Distribution Program Summaries
Duke Energy Carolinas, LLC
2022 DEC MYRP Technical Conference
Docket No. E-7, Sub 1276

Table of Contents

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.

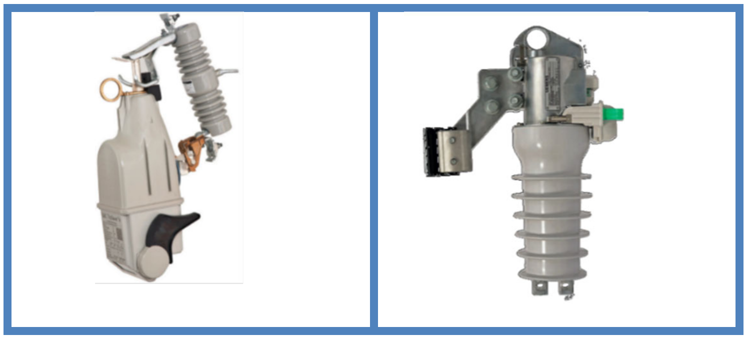
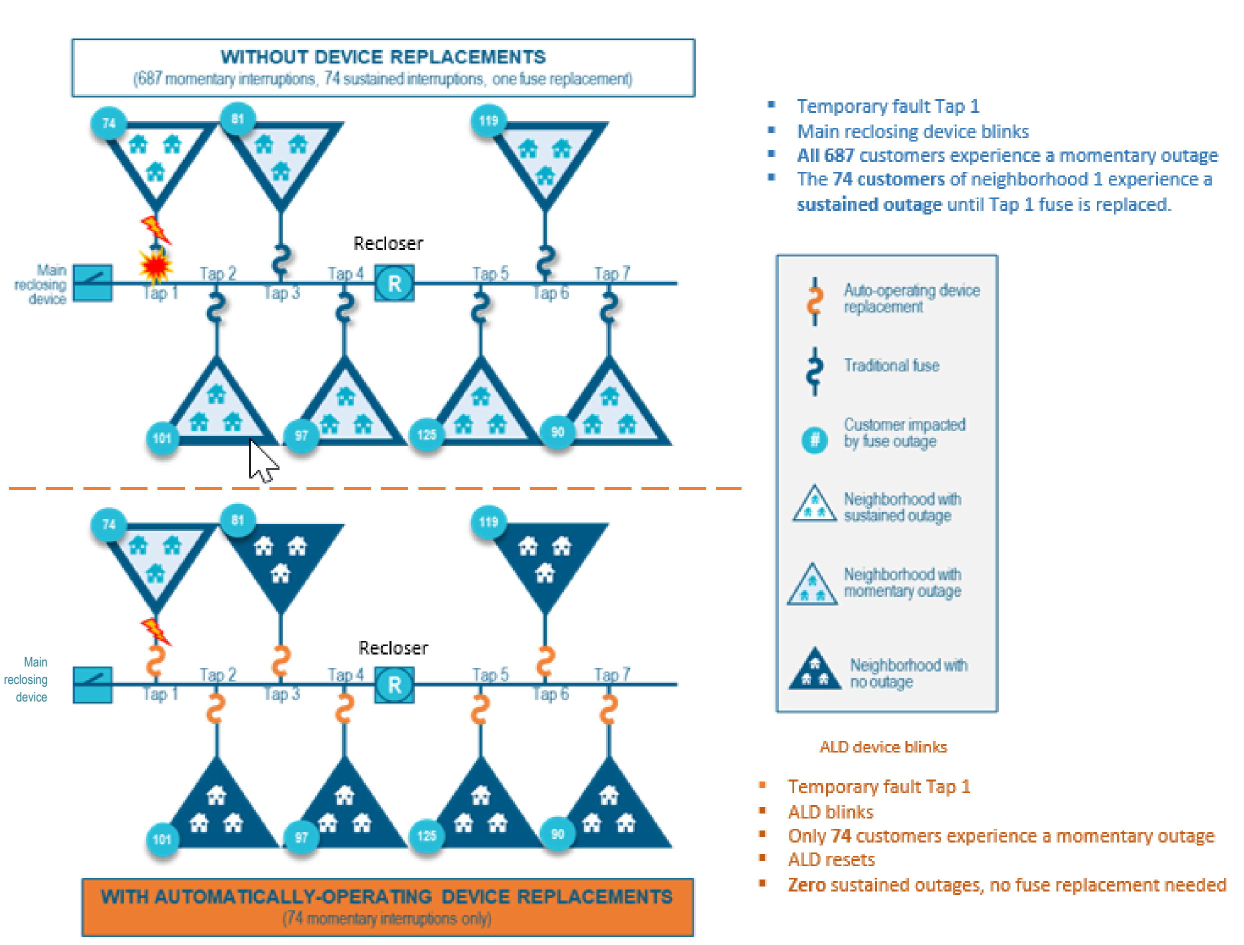


Figure 2: The schematic below represents a pre- and post-program example. Currently, when a fault occurs beyond a fuse, it's possible that the upstream reclosing device blinks affecting many customers plus the fuse melts with a sustained outage. Future state with an automated lateral device, the fault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



<table>
<tr><td colspan="5">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</td></tr>
<tr><td>DEC NC</td><td>Jan ’24-Dec ‘24</td><td>Jan ’25-Dec ‘25</td><td>Jan ’26-Dec ‘26</td><td>Total</td></tr>
<tr><td>Capital costs</td><td>$15.0M</td><td>$8.1M</td><td>$5.3M</td><td>$28.4M</td></tr>
<tr><td>O&M costs (installation only)</td><td>$.3M</td><td>$.1M</td><td>$.1M</td><td><b>$.5M</td></tr>
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<table>
<tr><th>Grid capabilities enabled</th><th>HB951 Policy Considerations addressed</th></tr>
<tr><td>Reliability
• Improve resiliency by increasing grid strength and ability to rapidly restore power
• Promote DER adoption by providing consistent power flow.</td><td>• Encourages DERS
• Encourages beneficial electrification, including electric vehicles
• Maintains adequate levels of reliability and customer service
• Promotes resilience and security of the electric grid</td></tr>
</table>

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

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

- 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	**$73.9M**
Total NPV Benefits	**$69.9M**
Net value of Program	**($4.0M)**
Benefit to Cost Ratio	**0.95**
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**.

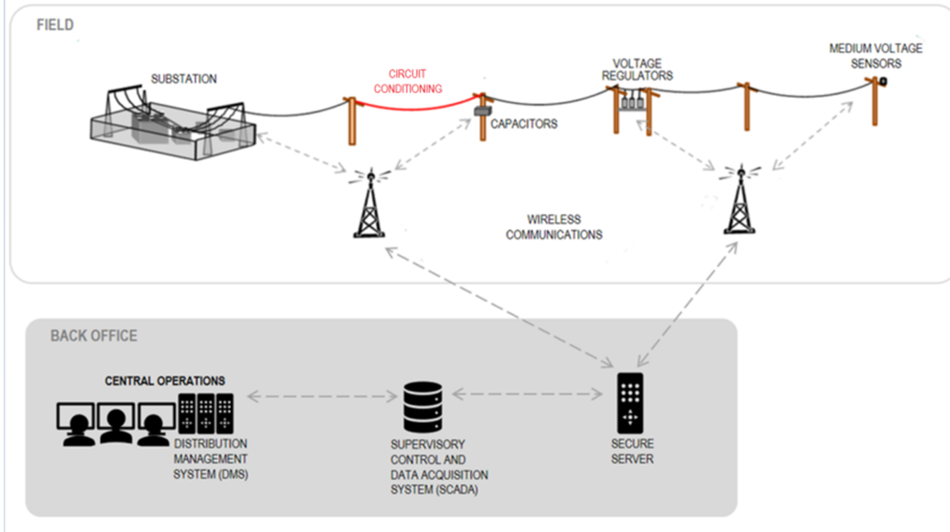


Figure 1: Conceptual View of Integrated Volt/VAR Control (IVVC).

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	**$96.6M**
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.

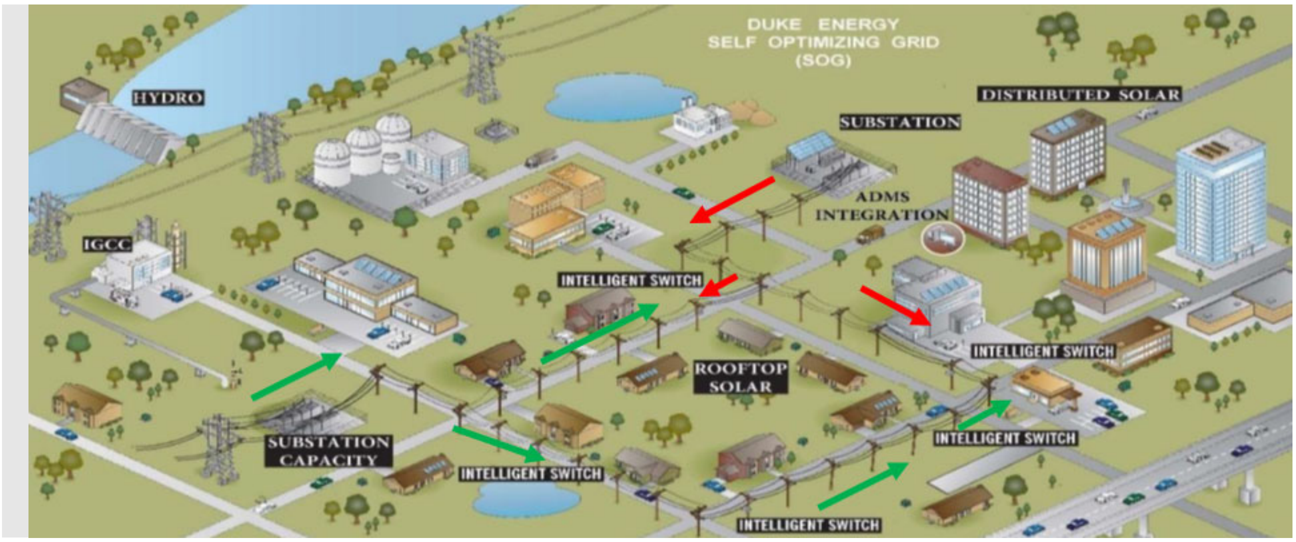


Figure 2

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.

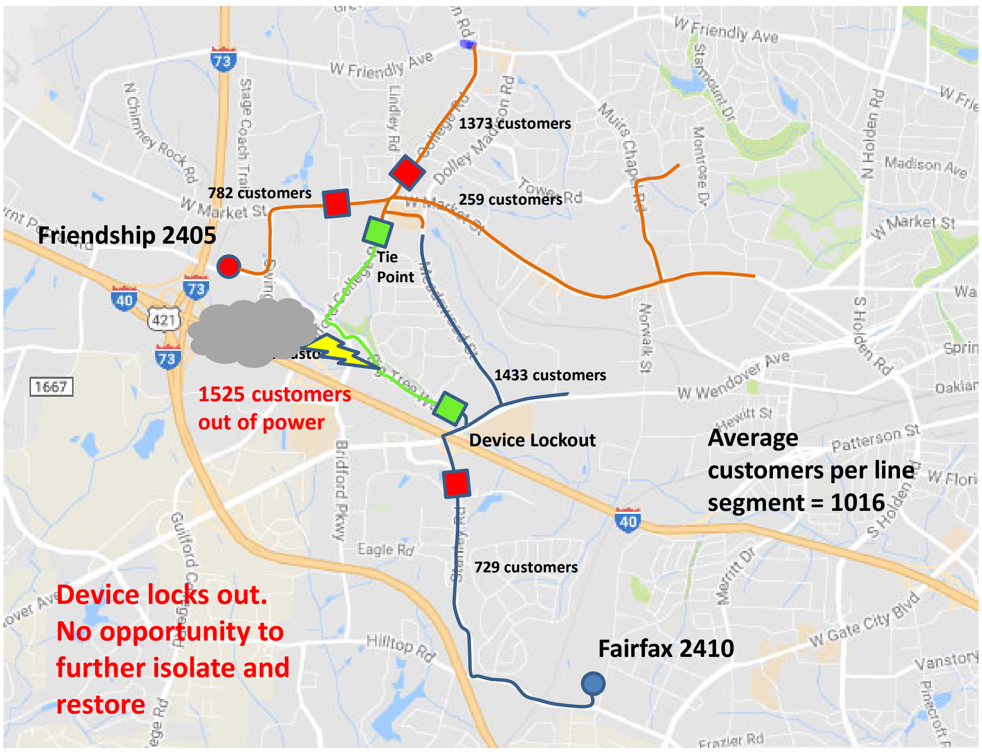
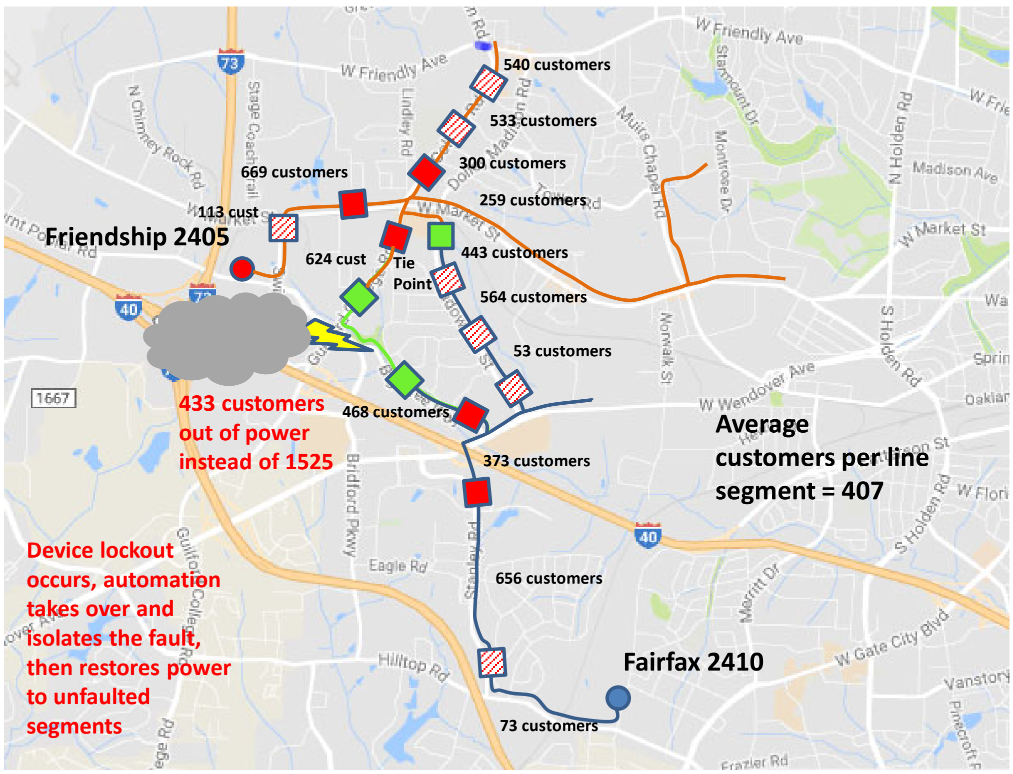


Figure 3

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.



<table>
<tr><td colspan="5">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</td></tr>
<tr><td>DEC NC</td><td>Jan ’24-Dec ‘24</td><td>Jan ’25-Dec ‘25</td><td>Jan ’26-Dec ‘26</td><td>Total</td></tr>
<tr><td>Capital costs</td><td>$127.8M</td><td>$58.4M</td><td>$84.6M</td><td>$270.8M</td></tr>
<tr><td>O&M costs (installation only)</td><td>$1.8M</td><td>$.8M</td><td>$1.2M</td><td>$3.8M</td></tr>
</table>

Grid capabilities enabled	**HB951 Policy Considerations addressed**
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	• 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.

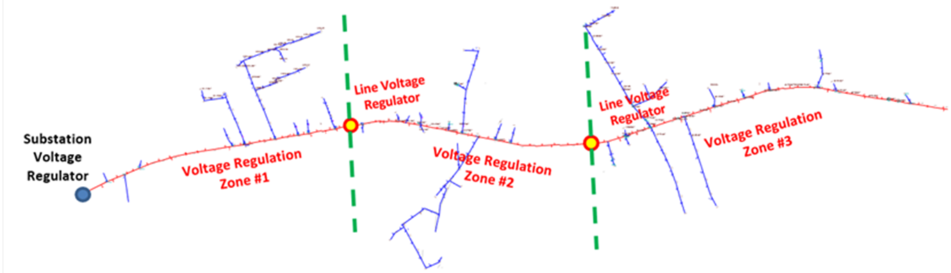


Figure 1: Illustration of voltage "Regulation Zones" on an example circuit (*for conceptual purposes only).*

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.