Residential Customers	$ 11,215,749	$ -	$ -	$ -	$ 166,200	$ 468,318	$ 880,981	$ 903,006	$ 925,581	$ 948,720
Avoided Momentary Outage Benefits (Non-MED/MED) - Small C&I Customers	$ 131,047,684	$ -	$ -	$ -	$ 1,941,927	$ 5,471,949	$ 10,293,610	$ 10,550,950	$ 10,814,724	$ 11,085,092
Avoided Momentary Outage Benefits (Non-MED/MED) - Medium & Large C&I Custom	$ 335,755,317	$ -	$ -	$ -	$ 4,975,382	$ 14,019,598	$ 26,373,104	$ 27,032,431	$ 27,708,242	$ 28,400,948
Total Customer Benefits	$ 478,523,026	$ -	$ -	$ -	$ 7,090,982	$ 19,980,921	$ 37,587,304	$ 38,526,987	$ 39,490,162	$ 40,477,416
COMBINED COSTS AND BENEFITS										
Total PV of Operational Benefits	$ 8,477,567	$ -	$ -	$ -	$ 131,796	$ 362,316	$ 664,950	$ 681,574	$ 698,613	$ 716,078
Total PV of Customer Benefits	$ 478,523,026	$ -	$ -	$ -	$ 7,090,982	$ 19,980,921	$ 37,587,304	$ 38,526,987	$ 39,490,162	$ 40,477,416
Total PV of Combined Benefits	$ 487,000,593	$ -	$ -	$ -	$ 7,222,777	$ 20,343,237	$ 38,252,254	$ 39,208,561	$ 40,188,775	$ 41,193,494
Total PV Program and On-Going Costs	$ 159,091,566	$ 31,816	$ 40,853,007	$ 60,931,090	$ 54,599,916	$ 28,240,965	$ -	$ -	$ -	$ -
Combined NPV of Program	$ 327,909,028	$ (31,816)	$ (40,853,007)	$ (60,931,090)	$ (47,377,139)	$ (7,897,728)	$ 38,252,254	$ 39,208,561	$ 40,188,775	$ 41,193,494
Ratio of NPV Benefits to NPV Costs	3.1									
Cumulative Net Benefits (Payback Period)		$ (31,816)	$ (40,884,822)	$ (101,815,912)	$ (149,193,051)	$ (157,090,779)	$ (118,838,524)	$ (79,629,963)	$ (39,441,189)	$ 1,752,306

AREA/PROJECT/PROGRAM	Targeted Underground (TUG) - 11
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	YEAR								
		2031	2032	2033	2034	2035	2036	2037	2038	2039
		9	10	11	12	13	14	15	16	17
COSTS										
Program Capital Costs	$ 143,222,365	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 15,754,460	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 158,976,825	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 114,741	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	$ 159,091,566	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS										
Avoided Outage Benefits	$ 4,238,784	$ 366,990	$ 376,165	$ 385,569	$ 395,208	$ 405,088	$ 415,216	$ 425,596	$ 436,236	$ 447,142
Avoided Vegetation Management Benefits	$ 4,238,784	$ 366,990	$ 376,165	$ 385,569	$ 395,208	$ 405,088	$ 415,216	$ 425,596	$ 436,236	$ 447,142
Total Operational Benefits	$ 8,477,567	$ 733,980	$ 752,330	$ 771,138	$ 790,417	$ 810,177	$ 830,431	$ 851,192	$ 872,472	$ 894,284
CUSTOMER BENEFITS										
Avoided Sustained Outage Benefits (Non-MED/MED) - Residential Customers	$ 504,276	$ 43,722	$ 44,815	$ 45,936	$ 47,084	$ 48,261	$ 49,468	$ 50,704	$ 51,972	$ 53,271
Avoided Sustained Outage Benefits (Non-MED/MED) - Small C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Sustained Outage Benefits (Non-MED/MED) - Medium & Large C&I Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Momentary Outage Benefits (Non-MED/MED) - Residential Customers	$ 11,215,749	$ 972,438	$ 996,749	$ 1,021,668	$ 1,047,210	$ 1,073,390	$ 1,100,225	$ 1,127,730	$ 1,155,924	$ 1,184,822
Avoided Momentary Outage Benefits (Non-MED/MED) - Small C&I Customers	$ 131,047,684	$ 11,362,219	$ 11,646,274	$ 11,937,431	$ 12,235,867	$ 12,541,764	$ 12,855,308	$ 13,176,691	$ 13,506,108	$ 13,843,760
Avoided Momentary Outage Benefits (Non-MED/MED) - Medium & Large C&I Custom	$ 335,755,317	$ 29,110,972	$ 29,838,746	$ 30,584,715	$ 31,349,333	$ 32,133,066	$ 32,936,392	$ 33,759,802	$ 34,603,797	$ 35,468,892
Total Customer Benefits	$ 478,523,026	$ 41,489,351	$ 42,526,585	$ 43,589,750	$ 44,679,493	$ 45,796,481	$ 46,941,393	$ 48,114,928	$ 49,317,801	$ 50,550,746
COMBINED COSTS AND BENEFITS										
Total PV of Operational Benefits	$ 8,477,567	$ 733,980	$ 752,330	$ 771,138	$ 790,417	$ 810,177	$ 830,431	$ 851,192	$ 872,472	$ 894,284
Total PV of Customer Benefits	$ 478,523,026	$ 41,489,351	$ 42,526,585	$ 43,589,750	$ 44,679,493	$ 45,796,481	$ 46,941,393	$ 48,114,928	$ 49,317,801	$ 50,550,746
Total PV of Combined Benefits	$ 487,000,593	$ 42,223,332	$ 43,278,915	$ 44,360,888	$ 45,469,910	$ 46,606,658	$ 47,771,824	$ 48,966,120	$ 50,190,273	$ 51,445,030
Total PV Program and On-Going Costs	$ 159,091,566	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Combined NPV of Program	$ 327,909,028	$ 42,223,332	$ 43,278,915	$ 44,360,888	$ 45,469,910	$ 46,606,658	$ 47,771,824	$ 48,966,120	$ 50,190,273	$ 51,445,030
Ratio of NPV Benefits to NPV Costs	3.1									
Cumulative Net Benefits (Payback Period)		$ 43,975,637	$ 87,254,552	$ 131,615,440	$ 177,085,350	$ 223,692,007	$ 271,463,831	$ 320,429,951	$ 370,620,224	$ 422,065,253

AREA/PROJECT/PROGRAM	Targeted Underground (TUG) - 11
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2040	2041	2042	2043	2044	2045	2046	2047	2048
		18	19	20	21	22	23	24	25	26
COSTS										
Program Capital Costs	$ 143,222,365	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Capital Contingency Costs	$ 15,754,460	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Capital Costs	$ 158,976,825	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program O&M Costs	$ 114,741	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Program Costs	$ 159,091,566	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS										
Avoided Outage Benefits	$ 4,238,784	$ 458,320	$ 469,778	$ 481,523	$ 493,561	$ 505,900	$ 518,548	$ 531,511	$ 544,799	$ 558,419
Avoided Vegetation Management Benefits	$ 4,238,784	$ 458,320	$ 469,778	$ 481,523	$ 493,561	$ 505,900	$ 518,548	$ 531,511	$ 544,799	$ 558,419
Total Operational Benefits	$ 8,477,567	$ 916,641	$ 939,557	$ 963,046	$ 987,122	$ 1,011,800	$ 1,037,095	$ 1,063,022	$ 1,089,598	$ 1,116,838
CUSTOMER BENEFITS										
Avoided Sustained Outage Benefits (Non-MED/MED) - Residential Customers	$ 504,276	$ 54,603	$ 55,968	$ 57,367	$ 58,802	$ 60,272	$ 61,778	$ 63,323	$ 64,906	$ 66,529
Avoided Sustained Outage Benefits (Non-MED/MED) - Small C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Sustained Outage Benefits (Non-MED/MED) - Medium & Large C&I Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Momentary Outage Benefits (Non-MED/MED) - Residential Customers	$ 11,215,749	$ 1,214,442	$ 1,244,803	$ 1,275,923	$ 1,307,822	$ 1,340,517	$ 1,374,030	$ 1,408,381	$ 1,443,590	$ 1,479,680
Avoided Momentary Outage Benefits (Non-MED/MED) - Small C&I Customers	$ 131,047,684	$ 14,189,854	$ 14,544,601	$ 14,908,216	$ 15,280,921	$ 15,662,944	$ 16,054,518	$ 16,455,881	$ 16,867,278	$ 17,288,960
Avoided Momentary Outage Benefits (Non-MED/MED) - Medium & Large C&I Custom	$ 335,755,317	$ 36,355,615	$ 37,264,505	$ 38,196,118	$ 39,151,021	$ 40,129,796	$ 41,133,041	$ 42,161,367	$ 43,215,401	$ 44,295,786
Total Customer Benefits	$ 478,523,026	$ 51,814,514	$ 53,109,877	$ 54,437,624	$ 55,798,565	$ 57,193,529	$ 58,623,367	$ 60,088,951	$ 61,591,175	$ 63,130,954
COMBINED COSTS AND BENEFITS										
Total PV of Operational Benefits	$ 8,477,567	$ 916,641	$ 939,557	$ 963,046	$ 987,122	$ 1,011,800	$ 1,037,095	$ 1,063,022	$ 1,089,598	$ 1,116,838
Total PV of Customer Benefits	$ 478,523,026	$ 51,814,514	$ 53,109,877	$ 54,437,624	$ 55,798,565	$ 57,193,529	$ 58,623,367	$ 60,088,951	$ 61,591,175	$ 63,130,954
Total PV of Combined Benefits	$ 487,000,593	$ 52,731,155	$ 54,049,434	$ 55,400,670	$ 56,785,687	$ 58,205,329	$ 59,660,462	$ 61,151,974	$ 62,680,773	$ 64,247,792
Total PV Program and On-Going Costs	$ 159,091,566	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Combined NPV of Program	$ 327,909,028	$ 52,731,155	$ 54,049,434	$ 55,400,670	$ 56,785,687	$ 58,205,329	$ 59,660,462	$ 61,151,974	$ 62,680,773	$ 64,247,792
Ratio of NPV Benefits to NPV Costs	3.1									
Cumulative Net Benefits (Payback Period)		$ 474,796,409	$ 528,845,843	$ 584,246,513	$ 641,032,200	$ 699,237,529	$ 758,897,991	$ 820,049,964	$ 882,730,737	$ 946,978,530

AREA/PROJECT/PROGRAM	Targeted Underground (TUG) - 11
PERIOD:	2024-2026
REGULATORY JURISDICTION:	DEC
STATE:	NC

	NPV of COST/BENEFIT STREAM	2049 27	2050 28	2051 29	2052 30	TOTAL
COSTS						
Program Capital Costs	$ 143,222,365	$ -	$ -	$ -	$ -	$ 166,237,490
Program Capital Contingency Costs	$ 15,754,460	$ -	$ -	$ -	$ -	$ 18,286,124
Total Program Capital Costs	$ 158,976,825	$ -	$ -	$ -	$ -	$ 184,523,614
Program O&M Costs	$ 114,741	$ -	$ -	$ -	$ -	$ 133,179
Total Program Costs	$ 159,091,566	$ -	$ -	$ -	$ -	$ 184,656,793
	$ -	$ -	$ -	$ -	$ -	$ -
Total On-Going Costs	$ -	$ -	$ -	$ -	$ -	$ -
OPERATIONAL BENEFITS						
Avoided Outage Benefits	$ 4,238,784	$ 572,379	$ 586,689	$ 601,356	$ 616,390	
Avoided Vegetation Management Benefits	$ 4,238,784	$ 572,379	$ 586,689	$ 601,356	$ 616,390	$ 12,220,048
Total Operational Benefits	$ 8,477,567	$ 1,144,759	$ 1,173,378	$ 1,202,712	$ 1,232,780	$ 12,220,048
CUSTOMER BENEFITS						
Avoided Sustained Outage Benefits (Non-MED/MED) - Residential Customers	$ 504,276	$ 68,192	$ 69,897	$ 71,644	$ 73,435	$ 1,454,959
Avoided Sustained Outage Benefits (Non-MED/MED) - Small C&I Customers	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Sustained Outage Benefits (Non-MED/MED) - Medium & Large C&I Customer	$ -	$ -	$ -	$ -	$ -	$ -
						$ -
Avoided Momentary Outage Benefits (Non-MED/MED) - Residential Customers	$ 11,215,749	$ 1,516,672	$ 1,554,589	$ 1,593,454	$ 1,633,290	$ 32,360,156
Avoided Momentary Outage Benefits (Non-MED/MED) - Small C&I Customers	$ 131,047,684	$ 17,721,184	$ 18,164,213	$ 18,618,319	$ 19,083,777	$ 378,104,338
Avoided Momentary Outage Benefits (Non-MED/MED) - Medium & Large C&I Custom	$ 335,755,317	$ 45,403,181	$ 46,538,260	$ 47,701,717	$ 48,894,260	$ 968,735,486
						$ -
Total Customer Benefits	$ 478,523,026	$ 64,709,228	$ 66,326,959	$ 67,985,133	$ 69,684,761	$ 1,380,654,938
COMBINED COSTS AND BENEFITS						
Total PV of Operational Benefits	$ 8,477,567	$ 1,144,759	$ 1,173,378	$ 1,202,712	$ 1,232,780	$ 24,440,095
Total PV of Customer Benefits	$ 478,523,026	$ 64,709,228	$ 66,326,959	$ 67,985,133	$ 69,684,761	$ 1,380,654,938
Total PV of Combined Benefits	$ 487,000,593	$ 65,853,987	$ 67,500,337	$ 69,187,845	$ 70,917,541	$ 1,405,095,034
Total PV Program and On-Going Costs	$ 159,091,566	$ -	$ -	$ -	$ -	$ 184,656,793
Combined NPV of Program	$ 327,909,028	$ 65,853,987	$ 67,500,337	$ 69,187,845	$ 70,917,541	$ 1,220,438,240
Ratio of NPV Benefits to NPV Costs	3.1					
Cumulative Net Benefits (Payback Period)		$ 1,012,832,517	$ 1,080,332,854	$ 1,149,520,699	$ 1,220,438,240	$ 2,440,876,481

Duke Energy Carolinas (DEC) NORTH CAROLINA IVVC EVALUAT

**Phase I and II deployments specific to DEC NC*

	Units	NPV (calculated)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
			FORECAST														
			Years (for reference only)														
Benefits	$	$842,602,640	$ -	$ 2,965,726	$ 5,895,398	$ 13,794,536	$ 21,283,923	$23,259,315	$31,702,446	$36,997,943	$119,910,641	$47,171,200	$49,721,752	$52,169,957	$63,045,918	$70,227,088	$72,644,921
Costs	$	$540,187,727	$ 1,119,634	$ 65,044,843	$ 67,162,966	$ 69,093,117	$ 70,708,863	$ 8,955,480	$30,947,346	$39,342,749	$ 33,240,530	$ 8,144,418	$ 8,418,714	$12,980,863	$ 9,678,581	$11,090,498	$11,708,562
Net	**$**	**$302,414,913**	**$(1,119,634)**	**$(62,079,118)**	**$(61,267,567)**	**$(55,298,580)**	**$(49,424,940)**	**$14,303,835**	**$ 755,100**	**$ (2,344,806)**	**$ 86,670,111**	**$39,026,782**	**$41,303,038**	**$39,189,094**	**$53,367,337**	**$59,136,590**	**$60,936,359**
BCR		1.6															
COSTS																	
Total Capital																	
Transmission	$	$174,749,914	$ -	$ 16,550,882	$ 16,945,409	$ 17,349,799	$ 17,764,299	$ 3,776,429	$14,247,438	$17,604,265	$ 11,481,871	$ -	$ -	$ 3,954,914	$ 4,053,787	$ 4,155,131	$ 4,259,010
Distribution	$	$210,481,241	$ 598,239	$ 34,691,140	$ 35,518,080	$ 36,365,694	$ 37,096,447	$ 855,496	$ 8,977,423	$12,652,885	$ 10,361,002	$ -	$ -	$ -	$ -	$ -	$ -
Telecom	$	$ 30,973,700	$ -	$ 5,636,317	$ 5,770,671	$ 5,908,383	$ 6,049,539	$ 527,875	$ 2,646,808	$ 3,448,238	$ 2,489,310	$ 0	$ 0	$ (0)	$ 0	$ 0	$ 0
IT	$	$ 11,112,374	$ -	$ 1,704,280	$ 1,628,557	$ 1,667,421	$ 1,585,287	$ 155,239	$ 778,379	$ 1,014,066	$ 732,062	$ -	$ -	$ 367,395	$ 349,645	$ 358,386	$ 339,047
PM	$	$ 19,707,587	$ 232,892	$ 4,407,400	$ 4,925,234	$ 5,038,744	$ 5,103,316	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ongoing	$	$ 27,349,339	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,485,900	$ 3,573,048	$ 3,662,374	$ 3,753,933	$ 308,470	$ 1,546,691	$ 2,015,016
	$	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capital	**$**	**$474,374,155**	**$ 831,131**	**$ 62,990,019**	**$ 64,787,951**	**$ 66,330,041**	**$ 67,598,887**	**$ 5,315,039**	**$26,650,048**	**$34,719,454**	**$ 28,550,145**	**$ 3,573,048**	**$ 3,662,374**	**$ 8,076,242**	**$ 4,711,901**	**$ 6,060,209**	**$ 6,613,073**
Total O&M																	
Transmission	$	$ 1,409,686	$ -	$ 148,965	$ 152,689	$ 156,506	$ 160,419	$ 75,529	$ 284,949	$ 352,085	$ 229,637	$ -	$ -	$ -	$ -	$ -	$ -
Distribution	$	$ 7,818,516	$ 288,502	$ 1,686,479	$ 1,728,641	$ 1,771,857	$ 1,752,463	$ 29,486	$ 213,620	$ 238,161	$ 229,234	$ -	$ -	$ -	$ -	$ -	$ -
Telecom	$	$ 374,663	$ -	$ 53,572	$ 54,911	$ 56,284	$ 57,691	$ 10,588	$ 52,936	$ 68,965	$ 49,786	$ -	$ -	$ -	$ -	$ -	$ -
IT	$	$ 13,151,937	$ -	$ 54,923	$ 137,309	$ 277,688	$ 418,067	$ 544,409	$ 674,194	$ 802,217	$ 929,089	$ 1,064,455	$ 1,190,358	$ 1,278,095	$ 1,278,095	$ 1,278,095	$ 1,278,095
PM	$	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ongoing	$	$ 43,058,769	$ -	$ 110,886	$ 301,465	$ 500,741	$ 721,336	$ 2,980,429	$ 3,071,599	$ 3,161,867	$ 3,252,639	$ 3,506,915	$ 3,565,983	$ 3,626,527	$ 3,688,585	$ 3,752,195	$ 3,817,395
Total O&M	**$**	**$ 65,813,571**	**$ 288,502**	**$ 2,054,825**	**$ 2,375,015**	**$ 2,763,075**	**$ 3,109,976**	**$ 3,640,441**	**$ 4,297,298**	**$ 4,623,295**	**$ 4,690,385**	**$ 4,571,370**	**$ 4,756,340**	**$ 4,904,622**	**$ 4,966,680**	**$ 5,030,289**	**$ 5,095,489**
Total Costs																	
Total Capital	$	$474,374,155	$ 831,131	$ 62,990,019	$ 64,787,951	$ 66,330,041	$ 67,598,887	$ 5,315,039	$26,650,048	$34,719,454	$ 28,550,145	$ 3,573,048	$ 3,662,374	$ 8,076,242	$ 4,711,901	$ 6,060,209	$ 6,613,073
Total O&M	$	$ 65,813,571	$ 288,502	$ 2,054,825	$ 2,375,015	$ 2,763,075	$ 3,109,976	$ 3,640,441	$ 4,297,298	$ 4,623,295	$ 4,690,385	$ 4,571,370	$ 4,756,340	$ 4,904,622	$ 4,966,680	$ 5,030,289	$ 5,095,489
Total Capital & O&M	**$**	**$540,187,727**	**$ 1,119,634**	**$ 65,044,843**	**$ 67,162,966**	**$ 69,093,117**	**$ 70,708,863**	**$ 8,955,480**	**$30,947,346**	**$39,342,749**	**$ 33,240,530**	**$ 8,144,418**	**$ 8,418,714**	**$12,980,863**	**$ 9,678,581**	**$11,090,498**	**$11,708,562**
BENEFITS																	
Operational Benefits																	
Improved VAR Mgmt	$	$ 89,711,275	$ -	$ 1,207,215	$ 2,333,710	$ 3,548,006	$ 4,813,044	$ 4,955,475	$ 5,561,915	$ 5,791,848	$ 6,003,446	$ 6,298,053	$ 6,530,947	$ 7,025,943	$ 7,449,689	$ 7,828,080	$ 8,393,477
Avoided Capacity Costs	$	$109,962,860	$ -	$ 1,758,511	$ 3,561,688	$ 5,410,382	$ 7,305,459	$ 7,398,238	$ 7,492,196	$ 7,587,346	$ 7,683,706	$ 7,781,289	$ 7,880,111	$ 7,980,189	$ 8,081,537	$ 8,184,172	$ 8,288,111
Avoided Fixed O&M Generation C	$	$ 4,608,029	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 76,644	$ 775,033	$ 796,583
Avoided Variable O&M Generatio	$	$ 23,796,894	$ -	$ -	$ -	$ 324,455	$ 524,156	$ 703,705	$ 1,017,079	$ 1,246,780	$ 2,057,398	$ 1,746,073	$ 2,082,388	$ 2,107,452	$ 1,943,778	$ 2,121,024	$ 2,411,000
Avoided Reagent Cost Generatio	$	$ 281,705	$ -	$ -	$ -	$ (583)	$ 5,062	$ 2,879	$ 18,955	$ 28,968	$ 12,315	$ 15,546	$ 28,534	$ 20,907	$ 16,667	$ 22,253	$ 30,052
Avoided Start Cost Generation	$	$ 12,056,328	$ -	$ -	$ -	$ (65,368)	$ 323,528	$ (641,605)	$ 706,323	$ 301,058	$ 594,130	$ 243,998	$ 594,646	$ 161,042	$ 568,154	$ 1,030,232	$ 844,611
SUBTOTAL:	**$**	**$240,417,091**	**$ -**	**$ 2,965,726**	**$ 5,895,398**	**$ 9,216,892**	**$ 12,971,249**	**$12,418,692**	**$14,796,468**	**$14,956,000**	**$ 16,350,995**	**$16,084,958**	**$17,116,627**	**$17,295,533**	**$18,136,469**	**$19,960,794**	**$20,763,835**
Customer Benefits																	
Avoided Fuel Costs	$	$368,653,700	$ -	$ -	$ -	$ 4,571,386	$ 8,297,974	$10,819,947	$16,880,652	$19,785,832	$ 25,929,170	$23,399,839	$22,687,340	$23,375,724	$29,390,479	$32,099,674	$33,764,161
SUBTOTAL:	**$**	**$368,653,700**	**$ -**	**$ -**	**$ -**	**$ 4,571,386**	**$ 8,297,974**	**$10,819,947**	**$16,880,652**	**$19,785,832**	**$ 25,929,170**	**$23,399,839**	**$22,687,340**	**$23,375,724**	**$29,390,479**	**$32,099,674**	**$33,764,161**
Operational Benefits & Customer Benefits																	
SUBTOTAL:	**$**	**$609,070,791**	**0**	**2,965,726**	**5,895,398**	**13,788,278**	**21,269,222**	**23,238,639**	**31,677,120**	**34,741,831**	**42,280,165**	**39,484,797**	**39,803,966**	**40,671,257**	**47,526,949**	**52,060,468**	**54,527,995**
Environmental Benefits																	
SO2	$	$ 7,387	$ -	$ -	$ -	$ 105	$ 374	$ 591	$ 471	$ 419	$ 1,324	$ 793	$ 778	$ 636	$ 1,069	$ 1,084	$ 486
NOX	$	$ 337,765	$ -	$ -	$ -	$ 6,154	$ 14,327	$ 20,085	$ 24,855	$ 22,694	$ 42,061	$ 28,310	$ 26,089	$ 29,858	$ 30,448	$ 32,168	$ 25,730
CO2	$	$233,186,698	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,232,999	$ 77,587,091	$ 7,657,301	$ 9,890,919	$11,468,207	$15,487,452	$18,133,367	$18,090,710
SUBTOTAL:	**$**	**$233,531,849**	**$ -**	**$ -**	**$ -**	**$ 6,259**	**$ 14,701**	**$ 20,675**	**$ 25,326**	**$ 2,256,112**	**$ 77,630,476**	**$ 7,686,403**	**$ 9,917,785**	**$11,498,700**	**$15,518,970**	**$18,166,620**	**$18,116,926**
TOTAL (all benefits)	**$**	**$842,602,640**	**$ -**	**$ 2,965,726**	**$ 5,895,398**	**$ 13,794,536**	**$ 21,283,923**	**$23,259,315**	**$31,702,446**	**$36,997,943**	**$119,910,641**	**$47,171,200**	**$49,721,752**	**$52,169,957**	**$63,045,918**	**$70,227,088**	**$72,644,921**

Duke Energy Carolinas (DEC) NORTH CAROLINA IVVC EVALUAT

**Phase I and II deployments specific to DEC NC*

	Units	NPV (calculated)	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Benefits	$	$842,602,640	$79,575,256	$91,175,775	$75,084,935	$83,206,541	$88,306,843	$109,021,424	$126,122,046	$109,733,512	$129,468,955	$119,236,368	$129,624,599	$1,751,347,019
Costs	$	$540,187,727	$11,644,693	$49,749,189	$51,653,642	$51,340,500	$45,180,488	$ 9,632,237	$ 29,652,019	$ 41,671,059	$ 33,150,127	$ 16,904,949	$ 11,274,227	$ 799,490,294
Net	**$**	**$302,414,913**	**$67,930,563**	**$41,426,586**	**$23,431,293**	**$31,866,041**	**$43,126,355**	**$ 99,389,187**	**$ 96,470,027**	**$ 68,062,453**	**$ 96,318,827**	**$102,331,420**	**$118,350,372**	**$ 951,856,725**
BCR		1.6												
COSTS														
Total Capital														
Transmission	$	$174,749,914	$ 852,627	$20,810,441	$22,008,175	$21,076,725	$18,946,505	$ 3,640,042	$ 18,795,510	$ 22,157,669	$ 16,386,118	$ 5,451,893	$ -	**$ 282,268,937**
Distribution	$	$210,481,241	$ -	$19,018,735	$19,494,204	$19,981,559	$20,481,098	$ 443,568	$ 4,654,726	$ 6,560,426	$ 5,372,102	$ -	$ -	**$ 273,122,823**
Telecom	$	$ 30,973,700	$ (0)	$ 0	$ (0)	$ 0	$ -	$ -	$ -	$ (0)	$ (0)	$ 0	$ 0	**$ 32,477,141**
IT	$	$ 11,112,374	$ 31,452	$ 441,962	$ 496,820	$ 446,969	$ 306,117	$ 26,247	$ 601,901	$ 619,028	$ 582,538	$ 434,009	$ 40,261	**$ 14,707,068**
PM	$	$ 19,707,587	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 19,707,587**
Ongoing	$	$ 27,349,339	$ 5,598,295	$ 4,247,231	$ 4,353,411	$ 4,462,247	$ -	$ -	$ -	$ 6,654,614	$ 5,048,623	$ 5,174,838	$ 5,304,209	**$ 59,188,899**
	$	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total Capital	**$**	**$474,374,155**	**$ 6,482,374**	**$44,518,370**	**$46,352,610**	**$45,967,499**	**$39,733,720**	**$ 4,109,857**	**$ 24,052,137**	**$ 35,991,737**	**$ 27,389,380**	**$ 11,060,740**	**$ 5,344,470**	**$ 681,472,455**
Total O&M														
Transmission	$	$ 1,409,686	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 1,560,778**
Distribution	$	$ 7,818,516	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 7,938,442**
Telecom	$	$ 374,663	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 404,733**
IT	$	$ 13,151,937	$ 1,278,095	$ 1,278,095	$ 1,278,095	$ 1,278,095	$ 1,278,095	$ 1,278,095	$ 1,278,095	$ 1,278,095	$ 1,278,095	$ 1,278,095	$ 1,278,095	**$ 25,264,129**
PM	$	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Ongoing	$	$ 43,058,769	$ 3,884,224	$ 3,952,725	$ 4,022,938	$ 4,094,906	$ 4,168,674	$ 4,244,286	$ 4,321,788	$ 4,401,227	$ 4,482,653	$ 4,566,114	$ 4,651,662	**$ 82,849,757**
Total O&M	**$**	**$ 65,813,571**	**$ 5,162,319**	**$ 5,230,819**	**$ 5,301,032**	**$ 5,373,001**	**$ 5,446,768**	**$ 5,522,380**	**$ 5,599,882**	**$ 5,679,322**	**$ 5,760,747**	**$ 5,844,209**	**$ 5,929,756**	**$ 118,017,839**
Total Costs														
Total Capital	$	$474,374,155	$ 6,482,374	$44,518,370	$46,352,610	$45,967,499	$39,733,720	$ 4,109,857	$ 24,052,137	$ 35,991,737	$ 27,389,380	$ 11,060,740	$ 5,344,470	$ 681,472,455
Total O&M	$	$ 65,813,571	$ 5,162,319	$ 5,230,819	$ 5,301,032	$ 5,373,001	$ 5,446,768	$ 5,522,380	$ 5,599,882	$ 5,679,322	$ 5,760,747	$ 5,844,209	$ 5,929,756	$ 118,017,839
Total Capital & O&M	**$**	**$540,187,727**	**$11,644,693**	**$49,749,189**	**$51,653,642**	**$51,340,500**	**$45,180,488**	**$ 9,632,237**	**$ 29,652,019**	**$ 41,671,059**	**$ 33,150,127**	**$ 16,904,949**	**$ 11,274,227**	**$ 799,490,294**
BENEFITS														
Operational Benefits														
Improved VAR Mgmt	$	$ 89,711,275	$ 8,936,560	$ 6,633,301	$ 6,828,770	$ 7,100,741	$ 7,333,229	$ 7,709,856	$ 8,056,471	$ 8,361,270	$ 8,648,115	$ 8,774,514	$ 8,903,115	**$ 165,026,788**
Avoided Capacity Costs	$	$109,962,860	$ 8,393,371	$ 8,499,966	$ 8,607,916	$ 8,717,236	$ 8,827,945	$ 8,940,060	$ 9,053,599	$ 9,168,580	$ 9,285,021	$ 9,402,940	$ 9,522,358	**$ 194,811,927**
Avoided Fixed O&M Generation C	$	$ 4,608,029	$ 814,267	$ 834,629	$ 855,491	$ 879,284	$ 898,800	$ 921,270	$ 944,301	$ 970,562	$ 992,112	$ 1,016,907	$ 1,042,330	**$ 11,818,213**
Avoided Variable O&M Generatio	$	$ 23,796,894	$ 3,352,826	$ 2,910,272	$ 1,922,811	$ 2,551,824	$ 2,454,961	$ 2,612,847	$ 2,662,879	$ 2,572,940	$ 2,651,723	$ 2,735,164	$ 3,663,994	**$ 48,377,530**
Avoided Reagent Cost Generatioı	$	$ 281,705	$ 51,991	$ (30,351)	$ 83,665	$ 27,876	$ 37,081	$ 45,179	$ 41,164	$ 45,463	$ 22,918	$ 24,504	$ 33,215	**$ 584,260**
Avoided Start Cost Generation	$	$ 12,056,328	$ 170,614	$ 1,042,944	$ 1,302,584	$ 1,428,153	$ 2,091,488	$ 3,871,262	$ 4,238,167	$ 2,507,034	$ 5,191,986	$ 2,394,498	$ 2,267,126	**$ 31,166,605**
SUBTOTAL:	**$**	**$240,417,091**	**$21,719,628**	**$19,890,760**	**$19,601,237**	**$20,705,114**	**$21,643,504**	**$ 24,100,474**	**$ 24,996,580**	**$ 23,625,848**	**$ 26,791,876**	**$ 24,348,527**	**$ 25,432,138**	**$ 451,785,322**
Customer Benefits														
Avoided Fuel Costs	$	$368,653,700	$34,973,815	$41,503,769	$35,313,935	$38,898,316	$40,103,484	$ 52,667,044	$ 65,422,888	$ 52,646,840	$ 61,917,963	$ 56,595,389	$ 63,168,975	**$ 794,214,595**
SUBTOTAL:	**$**	**$368,653,700**	**$34,973,815**	**$41,503,769**	**$35,313,935**	**$38,898,316**	**$40,103,484**	**$ 52,667,044**	**$ 65,422,888**	**$ 52,646,840**	**$ 61,917,963**	**$ 56,595,389**	**$ 63,168,975**	**$ 794,214,595**
Operational Benefits & Customer Benefits														
SUBTOTAL:	**$**	**$609,070,791**	**56,693,443**	**61,394,528**	**54,915,172**	**59,603,431**	**61,746,988**	**76,767,519**	**90,419,469**	**76,272,688**	**88,709,838**	**80,943,916**	**88,601,113**	**1,245,999,917**
Environmental Benefits														
SO2	$	$ 7,387	$ 1,279	$ 1,353	$ 165	$ (45)	$ 194	$ 165	$ 45	$ 60	$ 52	$ 82	$ 22	**$ 11,500**
NOX	$	$ 337,765	$ 34,030	$ 35,668	$ 23,636	$ 32,041	$ 24,855	$ 29,035	$ 24,549	$ 26,964	$ 34,037	$ 26,874	$ 20,645	**$ 615,112**
CO2	$	$233,186,698	$22,846,504	$29,744,225	$20,145,962	$23,571,115	$26,534,805	$ 32,224,706	$ 35,677,984	$ 33,433,800	$ 40,725,026	$ 38,265,496	$ 41,002,819	**$ 504,720,489**
SUBTOTAL:	**$**	**$233,531,849**	**$22,881,813**	**$29,781,246**	**$20,169,763**	**$23,603,111**	**$26,559,855**	**$ 32,253,905**	**$ 35,702,578**	**$ 33,460,823**	**$ 40,759,116**	**$ 38,292,452**	**$ 41,023,486**	**$ 505,347,101**
TOTAL (all benefits)	**$**	**$842,602,640**	**$79,575,256**	**$91,175,775**	**$75,084,935**	**$83,206,541**	**$88,306,843**	**$109,021,424**	**$126,122,046**	**$109,733,512**	**$129,468,955**	**$119,236,368**	**$129,624,599**	**$1,751,347,019**

DEC NC COST-BENEFIT ANALYSIS - DISTRIBUTION PORTFOLIO SUMMARY

Net Present Value (Primary Costs and Benefits)

Substation and Line Projects

Program	NPV Costs			NPV Benefits				B/C Ratio
	Capital	O&M	Total	Operational	Customer	Other	Total	
Self-Optimizing Grid (Full SOG and Partial SOG)	$ 228,970,448	$ 9,478,670	$ 238,449,118	$ -	$ 1,311,577,330	$ 36,971,634	$ 1,348,548,964	5.7
Distribution H&R: Laterals	$ 354,750,158	$ 6,797,936	$ 361,548,093	$ 9,487,387	$ 889,006,803	$ -	$ 898,494,190	2.5
Distribution H&R: Storm	$ 41,042,000	$ 791,975	$ 41,833,976	$ 2,201,659	$ 165,744,170	$ -	$ 167,945,829	4.0
Distribution H&R: Public Interference	$ 78,800,972	$ 1,507,044	$ 80,308,016	$ -	$ 99,946,384	$ -	$ 99,946,384	1.2
Distribution Automation: Fuse Replacement	$ 24,245,934	$ 648,187	$ 24,894,120	-	$ 66,978,669	$ -	$ 66,978,669	2.7
Long Duration Interruptions (LDI)	$ 19,015,596	$ 683,560	$ 19,699,156	$ 711,208	$ 319,499,044	$ -	$ 320,210,253	16.3
Targeted Undergrounding (TUG)	$ 158,976,825	$ 114,741	$ 159,091,566	$ 8,477,567	$ 478,523,026	$ -	$ 487,000,593	3.1
Total NPV Costs and Benefits (Programs with CBA:	**$ 905,801,932**	**$ 20,022,113**	**$ 925,824,045**	**$ 20,877,821**	**$ 3,331,275,426**	**$ 36,971,634**	**$ 3,389,124,882**	**3.7**
Total NPV Costs and Benefits (Non-CBA Programs)	**$ 631,052,237**	**10,120,808**	**$ 641,173,045**	**$ -**	**$ -**	**$ -**	**$ –**	**–**
Total NPV Costs and Benefits (All Programs)	**$ 1,536,854,169**	**$ 30,142,921**	**$ 1,566,997,090**	**$ 20,877,821**	**$ 3,331,275,426**	**$ 36,971,634**	**$ 3,389,124,882**	**2.2**

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Financial cost-benefit analyses methodology

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Overall methodology

- Benefits calculation and cost-benefits analysis completed using methodology from previous rate case filings
- Expected financial benefits based primarily on customer (e.g., reliability improvements) and operational savings
- Cost-benefit analyses completed at the improvement program level; similar to analysis for SOG in previous rate case filings

Data inputs

- **Aggregate resource / input** requirements determined based:
  - Substation characteristics
  - Historical project data: average requirements for completion of work
- **Expected reliability improvements** determined based on:
  - Historic performance for identified circuits
  - Historical project data: average improvements associated with program

Methodology for benefits and costs

- **Program costs** calculated using aggregate resource / input requirements and projected unit costs (based on historic project data)
- **Program benefits** calculated as financial value of:
  - Customer savings (expected reliability improvements, using Interruption Cost Estimate (ICE) Calculator used as data input)
  - Operational savings (e.g., avoided O&M)
  - Other savings (e.g., fuel costs, environmental)
- Timing of costs and benefits determined from expected project schedules

Excel-based cost-benefit analysis (CBA)

- Projected schedule of **program costs and benefits** tabulated in excel
  - Benefits segmented by (1) sustained outage avoidance, (2) momentary outage avoidance, and (3) operational savings
  - Costs segmented by (1) capital, (2) contingency, (3) O&M, and (4) ongoing
- Present value (as of current year) calculated for costs and benefits
- Net present value and benefit-cost ratio calculated for each program
- Sensitivity analysis tab included for variance on key inputs

Source: ICE Calculator

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Overview of ICE Calculator

ICE CALCULATOR

Nexant

- **Interruption Cost Estimate (ICE) Calculator is an electric reliability, online planning tool** developed by Lawrence Berkeley National Laboratory (LBNL) and Nexant, Inc with funding from the U.S. Dept. of Energy (DoE)
- Tool is **designed for electric reliability planners at utilities, government organizations, and other entities** that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States
- **Translates reliability improvements into value** by using data from 34 previous Customer Interruption Cost studies from 10 utilities between 1989-2012.

Data inputs to ICE

- State
- Customers
  - Non-residential
  - Residential
- Reliability metrics
  - SAIDI
  - SAIFI

Analytical model run

Outputs from ICE / inputs to CBA

- **Cost data by customer sector** (Residential, Small C&I, Med./Large C&I)
  - Cost per Outage Event
  - Cost per Average kW
  - Cost per Unserved kWh

Generalized CBA Calculated Reliability Improvement Value:

Number of Events Eliminated * Average Number of Customers Impacted * ICE Cost per Outage Event (Based on Duration)

Source: ICE Calculator