

April 1, 2026

NYSEG and RG&E

Five-Year Capital Investment Plan (2026-2030)



NYSEG & RG&E 5-Year Capital Investment Plan**Table of Contents**

Chapter 1	Executive Summary	8
Chapter 2	Introduction / Objective	13
Chapter 3	Planning Process.....	15
Section 3.1	Planning Process	15
Section 3.2	Planning Objectives	15
Section 3.3	Contributors	16
Section 3.4	Plan Overview	16
Section 3.5	Phases of the Planning Process	17
Section 3.6	Capital Investment Planning Approval Process	22
Chapter 4	Project / Program Categorization.....	26
Chapter 5	Capital Investment Plan.....	28
Chapter 6	Electric and Generation Capital Investment Forecast.....	29
Section 6.1	Electric and Generation Capital Investment Requirements	29
Section 6.2	Electric Asset Condition Capital Investment Forecast.....	30
Section 6.3	Electric Customer Focus Capital Investment Forecast.....	35
Section 6.4	Electric Modernization Capital Investment Forecast	39
Section 6.5	Electric Innovation Capital Investment Forecast	41
Section 6.6	Electric Reliability Capital Investment Forecast	43
Section 6.7	Electric Resiliency Capital Investment Forecast	49
Section 6.8	Electric Compliance Capital Investment Forecast.....	52
Section 6.9	Hydro Generation Capital Investment Forecast	55
Section 6.10	Clean Energy Transformation Capital Investment Forecast.....	59
Section 6.11	Electric AMI Capital Investment Forecast	61
Chapter 7	Gas Capital Investment Forecast	62
Section 7.1	Gas Capital Investment Requirements.....	62
Section 7.2	Gas Asset Condition Capital Investment Forecast.....	63
Section 7.3	Gas Mandatory Capital Investment Forecast	66
Section 7.4	Gas Modernization Capital Investment Forecast	68
Section 7.5	Gas Reliability Capital Investment Forecast.....	69
Section 7.6	Gas AMI Capital Investment Forecast.....	71
Chapter 8	Common Capital Investment Forecast	72
Section 8.1	Buildings and Facilities Capital Forecast.....	74
Section 8.2	Customer Service Capital Forecast.....	78
Section 8.3	Fleet Capital Forecast.....	80
Section 8.4	Information Technology Capital Forecast.....	82
Section 8.5	Operational Smart Grids Capital Forecast	86
Section 8.6	Security Capital Forecast	90
Section 8.7	Training Capital Forecast.....	92





NYSEG and RG&E 5-Year Capital Investment Plan

Appendix A - Capital Investment Forecast	94
NYSEG Electric Projects	95
RG&E Electric Projects	96
NYSEG Gas Projects	97
RG&E Gas Projects	98
NYSEG Common Projects	99
RG&E Common Projects	100
Appendix B - Capital Project Summaries	101
Appendix C - Disadvantaged Communities	102
NYSEG Electric Projects	103
RG&E Electric Projects	107
NYSEG Gas Projects	110
RG&E Gas Projects	111
NYSEG Common Projects	112
RG&E Common Projects	115





NYSEG and RG&E 5-Year Capital Investment Plan

List of Figures

Figure 1 – Investment Planning and Approval Process.....	22
Figure 2 – Investment Planning Gates	25
Figure 3 – NYSEG and RG&E Capital Investment Plan.....	28
Figure 4 – NYSEG and RG&E Common Allocation Factors.....	72





NYSEG and RG&E 5-Year Capital Investment Plan

List of Tables

Table 1 – NYSEG Electric and Generation Capital Investment Forecast	29
Table 2 – RG&E Electric and Generation Capital Investment Forecast	30
Table 3 – NYSEG Electric Asset Condition Capital Investment Forecast.....	31
Table 4 – RG&E Electric Asset Condition Capital Investment Forecast	32
Table 5 – NYSEG Electric Customer Focus Capital Investment Forecast	35
Table 6 – RG&E Electric Customer Focus Capital Investment Forecast.....	35
Table 7 – NYSEG Electric Modernization Capital Investment Forecast	39
Table 8 – RG&E Electric Modernization Capital Investment Forecast	39
Table 9 – NYSEG Electric Innovation Capital Investment Forecast	41
Table 10 – RG&E Electric Innovation Capital Investment Forecast	41
Table 11 – NYSEG Electric Reliability Capital Investment Forecast	45
Table 12 – RG&E Electric Reliability Capital Investment Forecast.....	45
Table 13 – NYSEG Electric Resiliency Capital Investment Forecast	49
Table 14 – RG&E Electric Resiliency Capital Investment Forecast.....	50
Table 15 – NYSEG Electric Compliance Capital Investment Forecast.....	52
Table 16 – RG&E Electric Compliance Capital Investment Forecast	53
Table 17 – NYSEG Hydro Generation Capital Investment Forecast.....	56
Table 18 – RG&E Hydro Generation Capital Investment Forecast	57
Table 19 – NYSEG Clean Energy Transformation Capital Investment Forecast.....	59
Table 20 - RG&E Clean Energy Transformation Capital Investment Forecast.....	59
Table 21 – NYSEG AMI Capital Investment Forecast.....	61
Table 22 –RG&E AMI Capital Investment Forecast	61
Table 23 – NYSEG Gas Capital Investment Forecast.....	62
Table 24 – RG&E Gas Capital Investment Forecast	62
Table 25 – NYSEG Gas Asset Condition Capital Investment Forecast.....	63
Table 26 – RG&E Gas Asset Condition Investment Forecast	63
Table 27 – NYSEG Gas Mandatory Capital Investment Forecast.....	66
Table 28 – RG&E Gas Mandatory Capital Investment Forecast	66
Table 29 – NYSEG Gas Modernization Capital Investment Forecast	68
Table 30 – RG&E Gas Modernization Capital Investment Forecast.....	68





NYSEG and RG&E 5-Year Capital Investment Plan

Table 31 – NYSEG Gas Reliability Capital Investment Forecast	69
Table 32 – RG&E Gas Reliability Capital Investment Forecast.....	69
Table 33 – NYSEG Gas AMI Capital Investment Forecast	71
Table 34 – RG&E Gas AMI Capital Investment Forecast.....	71
Table 35 – NYSEG Common Capital Investment Forecast.....	73
Table 36 – RG&E Common Capital Investment Forecast	73
Table 37 – NYSEG Building and Facilities Capital Investment Forecast.....	75
Table 38 – RG&E Building and Facilities Capital Investment Forecast	75
Table 39 – NYSEG Customer Service Capital Investment Forecast	78
Table 40 – RG&E Customer Service Capital Investment Forecast	79
Table 41 – NYSEG Fleet Capital Investment Forecast	81
Table 42 – RG&E Fleet Capital Investment Forecast.....	81
Table 43 – NYSEG Information Technology Investment Forecast	82
Table 44 – RG&E Information Technology Investment Forecast	83
Table 45 – NYSEG Operational Smart Grids Investment Forecast.....	86
Table 46 – RG&E Operational Smart Grids Investment Forecast	87
Table 47 – NYSEG Security Investment Forecast	90
Table 48 – RG&E Security Investment Forecast.....	90
Table 49 – NYSEG Training Investment Forecast	92
Table 50 – RG&E Training Investment Forecast.....	92





NYSEG and RG&E 5-Year Capital Investment Plan

List of Appendices

Appendix A - Capital Investment Forecast
Appendix B - Capital Project Summaries
Appendix C - Disadvantaged Communities





NYSEG and RG&E 5-Year Capital Investment Plan

Chapter 1 Executive Summary

This document presents a comprehensive five-year Capital Investment Plan for the electric transmission, distribution, generation, and natural gas businesses of New York State Electric & Gas Corporation (“NYSEG”) and Rochester Gas and Electric Corporation (“RG&E”), for the period 2026 through 2030 (the “Plan”). This Plan is intended to reflect the prioritized needs/projects of the Companies’ systems over the next five years for NYSEG and RG&E (the “Companies”) to continue to provide safe, secure, reliable, and resilient service to customers and help New York State reach its environmental and clean energy goals. The Companies’ total plan of \$ 13.7 billion reflects needed investments of \$12.3 billion in the electric and generation systems and \$1.4 billion in the gas system over the five-year period 2026-2030 and is in alignment with the Companies investment plan included in its pending rate case. These investments will allow the Companies to continue efforts on improving their overall service to customers. They are also intended to mitigate the potential for continued future negative reliability impacts. Finally, they will help achieve the State’s clean energy goals; especially, the target of 70% renewable generation by 2030 through the Companies’ Phase 1 projects.

	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	Total 2026-2030
NYSEG Electric	1,092.2	1,591.1	1,789.4	1,904.9	2,208.9	8,586.5
NYSEG Gas	131.4	143.0	134.2	142.4	143.1	694.1
Subtotal NYSEG	1,223.6	1,734.1	1,923.7	2,047.4	2,352.0	9,280.6
RG&E Electric	402.9	505.4	680.4	919.8	1,197.9	3,706.3
RG&E Gas	124.8	131.4	137.4	155.5	137.8	686.9
Subtotal RG&E	527.6	636.9	817.8	1,075.2	1,335.7	4,393.2
Total	1,751.2	2,370.9	2,741.4	3,122.6	3,687.7	13,673.9

The Companies use a rigorous and structured investment planning process to determine the overall level of need and govern the eventual plan to implement, which includes consideration of benefits and costs through the use of a prioritization approach described in Chapter 2, below. This includes a capital investment planning, prioritization and approval process that assesses the system needs and introduces projects and programs to address those needs in relation to the strategic objectives of the Companies. The result is a comprehensive capital investment plan that includes projects and programs related to





NYSEG and RG&E 5-Year Capital Investment Plan

(1) Asset Condition, (2) Customer Focus, (3) Modernization, (4) Innovation, (5) Reliability, (6) Resiliency, (7) Compliance, (8) Hydro-Generation, (9) Clean Energy Transformation and (10) Mandatory. In addition, the Companies also review the capital investments needed to support functions such as (11) Common; Buildings and Facilities, Customer Service, Fleet, Information Technology, Operational Smart Grids, Security and Training.

The Plan contains projects and programs categorized by their main driver of the investment as follows, listed in no particular order. A project or program may have aspects that could be assigned to several different categories; however, the plan has assigned each project or program to one and only one category that reflects the most predominant underlying system need being addressed.

- Asset Condition: This category includes those projects and programs that are needed to address assets deemed to be beyond their useful operating life expectancy. These projects / programs are identified as a result of various Planning studies, ongoing Maintenance programs, and immediate needs brought forth by System Operations. For Gas, this group includes Regulator and gate station improvements, distribution and transmission main replacement projects, pressure reliability projects, and other asset condition projects.
- Customer Focus: This category includes those projects and programs that are needed to meet the needs of our customers. This category of projects / programs includes initiatives such as new connections, state and municipal projects, customer lighting, etc.
- Modernization: This category includes those projects and programs that are needed to enhance the Companies' ability to operate the system in a more effective and efficient manner. This category of projects / programs includes those which are designed to address outdated business systems, metering infrastructure, etc.
- Innovation: This category includes projects that introduce a new or significantly improved product or process, a new business practice or development of external relations.





NYSEG and RG&E 5-Year Capital Investment Plan

- Reliability: This category includes those projects and programs that are needed to address immediate and longer-term system needs such as thermal / capacity overloads, voltage, and loss-of-load violations. For Gas, this group includes the Leak Prone Pipe Replacement program and regulator station upgrades not related to asset condition.
- Resiliency: This category includes those projects and programs that are needed to strengthen existing facilities to withstand extreme weather events and improve system restoration capabilities following any number of unplanned transmission and distribution contingency events. These projects/programs seek to improve overall system flexibility and provide system operators with the appropriate visibility and field infrastructure to quickly restore power and minimize customer exposure following a contingency event.
- Compliance (Electric Only): This category includes those projects and programs that are needed to address compliance requirements/criteria, mandates, orders, or other regulatory / governmental direction such as the NERC BES Program or the NERC Alert Program.
- Hydro-Generation: This category provides the capital requirements for Hydro Generation facilities to replace obsolete and aged infrastructure, addresses other generating station updates, and minor capital expenditures to maintain these assets.
- Clean Energy Transformation: This category includes those projects and programs that are needed to enhance system capabilities and accommodate an increased level of renewable resource penetration and/or support proposed local municipality grid modification initiatives (e.g., “electrification”). This category includes projects such as the Power New York (PNY) Transmission Projects that were recently developed in support of NY’s Climate Leadership and Community Protection Act (CLCPA).





NYSEG and RG&E 5-Year Capital Investment Plan

- Mandatory (Gas only): This category includes projects and programs that are required by tariff, regulatory order, or law and/or related to the safety of employees and/or the general public.
- Common: This category includes expenditures grouped into Buildings and Facilities, Customer Service, Fleet, Information Technology, Operational Smart Grids, Security, and Training.

The proposed capital expenditures in this plan are designed to allow the Companies to meet business objectives, including the provision to its customers of safe, reliable service while meeting future system needs, improving reliability and accommodating the increased proliferation of clean energy resources in support of NY's CLCPA initiative and local municipality decarbonization initiatives.

Make Ready is affected by new and expanded government initiatives. In 2022, Governor Hochul announced the start of the \$1 billion ConnectALL initiative, which is intended to deliver affordable broadband to millions of New Yorkers statewide. As a result of this initiative, the Companies have begun to see significant increases in pole attachment applications by broadband companies impacting the Companies' infrastructure. As a result of these applications, the Companies may experience extraordinary increases in the level of pole attachment requests, which would have a corresponding material increase in the Companies' Make Ready costs to accommodate broadband expansion initiatives.

New government obligations to pay prevailing wages will affect an increase in the Capital portfolio. On August 16, 2023, Governor Hochul signed the Roadway Excavation Quality Assurance Act. The law went into effect on September 15, 2023. The law subjects utility construction work within permitted right of way to prevailing wage requirements. The law applies to contractors and subcontractors performing such work and is also applicable any time a permit is required to be obtained from the state, a county, or a municipality to use, excavate, or open a street.





April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

The contractors that NYSEG and RG&E utilize to perform the majority of our capital work use non-union labor and the requirement to pay a prevailing wage will increase the hourly wage, supplemental benefits and the required taxes, and thus significantly increase the cost of capital gas projects. These costs were not contemplated in the Companies' latest rate filing and are not reflected in the costs in this document as we continue to work with our contractors to update the costs associated to comply with the law and the agreements with our contractors.



Take care of the environment.
Print in black and white and only if necessary.



NYSEG and RG&E 5-Year Capital Investment Plan

Chapter 2 Introduction / Objective

The objective of this document is to present a comprehensive five-year Capital Investment Plan for the electric and natural gas transmission, distribution, and hydro generation businesses of AVANGRID Networks' New York operating companies, New York State Electric & Gas Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RG&E," and collectively with NYSEG, the "Companies"), for the period 2026 through 2030.

This investment plan includes those projects and programs that are most critical in the continued improvement / enhancement of system performance, focusing on key factors such as system reliability, resiliency, renewal of aged assets, and grid enhancements to accommodate an increased level of clean energy transformation source penetration.

This proposed capital investment plan relies heavily on the prioritization of projects and programs in alignment with the strategic objectives of each Company. Each investment is evaluated on five categories that align to the Companies' corporate priorities, strategy, and vision: Safety, Reliability, Asset Condition, Customer Focus, and Strategic and Efficiency.

The contents of this document are organized as follows:

- Executive Summary (Chapter 1): Offers an Executive Summary of the contents within this document.
- Introduction / Objective (Chapter 2): Introduces the document and its content.
- Planning Process (Chapter 3): Provides an overview of the Planning and Approval Processes including strategic objectives of the Companies. Also included in this chapter is a brief investment summary of electric and gas for each of the Companies.
- Project / Program Categorization (Chapter 4): Provides a list of categories and associated definitions that were developed as part of this plan. All projects and programs described herein have been categorized in accordance with these definitions.





NYSEG and RG&E 5-Year Capital Investment Plan

- Capital Investment Plan (Chapter 5): Provides and describes the Capital Investment Forecast required to meet the Companies' strategic objectives, consistent with NY State energy and climate goals. The forecast has been grouped into categories which describe the main drivers for the investments presented.
- Electric and Generation Capital Investment Forecast (Chapter 6) Provides and describes the Electric and Generation Capital Investment Forecast required to meet the Companies' strategic objectives, consistent with NY State energy and climate goals. The forecast has been grouped into categories which describe the main drivers for the investments presented.
- Gas Capital Investment Forecast (Chapter 7): describes the Natural Gas Capital Investment Forecast required to meet the Companies' strategic objectives, consistent with NY State energy and climate goals. Likewise, the plan has been grouped into categories which describe the main drivers for the investments.
- Common Capital Investment Forecast (Chapter 8): Outlines the Common Capital Investment Forecast to meet the strategic objectives of the Companies, consistent with NY State energy and climate goals. These projects and programs support more than one of the businesses and are categorized, by the most predominant area driving the investment.





Chapter 3 Planning Process

The process for planning and executing the Companies' capital investments is critical to the overall success of the Plan. The process is a rigorous approach that addresses selection, prioritization, approval, execution, and governance of the capital portfolio of projects and programs. The Plan is refreshed annually by reviewing and updating the projects and programs, aligning functional needs, and synchronizing resources, costs, and schedules.

Section 3.1 Planning Process

The following is a description of the annual capital investment planning process for NYSEG and RG&E. Details of each of the Company's investment forecasts are included in the chapters following this one.

Section 3.2 Planning Objectives

In identifying projects / programs included in a capital investment plan, each Company considers the following strategic objectives:

- Maintaining safety and improving, where needed, security.
- Meeting customers' electric and gas needs.
- Achieving service reliability and quality targets.
- Replacing assets and facilities based on underlying condition assessment and obsolescence.
- Improving the network's overall performance, effectiveness, and efficiency.
- Sustaining the environment and transforming the grid, including enhancing system robustness to accommodate the increased proliferation of clean energy resources in support of NY's Climate Leadership and Community Protection Act (CLCPA) initiative, and local municipality decarbonization initiatives (e.g., "electrification").





NYSEG and RG&E 5-Year Capital Investment Plan

During the planning process, each Company selects projects aimed at achieving one or more of these objectives in a cost-effective and timely manner.

Section 3.3 Contributors

The contributors to the plan include both operational business areas as well as those areas that support the operation of the business. Each group is responsible for a sector of the business and coordination and communication occurs between each as the system needs are assessed and the investment plan is developed and refined.

The business and support areas that contribute to each Company plan are as follows:

- Operational Business Areas: Customer Service, Electric Operations, Energy Services, Gas Operations, Generation, Operational Smart Grids, Integrated System Planning, Process & Technology, Projects, and Energy Strategy Policy Transformation.
- Support Business Areas: General Services and Fleet, Information Technology, Training, and Security.

Section 3.4 Plan Overview

The investment plan is developed to meet the needs of customers, improve reliability, strengthen the system against the adverse effects of major storms, provide assurance that cyber and physical aspects of the system are secure, support grid enhancement to accommodate NY's aggressive CLCPA objectives, and achieve the long-term business objectives of the Company. The projects and programs proposed in the plan are those that have been analyzed and determined to be necessary to support the delivery of safe and reliable service to customers.

The Companies endeavor to develop a prioritized plan as part of the annual planning process but reprioritizes as necessary based on emergent needs. Examples that can involve reprioritization include, but are not limited to, storms, equipment failure, and customer reactive work. Therefore, at any single point in time, the plan is a current snapshot of the portfolio of projects and overall system needs, which will likely change





NYSEG and RG&E 5-Year Capital Investment Plan

as a result of ongoing re-evaluation and re-prioritization processes embedded within the investment planning process.

For example, many of the electric projects reduce the risk of service outages in the event of contingency situations while other projects address mandates issued by state and federal regulators. We also anticipate that new regulations and requirements will be forthcoming during the term of this Plan. In addition, there are several projects that continue the process of bringing the electric delivery system up to present day standards by modernizing equipment, employing software and IT platforms, and expanding system automation. These standards are reviewed regularly and reassessed to identify the solutions tailored to meet the needs of our customers. The phases of the planning process are described in Section 3.5. While the plan phases are defined, the process is fluid and the re-iteration through the phases occurs many times throughout the year as new factors are introduced and other factors change such as regulatory requirements, customer needs, and system conditions.

Section 3.5 Phases of the Planning Process

Phase I – Initiation and Planning: During this initial phase, the business areas focus on the Companies' strategic objectives to meet the needs of the systems and of its customers effectively and efficiently. A description of each of those objectives are as follows:

- **Objective 1 – Maintain and Improve System Safety:** Safety is each Company's number one priority, and each Company accordingly places significant emphasis on the safety of its employees and the public. The Companies operate a "no harm" culture and will continue to make investments to assure the safe and reliable operation of the system.

No aspect of the Companies' operations is more important than accident prevention. Safety is a value that does not change. There is no job so





NYSEG and RG&E 5-Year Capital Investment Plan

important that established safety rules should ever be compromised.

Management strives to provide a hazard-free work environment that complies with all applicable health and safety laws and regulations, and educates employees, customers and the public about health and safety hazards associated with our operations. Further, management is committed to the recognition, assessment, and control of health and safety hazards related to each of the Company's facilities and operations.

Each Company continues to upgrade the physical security at and around the NYSEG and RG&E facilities as well as the overall cyber security infrastructure to keep the Companies' employees and the public safe, to help ensure the integrity of the Companies' systems and provide reliable service to customers. These upgrades include improved access control, video surveillance and alarming capabilities. More stringent NERC standards require the Companies to improve and expand its security capabilities to protect critical electric system infrastructure. Further, the challenges that each Company faces to ensure data protection, privacy and ensuring compliance with regulatory and legal mandates continue to grow as threats evolve and grow increasingly more sophisticated.

- **Objective 2 – Meet the Electric Needs of our Customers:** Each Company needs to provide reliable and dependable electric service to large commercial and industrial customers as well as residential customers. Often large commercial and industrial customers require an upgrade to a Company's electric facilities to meet their needs, and the Companies strive to make these upgrades in a timely manner. In certain cases, all, or a portion of the costs of these upgrades may be offset by contributions from the specifically affected customers. The Companies are working to enhance the process through which customer contributions in aid of construction ("CIAC") are determined. Additionally, with the increased proliferation of distributed energy resources





NYSEG and RG&E 5-Year Capital Investment Plan

(DER) on the electric system, the Companies must interconnect large and small generation projects to its transmission and distribution system, as requested by customers and in accordance with applicable regulatory requirements.

- **Objective 3 – Achieve Service Reliability and Quality Targets**: The Electric Plan supports this strategic objective by the following actions:
 - Prevent or minimize system violations on lines and transformers and other electrical elements under normal operating conditions (N-0) at peak demand.
 - Prevent or minimize system adverse impacts caused by contingency situations (N-1) and (N-1-1)
 - Enhance operation and restoration of the system through replacement and modernization of end-of-life equipment.

- **Objective 4 – Replace Assets and Facilities Based on Condition and Obsolescence**: Each Company continuously reviews equipment and facilities to determine which assets may be in need of replacement. Typically, those assets are identified due to one of the following conditions:
 - Equipment and facilities with high failure rates.
 - Technological obsolescence (e.g. inability to obtain spare parts).
 - Facilities that are determined to be beyond their useful operating life and the maintenance of such equipment is no longer cost effective.
 - Equipment with high maintenance costs for reasons other than their deteriorating condition.
 - Risk of not meeting safety, reliability, and environmental objectives; and
 - Other indicators of asset health.





NYSEG and RG&E 5-Year Capital Investment Plan

- **Objective 5 – Improve Effectiveness and Efficiency Through**

Modernization: Each Company continually looks for ways to make operations more effective and efficient. One of those ways is through network automation. The Companies continue to modernize the operations of their systems, enhancing the effectiveness with which NYSEG and RG&E serves customers, and enhancing reliability and efficiency. On the electric system, the primary customer benefit of automation is more efficient and effective response to distribution circuit outages thereby limiting the number of customers impacted by an outage event. The crews restoring service will receive notification of an outage sooner than they would have absent an automated system of notification. Adding reclosers on distribution lines reduces the potential number of customers whose service is impacted during an outage and reclosers can quickly relay the location of an outage to the Companies' energy control centers (ECCs). Additionally, the Companies project an increase in crew efficiency due to the reduction of travel time to assess an outage. Investment in automation will also be compatible with technologies required for the development of a smart grid.

- **Objective 6 – Enable Clean Energy Transformation**: Advance New York State's CLCPA goals and other clean energy / decarbonization (i.e., electrification) initiatives being proposed by the state and local municipalities.

Phase II – Data Gathering and Analysis: Given the objectives of the Companies, the business areas analyze data to determine whether the objectives are being met. The data is collected and provided through several different methods such as asset condition health assessments, inspection programs, failed equipment information, and asset replacement practices.





NYSEG and RG&E 5-Year Capital Investment Plan

The business areas determine the data that needs to be collected and reviewed to assess the system needs. For instance, fleet replacement is determined by application of the established fleet replacement procedure which contains specific criteria for replacement including age, maintenance, and condition. With electric and gas equipment, there are many factors which contribute to the inclusion of projects in the plan, including customer and capacity needs, the overall obligation to serve, reliability indices, asset health, system hardening needs, adherence to operating standards, and support of normal operations. New projects are initiated, and current projects may be adjusted, based on the information that has been collected and analyzed.

Phase III – Individual Budget and Plan Development: Upon the completion of the analysis and data gathering efforts, the business areas then develop and/or modify the individual project forecasts. These individual project forecasts comprise a business area's forecast which in turn becomes a component of the Companies total capital plan. Business area plans can-and-do change based on a variety of factors, including system conditions, customer needs, regulatory requirements, supply chain lead times, and material costs. These conditions are reviewed and addressed by the business areas.

Phase IV – Plan Review and Alignment: Utilizing the information and budget data from each area's individual plans, the Companies' capital investment plan is compiled. The plan is reviewed for alignment across the business areas and may be adjusted during the review process.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 3.6 Capital Investment Planning Approval Process

The Companies' have designed the Planning and Investment Approval Process to be in alignment with the Companies' planning objectives as described above. The process includes Governance oversight, and project review and approval stage gates with an overall focus on project justification, review, and prioritization. A graphic representation of the planning processes is shown below.

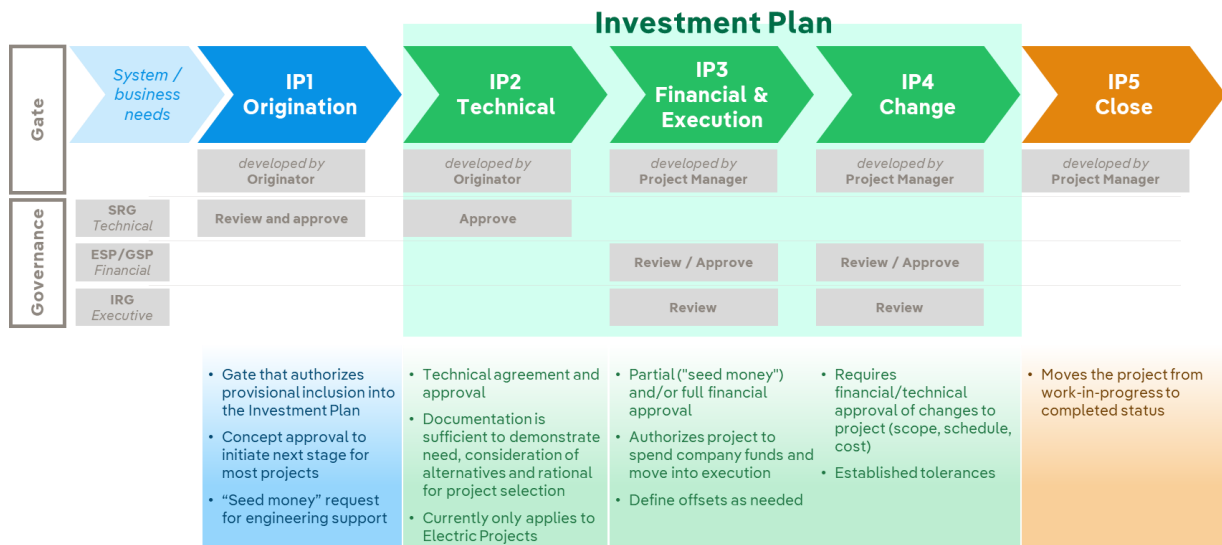


Figure 1 – Investment Planning and Approval Process

Governance:

Depending on the value, complexity and nature of the investment, proposed projects and previously identified projects are reviewed by one or more of the following governance review groups through the approval process.

- System Review Group (SRG) – This group reviews the technical and engineering aspects of certain electric system investments.
- Electric/Gas Strategic Planning Group (ESP/GSP) – This group provides for the review and approval of investments for inclusion in the plan, as well as providing financial authorization. This group reviews projects across all electric, gas, and





NYSEG and RG&E 5-Year Capital Investment Plan

common business areas and provides both initial financial approval as well as approval for changes.

- Investment Review Group (IRG) – This group is comprised of executives and provides them the opportunity to review investments to move forward as suggested.

Stages in the Investment Planning Approval Process:

The approval process consists of a staged approach. This staged approach to investment approval where investments are approved at distinct points (gates, noted as IP1, IP2, etc. in Figure 1) throughout the process provides for:

- Separate concept and technical/engineering approval stages that ensure only those projects that have viable solutions have resources allocated to develop full technical specifications.
- Separate governance reviews and approvals for financial/execution before expending funds.
- Re-approval of investments while not necessary for all projects does allow for Governance Teams to challenge the underlying reasons for those that do propose a change to the scope, schedule, or cost of a project. This also has the advantage in that it tends to draw out lessons learned for application to future projects.

The five-stage Investment Planning Approval gates are described in detail below and illustrated in Figure 2.

- **Conceptual Approval (IP1)**: An IP1 is required to initiate a new project/program for its inclusion into the capital investment plan. All projects not currently in the capital investment plan begin with this phase. IP1's are presented to the





NYSEG and RG&E 5-Year Capital Investment Plan

appropriate governance groups for approval or further action based on the level and complexity of the projects.

- **Technical/Engineering Approval (IP2)**: The approval is facilitated by the SRG governance group to review the need and technical aspects of certain electric projects including proposed solution design, alternatives considered, capital expenditure levels, project timeline, environmental concerns, and other pertinent information deemed necessary.
- **Financial/Execution Approval (IP3)**: This stage represents the approval to expend funds on the execution of the project. For those projects requiring IP2 approval, this stage follows that approval. This is done by submitting an IP3 for review and approval. They are presented to appropriate governance groups for approval or further action based on the level and complexity of the projects and then flows through the required grants of signing authority. Discussions at governance groups include level of the budget, regulatory position, alternative options, project risks, and other project details.
- **Change Approval (IP4)**: An IP4 is required for all project changes that fall outside allowed project tolerance parameters. Project changes are presented to the governance review groups based on the complexity and level of the investment. The discussions include reason for the change to scope, schedule and/or cost, nature of the expenditure, impact on current budget/forecast/plan, and regulatory considerations.
- **Project Close (IP5)**: When a project is materially, technically, and financially complete, the project manager follows through with closure procedures.





NYSEG and RG&E 5-Year Capital Investment Plan

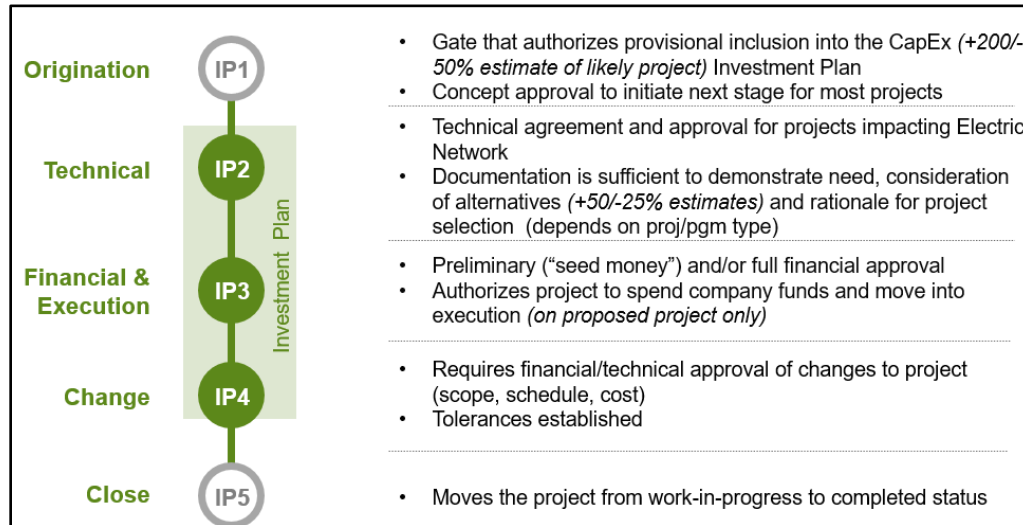


Figure 2 – Investment Planning Gates





Chapter 4 Project / Program Categorization

The following is a list of principal categories that were applied across the portfolio of projects / programs with associated descriptions for each. *It should be noted that these categories are not listed in any particular order.*

- Asset Condition: This category includes those projects and programs that are needed to address assets deemed to be beyond their useful operating life expectancy. These projects / programs are identified as a result of various Planning studies, ongoing Maintenance programs, and immediate needs brought forth by System Operations. For Gas, this group includes Regulator and gate station improvements, distribution and transmission main replacement projects, pressure reliability projects, and other asset condition projects.
- Customer Focus: This category includes those projects and programs that are needed to meet the needs of our customers. This category of projects / programs includes initiatives such as new connections, state and municipal projects, customer lighting, etc.
- Modernization: This category includes those projects and programs that are needed to enhance the Companies' ability to operate the system in a more effective and efficient manner. This category of projects / programs includes those which are designed to address outdated business systems, metering infrastructure, etc.
- Innovation: This category includes projects that introduce a new or significantly improved product or process, a new business practice or development of external relations.
- Reliability: This category includes those projects and programs that are needed to address immediate and longer-term system needs such as thermal / capacity overloads, voltage, and loss-of-load violations. For Gas, this group includes the Leak Prone Pipe Replacement program and regulator station upgrades not related to asset condition.





NYSEG and RG&E 5-Year Capital Investment Plan

- Resiliency: This category includes those projects and programs that are needed to strengthen existing facilities to withstand extreme weather events and improve system restoration capabilities following any number of unplanned transmission and distribution contingency events. These projects/programs seek to improve overall system flexibility and provide system operators with the appropriate visibility and field infrastructure to quickly restore power and minimize customer exposure following a contingency event.
- Compliance (Electric Only): This category includes those projects and programs that are needed to address compliance requirements/criteria, mandates, orders, or other regulatory / governmental direction such as the NERC BES Program or the NERC Alert Program.
- Hydro-Generation: This category provides the capital requirements for Hydro Generation facilities to replace obsolete and aged infrastructure, addresses other generating station updates, and minor capital expenditures to maintain these assets.
- Clean Energy Transformation: This category includes those projects and programs that are needed to enhance system capabilities and accommodate an increased level of renewable resource penetration and/or support proposed local municipality grid modification initiatives (e.g., “electrification”). This category includes projects such as the Power New York (PNY) Transmission Projects that were recently developed in support of NY’s Climate Leadership and Community Protection Act (CLCPA).
- Mandatory (Gas only): This category includes projects and programs that are required by tariff, regulatory order, or law and/or related to the safety of employees and/or the general public.
- Common: This category includes expenditures grouped into Buildings and Facilities, Customer Service, Fleet, Information Technology, Operational Smart Grids, Security, and Training.





NYSEG and RG&E 5-Year Capital Investment Plan

Chapter 5 Capital Investment Plan

The Capital Investment Plan, summarized by Company and Line of Business for the five-years, 2026-2030, is presented below:

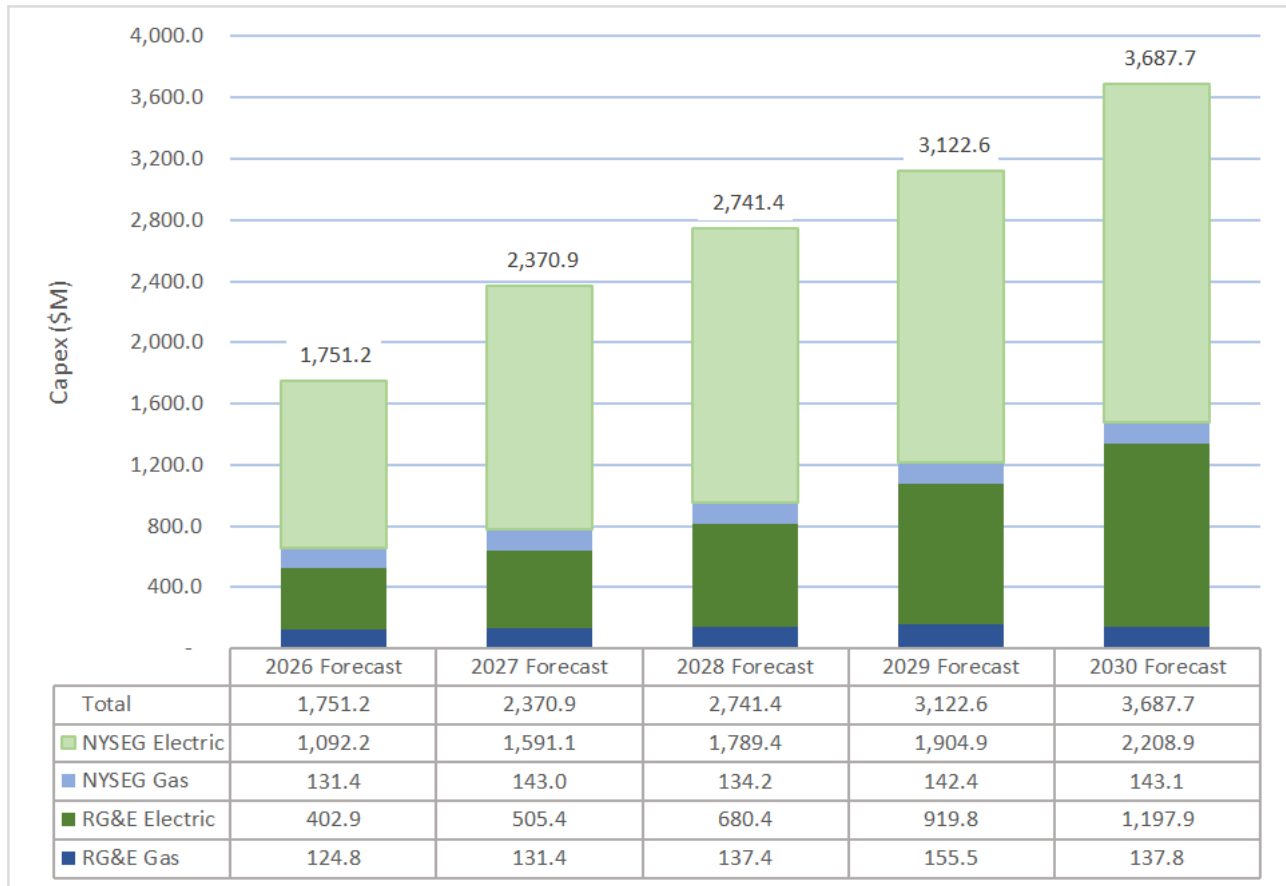


Figure 3 – NYSEG and RG&E Capital Investment Plan





NYSEG and RG&E 5-Year Capital Investment Plan

Chapter 6 Electric and Generation Capital Investment Forecast

This section will further detail by major investment category the overall Electric and Generation capital investments. The categorization of the Plan is grouped into Asset Condition, Reliability, Resiliency, Compliance, Clean Energy Transformation, Customer Focus, Modernization, Innovation, Hydro-Generation and Advanced Metering Infrastructure (AMI). The sub sections below summarize the major investment categories for the five years 2026-2030.

Section 6.1 Electric and Generation Capital Investment Requirements

The Capital Investment Forecast for the five-year period 2026-2030 for NYSEG Electric and Generation¹ Table 1 and for RG&E Electric and Generation² Table 2 are shown below.

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
<i>\$ in thousands</i>							
1 Asset Condition		\$ 192,316	\$ 399,506	\$ 500,414	\$ 468,743	\$ 664,490	\$ 2,225,469
2 Customer Focus		175,494	208,888	231,358	227,929	236,637	1,080,306
3 Modernization		2,219	22,441	12,324	11,919	14,528	63,431
4 Innovation		9,381	-	-	-	-	9,381
5 Reliability		97,850	157,815	238,208	447,435	670,942	1,612,251
6 Resiliency		156,807	138,387	109,865	56,335	54,553	515,947
7 Compliance		66,082	80,335	167,403	273,511	298,823	886,155
8 Hydro-Generation		27,115	41,115	29,676	29,638	27,493	155,036
9 Clean Energy Transformation		211,027	405,182	370,743	267,954	139,304	1,394,210
10 AMI		6,651	-	-	-	-	6,651
11 Subtotal Electric Capital		944,942	1,453,669	1,659,992	1,783,464	2,106,769	7,948,836
12							
13 Common Allocation to Electric Business		147,238	137,403	129,447	121,472	102,144	637,704
14 Total NYSEG Electric Capital		\$ 1,092,180	\$ 1,591,073	\$ 1,789,439	\$ 1,904,936	\$ 2,208,912	\$ 8,586,540

Table 1 – NYSEG Electric and Generation Capital Investment Forecast

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
<i>\$ in thousands</i>							
1 Asset Condition		\$ 62,710	\$ 67,205	\$ 61,481	\$ 120,163	\$ 125,213	\$ 436,772
2 Customer Focus		83,074	104,255	70,379	71,174	72,615	401,497
3 Modernization		1,145	601	2,876	2,883	3,146	10,652
4 Innovation		2,661	-	-	-	-	2,661
5 Reliability		107,781	184,003	388,394	543,910	844,619	2,068,707
6 Resiliency		19,882	30,032	22,382	43,201	41,708	157,204
7 Compliance		41,172	28,281	28,946	54,172	59,175	211,745
8 Hydro-Generation		14,735	30,919	51,239	36,700	9,800	143,393
9 AMI		3,002	-	-	-	-	3,002
10 Subtotal Electric Capital		336,163	445,295	625,696	872,203	1,156,276	3,435,633
11							
12 Common Allocation to Electric Business		66,705	60,151	54,674	47,585	41,590	270,704
13 Total RG&E Electric Capital		\$ 402,868	\$ 505,446	\$ 680,370	\$ 919,788	\$ 1,197,866	\$ 3,706,337

¹ Note: NYSEG Common allocation to the Electric Line of Business is 81.53%.

² Note: RG&E Common allocation to the Electric Line of Business is 74.64%.





NYSEG and RG&E 5-Year Capital Investment Plan

Table 2 – RG&E Electric and Generation Capital Investment Forecast

Section 6.2 Electric Asset Condition Capital Investment Forecast

This category provides a further breakdown of expenditures required to accommodate projects and programs related to asset condition improvements. The Electric Asset Condition Capital Investment Forecast is summarized for NYSEG Electric in Table 3 and for RG&E Electric in Table 4.

	A	B	C	D	E	F	G
	\$ in thousands						
	2026	2027	2028	2029	2030	Total 2026-2030	
1 Asset Condition	\$ 192,318	\$ 399,508	\$ 500,416	\$ 468,745	\$ 664,492	\$ 2,225,469	
2 TLD Replacements NYSEG	-	-	842	68,678	133,789	203,309	
3 TLD Replacements-NYSEG-L47	2,020	1,948	-	-	-	3,969	
4 TLD Replacements-NYSEG-L48	2,020	1,948	-	-	-	3,969	
5 TLD Replacements-NYSEG-L994	3,940	-	-	-	-	3,940	
6 TLD Replacements-NYSEG-L805	1,111	-	-	-	-	1,111	
7 TLD Replacements-NYSEG-L957	1,212	-	-	-	-	1,212	
8 TLD Replacements-NYSEG-L349	3,536	-	-	-	-	3,536	
9 TLD Replacements-NYSEG-L810	606	-	-	-	-	606	
10 TLD Replacements-NYSEG-L813	3,556	-	-	-	-	3,556	
11 TLD Replacements-NYSEG-L991	4,475	-	-	-	-	4,475	
12 TLD Replacements-NYSEG-L350	16,164	5,163	-	-	-	21,327	
13 TLD Replacements-NYSEG-L997	3,334	-	-	-	-	3,334	
14 TLD Replacements-NYSEG-L517	7,779	-	-	-	-	7,779	
15 TLD Replacements-NYSEG-L819	1,010	9,547	-	-	-	10,558	
16 TLD Replacements-NYSEG-L916	2,020	16,757	-	-	-	18,777	
17 TLD Replacements-NYSEG-L954	2,020	12,665	-	-	-	14,685	
18 TLD Replacements-NYSEG-L959	505	3,020	-	-	-	3,525	
19 TLD Replacements-NYSEG-L911	202	1,754	-	-	-	1,956	
20 TLD Replacements-NYSEG-L914	2,707	11,491	11,325	-	-	25,523	
21 TLD Replacements-NYSEG-L31	606	1,948	6,664	-	-	9,219	
22 TLD Replacements-NYSEG-L417	808	1,948	8,113	-	-	10,870	
23 TLD Replacements-NYSEG-L531	404	974	4,926	-	-	6,304	
24 TLD Replacements-NYSEG-L555	505	1,948	7,147	-	-	9,601	
25 TLD Replacements-NYSEG-L912	202	195	1,545	-	-	1,942	
26 TLD Replacements-NYSEG-L977	303	487	-	-	-	790	
27 TLD Replacements-NYSEG-L998	808	-	-	-	-	808	
28 TLD Replacements-NYSEG-L522 (Ithaca)	202	195	1,724	-	-	2,121	
29 TLD Replacements-NYSEG-L520	202	195	1,835	-	-	2,232	
30 TLD Replacements-NYSEG-L814	404	974	8,089	-	-	9,467	
31 TLD Replacements-NYSEG-L422	404	974	6,312	-	-	7,690	
32 TLD Replacements-NYSEG-L455	404	974	5,090	-	-	6,468	
33 TLD Replacements-NYSEG-L535	303	682	4,477	-	-	5,462	
34 TLD Replacements-NYSEG-L974	505	1,948	17,912	-	-	20,365	
35 TLD Replacements-NYSEG-L508	303	585	3,018	-	-	3,906	
36 TLD Replacements-NYSEG-L341	303	585	3,463	-	-	4,350	
37 TLD Replacements-NYSEG-L514	25	88	-	-	-	113	
38 TLD Replacements-NYSEG-L532 (Ithaca)	25	88	-	-	-	113	
39 TLD Replacements-NYSEG-L552	152	750	-	-	-	902	
40 TLD Replacements-NYSEG-L525	-	24	87	-	-	111	
41 TLD Replacements-NYSEG-L884	-	244	483	2,601	-	3,328	
42 TLD Replacements-NYSEG-L574	-	146	633	-	-	779	
43 TLD Replacements-NYSEG-L342	-	146	1,077	-	-	1,223	
44 TLD Replacements-NYSEG-L806	-	97	290	5,154	-	5,541	
45 TLD Replacements-NYSEG-L441	-	146	1,188	-	-	1,334	
46 TLD Replacements-NYSEG-L955	-	146	290	10,756	-	11,192	
47 TLD Replacements-NYSEG-L879	-	97	193	708	-	999	
48 TLD Replacements-NYSEG-L917	-	487	1,932	14,985	-	17,404	
49 TLD Replacements-NYSEG-L802	-	102	290	7,586	-	7,978	
50 TLD Replacements-NYSEG-L589	-	195	386	1,195	-	1,776	
51 TLD Replacements-NYSEG-L65	-	292	483	3,882	-	4,657	
52 TLD Replacements-NYSEG-L587	-	97	348	-	-	445	
53 TLD Replacements-NYSEG-L549	-	146	966	-	-	1,112	
54 TLD Replacements-NYSEG-L522 (Lancaster)	-	24	87	-	-	111	





April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
55	NYSEG Line 38/39 345 kV Structure Upgrades	1,436	1,390	1,379	-	-	4,205
56	TLD Replacements-NYSEG-L943	8,082	6,625	-	-	-	14,707
57	Line 880 Rebuild	425	8,403	5,246	46	-	14,120
58	NYSEG - Electric Ops (Line Insp CAP)	17,804	18,023	18,788	19,709	20,940	95,263
59	NYSEG - Pole Replace (WPIT) Program CAP	24,028	24,346	25,362	26,578	28,221	128,535
60	New Gardenville Substation Rebuild	737	4,161	18,018	42,627	59,544	125,087
61	NYSEG T&S Asset Condition Replacement Program	-	20,000	40,000	40,000	40,000	140,000
62	NYSEG PCB Transformer Replacements	3,988	4,048	4,249	4,559	4,949	21,792
63	South Perry New Sub & Trans Line Upgrade	14,858	17,254	32,318	-	-	64,431
64	Meyer Substation Rebuild	19,331	21,265	39,186	-	-	79,782
65	Line 890 Rebuild	-	13,514	12,355	26	-	25,895
66	Circuit 590 Rebuild	-	10,015	10,732	11,019	22,193	53,960
67	NYSEG - Subst Minor Capital	6,306	6,431	6,774	7,188	7,749	34,448
68	General Equipment - OPS-T&D	3,837	3,437	3,540	3,646	3,756	18,217
69	NYSEG - Subst Major Capital	2,139	2,193	2,323	2,477	2,676	11,808
70	NYSEG Substation Modernization - Noyes Island D	3,659	5,097	14,986	20,585	309	44,637
71	NYSEG URD Replacement Program	947	999	1,044	1,118	1,209	5,317
72	NYSEG - Battery Program	1,615	1,696	1,781	1,834	1,889	8,814
73	General Equipment - OPS-SO	999	1,029	1,060	1,092	1,124	5,304
74	NYSEG 46 kV Line 805 Upgrades - Brewster	-	12,512	12,853	14,158	20,039	59,563
75	Cobble Hill Transformer Replacement	2,403	-	-	-	-	2,403
76	Homer City 345kV Transmission Line Upgrade	-	104,396	103,069	99,865	228,854	536,183
77	Mobile Substation Evaluation - NYSEG	3,715	3,587	3,557	-	-	10,858
78	NYSEG Substation Modernization - South Owego	-	-	17,882	34,151	66,055	118,088
79	Homer City Capital Breakers & Upgrades	-	9,680	5,829	4,913	-	20,421
80	NYSEG - C Truss	2,927	2,992	3,054	3,118	3,184	15,276
81	NYSEG Spare Circuit Breaker Program	2,804	3,182	2,674	2,977	3,010	14,647
82	NYSEG 001 Spare Tx Pgm 120-36.2kV 50MVA	660	-	-	-	-	660
83	NYSEG 002 Spare Tx Pgm 120-36.2kV 50MVA	660	-	-	-	-	660
84	NYSEG 003 Spare Tx Pgm 36-13.2kV 37.3MVA	504	-	-	-	-	504
85	NYSEG 004 Spare Tx Pgm 46-13.2kV 14MV	504	-	-	-	-	504
86	NYSEG 005 Spare Tx Pgm 34.5-12.5/4.8kV 20MVA	584	1,700	749	-	-	3,032
87	NYSEG 006 Spare Tx Pgm 34.5-12.5/4.8kV 12MVA	531	1,537	680	-	-	2,747
88	NYSEG 007 SprTxPgm 34.5-12.5/4.8kV 10MVA	424	1,281	547	-	-	2,252
89	NYSEG 008 SprTxPgm 115-34.5/12.5kV 30MVA	841	2,562	1,087	-	-	4,490
90	NYSEG 009 SprTxPgm 46/4.8kV 2.5MVA	120	347	154	-	-	621
91	NYSEG 010 SprTxPgm 34.5-12.5/4.8kV 2.5MVA	120	347	154	-	-	621
92	NYSEG 011 SprTxPgm 34.5-12.5/4.8kV 2.5MVA	120	347	154	-	-	621
93	NYSEG 012 SprTxPgm 34.5-12.5/4.8kV 2.5MVA	120	347	154	-	-	621
94	NYSEG 013 SprTxPgm 34.5-12.5/4.8kV 20MVA	-	548	1,661	707	-	2,917
95	NYSEG 014 SprTxPgm 34.5-12.5/4.8kV 12MVA	-	548	1,502	643	-	2,693
96	NYSEG 015 SprTxPgm 115-34.5/12.5kV 30MVA	-	841	2,562	1,087	-	4,490
97	NYSEG 016 SprTxPgm 46/4.8kV 2.5MVA	-	120	347	154	-	621
98	NYSEG 017 SprTxPgm 34.5-12.5/4.8kV 2.5MVA	-	120	347	154	-	621
99	NYSEG 018 SprTxPgm 34.5-12.5/4.8kV 2.5MVA	-	120	347	154	-	621
100	NYSEG 019 SprTxPgm 34.5-12.5/4.8kV 2.5MVA	-	120	347	154	-	621
101	NYSEG 020 SprTxPgm 34.5-12.5kV 3.3MVA	-	120	347	154	-	621
102	NYSEG Spare Power Transformer Program	-	-	-	8,306	15,000	23,306
103	All Other Asset Condition	-	-	-	-	-	-
104	Total	\$ 192,318	\$ 399,508	\$ 500,416	\$ 468,745	\$ 664,492	\$ 2,225,469

Table 3 – NYSEG Electric Asset Condition Capital Investment Forecast



Take care of the environment.
Print in black and white and only if necessary.



April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
1	<i>\$ in thousands</i>						
2	Asset Condition	\$ 62,710	\$ 67,205	\$ 61,481	\$ 120,163	\$ 125,213	\$ 436,772
3	TLD Replacements RGE	3,000	3,955	2,820	11,559	18,393	39,727
4	TLD Replacements-RGE-L701	1,954	1,347	-	-	-	3,302
5	TLD Replacements-RGE-L795	489	2,502	6,626	6,978	-	16,594
6	RGE T&S Asset Condition Replacement Program	-	5,000	10,000	20,000	20,000	55,000
7	Station 29 Modernization Project	169	184	1,868	9,074	11,434	22,729
8	RGE - Pole Replace (WPIT) Program	5,680	5,897	6,112	6,329	6,638	30,656
9	Station 82 Upgrades	638	699	798	12,523	22,864	37,522
10	Station 37 Modernization Project	236	253	999	18,453	23,585	43,526
11	Station 43 Circuit Upgrades	7,511	2,630	-	-	-	10,142
12	Station 34 Modernization Project	135	145	156	168	180	783
13	Station 156 Circuit Upgrades	2,388	-	-	-	-	2,388
14	Station 192 Circuit Upgrades	4,653	4,356	-	-	-	9,008
15	Station 5 Substation Mod D	1,491	-	-	-	-	1,491
16	RGE - Electric Ops (Line Insp CAP)	1,965	2,036	2,105	2,176	2,276	10,558
17	RGE PCB Transformer Replacements	1,597	1,779	1,861	1,978	2,121	9,337
18	RGE URD Replacement Program	2,272	2,402	2,534	2,672	2,854	12,734
19	RGE - Subst Major Capital	1,861	1,925	1,988	2,051	2,140	9,966
20	RGE - Subst Minor Capital	878	913	954	996	1,055	4,797
21	RGE - UG Cable Replacements	3,219	3,272	3,317	3,360	3,442	16,611
22	General Equipment - OPS-T&D	1,075	1,101	928	956	985	5,045
23	Battery Prog RGE	619	633	641	649	661	3,205
24	General Equipment - OPS-SO	327	337	347	357	368	1,736
25	RGE Station 5 - Transmission Line Upgrades	4,376	9,713	-	-	-	14,088
26	RGE Line 920 Replacement Prj Cap	6,274	6,139	10,132	13,723	-	36,268
27	Mobile Substation Evaluation - RGE	1,202	1,184	1,165	-	-	3,551
28	Station 192 Trans Facilities Upgrade	4,909	1,251	-	-	-	6,160
29	Station 43 Modernization Project	-	1,057	-	-	-	1,057
30	RGE - C Truss	240	245	250	255	261	1,250
31	RGE Spare Circuit Breaker Program	907	1,050	876	961	956	4,750
32	RGE Spare Power Transformer Program	-	-	-	3,726	5,000	8,726
33	RGE 001 Spare Tx Pgm 120-13.2kV 22.4MVA	656	-	-	-	-	656
34	RGE 002 Spare Tx Pgm 120-13.2kV 22.4MVA	656	-	-	-	-	656
35	RGE 003 Spare Tx Pgm 34.5-12.5/4kV 22.4MVA	608	1,798	590	-	-	2,996
36	RGE 004 Spare Tx Pgm 115-34.5/12.5kV 20MVA	726	2,147	705	-	-	3,577
37	RGE 005 Spare Tx Pgm 115-34.5/12.5kV 20MVA	-	716	2,114	694	-	3,523
38	All Other Asset Condition Replacement	-	540	1,594	523	-	2,657
39	All Other Asset Condition	-	-	-	-	-	-
39	Total	\$ 62,710	\$ 67,205	\$ 61,481	\$ 120,163	\$ 125,213	\$ 436,772

Table 4 – RG&E Electric Asset Condition Capital Investment Forecast

The following describes some of the key program investments which are forecasted under the Electric Asset Condition category:

- **Transmission Line Deficiency (TLD) Replacement Program:** The Transmission Line Deficiencies (TLD) Replacement program generally focuses on an “in-kind³” structure replacement strategy on transmission lines with known structural / equipment needs. Each year, the Companies’ conduct several types of transmission line inspections (e.g., crossarm, aerial, infrared, ground line, and visual inspections) to identify transmission line asset condition needs at NYSEG

³ The “in-kind” replacement approach is aimed at replacing single facilities that do not meet minimum structural loading criteria. Facilities identified for replacement are designed in accordance with the most current NYSEG and RG&E structural standard requirements.



Take care of the environment.
Print in black and white and only if necessary.



NYSEG and RG&E 5-Year Capital Investment Plan

and RG&E. These needs are prioritized based on factors such as TLD severity, the number of TLDs per line segment, voltage level, and connected customers. Once prioritized, individual project scopes are developed to address these deficiencies. Generally, this program employs an in-kind replacement strategy, adhering to the latest National Electric Safety Code (“NESC”) and NYSEG/RG&E structural requirements, focusing on needs identified through previous inspection surveys. In some cases, additional scoping is necessary to address secondary needs like conductor sag and span length violations.

- Distribution Line Deficiencies (DLD) Program: The Distribution Line Deficiencies (DLD) program (previously Distribution Line Inspection DLI) seeks to perform permanent repairs on all existing open notifications resulting from distribution line inspections. The DLD Program consolidates distribution notifications generated from several pole inspection programs that the Companies routinely perform (i.e., distribution infrared inspections and distribution line visual inspections). These notifications identify needs such as cross-arm, insulator, guy wire, and pole deficiencies. These identified needs are then grouped and prioritized for action based on their severity level (i.e., Level I, Level II, and Level III), number of DLDs per segment, and connected customers.
- Wood Pole Inspect and Treat (WPIT) Program: The Wood Pole Inspect and Treat (WPIT) program is a program focused to address the growing number of asset condition needs identified among NYSEG & RG&E’s fleet of wooden-type distribution and transmission poles as part of routine field inspections. Field inspections are performed across all NYSEG and RG&E divisions, on a yearly basis, to identify wood poles that are deemed in need of replacement or repairs. Inspections include ground line evaluations to identify instances of wood decay, excavation, and boring techniques to identify decay at-or-below ground line, and “Sounding” the pole which includes striking the pole with a mallet and listening for signs of a hollow structure. This program employs an in-kind





NYSEG and RG&E 5-Year Capital Investment Plan

replacement strategy, adhering to the latest National Electric Safety Code (“NESC”) and NYSEG/RG&E structural requirements. These notifications are prioritized based on reliability impact for NYSEG and RG&E, by the number of customers downstream of the specific location, the historical customer impact, the device type, and the historical incident count.

- Transmission and Substation Asset Condition Program: The objective of the T&S Asset Condition Replacement Program is to conduct system-wide T&S facility surveys, to determine the overall health of the NYSEG and RG&E systems and develop a long-term mitigation strategy (projects) to enhance the condition of these assets. The Companies’ five-year plan is to comprehensively assess underground cable facilities at RG&E and NYSEG, prioritize needs based on risk of failure and impacts to customers, and develop projects to replace underground cable that is deemed beyond its useful operating life with a high risk of failure and customer exposure. In addition to replacement, the plan includes rejuvenation of cables that are still within their useful life but show signs of aging. To conduct these specialized cable assessment studies, the Companies’ investment plan includes small expenditures in 2026 and larger investments in 2027 and beyond to be used for specific underground replacement and rejuvenation projects as identified.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 6.3 Electric Customer Focus Capital Investment Forecast

This category provides a further breakdown of expenditures required to accommodate projects and programs related to customer focus. The Electric Customer Focus Investment Forecast is summarized for NYSEG Electric in Table 5 and for RG&E Electric in Table 6.

	A	B	C	D	E	F	G
	\$ in thousands						
		2026	2027	2028	2029	2030	Total 2026-2030
1	Customer Focus	\$ 175,494	\$ 208,888	\$ 231,358	\$ 227,929	\$ 236,637	\$ 1,080,306
2	NYSEG - Dist Line	34,463	33,819	34,474	35,441	37,148	175,344
3	Make Ready	52,546	67,770	67,225	55,884	56,473	299,898
4	NYSEG - Trans line	17,244	17,155	17,524	18,005	18,744	88,671
5	NYSEG - Res Line	15,584	15,287	15,588	16,031	16,813	79,302
6	NYSEG - Serv Conn	11,258	10,967	11,166	11,479	12,065	56,935
7	NYSEG - Ind/Comm	8,352	8,136	8,308	8,575	9,063	42,433
8	NYSEG - Street Light	2,604	2,574	2,625	2,696	2,814	13,313
9	NYSEG CAPEX EL Meters	3,186	3,281	3,396	3,497	3,602	16,962
10	NYSEG - Storms Electric	16,330	16,330	16,330	16,330	16,330	81,652
11	Community Distributed Generation Billing Phase II	1,221	-	-	-	-	1,221
12	Community Distributed Generation Billing Program	-	1,099	1,143	1,189	1,237	4,668
13	NYSEG Customer Cost Allocation Program (CCAP)	9,176	28,983	50,022	55,146	58,531	201,858
14	NYSEG - Gov't Highway	3,530	3,488	3,558	3,655	3,816	18,048
15	All Other Customer Focus	-	-	-	-	-	-
16	Total	\$ 175,494	\$ 208,888	\$ 231,358	\$ 227,929	\$ 236,637	\$ 1,080,306

Table 5 – NYSEG Electric Customer Focus Capital Investment Forecast

	A	B	C	D	E	F	G
	\$ in thousands						
		2026	2027	2028	2029	2030	Total 2026-2030
1	Customer Focus	\$ 83,074	\$ 104,255	\$ 70,379	\$ 71,174	\$ 72,615	\$ 401,497
2	RGE Dist Line	15,783	15,987	16,155	16,310	16,704	80,939
3	Make Ready	31,445	20,520	14,253	13,979	13,888	94,084
4	RGE - Res Line	5,568	5,645	5,713	5,776	5,921	28,623
5	Town of Brighton Arc-Lighting Circuit	3,402	17,320	323	-	-	21,045
6	RGE - Serv Conn	3,843	3,873	3,889	3,900	3,995	19,500
7	RGE - Ind/Comm	3,503	3,535	3,565	3,591	3,687	17,882
8	RGE - Trans line	1,986	2,013	2,036	2,057	2,106	10,198
9	Aqueduct Re-Imagined	3,042	15,959	-	-	-	19,001
10	RGE CAPEX EL Meters	903	1,178	1,375	1,473	1,571	6,501
11	RGE - Street Light	1,049	1,064	1,078	1,091	1,118	5,401
12	RGE Customer Cost Allocation Program (CCAP)	2,106	6,787	11,622	12,629	13,186	46,331
13	Community Distributed Generation Billing Program	-	1,099	1,143	1,189	1,237	4,668
14	Community Distributed Generation Billing Phase II	1,131	-	-	-	-	1,131
15	RGE STORM ELECTRIC	2,844	2,844	2,844	2,844	2,844	14,222
16	RGE - Gov't Highway Majors CAP	4,515	4,449	4,379	4,307	4,283	21,933
17	RGE - Gov't HW	1,954	1,980	2,004	2,026	2,075	10,039
18	All Other Customer Focus	-	-	-	-	-	-
19	Total	\$ 83,074	\$ 104,255	\$ 70,379	\$ 71,174	\$ 72,615	\$ 401,497

Table 6 – RG&E Electric Customer Focus Capital Investment Forecast

The following describes some of the key project and program investments which are forecasted under the Electric Customer Focus category:





NYSEG and RG&E 5-Year Capital Investment Plan

- Make Ready: The Make Ready program is working to make our infrastructure available to meet the broadband communication needs of our customers in response to programs like NY ConnectALL. As this work has evolved, we have developed, with input from NYDPS Staff and other stakeholders, guidelines for the cost treatment of the different situations encountered in the field that are more closely aligned with those used by other New York utilities. In 2022, Governor Hochul announced the start of the \$1 billion ConnectALL initiative, which is intended to deliver affordable broadband to millions of New Yorkers statewide. On Friday June 6th, 2025, the U.S. Commerce Department (NTIA) dramatically modified its \$42.45 billion BEAD funding program to favor lower cost broadband services (i.e., satellite service and unlicensed fixed wireless service) over higher cost fiber-based broadband service. NTIA's modification scraps entirely the fiber-based and values-based preferences in every one of the 56 already-approved Initial Proposals from each State and Territory, in favor of a single regulation-free preference based (almost) entirely on the cost to deploy. Even States that already finished their bidding processes (e.g., Louisiana, Nevada and Delaware) must now conduct a new round of bidding that rejects earlier bidding preferences in favor of lower cost deployments. Because satellite and fixed wireless services appear to have the advantage in this new cost-based bidding, it seems we can expect fewer BEAD-funded fiber deployments to hard-to-reach rural and unserved areas. As a result of these potential applications, the Companies are prepared to pivot to accommodate changes in the level of pole attachment requests, which have the potential of material increases in the Companies' costs to accommodate broadband expansion initiatives.
- Distribution (Dist.) Line Program: The Distribution Line program consists of replacing infrastructure due to emergency situations causing interruptions in service. This program is for unplanned, reactive work on the electric distribution





NYSEG and RG&E 5-Year Capital Investment Plan

system such as car hit poles, damaged conductors, transformers, and poles.

This program is budgeted each year based on the cost that has occurred in previous years. It is difficult to predict what may break and/or be damaged by others, so a historical-based estimate is used.

- Transmission (Trans.) Line Program: The Transmission Line program consists of addressing safety concerns by replacing reject poles, car hit poles, damaged conductors, and similar unplanned, reactive work on the electric transmission system 34.5kv or higher. Work is also performed to replace individual units of property identified as emergent from the transmission line inspection program in addition to addressing CAIDI/SAIFI hot spots in the same calendar year.
- Residential (Res.) Line Program: This program provides distribution line extensions and necessary facilities (poles, transformers, conductors, conduit, hand holds, manholes, etc.) to provide service to both large scale residential development projects and individual residential units or meters. The requirement for each project is unique based on the requirements of development projects, the project locations, and the existing electric system infrastructure. This program is budgeted based on historical spend and any added increase or decrease from various residential customers if communicated in advance. If a project is greater than \$500K a separate tracking order is created.
- Service Connection (Serv. Conn.) Program: This program installs or upgrades new electric service to individual residential units at the customer's request. Included within the program is anything required for constructing, expanding, replacing, or relocating electric infrastructure assets to connect residential customers. Meters required as part of customer projects are also included on this line item. The cost of the service is comprised of tariff portions as well as customer payments for the amounts above the tariff required provision.
- Government (Gov't) Highway Program: This program relocates electric facilities that conflict with highway, road, and street projects being undertaken by





NYSEG and RG&E 5-Year Capital Investment Plan

municipalities and other government agencies. This program is budgeted based on historical spend while considering any added increase or decrease based on information received from various government agencies, if communicated in advance. Many of these requests are made in year by the government agencies and are therefore unplanned.

- Industrial Commercial (Ind/Comm) Program: This program provides service connections for industrial and commercial customers. Included within the program is anything required for constructing, expanding, replacing, or relocating electric infrastructure assets to connect commercial customers. The cost of the service is comprised of tariff portions as well as customer payments for the amounts above the tariff required provision. This program is budgeted based on historical spend and any added increase or decrease from the various commercial customers if communicated in advance.
- Customer Cost Allocation Program (CCAP): The CCAP is a newly established initiative aimed at supporting emergent system capacity needs initiated by customers wishing to connect to the NYSEG and RG&E systems. NYSEG and RG&E have seen a significant increase in load interconnection requests, many of which require substantial T&S upgrades that are more costly than distribution-only upgrades. The CCAP will enable the Companies to fund their portion of emergent capacity-driven projects, allowing new customers to connect to the NYSEG and RG&E grid. The portion of the Companies' investment will be objectively determined based on the unique characteristics of the project and in consideration of the NYSEG and RG&E tariff procedures. In some cases, this will bring economic opportunities, housing, and access to electrification infrastructure within the NYSEG and RG&E territories.



**NYSEG and RG&E 5-Year Capital Investment Plan****Section 6.4 Electric Modernization Capital Investment Forecast**

This category provides a further breakdown of expenditures required to accommodate projects and programs related to modernization. The Electric Modernization Investment Forecast is summarized for NYSEG Electric in Table 7 and for RG&E Electric in Table 8 respectively.

	A	B	C	D	E	F	G
	\$ in thousands						
		2026	2027	2028	2029	2030	Total 2026-2030
1	Modernization	\$ 2,219	\$ 22,441	\$ 12,324	\$ 11,919	\$ 14,528	\$ 63,431
2	EMS/ADMS Deployment	-	654	5,838	5,854	6,388	18,735
3	Application Interface Upgrades NYSEG	42	42	-	-	-	84
4	MV90/IEE Service Mode	1,608	-	-	-	-	1,608
5	Networks ECTRM	490	490	-	-	-	980
6	Java SS Microgrid BESS	79	21,256	6,486	6,064	8,140	42,025
7	All Other Modernization	-	-	-	-	-	-
8	Total	\$ 2,219	\$ 22,441	\$ 12,324	\$ 11,919	\$ 14,528	\$ 63,431

Table 7 – NYSEG Electric Modernization Capital Investment Forecast

	A	B	C	D	E	F	G
	\$ in thousands						
		2026	2027	2028	2029	2030	Total 2026-2030
1	Modernization	\$ 1,145	\$ 601	\$ 2,876	\$ 2,883	\$ 3,146	\$ 10,652
2	MV90/IEE Service Mode	866	-	-	-	-	866
3	Application Interface Upgrades RGE	19	19	-	-	-	38
4	EMS/ADMS Deployment	-	322	2,876	2,883	3,146	9,228
5	Networks ECTRM	260	260	-	-	-	520
6	All Other Modernization	-	-	-	-	-	-
7	Total	\$ 1,145	\$ 601	\$ 2,876	\$ 2,883	\$ 3,146	\$ 10,652

Table 8 – RG&E Electric Modernization Capital Investment Forecast

The following describes some of the key project and program investments which are forecasted under the Electric Modernization category:

- **EMS/ADMS Deployment:** This project plans to evaluate in phases the enhancement of the Companies' Energy Management System (EMS) and the deployment of a new Advanced Distribution Management System (ADMS). These systems will provide enhanced and new functionalities to operate the Companies electric transmission and distribution systems.
- **Java SS Microgrid BESS:** The Java Microgrid project addresses a reliability need for loss of a substation transformer by installing a Microgrid utilizing a Battery Energy Storage System (BESS). This NYSEG owned BESS consists of a 4 MW,





NYSEG and RG&E 5-Year Capital Investment Plan

35 MWh battery to provide back-up to multiple substation circuits during a sustained outage for up to 8 hours to 1,700 customers.

- MV90/IEE Service Mode: This project will enhance the existing MV90 interval data system which relies on phone lines and manual intervention to convert interval data into billing data by implementing a new solution that leverages the AMI system. This will improve metering and interval data collection for the Company's 1,800 largest customers.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 6.5 Electric Innovation Capital Investment Forecast

This category provides a further breakdown of expenditures required to accommodate projects and programs related to innovation. The Electric Innovation Investment Forecast is summarized for NYSEG Electric in Table 9 and for RG&E Electric in Table 10.

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	Innovation	\$ 9,381	\$ -	\$ -	\$ -	\$ -	\$ 9,381
2	NYSEG IEDR Phase II	3,900	-	-	-	-	3,900
3	Stephentown BESS NYSEG	611	-	-	-	-	611
4	Wales Center Energy Storage	3,429	-	-	-	-	3,429
5	NY Spectrum HW Refresh CapEx	1,441	-	-	-	-	1,441
6	All Other Innovation	-	-	-	-	-	-
7	Total	\$ 9,381	\$ -	\$ -	\$ -	\$ -	\$ 9,381

Table 9 – NYSEG Electric Innovation Capital Investment Forecast

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	Innovation	\$ 2,661	\$ -	\$ -	\$ -	\$ -	\$ 2,661
2	RG&E IEDR Phase II	2,002	-	-	-	-	2,002
3	NY Spectrum HW Refresh CapEx	659	-	-	-	-	659
4	All Other Innovation	-	-	-	-	-	-
5	Total	\$ 2,661	\$ -	\$ -	\$ -	\$ -	\$ 2,661

Table 10 – RG&E Electric Innovation Capital Investment Forecast

The Innovation category focuses on new or improved products, processes, and/or organizational methods in business practices or external relations. Projects may have various aspects that could overlap product, process and/or organizational method descriptors.

Many of the projects in this category support PNY in a wide variety of ways – from developing energy storage projects to increase grid flexibility to improving analytical capabilities through grid model enhancements increasing the accuracy and detail of grid planning and operations.

Product innovation is the introduction of a good or service that is new or significantly improved with respect to its characteristics or intended uses. This includes significant improvements in technical specifications, components and materials, incorporated





NYSEG and RG&E 5-Year Capital Investment Plan

software, user friendliness or other functional characteristics. Projects that support this aspect of Innovation and are being advanced at NYSEG include the installation of battery energy storage systems at two substations. Additionally, projects that are in progress at both NYSEG and RG&E that support product innovation include Integrated Energy Data Resource (IEDR) projects and upgrading our Spectrum SCADA system replacing Energy Management System hardware and software. Process innovation is the implementation of a new or significantly improved production or delivery method. This includes significant changes in techniques, equipment and/or software. Projects that support this aspect of innovation include the installation of a CYME server to support time-series power flow analyses and integrate load and DER forecasting tools.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 6.6 Electric Reliability Capital Investment Forecast

This category provides a further breakdown of expenditures required to accommodate projects and programs related to reliability. The Electric Reliability Capital Investment Forecast is summarized for NYSEG Electric in Table 11 and for RG&E Electric in Table 12.

	A	B	C	D	E	F	G
	\$ in thousands						
	2026	2027	2028	2029	2030	Total 2026-2030	
1 Reliability	\$ 97,852	\$ 157,817	\$ 238,211	\$ 447,437	\$ 670,944	\$ 1,612,251	
2 NYSEG Animal Guard Program	1,748	1,781	1,863	1,959	2,088	9,439	
3 34.5 kV NYSEG Line 455 Upgrades	4,879	5,294	4,998	14,004	-	29,175	
4 CYME DDP - AMI/PI Integration	-	625	-	-	-	625	
5 Proactive Planning - Ferndale	18,779	13,234	1,827	-	-	33,840	
6 Sub Transmission Automation Keuka	1,411	3,487	-	-	-	4,897	
7 Hosting Capacity Automation	-	-	1,132	-	-	1,132	
8 Afton Sub - Add new 34.5kV Circuit	-	437	3,497	2,241	-	6,175	
9 NYSEG New York Coordinated Grid Planning Process	72	138	137	68	138	554	
10 NYSEG 521 Line Reliability	-	502	-	-	-	502	
11 NYSEG - Elec Better	-	36	13,849	14,229	14,809	42,924	
12 NYSEG 2024 Betterment - Morningside Heights 455	130	-	-	-	-	130	
13 NYSEG Warners 526 - 2026 Betterments	743	-	-	-	-	743	
14 NYSEG Wales 325	1,469	-	-	-	-	1,469	
15 NYSEG Stolle Rd 551	1,371	-	-	-	-	1,371	
16 NYSEG Raylinski Tap 606(635T606)	1,812	-	-	-	-	1,812	
17 NYSEG Pound Ridge 457	2,155	-	-	-	-	2,155	
18 NYSEG Worst Performing Zones of Protection - 2027 Betterments	892	910	1,731	1,779	1,851	7,163	
19 NYSEG Engineering and Material LLTs for 2028 Projects	2,973	2,395	1,731	1,779	1,851	10,730	
20 NYSEG Overloaded Step Banks - 2027 Betterments	-	1,916	-	-	-	1,916	
21 NYSEG Mapleton 520	-	1,518	-	-	-	1,518	
22 NYSEG Roll Road 545 - 2027 Betterments	-	1,518	-	-	-	1,518	
23 NYSEG Sylvan Lake 481	-	1,518	-	-	-	1,518	
24 NYSEG Warners 526 - 2027 Betterments	-	1,518	-	-	-	1,518	
25 NYSEG Crellin 615 (615T630)	1,469	-	-	-	-	1,469	
26 NYSEG Blossom 313	882	-	-	-	-	882	
27 NYSEG Roll Road 524/529/545 - 2026 Betterments	833	-	-	-	-	833	
28 NYSEG Voak Rd 589	-	759	-	-	-	759	
29 NYSEG Erie St 203	-	664	-	-	-	664	
30 NYSEG CAS Plattsburgh Ashley	-	-	6,312	28,600	64,334	99,247	
31 NYSEG CAS Hornell Arkport	-	-	12,935	36,806	76,857	126,599	
32 NYSEG CAS Auburn Southern Loop	-	-	7,152	27,906	75,474	110,531	
33 NYSEG CAS Geneva McDougall	-	3,561	25,786	52,100	21,414	102,861	
34 NYSEG CAS Ithaca Northern Loop	-	-	-	40,047	100,718	140,766	
35 NYSEG CAS Liberty Hilldale	-	-	-	13,601	74,751	88,353	
36 NYSEG CAS Binghamton CN Bridge	-	5,677	51,986	93,157	59,603	210,424	
37 NYSEG - Breaker Replacement Program	13,436	1,539	5,605	21,940	33,666	76,185	
38 Circuit Breaker Replacement - Caton Avenue	1,806	64	-	-	-	1,870	
39 Circuit Breaker Replacement - Dick Rd	1,201	2,176	-	-	-	3,377	
40 Circuit Breaker Replacement - Ferndale	528	742	-	-	-	1,270	
41 Circuit Breaker Replacement - Hancock	861	5	-	-	-	866	
42 Circuit Breaker Replacement - Lake Ave	915	-	-	-	-	915	
43 Circuit Breaker Replacement - Legion Drive	801	1,451	-	-	-	2,252	
44 Circuit Breaker Replacement - 14th Street	-	1,032	1,834	820	-	3,685	
45 Circuit Breaker Replacement - Axtell Rd	-	301	447	-	-	747	
46 Circuit Breaker Replacement - Beekmantown	-	150	223	-	-	374	
47 Circuit Breaker Replacement - Bulkhead	-	751	1,117	-	-	1,868	
48 Circuit Breaker Replacement - Cadville	-	751	1,117	-	-	1,868	
49 Circuit Breaker Replacement - Cayuga	-	301	447	-	-	747	
50 Circuit Breaker Replacement - Bridgewater	-	201	398	273	-	872	
51 Circuit Breaker Replacement - Chatham Hilltop	-	58	333	512	-	902	
52 Circuit Breaker Replacement - Cooperstown	-	601	894	-	-	1,495	
53 Circuit Breaker Replacement - Cross River	-	451	670	-	-	1,121	





April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
54	Circuit Breaker Replacement - Grossinger	-	301	447	-	-	747
55	Circuit Breaker Replacement - Finch Hollow	-	150	223	-	-	374
56	Circuit Breaker Replacement - Endicott Hill	-	301	447	-	-	747
57	Circuit Breaker Replacement - Gorham	-	301	447	-	-	747
58	Circuit Breaker Replacement - Harris Lake	-	150	223	-	-	374
59	Circuit Breaker Replacement - Hazel	-	667	833	-	-	1,500
60	Circuit Breaker Replacement - Hyde	-	301	447	-	-	747
61	Circuit Breaker Replacement - Jordan	-	301	447	-	-	747
62	Circuit Breaker Replacement - Livingston Manor	-	150	223	-	-	374
63	Circuit Breaker Replacement - Mac Dougall	-	301	447	-	-	747
64	Circuit Breaker Replacement - Macedon	-	953	2,114	1,912	-	4,980
65	Circuit Breaker Replacement - Madison	-	451	670	-	-	1,121
66	Circuit Breaker Replacement - Maplewood	-	451	670	-	-	1,121
67	Circuit Breaker Replacement - Mohansic	-	1,352	2,011	-	-	3,363
68	Circuit Breaker Replacement - Mulberry	-	251	872	1,366	-	2,489
69	Circuit Breaker Replacement - Dayton	-	150	223	-	-	374
70	Circuit Breaker Replacement - Phelps	-	301	746	820	-	1,867
71	Circuit Breaker Replacement - Pound Ridge	-	1,052	1,564	-	-	2,616
72	Circuit Breaker Replacement - Richfield Springs	-	174	602	943	-	1,718
73	Circuit Breaker Replacement - Roll Rd	-	251	872	1,366	-	2,489
74	Circuit Breaker Replacement - Sackett Lake	-	301	447	-	-	747
75	Circuit Breaker Replacement - Sampson	-	301	447	-	-	747
76	Circuit Breaker Replacement - Sands Creek	-	208	423	312	-	943
77	Circuit Breaker Replacement - Snyders Lake	-	50	174	273	-	498
78	Circuit Breaker Replacement - Union Springs	-	150	223	-	-	374
79	Circuit Breaker Replacement - Goulds	-	301	447	-	-	747
80	Circuit Breaker Replacement - Wende	-	301	447	-	-	747
81	Circuit Breaker Replacement - Woodruff Pond	-	319	597	326	-	1,242
82	Circuit Breaker Replacement - Dresden	-	301	447	-	-	747
83	Circuit Breaker Replacement - West Elmira	516	905	-	-	-	1,421
84	Circuit Breaker Replacement - Transit	1,275	-	-	-	-	1,275
85	Circuit Breaker Replacement - Stilesville	1,381	29	-	-	-	1,410
86	Circuit Breaker Replacement - Stephentown	286	518	-	-	-	804
87	Circuit Breaker Replacement - Sleight Road	2,723	-	-	-	-	2,723
88	Circuit Breaker Replacement - Sand Street	637	-	-	-	-	637
89	Circuit Breaker Replacement - River Road	716	1,347	-	-	-	2,063
90	Circuit Breaker Replacement - Park Ave	425	-	-	-	-	425
91	Circuit Breaker Replacement - Orchard Park	915	-	-	-	-	915
92	Circuit Breaker Replacement-N. Endicott-Binghamton-Phase 2	608	1,244	-	-	-	1,852
93	Circuit Breaker Replacement - New Berlin	343	622	-	-	-	965
94	Circuit Breaker Replacement - Morgan Road	1,079	2,073	-	-	-	3,151
95	Circuit Breaker Replacement - Milliken	2,782	-	-	-	-	2,782
96	Circuit Breaker Replacement - Locus St	716	1,347	-	-	-	2,063
97	Circuit Breaker Replacement-Northside-Binghamton-Phase 2	392	829	-	-	-	1,221
98	Circuit Breaker Replacement - Wynthskill	531	-	-	-	-	531
99	Circuit Breaker Replacement - Brothertown Road	432	933	-	-	-	1,365
100	Circuit Breaker Replacement - Lyon MTN	-	50	174	273	-	498
101	NYSEG Distribution Load Relief Program	-	513	283	36,034	28,568	65,398
102	NYSEG - Regulator Replacement Project	58	-	-	-	-	58
103	Crafts 13.2kV Load Transfer to Croton Falls	257	-	-	-	-	257
104	W. Winfield 12.5KV Load Relief	4,158	3,823	-	-	-	7,981
105	New Centerport Substation (Port Byron - Load relief)	5,907	23,536	204	-	-	29,647
106	NYSEG Distribution Load Relief - Erie Street	-	1,132	3,626	5,608	15,562	25,928
107	NYSEG Distribution Load Relief - State Street	-	2,274	6,749	1,003	248	10,273
108	NYSEG Distribution Load Relief - Grant Ave	-	1,549	5,665	226	-	7,440
109	NYSEG Distribution Load Relief - Cantitoe	1,282	4,011	452	566	184	6,495
110	NYSEG Distribution Load Relief - Stryker Ave	1,426	4,359	433	-	-	6,218
111	NYSEG Distribution Load Relief - Orchard Park	-	1,450	4,446	221	-	6,117
112	NYSEG Distribution Load Relief - Maplewood	-	1,450	4,404	226	-	6,079
113	NYSEG Distribution Load Relief - Jarvis Street	462	2,224	384	197	516	3,783
114	NYSEG Distribution Load Relief - Clyde	-	486	1,113	157	-	1,757
115	NYSEG Distribution Load Relief - West Elmira	246	715	-	-	-	961
116	NYSEG Distribution Load Relief - Hamburg	-	238	532	167	-	937
117	NYSEG Distribution Load Relief - Transit Street	-	333	458	136	-	927
118	NYSEG Distribution Load Relief - Jordanville	-	651	-	-	-	651
119	NYSEG Distribution Load Relief - Snows Corner Tap	-	521	-	-	-	521
120	NYSEG Distribution Load Relief - Wileyville Tap	-	338	-	-	-	338
121	NYSEG Distribution Load Relief - Bath	-	155	-	-	-	155
122	NYSEG Distribution Load Relief - Randolph	-	149	-	-	-	149
123	NYSEG Distribution Load Relief - Silver Springs Tap	-	149	-	-	-	149
124	NYSEG Distribution Load Relief - West Patterson	-	30	-	-	-	30
125	Holland Substation DLR	-	4,157	6,798	11,001	4,157	26,113
126	Proactive Planning - Kents Falls	7,132	18,423	16,312	429	-	42,296
127	NYSEG Transmission Reinforcement Program	-	-	19,972	32,051	94,150	146,173
128	Lancaster Division Substation Upgrade - Wehrle Drive Substation	-	1,589	-	-	-	1,589
129	Livingston Manor Automatic Throwover Scheme	-	1,589	-	-	-	1,589
130	Spencer Automatic Throw-Over Scheme	-	1,589	-	-	-	1,589
131	Stryker Ave Substation Upgrade	-	1,589	-	-	-	1,589
132	Woodruff Pond and West Chazy Reconfiguration	-	298	-	-	-	298
133	All Other Reliability	-	-	-	-	-	-
134	Total	\$ 97,852	\$ 157,817	\$ 238,211	\$ 447,437	\$ 670,944	\$ 1,612,251



Take care of the environment.
Print in black and white and only if necessary.



April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

Table 11 – NYSEG Electric Reliability Capital Investment Forecast

	A	B	C	D	E	F	G
	\$ in thousands						
	2026	2027	2028	2029	2030	Total 2026-2030	
1 Reliability	\$ 107,781	\$ 184,003	\$ 388,394	\$ 543,910	\$ 844,619	\$ 2,068,707	
2 RGE Animal Guards	1,043	1,091	1,140	1,191	1,259	5,726	
3 Replace DC Pilot Wire System	2,645	-	-	-	-	2,645	
4 Station 89 Upgrades	-	-	-	-	5,720	5,720	
5 Proactive Planning - Station 124	20,557	14,292	12,775	-	-	47,624	
6 RGE New York Coordinated Grid Planning Process	70	137	135	66	132	540	
7 Station 117	310	333	-	-	-	643	
8 Station 46 - Circuit 261	1,862	7,114	13,298	263	-	22,537	
9 Station 117 Circuit Upgrades	2,895	735	-	-	-	3,630	
10 Station 51	5,498	87	-	-	-	5,585	
11 Station 255 12 kV Yard Addition to Proactive Planning - Station 255	14,778	7,933	1,971	-	-	24,683	
12 RGE STA 001 4T Transformer Failure Solution	-	1,191	2,304	3,108	1,368	7,972	
13 CYME DDP - AMI/PI Integration	-	619	-	-	-	619	
14 Hosting Capacity Automation	-	-	1,132	-	-	1,132	
15 Network Protectors	4,304	4,398	4,490	4,584	4,681	22,457	
16 RGE - Elec Better	6,683	6,767	6,838	6,905	7,025	34,218	
17 RGE CAS Greece	-	19,618	51,606	105,190	187,319	363,734	
18 RGE CAS Downtown	-	41,495	76,743	126,446	220,087	464,772	
19 RGE CAS Victor	-	11,129	52,141	61,495	82,952	207,716	
20 RGE CAS Penfield	-	-	65,472	154,409	214,823	434,705	
21 RGE - Breaker Replacement Program	4,657	2,272	6,171	14,227	13,385	40,712	
22 Circuit Breaker Replacement - Station 112	-	828	1,512	-	-	2,340	
23 Circuit Breaker Replacement - Station 131	-	332	783	582	-	1,696	
24 Circuit Breaker Replacement - Station 405	-	217	329	-	-	546	
25 Circuit Breaker Replacement - Station 418 Ph2	-	391	714	-	-	1,105	
26 Circuit Breaker Replacement - Station 84	-	276	504	-	-	780	
27 Circuit Breaker Replacement - Station 85	-	736	1,344	-	-	2,080	
28 Circuit Breaker Replacement - Station 89	-	1,113	1,683	-	-	2,796	
29 Circuit Breaker Replacement - Station 90	-	368	672	-	-	1,040	
30 Circuit Breaker Replacement - Station 93	-	276	504	-	-	780	
31 Circuit Breaker Replacement - Station 13A	1,211	-	-	-	-	1,211	
32 Circuit Breaker Replacement - Station 48	2,406	-	-	-	-	2,406	
33 Circuit Breaker Replacement - Station 160	84	333	-	-	-	417	
34 Circuit Breaker Replacement - Station 53	80	314	-	-	-	394	
35 Circuit Breaker Replacement - Station 62	151	599	-	-	-	751	
36 Circuit Breaker Replacement - Station 67	1,406	1,715	-	-	-	3,120	
37 Circuit Breaker Replacement - Station 418 Ph1	1,389	3,647	-	-	-	5,036	
38 Circuit Breaker Replacement - Station 86	168	1,498	-	-	-	1,667	
39 Circuit Breaker Replacement - Station 33	1,743	-	-	-	-	1,743	
40 Circuit Breaker Replacement - Station 114	-	1,365	-	-	-	1,365	
41 RG&E Distribution Load Relief Program	-	4,094	6,340	18,839	25,443	54,717	
42 Station 416 Load Relief	1,735	-	-	-	-	1,735	
43 RGE Distribution Load Relief - Station 16	-	1,101	7,527	6,654	-	15,282	
44 RGE Distribution Load Relief - Station 45	-	1,389	10,452	-	-	11,842	
45 RGE Distribution Load Relief - Station 205	-	1,550	3,547	341	425	5,862	
46 RGE Transmission Reinforcement Program	12,000	13,000	26,919	39,609	80,000	171,527	
47 RGE Transmission Reinforcement Program - Line 804	-	788	-	-	-	788	
48 RGE Transmission Reinforcement Program - Line 759	-	1,576	-	-	-	1,576	
49 Rochester Transmission Reinforcement Program - Station 202	-	335	-	-	-	335	
50 New TL 812 & DL 418	357	390	7,355	-	-	8,102	
51 Line 798 Uprate	45	8,618	-	-	-	8,663	
52 Station 55 34.5/12kV Rebuild	22	24	2,238	-	-	2,283	
53 Station 73 Distribution Upgrades	3	3	6,260	-	-	6,266	
54 Webster Project - Station 55	3,107	4,000	8,161	-	-	15,268	
55 Line 778 Uprate - Station 42 to 43	4,816	-	-	-	-	4,816	
56 Line 799 Uprate	-	7,403	-	-	-	7,403	
57 Webster Project - Station 73	4,963	3,455	3,854	-	-	12,272	
58 Webster Project - Station 62	2,343	2,537	-	-	-	4,880	
59 Webster Project - Station 42	2,917	16	-	-	-	2,933	
60 Webster Project - Station 424	289	348	1,477	-	-	2,114	
61 Webster Project - Station 420	1,246	153	-	-	-	1,400	
62 All Other Reliability	-	-	-	-	-	-	
63 Total	\$ 107,781	\$ 184,003	\$ 388,394	\$ 543,910	\$ 844,619	\$ 2,068,707	

Table 12 – RG&E Electric Reliability Capital Investment Forecast



Take care of the environment.
Print in black and white and only if necessary.



NYSEG and RG&E 5-Year Capital Investment Plan

The following describes some of the key program investments which are forecasted under the Electric Reliability category:

- Distribution Load Relief Program: The Distribution Load Relief Program comprises sub-projects aimed at addressing immediate or imminent capacity needs across the NYSEG and RG&E fleet of substations and selected distribution circuits. Each year, the Integrated System Planning Team conducts a system-wide study to prioritize facilities most affected by distribution-level capacity constraints. These prioritized facilities are further evaluated to identify additional capacity needs, including those on sub-transmission or transmission facilities. Solution alternatives are developed and compared based on various factors, such as cost, execution duration, and post-project headroom (MW) availability. After an internal technical review and approval process, selected project alternatives are separated from the program level and executed as individual sub-projects. The program's objective is to mitigate known capacity needs in the most effective and timely manner while avoiding additional scope that could increase project costs and duration. The Companies rely on this program as a short-term strategy to address capacity needs, ensuring system operators can manage the system under “all-lines-in” N-0 conditions. Since its establishment in 2023, the Companies have completed five load relief projects, currently have 13 in execution, and plan to invest in 30-40 projects over the next five years. Of the 13 in execution, nine projects are expected to be in-service in 2025 and the remaining four projects have in-service dates ranging from 2026-2030.
- Comprehensive Area Studies (Distribution-Planning): The CAS Program consists of sub-divisional area solutions aimed at addressing all system needs within the studied area. Areas within the Companies' 17 divisions are prioritized based on the sum of current and future (10 and 20-year forecasted) capacity needs at the distribution-level, as well as other factors like known T&S asset condition needs





NYSEG and RG&E 5-Year Capital Investment Plan

and distribution line deficiencies. While areas may include known and near-term system needs, the primary objective of this program is to transform the system and position the Companies to develop a 21st-century grid model that improves resiliency, reliability, and capacity. The Companies will make significant investments in 11 sub-areas (4 RG&E and 7 NYSEG) and will continue to conduct studies across their territories to support future customer demands and CLCPA goals.

- Transmission Reinforcement Program: The Transmission Reinforcement Program aims to address system reliability needs identified through periodic NYSEG and RG&E transmission reliability assessments, known as Local Area Studies (“LAS”). These assessments, last completed in 2023, identify existing and future thermal, voltage, and loss-of-load needs across the Companies' territories and propose pre-conceptual (electrical-only) solution alternatives to mitigate these needs. The Transmission Reinforcement Program focuses on advancing project opportunities that impact transmission-only elements which are capacity constrained or pose a single element contingency loss-of-load risk to customers. Starting in 2028, the Companies will make significant investments in the transmission system under this program. The prioritization strategy focuses first on loss-of-load risks, which support short-term SAIFI improvements and can be executed more quickly and at lower costs compared to larger system capacity upgrades. The next priority will be projects designed to mitigate thermal and voltage (a.k.a., capacity) needs, including line reconductoring, line rebuilds, substation upgrades, and capacitor bank installations.
- Breaker Replacement Program: The Circuit Breaker Replacement Program is an annual initiative focused on replacing transmission and distribution circuit breakers that have exceeded their useful operating life. The Companies annually select specific substation locations where breakers are deemed most impactful to customer outage exposure or future SAIFI risks. Although the Asset





NYSEG and RG&E 5-Year Capital Investment Plan

Management circuit breaker health and risk algorithm informs scoring based on field data inputs, the prioritized list of sub-project opportunities considers substation topology, networked versus radial facilities, downstream customer count, and construction challenges within the existing substation yard. The most current circuit breaker data for the Companies indicates that 37% of NYSEG breakers and 29% of RG&E breakers are in poor/very poor condition. Although this program could fall under the asset condition category, the Companies believe the program offers significant reliability benefits (i.e., SAIFI avoidance) and therefore it belongs within the reliability category.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 6.7 Electric Resiliency Capital Investment Forecast

This category provides a further breakdown of expenditures required to accommodate projects and programs related to resiliency. The Electric Resiliency Capital Investment Forecast is summarized for NYSEG Electric in Table 13 and for RG&E Electric in Table 14.

	A	B	C	D	E	F	G
	\$ in thousands						
	2026	2027	2028	2029	2030	Total 2026-2030	
1 Resiliency	\$ 156,807	\$ 138,387	\$ 109,865	\$ 56,335	\$ 54,553	\$ 515,947	
2 NYSEG - SCADA/Automation	9,869	10,727	8,073	8,754	9,111	46,536	
3 Trip Saver	2,922	2,993	3,164	3,368	3,641	16,088	
4 Climate Change Resilience - Targeted Undergrounding - NYSEG	-	-	4,345	12,051	12,200	28,596	
5 NYSEG Automation - Ithaca	239	-	-	-	-	239	
6 NYSEG Automation - Brewster	182	-	-	-	-	182	
7 NYSEG Automation - Liberty	1,548	-	-	-	-	1,548	
8 NYSEG Automation - Auburn	3,181	-	-	-	-	3,181	
9 NYSEG Automation - Binghamton	9,110	-	-	-	-	9,110	
10 NYSEG DAP 2026 - Hornell	295	-	-	-	-	295	
11 NYSEG DAP 2026 - Mechanicville	1,330	-	-	-	-	1,330	
12 NYSEG DAP 2026 - Oneonta	3,957	-	-	-	-	3,957	
13 NYSEG DAP 2026 - Lancaster	2,560	-	-	-	-	2,560	
14 NYSEG DAP 2026 - Geneva	2,327	-	-	-	-	2,327	
15 NYSEG DAP 2026 - Elmira	2,211	-	-	-	-	2,211	
16 NYSEG DAP 2026 - Lockport	698	-	-	-	-	698	
17 NYSEG DAP 2026 - Plattsburgh	698	-	-	-	-	698	
18 New York 21st Century Grid Plan (Cheektowaga)	14,778	11,634	3,004	365	-	29,781	
19 Lancaster Project - Losson Road Substation 34.5/12.5 kV GIS Upgrade	12,148	14,474	4,698	-	-	31,320	
20 Lancaster Project - Blossom Road Substation 34.5/12.5 kV GIS Upgrade	12,303	15,135	2,159	-	-	29,597	
21 Lancaster Project - Walden Ave & Sloan - Distribution upgrades	5,154	10,950	16,454	401	-	32,958	
22 Lancaster Project - Losson Road - Distribution upgrades	3,207	6,814	10,238	249	-	20,508	
23 Lancaster Project - North Broadway - Expansion	12,335	3,964	1,648	-	-	17,947	
24 Lancaster Project - Blossom Road - Distribution upgrades	2,489	5,288	7,946	193	-	15,915	
25 Lancaster Project - Line 532 - Reroute	4,490	6,796	2,867	-	-	14,154	
26 Lancaster Project - Blossom to Losson - Distribution Express feeder	1,595	3,369	3,341	190	-	8,495	
27 Lancaster Project - Losson - Distribution Express feeder	1,595	3,369	3,341	190	-	8,495	
28 Lancaster Project - Losson Road - Distribution Center	3,443	2,863	1,632	-	-	7,938	
29 Lancaster Project - Sloan - Distribution Center	3,338	2,783	1,565	-	-	7,686	
30 Lancaster Project - Sloan to Losson - Distribution Express feeder	1,246	2,632	2,579	149	-	6,605	
31 Lancaster Project - Walden Ave to Sloan - Distribution Express feeder	1,196	2,527	2,506	143	-	6,371	
32 Resiliency	104	-	3,440	4,245	22,322	30,110	
33 NYSEG Resiliency - Flat Street 597	123	-	-	-	-	123	
34 NYSEG Resiliency - Kattleville 422	7,876	-	-	-	-	7,876	
35 NYSEG Resiliency - Greenidge 596	3,730	-	-	-	-	3,730	
36 NYSEG RESILIENCY 2027 - LYON MTN 510	-	-	3,062	8,871	2,959	14,892	
37 NYSEG RESILIENCY 2027 - GOLDEN BRIDGE 418	-	-	343	1,055	361	1,759	
38 NYSEG RESILIENCY 2027 - CROSS RIVER 469	-	-	1,748	4,666	1,552	7,967	
39 NYSEG RESILIENCY 2027 - MILFORD 227	-	3,551	12,475	4,128	-	20,154	
40 NYSEG RESILIENCY 2027 - KENT 526	-	-	573	953	307	1,833	
41 NYSEG RESILIENCY 2027 - WALES CENTER 326	-	-	2,341	6,363	2,099	10,803	
42 NYSEG Resiliency - Shandaken 501	3,742	-	-	-	-	3,742	
43 NYSEG Resiliency Cemetery Rd 490/ North Broadway 535	2,614	-	-	-	-	2,614	
44 NYSEG Resiliency 2026 - Cantitoe 497	-	10,791	6,324	-	-	17,116	
45 NYSEG Resiliency 2027 - S. Owego 540	1,039	9,197	-	-	-	10,236	
46 NYSEG Resiliency 2027 - Genegantslets 422	14,721	8,531	-	-	-	23,252	
47 Kline Kill 630 - 631	2,414	-	-	-	-	2,414	
48 All Other Resiliency	-	-	-	-	-	-	
49 Total	\$ 156,807	\$ 138,387	\$ 109,865	\$ 56,335	\$ 54,553	\$ 515,947	

Table 13 – NYSEG Electric Resiliency Capital Investment Forecast





NYSEG and RG&E 5-Year Capital Investment Plan

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
1	<i>\$ in thousands</i>						
1	Resiliency	\$ 19,882	\$ 30,032	\$ 22,382	\$ 43,201	\$ 41,708	\$ 157,204
2	SCADA/Automation RGE	5,933	4,407	4,245	4,465	4,530	23,580
3	Trip Saver	1,013	1,491	1,576	1,666	1,780	7,526
4	Climate Change Resiliency - Targeted Undergrounding - RG&E	-	-	4,245	11,586	11,513	27,344
5	Distribution Automation - RGE	-	-	-	14,179	14,101	28,280
6	RGE Automation - Central	943	9,629	-	-	-	10,572
7	Automation RGE Canandaigua	1,209	2,512	-	-	-	3,722
8	Resiliency	-	-	-	9,790	9,784	19,574
9	RGE Resiliency 0056RO5180	1,210	-	-	-	-	1,210
10	RGE Resiliency 0230RO5163	7,161	-	-	-	-	7,161
11	RGE Resiliency 0205LS5202	956	-	-	-	-	956
12	RGE Resiliency 0104RO5156	-	1,345	2,519	754	-	4,618
13	RGE Resiliency 0195LS5153	-	1,547	2,617	760	-	4,924
14	RGE Resiliency 0143CF5146	1,195	9,101	7,179	-	-	17,475
15	RGE Resiliency 0419RO5120	261	-	-	-	-	261
16	All Other Resiliency	-	-	-	-	-	-
17	Total	\$ 19,882	\$ 30,032	\$ 22,382	\$ 43,201	\$ 41,708	\$ 157,204

Table 14 – RG&E Electric Resiliency Capital Investment Forecast

The following describes some of the key project and program investments which are forecasted under the Electric Resiliency category:

- **Distribution Automation Program:** The Distribution Automation Program is an annual initiative designed to address distribution circuits experiencing customer outages across the NYSEG and RG&E service territories. Each year, the Companies identify the most negatively impacted distribution circuits from a SAIFI perspective using three years of historical SAIFI data. This process ensures that investments are prioritized on circuits with higher levels of criticality. Solutions typically involve the deployment of reclosers and SCADA switches on identified circuits, using customer count criteria (i.e., 500 customer pockets) as the basis to inform the design of each circuit. Since its inception, this program has successfully reduced customer outage exposure, particularly for faults occurring downstream from the substation circuit breaker.
- **Resiliency Program:** The Resiliency Program is an annual initiative aimed at addressing distribution circuits with the highest levels of customer outages across the NYSEG and RG&E service territories, identified using three years of historical SAIFI data including those from storms. For those circuits under study, Integrated System Planning conducts a comprehensive needs and solutions





NYSEG and RG&E 5-Year Capital Investment Plan

assessment to ensure all electrical and asset condition needs are identified. This assessment informs the development of complete solutions to address all identified needs. Solutions may include upgrades to system topologies (e.g., new distribution tie points), hardening of pole and wire infrastructure, and the deployment of automation devices based on established criteria from the Distribution Automation Program (i.e., 500 customer pockets). Although new projects are identified annually, the circuit-level sub-projects are more complex and require extensive engineering and material procurement as compared to the Automation Program. Consequently, it is common for these sub-projects to span multiple years.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 6.8 Electric Compliance Capital Investment Forecast

This category provides a further breakdown of expenditures required to accommodate projects and programs related to compliance. The Electric Compliance Capital Investment Forecast is summarized for NYSEG Electric in Table 15 and for RG&E Electric in Table 16.

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	Compliance	\$ 66,082	\$ 80,335	\$ 167,403	\$ 273,511	\$ 298,823	\$ 886,155
2	FERC 881 Regulatory Compliance	4,153	-	-	-	-	4,153
3	NYSEG FERC 2222	2,854	-	-	-	-	2,854
4	IT-OT NERC CIP Asset Transition	1,234	-	-	-	-	1,234
5	NERC Compliance Program - NYSEG	1,637	1,621	1,653	1,698	1,771	8,380
6	NYSEG FIRE PROTECTION TRANSMISSION	240	80	82	84	-	487
7	BES - South Oneonta Area - Fraser	40,448	25,958	-	-	-	66,406
8	BES - Erie Street	1,821	2,679	63,145	42,913	31,449	142,007
9	BES - 981 Line Uprate	269	287	4,058	13,171	2,200	19,985
10	BES - Border City / Haley	33	33	-	51,069	84,550	135,685
11	BES - Coopers Corners	-	4,347	39,194	51,342	38,781	133,664
12	BES - Frog Valley part of WBS UH-N0000581	-	-	-	5,743	16,852	22,595
13	BES - Fuller Hollow / Langdon	82	1,161	2,303	1,419	5,107	10,071
14	BES - Klinekill RPR	-	-	-	-	9,150	9,150
15	BES - Wagner Hill	59	149	216	-	-	424
16	BES - Ten Mile River to	-	-	-	-	8,628	8,628
17	BES - Sleight Road StatCom	2	11,148	17,535	23,391	21,588	73,663
18	New 115 kV Baker Hill Substation	-	747	2,056	145	1,866	4,814
19	BES - NY Klinekill	-	89	98	193	-	379
20	BES - NY Healey Road	30	2,224	2,244	3,630	1,721	9,849
21	BES Fuller Hollow + L939 + L952 + RR	80	3,861	573	1,494	4,928	10,935
22	BES SS Colliers	183	1,775	2,441	5,018	2,761	12,179
23	BES SS East Norwich	282	1,412	1,399	1,602	3,820	8,515
24	BES - Cold Springs	-	-	-	5,743	16,852	22,595
25	BES - Ten Mile to Pleasant Valley New 115 kV Line	-	-	-	13,218	14,002	27,220
26	BES - Klinekill to Falls Park New 115 kV Line	-	-	7,795	10,810	14,332	32,937
27	BES TL 727 Langdon Road to Fuller Hollow	26	439	2,112	2,194	1,629	6,400
28	N58495 - BES TL 842 - Baker Hill to Pierce Avenue 46 kV	-	-	-	74	3,418	3,492
29	N58495 - BES TL 843 - Baker Hill to Morris 46kV	-	15	1	1,304	1,605	2,925
30	Morris 46/4.8 kV Substation Upgrades	72	545	328	517	632	2,094
31	Pierce SS	50	51	54	136	454	744
32	New 115 kV Line from Baker Hill to Colliers	43	84	621	2,682	5,503	8,932
33	New 115 kV Line from Baker Hill to Fraser	-	1,352	1,894	2,726	3,644	9,616
34	New 115 kV Line from Baker Hill to East Norwich	-	108	695	1,398	1,034	3,235
35	NERC Alert Priority III	438	452	478	509	547	2,425
36	NERC Alert Priority III-NYSEG-Line 951	3,170	-	-	-	-	3,170
37	NERC Alert Priority III-NYSEG-Line 969	-	-	-	1,566	-	1,566
38	NERC Alert Priority III-NYSEG-Line 973	-	-	-	13,571	-	13,571
39	NERC Alert Priority III-NYSEG-Line 974	-	12,584	-	-	-	12,584
40	NERC Alert Priority III-NYSEG-Line 975	-	-	16,206	-	-	16,206
41	NERC Alert Priority III-NYSEG-Line 976	-	-	221	-	-	221
42	NERC Alert Priority III-NYSEG-Line 979	-	-	-	3,124	-	3,124
43	NERC Alert Priority III-NYSEG-Line 994	2,309	-	-	-	-	2,309
44	NERC Alert Priority III-NYSEG-Line 998	-	7,132	-	-	-	7,132
45	NERC Alert Priority III-NYSEG-Line 958	-	-	-	9,221	-	9,221
46	NERC Alert Priority III-NYSEG-Line 964	-	-	-	1,806	-	1,806
47	NERC Alert Priority III-NYSEG-Line 929	2,441	-	-	-	-	2,441
48	NERC Alert Priority III-NYSEG-Line 936	1,937	-	-	-	-	1,937
49	NERC Alert Priority III-NYSEG-Line 991	2,189	-	-	-	-	2,189
50	All Other Compliance	-	-	-	-	-	-
51	Total	\$ 66,082	\$ 80,335	\$ 167,403	\$ 273,511	\$ 298,823	\$ 886,155

Table 15 – NYSEG Electric Compliance Capital Investment Forecast





NYSEG and RG&E 5-Year Capital Investment Plan

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	Compliance	\$ 41,172	\$ 28,281	\$ 28,946	\$ 54,172	\$ 59,175	\$ 211,745
2	RG&E FERC 2222	1,303	-	-	-	-	1,303
3	FERC 881 Regulatory Compliance RGE	1,574	-	-	-	-	1,574
4	IT-OT NERC CIP Asset Transition	629	-	-	-	-	629
5	RG&E FIRE PROTECTION TRANSMISSION	590	507	520	-	-	1,617
6	NERC Compliance Program - RGE	770	780	789	798	817	3,954
7	BES - Line 949 115 kV Line Addition	32,847	17,113	1,492	-	-	51,451
8	BES - 947 Line Upgrade	2,823	8,002	14,948	28,174	32,983	86,930
9	BES NY.L946	435	911	3,405	22,606	823	28,179
10	BES NY.L917	976	529	4,550	871	11,184	18,109
11	BES NY.L945	1,070	439	3,243	1,722	13,369	19,841
12	BES - Hook Rd Upgrades (ST 127)	1	-	-	-	-	1
13	BES - Station 056 Reconfiguration	(1,845)	-	-	-	-	(1,845)
14	All Other Compliance	-	-	-	-	-	-
15	Total	\$ 41,172	\$ 28,281	\$ 28,946	\$ 54,172	\$ 59,175	\$ 211,745

Table 16 – RG&E Electric Compliance Capital Investment Forecast

The following describes some of the key project and program investments which are forecasted under the Electric Compliance category:

- BES Program NERC Compliance:** The objective of the NYSEG/RG&E Bulk Electric System (BES) Program is to identify and address system deficiencies on the portion of the BES of NYSEG and RG&E in accordance with mandatory North American Electric Reliability Corporation (NERC) reliability standards. The criteria and system performance requirements for the BES are provided in NERC's TPL-001-4 standard. Each transmission owner has an obligation to demonstrate through planning studies that its portion of the BES meets all mandatory NERC requirements. In cases where unacceptable reliability performance is detected, a documented Corrective Action Plan (e.g., a project) showing how these deficiencies will be mitigated must be developed. To be compliant with NERC Transmission Planning (TPL) requirements, the Companies periodically perform a comprehensive planning assessment to evaluate system performance over both the near-term and long-term planning horizons. The most recent comprehensive assessments were performed in 2018 and 2024. Although the primary focus of this program is to address BES reliability deficiencies, some of the recommended solutions have also been designed to mitigate asset condition and local reliability deficiencies at the same





NYSEG and RG&E 5-Year Capital Investment Plan

substation locations where significant BES upgrades are being recommended.

This approach ensures that a comprehensive and cost-effective solution is developed. It should be noted that 13 previously identified BES projects are now included in the PNY Transmission Projects Phase 1 suite of projects in support of the State's CLCPA objectives.

- NERC Alert Priority III Program: The objective of the NERC Alert Priority III Program is to address electric system deficiencies that have been identified by NERC as posing a potential risk to the reliability or security of the bulk power system. The scope of the program entails identifying assets that are in critical condition, or which violate applicable construction standards, such as maintaining proper physical clearances. Where deficiencies are found, the program develops detailed and actionable plans to bring the delivery system of our service areas into full compliance. Examples of actions included, but are not limited to, the replacement or modification of structures that are deemed to be in violation of applicable NESC Code, replacement of facilities in very poor condition, and the mitigation of insufficient ground/structure clearances.





NYSEG and RG&E 5-Year Capital Investment Plan**Section 6.9 Hydro Generation Capital Investment Forecast**

The Companies own and operate hydroelectric and fossil fuel generating facilities. The NYSEG generating facilities currently include six active hydroelectric generating facilities and 4 four small fossil-fuel facilities having a total nameplate capacity of approximately 69.5MW (61.4MW hydro and 8.1MW fossil). The active hydroelectric and fossil-fuel generating facilities are located from Plattsburgh (northeast New York) to Rochester. The RG&E facilities include three active hydroelectric facilities having a total nameplate capacity of 57.1MW; all facilities are located within the City of Rochester. All active hydroelectric facilities are under the Federal Energy Regulatory Commission (“FERC”) jurisdiction with three retired NYSEG and RG&E hydroelectric facilities, NYSEG Keuka, RG&E Station 160 and Station 170, located in the southern tier region. The water retaining structures that remain at the retired hydroelectric facilities are operational and under jurisdiction of the New York State Department of Environmental Conservation. All active hydroelectric generating facilities are operated as run-of-river, meaning that water that enters the facility impoundment cannot be stored, but produce energy from the river flow that is available at a given time in the respective watershed.

NYSEG presently has four fossil-fuel standby diesel generators, with a total combined capacity of 8.1MW. The diesel generators are located at Harris Lake (two generators), Blue Mountain, and Long Lake substations in the Adirondack region. The diesel generators are dispatched to generate electric energy to serve local customers upon loss of the transmission lines that serve these stations. RG&E does not have any fossil-fuel generating facilities.

This category provides a further breakdown of the expenditures required to accommodate projects and programs related to the Hydro Generation facilities owned by the Companies. The Hydro Generation Investment Forecast is summarized for NYSEG and RG&E in Table 17 and Table 18, respectively.





April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
1	<i>\$ in thousands</i>						
2	Hydro-Generation	\$ 27,115	\$ 41,115	\$ 29,676	\$ 29,638	\$ 27,493	\$ 155,036
3	Upper Mechanicville Intake Upgrades And Downstream Passage Project	757	7,267	7,840	-	-	15,864
4	Kents Falls - Capital Project	11,414	18,401	680	-	-	30,494
5	High Falls Intake Upgrade Project	246	-	-	-	-	246
6	NYSEG Minor Capital Program	1,508	1,512	1,545	1,588	1,652	7,805
7	Kents Falls Unit 2 Turbine-Generator Major Rebuild	3	460	447	3,441	409	4,761
8	Mechanicville Upstream Eel Ladder Project	1,834	-	-	-	-	1,834
9	Cadyville Upgrade Unit 1 & Unit 2 Turbine-Generator Cooling Water System	327	337	1,331	265	-	2,260
10	Saranac Plant Control Systems Upgrade Project	694	-	-	-	-	694
11	Bradford Concrete Spillway And Toe Resurfacing Improvement Project	1,390	126	-	-	-	1,516
12	High Falls Unit 2 Generator Rewind	392	-	-	-	-	392
13	Kents Falls Internal Riser Shaft and Tank Project	3,410	3,416	395	-	-	7,221
14	Bradford Dam Automation Project	-	531	375	1,269	220	2,394
15	Mill C Spillway Concrete Improvements Project	290	4,341	13	-	-	4,644
16	Rainbow Falls Powerhouse Entrance Hill Stabilization	47	-	-	-	-	47
17	Kents Falls Dam Low Level Floodgate Project	2,577	-	-	-	-	2,577
18	Cadyville and Kents Falls Facility and Window Upgrades	344	774	210	-	-	1,328
19	Cadyville Switchgear And Generator Protection Upgrade Project	-	332	1,250	2,653	228	4,463
20	High Falls Draft Tube Stop Logs and Gantry Project	7	444	862	2,730	382	4,425
21	High Falls U1 T-G Major Rebuild	-	-	478	446	3,475	4,400
22	High Falls Unit 3 Turbine Rebuild & Draft Tube Upgrade Project	-	-	-	561	575	1,136
23	Kents Falls Switchgear and Generator Protection	-	-	-	-	374	374
24	Kents Falls Unit 1 Generator Rewind Project	-	459	2,728	408	-	3,595
25	Mill C Intake Stop Gate Upgrade Project	-	-	-	-	326	326
26	Mill C Switchgear and Generator Protection	-	-	-	370	1,298	1,668
27	Mill C U2 T-G Major Rebuild	-	-	-	-	483	483
28	Rainbow Falls Low Level Floodgate Upgrades & Downstream Abutment Res	-	429	410	2,801	347	3,986
29	Rainbow Falls Penstock Replacement	-	405	480	2,050	6,139	9,074
30	Rainbow Falls Power Canal and Gatehouse Upgrade Project	-	-	467	560	2,001	3,028
31	Roof Upgrades (Cadyville, Rainbow Falls)	976	215	-	-	-	1,191
32	Upper Mechanicville Boat Launch/River Access	-	-	-	-	284	284
33	Upper Mechanicville Generator Protection and Controls Upgrade Project	-	374	1,287	2,520	313	4,494
34	Upper Mechanicville Plant Control System Upgrade Project	-	308	604	284	-	1,196
35	Upper Mechanicville Unit 1 Turbine-Generator Major Overhaul / Rebuild Proj	771	539	6,958	5,506	1,069	14,844
36	Upper Mechanicville Unit 2 Generator Rewind	-	-	478	446	4,666	5,590
37	Mill C Powerhouse A Crane Upgrade	-	326	364	1,256	288	2,234
38	NYSEG Cadyville Draft Tube/Scroll Case Upgrade Project	-	-	-	-	350	350
39	NYSEG Cadyville Low Level and Midlevel Gate Upgrade	-	-	353	367	2,498	3,218
40	NYSEG Hydro Tools - Capital	122	117	116	116	117	587
41	All Other Hydro	5	3	2	1	1	11
42	Total	\$ 27,115	\$ 41,115	\$ 29,676	\$ 29,638	\$ 27,493	\$ 155,036

Table 17 – NYSEG Hydro Generation Capital Investment Forecast



Take care of the environment.
Print in black and white and only if necessary.



April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
1	<i>\$ in thousands</i>						
1	Hydro-Generation	\$ 14,735	\$ 30,919	\$ 51,239	\$ 36,700	\$ 9,800	\$ 143,393
2	Hydro Generation Station 2 Modernization Project	1,930	10,662	17,181	18,835	1,340	49,947
3	RG&E Minor Capital Program	1,472	1,598	1,520	1,542	1,580	7,711
4	Station 2 Central Ave Dam Superstructure Modernization	208	2,306	535	-	-	3,048
5	Station 5 Gate 3 Rubplate, Rubplate and Breastwall Seal Upgrade Project	2,168	-	-	-	-	2,168
6	RG&E Powerhouse / Facility Structures	-	247	285	833	150	1,515
7	RGE Production	600	350	100	-	-	1,050
8	Roof Upgrades (Station 5, Station 26, Station 160)	-	-	-	-	265	265
9	S160 Toe Scour Upgrade Project	372	401	2,131	92	-	2,996
10	S26 U1 Wicket Gate Bushing Upgrade	-	-	-	-	222	222
11	S5 Brewer Street Water and Fire Lines	-	281	293	1,438	169	2,181
12	S5 Pier Foundations and Overhead Superstructure Demolition	-	-	-	-	288	288
13	S5 Spillgate #4A Rock Stabilization	-	-	-	-	436	436
14	S5 Spillgate #4B Rock Stabilization	-	-	-	-	436	436
15	S5 U1 Wicket Gate Bushing Upgrade	-	304	661	124	-	1,089
16	S5 U2 Wicket Gate Bushing Upgrade	-	-	246	591	106	943
17	S5 Unit 3 Turbine-Generator New Runner	-	-	-	-	291	291
18	Station 170 Dam Resurfacing and Power Upgrades Projects	-	382	364	2,585	356	3,686
19	Station 2 Generator Protection and Controls Upgrade Project	-	254	569	159	-	982
20	Station 2 Unit 1 Turbine Wicket Gate Bushing Upgrade	-	183	250	1,208	622	2,263
21	Station 26 Generator Protection and Controls Upgrade Project	-	254	569	159	-	982
22	Station 26 Intake Deck/Gate Hoist Upgrades and Resurfacing	455	468	3,421	318	-	4,662
23	Station 5 Gate 2 Rubplate, Bottom Seal, Hinge Upgrade and Rock Stabilizati	461	458	2,778	344	-	4,040
24	Station 5 Gate 5 Rubplate, Bottom Seal, Hinge Upgrade and Rock Stabilizati	-	454	450	2,734	343	3,980
25	Station 5 Generation Protection and Controls Upgrade Project	1,037	571	-	-	-	1,608
26	Station 5 Old House Stabilization Project	2,113	132	-	-	-	2,245
27	Station 5 Penstock Lining and Coating Upgrade Project	436	443	2,127	341	-	3,347
28	Station 5 Powerhouse Backup Generator Upgrade	315	271	769	205	-	1,559
29	Station 5 Powerhouse Rock Scaling and Stabilization Project	479	533	3,131	374	-	4,517
30	Station 5 Surge Tank Expansion Project	515	453	2,633	355	-	3,957
31	Station 5 Unit 1, Unit 2 & Unit 3 Turbine-Generator Guide Bearing Water Filtr	315	333	914	242	-	1,804
32	Station 5 Unit 3 Turbine-Generator New Turbine Isolation Valve	309	556	1,563	1,098	-	3,526
33	Station 5 Water Conveyance (Tunnel) System Project	707	4,751	5,173	571	-	11,202
34	RG&E Station 5 Glycol Heating Upgrade Project	303	324	1,292	184	-	2,103
35	S5 U3 Wicket Gate Bushing Upgrade	-	-	246	647	106	999
36	Station 2 Relicensing	-	-	-	-	774	774
37	Station 26 Relicensing	-	-	-	-	778	778
38	Station 5 Powerhouse Sewer Upgrade	-	-	-	392	446	838
39	Station 5 Rack Raker Upgrade	-	570	881	1,218	209	2,877
40	Station 5 Relicensing	-	-	-	-	774	774
41	RG&E Hydro Tools - Capital	117	115	113	111	111	568
42	Station 5 Powerhouse Access Road Rockfall Stabilization Project	305	3,231	1,045	-	-	4,581
43	All Other Hydro	120	35	-	-	-	155
44	Total	\$ 14,735	\$ 30,919	\$ 51,239	\$ 36,700	\$ 9,800	\$ 143,393

Table 18 – RG&E Hydro Generation Capital Investment Forecast

The following describes some of the key project and program investments which are forecasted under the Hydro Generation category:

- **Station 2 Modernization:** Project involves deepening the area in front of and under the facility's water intake to allow the installation of a new and larger penstock that will allow increased water conveyance, improved conveyance of aquatic species downstream of the intake structure to comply with the FERC License Amendment and the installation of a new turbine isolation valve for the Unit 1 turbine-generator. Sections of the existing penstock are at end-of-life (circa 1900's) and do not allow for potential future expansion of the hydroelectric



Take care of the environment.
Print in black and white and only if necessary.



NYSEG and RG&E 5-Year Capital Investment Plan

facility. The investment will restore reliable operation of the 8.5MW facility and further supports the New York State Clean Energy Goal initiatives for generation of clean, renewable energy.

- Mechanicville Intake Upgrades and Downstream Passage: Project is required as an outcome of the 50-year operating license issued by the FERC, effective April 1, 2021. NYSEG is required to comply with the Settlement Agreement that requires upgrades to the facility to protect aquatic species (improve survivability), specifically the American eel, which are located upstream of the water intake structure. Upgrades to the facility will allow for a safe alternative path for American eels to move downstream of the hydroelectric facility.
- Kent Falls Capital: Project involves the installation of new ring girders that support the penstock and will replace the end-of-life penstock saddles, the installation of new penstock sections, and the relining of the existing penstocks from the outlet of the existing penstock trifurcation to each turbine-generator.
- High Falls Intake Upgrades: Project is being undertaken by NYSEG as a part of the current FERC license for the Facility. The Company is required to upgrade the existing intake trash racks from 2-inch clear space opening to 1-inch openings for fish protection per the License and per the New York State Department of Environmental Conservation (NYSDEC) 401 Water Quality Certification. Installation of the new intake trash racks at High Falls is required to be completed by no later than April 13, 2026, as outlined in the Settlement Agreement and FERC License.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 6.10 Clean Energy Transformation Capital Investment Forecast

This category provides a further breakdown of expenditures required to accommodate projects and programs related to Clean Energy Transformation. The Clean Energy Transformation Capital Investment Forecast is summarized for NYSEG Electric in Table 19 and RG&E Electric in Table 20.

	A	B	C	D	E	F	G
	\$ in thousands						
	2026	2027	2028	2029	2030	Total 2026-2030	
1	Clean Energy Transformation	\$ 211,027	\$ 405,182	\$ 370,743	\$ 267,954	\$ 139,304	\$ 1,394,210
2	PNY Phase-1 Line 962 Rebuild	16,639	28,774	30,627	30,847	22,944	129,832
3	PNY Phase 1 - Jennison 115/46 kV Substation Upgrades	31,730	51,050	35,025	8,147	-	125,953
4	PNY Phase 1 - 115 kV Line 961 Rebuild	11,268	17,810	26,452	26,192	8,603	90,326
5	PNY Phase 1 - Trans Line - 949 Rebuild	5,709	47,541	28,668	9,485	-	91,403
6	PNY Phase 1 - Lounsberry 115/12.5 kV Substation Full Rebuild	3,359	23,354	9,418	-	-	36,131
7	PNY Phase 1 - Trans Line - 946 Rebuild	4,999	29,976	19,628	13,236	2,334	70,172
8	PNY Phase 1 - Clarks Corners	18,068	8,239	-	-	-	26,308
9	PNY Phase 1 - Trans Line - 982 Rebuild	7,784	19,052	21,383	13,382	338	61,939
10	PNY Phase 1 - Oakdale Westover Solution	76,688	92,874	79,881	35,130	2,491	287,065
11	PNY Phase 1 - Trans Line - 945 Reroute	7,706	12	-	-	-	7,718
12	Robinson Road 230/115/34.5 kV Substation Upgrades	-	18,119	31,430	64,565	43,626	157,741
13	Stolle Road 345/230/115/34.5 kV Substation Upgrades	-	28,433	28,195	28,124	28,432	113,184
14	Coddington 115/34.5 kV Substation Upgrades	-	12,764	12,657	12,625	12,763	50,809
15	Etna 115/34.5/4.8 kV Substation Full Rebuild	6,263	21,309	47,379	26,221	17,772	118,944
16	PNY - South Owego Upgrades	5,474	643	-	-	-	6,117
17	West Hill SS	2,219	-	-	-	-	2,219
18	Trumansburg SS	2,707	-	-	-	-	2,707
19	Cayuga Heights SS	1,873	-	-	-	-	1,873
20	Fourth St SS	8,540	5,230	-	-	-	13,769
21	All Other Clean Energy Transformation	-	-	-	-	-	-
22	Total	\$ 211,027	\$ 405,182	\$ 370,743	\$ 267,954	\$ 139,304	\$ 1,394,210

Table 19 – NYSEG Clean Energy Transformation Capital Investment Forecast

	A	B	C	D	E	F	G
	\$ in thousands						
	2026	2027	2028	2029	2030	Total 2026-2030	
1	Clean Energy Transformation	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
2		-	-	-	-	-	-
3	Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Table 20 - RG&E Clean Energy Transformation Capital Investment Forecast

The following describes some of the key project and program investments which are forecasted under the Clean Energy Transformation category:

- PNY Transmission Projects Phase 1: The portfolio of PNY Phase 1 Transmission Projects originally consisted of 23 projects which were all included in the Companies' PNY Phase 1 petition which was filed on December 23, 2021. The NYPSC responded on 12/15/2022 with an order granting full approval for continued investment in nine of these projects, as well as partial approval for continued investment with scope reduction for four projects. Ten projects were





NYSEG and RG&E 5-Year Capital Investment Plan

not approved and were subsequently removed from the group of PNY Phase 1 program and placed into the BES Program. The approved PNY Phase 1 projects achieve multiple benefits by mitigating both asset condition and reliability needs (including NERC BES compliance requirements) as well as increasing transmission system headroom to accommodate existing and planned transmission-connected renewable resources. The projects are spread throughout the Binghamton, Ithaca, Lancaster, Lockport, and Oneonta areas within NYSEG's territory. The projects are not truly incremental to the Companies' capital plan; rather, the PNY Phase 1 Projects represent an acceleration of business-as-usual projects that happen to support State CLCPA objectives but that would be needed anyway to address traditional reliability and asset condition needs.

- Ithaca Electrification Projects Phase 1: These local transmission and distribution projects are needed to solve existing reliability needs and will help to support timely execution of the City of Ithaca's electrification initiative. Voltage and thermal violations exist under a range of contingency conditions in the transmission and distribution network between Coddington and Etna Substations in NYSEG's Ithaca Division. To resolve the voltage violations, three shunt capacitors are proposed at (1) West Hill, (2) Trumansburg, and (3) Cayuga Heights. There is a plan to rebuild Coddington substation as part of the PNY Transmission Projects Phase 1 effort, which will resolve the thermal violations in the long term (2026-2027), but in the short term a mobile 115/34.5 kV transformer will be installed at Coddington. Two transformers at Fourth Street will be replaced with larger units, and the 8.3 kV distribution network (which is islanded from the 12.5 kV surrounding network) will be upgraded to 12.5 kV.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 6.11 Electric AMI Capital Investment Forecast

This category is for AMI. The Electric AMI Investment Forecast is summarized for NYSEG Electric in Table 21 and for RG&E

Electric in Table 22 respectively.

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	AMI	\$ 6,651	\$ -	\$ -	\$ -	\$ -	\$ 6,651
2	NYSEG - AMI Project	6,022	-	-	-	-	6,022
3	AMI Project Growth	629	-	-	-	-	629
4	Total	\$ 6,651	\$ -	\$ -	\$ -	\$ -	\$ 6,651

Table 21 – NYSEG AMI Capital Investment Forecast

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	AMI	\$ 3,002	\$ -	\$ -	\$ -	\$ -	\$ 3,002
2	RGE - AMI Project	2,838	-	-	-	-	2,838
3	AMI Project Growth	164	-	-	-	-	164
4	Total	\$ 3,002	\$ -	\$ -	\$ -	\$ -	\$ 3,002

Table 22 –RG&E AMI Capital Investment Forecast

This category is the on-going installation of AMI in NYSEG and RG&E service territories. NY AMI is an essential foundational system in realizing Reforming the Energy Vision (REV) goals to empower customers through new tools and information to effectively manage and reduce usage, establish, and animate new markets to promote the implementation of DERs, and minimize environmental impacts of power generation and energy consumption. NYSEG and RG&E will gain early outage detection to assist with restoration efforts as well as streamline internal business processes.





NYSEG and RG&E 5-Year Capital Investment Plan

Chapter 7 Gas Capital Investment Forecast

This section will further detail, by major investment category, the overall Gas capital investments. The categorization of the Plan is grouped into, in no particular order, Asset Condition, Mandatory, Modernization, Reliability, and AMI. The sub sections below summarize the major investment categories for the five years 2026-2030.

Section 7.1 Gas Capital Investment Requirements

The Capital Investment Forecast for five-year period 2026-2030 for NYSEG⁴ and RG&E⁵ Gas Lines of Business are shown in Table 23 and Table 24, respectively.

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	Asset Condition	\$ 23,078	\$ 12,056	\$ 19,485	\$ 15,543	\$ 18,238	\$ 88,400
2	Mandatory	16,258	17,247	19,981	20,784	22,099	96,370
3	Modernization	7,233	6,695	2,829	2,954	639	20,349
4	Reliability	50,119	75,856	62,599	75,647	78,934	343,155
5	AMI	1,348	-	-	-	-	1,348
6	Subtotal Gas Capital	98,036	111,854	104,894	114,928	119,911	549,622
7							
8	Common Allocation to Gas Business	33,356	31,128	29,325	27,519	23,140	144,467
9	Total NYSEG Gas Capital	\$ 131,391	\$ 142,981	\$ 134,220	\$ 142,446	\$ 143,050	\$ 694,089

Table 23 – NYSEG Gas Capital Investment Forecast

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	Asset Condition	\$ 24,925	\$ 16,206	\$ 14,385	\$ 37,856	\$ 32,357	\$ 125,729
2	Mandatory	16,282	26,499	23,529	22,603	23,162	112,075
3	Modernization	4,833	4,599	146	142	450	10,170
4	Reliability	54,377	63,677	80,757	78,688	67,749	345,248
5	AMI	1,696	-	-	-	-	1,696
6	Subtotal Gas Capital	102,113	110,980	118,818	139,289	123,718	594,917
7							
8	Common Allocation to Gas Business	22,664	20,437	18,576	16,168	14,131	91,976
9	Total RG&E Gas Capital	\$ 124,777	\$ 131,417	\$ 137,394	\$ 155,457	\$ 137,849	\$ 686,893

Table 24 – RG&E Gas Capital Investment Forecast

⁴ Note: NYSEG Common allocation to the Gas Line of Business is 18.47%.

⁵ Note: RG&E Common allocation to the Gas Line of Business is 25.36%.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 7.2 Gas Asset Condition Capital Investment Forecast

The Asset Condition Capital Investment Forecast for NYSEG Gas is shown in Table 25 and for RG&E in Table 26.

A	B	C	D	E	F	G
<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1 Asset Condition	\$ 23,078	\$ 12,056	\$ 19,485	\$ 15,543	\$ 18,238	\$ 88,400
2 NYSEG Dist Main Replacement	5,688	5,618	6,839	7,028	7,341	32,514
3 NYSEG Gas Operations Departmental	1,577	1,564	1,596	1,640	1,709	8,086
4 Baltimore Ave DRS Relocation	-	-	-	-	1,996	1,996
5 Border City DRS Rebuild	-	-	4,370	-	-	4,370
6 NYSEG Reg Mod & Auto Pgm GRMP	4,318	4,875	6,679	6,875	7,192	29,939
7 Vienna Road Regulator Station GRMP	11,494	-	-	-	-	11,494
8 All Other Asset Condition	-	-	-	-	-	-
9 Total	\$ 23,078	\$ 12,056	\$ 19,485	\$ 15,543	\$ 18,238	\$ 88,400

Table 25 – NYSEG Gas Asset Condition Capital Investment Forecast

A	B	C	D	E	F	G
<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1 Asset Condition	\$ 24,925	\$ 16,206	\$ 14,385	\$ 37,856	\$ 32,357	\$ 125,729
2 Caledonia Station Rebuild	-	4,782	-	-	-	4,782
3 CM-1 Pipeline: Section 4 Chill GS to Bal	15,126	-	-	-	-	15,126
4 RGE Dist Main Replacement	2,673	2,717	3,259	3,306	3,393	15,349
5 Mt Read (SF115 psig) Main Replacement	-	-	-	20,277	20,167	40,444
6 RGE Gas Operations Departmental	419	425	430	435	446	2,155
7 Industrial Gas Service Replacement - RGE	-	1,447	-	-	-	1,447
8 Rebuild Station 449 - Valentown Rd & CR9	-	-	1,294	-	-	1,294
9 RGE Reg Mod & Auto Pgm GRMP	6,707	6,834	7,990	8,122	8,352	38,005
10 RS 369 East Station Rebuild GRMP	-	-	1,412	5,715	-	7,127
11 All Other Asset Condition	-	-	-	-	-	-
12 Total	\$ 24,925	\$ 16,206	\$ 14,385	\$ 37,856	\$ 32,357	\$ 125,729

Table 26 – RG&E Gas Asset Condition Investment Forecast

The Gas asset condition category can be separated into three broad groups – Equipment, Main Replacement and Regulator Station Modernization.

The Equipment group is related to the purchase of tools and equipment needed and used by gas field employees to inspect, operate, maintain, or repair the gas system.

The Main Replacement group is related to replacing mains (defined as non-leak prone) due to condition, damage caused by third parties, conflicts with existing or proposed construction (other than highway work) and other miscellaneous field conditions. Major projects that are undertaken by the Companies also fall within this group. These major projects are in response to mains that are in poor condition and need to be replaced to maintain a safe and reliable system. The major programs and projects in this group are:





NYSEG and RG&E 5-Year Capital Investment Plan

- Distribution Main Replacement: This is a program to replace gas mains as required due to several factors including, but not limited to, poor asset conditions, conflicts with existing or proposed structures, and other miscellaneous field conditions discovered as part of normal operations or other construction and inspection activities.
- CM-1 Pipeline Section 4 Chili GS to Ballantyne Rd: This project addresses asset condition by replacing transmission pipe installed in the 1950s. The new pipeline will be designed to operate at less than 20% SMYS. Replacement of the pipeline will maintain gas supply to the Rochester area and improve transmission system and distribution system reliability by replacing existing 22 1/2-inch gas main parallel to CM-5 pipeline (Chili Gate Station (GS) to Ballantyne Road) with 23,400 linear feet of 16-inch wrapped steel pipe.

Major Regulator and Gate Station rebuilds are included in this category if the primary reason for upgrading or rebuilding the station is due to asset condition. The key projects in this group are:

- Vienna Road Regulator Station: Vienna Road Regulator Station is critical for NYSEG Gas Control to balance daily nominations between National Fuel and Eastern Gas Transmission and Storage ("EGTS").. The station has been in operation for over 60 years, with much of the equipment at or beyond its service life. The overpressure protection relief valves and regulators are obsolete. Replacement parts are no longer available. The existing heater experiences operational issues multiple times in the coldest points during the heating season, requiring manual restart of the equipment. The flow meter measuring the gas coming from the Arcadia Gate Station is located in a vault below grade that is prone to filling with water, leading to intermittent signal loss. The majority of gas into the northern part of the NYSEG Geneva franchise passes through this





NYSEG and RG&E 5-Year Capital Investment Plan

station and the station is a critical system component that ensures reliable service to approximately 27,000 customers.

- Caledonia Station Rebuild: The Caledonia Gate Station is a primary gas supply source to the RG&E system and supplies gas to the western portions of the franchise and also serves as a redundant source of gas for the eastern portions of the franchise. The RG&E franchise requires upgrades to this gate station for safe, reliable, and efficient operation and to address facilities and equipment that are at end of life. The upgrades and replacements associated with this project are necessary to avoid potentially significant future maintenance cost.
- Mendon Gate Station: The Mendon Gate Station is a primary gas supply source to the RG&E system and supplies gas to the eastern portions of the franchise and also serves as a redundant source of gas for the western portions of the franchise. This project will upgrade equipment that is at end of life, modernize facilities, increase operational efficiencies, eliminate potential environmental concerns, install additional Gas Control/ECC remote control equipment and increase safety and security at the primary gate station feeding the eastern portion of the RG&E Rochester franchise. Approximately 150,000 customers in the eastern portion of Rochester area are served downstream of this station. These improvements will help to continue to provide a safe and reliable natural gas supply to customers.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 7.3 Gas Mandatory Capital Investment Forecast

The Mandatory Capital Investment Forecast for NYSEG and RG&E are shown in Table 27 and Table 28, respectively.

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
1	<i>\$ in thousands</i>						
1	Mandatory	\$ 16,258	\$ 17,247	\$ 19,981	\$ 20,784	\$ 22,099	\$ 96,370
2	NYSEG New Services	3,018	2,925	3,195	3,285	3,462	15,885
3	NYSEG Dist Mains New Business	2,423	2,379	2,822	2,900	3,036	13,560
4	NYSEG Non LP Srv Repl Program	4,747	4,675	5,554	5,711	5,975	26,662
5	NYSEG CAPEX Gas Meters	2,972	3,950	4,152	4,152	4,254	19,481
6	NYSEG Government Jobs	1,641	1,764	2,318	2,605	2,980	11,308
7	Large Government Jobs - NYSEG	1,007	1,103	1,465	1,655	1,893	7,124
8	NYSEG CAPEX Regulators	450	450	475	475	500	2,350
9	All Other Mandatory	-	-	-	-	-	-
10	Total	\$ 16,258	\$ 17,247	\$ 19,981	\$ 20,784	\$ 22,099	\$ 96,370

Table 27 – NYSEG Gas Mandatory Capital Investment Forecast

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
1	<i>\$ in thousands</i>						
1	Mandatory	\$ 16,282	\$ 26,499	\$ 23,529	\$ 22,603	\$ 23,162	\$ 112,075
2	RGE Dist Mains New Business	2,290	2,320	2,654	2,680	2,750	12,694
3	RGE CAPEX Gas Meters	2,885	3,297	3,503	3,709	3,915	17,307
4	RGE New Services	2,671	2,712	3,166	3,206	3,291	15,045
5	Large Government Jobs - RG&E	2,529	2,818	3,777	4,206	4,733	18,064
6	RGE Non LP Srv Repl Program	3,881	3,940	4,781	4,843	4,967	22,411
7	RGE Government Jobs	1,727	1,917	2,538	2,818	3,165	12,165
8	RGE CAPEX Regulators	300	310	320	330	340	1,600
9	Rt 15 Corridor Safety Enhancements	-	7,771	-	-	-	7,771
10	Thruway Park/Hendrix Rd Short Segment	-	1,415	-	-	-	1,415
11	Burben Way Short Segment	-	-	-	811	-	811
12	900, 920 Penfield-Walworth Rd Short Seg	-	-	2,791	-	-	2,791
13	All Other Mandatory	-	-	-	-	-	-
14	Total	\$ 16,282	\$ 26,499	\$ 23,529	\$ 22,603	\$ 23,162	\$ 112,075

Table 28 – RG&E Gas Mandatory Capital Investment Forecast

The projects and programs in the Mandatory category are required by tariff, regulation and legislation, or safety. Below are some of the major projects and programs in this category:

- **Distribution Mains – New Business**: This program installs new gas mains to customers in accordance with the tariff. This program extends new gas mains to new customers to comply with our obligation to provide service.
- **New Services**: This program installs gas services to new customers (residential, commercial, or business customers) in accordance with the tariff. This program





NYSEG and RG&E 5-Year Capital Investment Plan

extends new gas service lines to new customers to comply with our obligation to serve.

- Non-Leak Prone (LP) Service Replacements: This program replaces any service associated with a gas main replacement project that does not qualify as a leak prone service in accordance with the DIMP, replaces gas services in conflict with street reconstruction projects in accordance with terms and conditions to occupy public rights-of-way.
- Government Jobs: This program addresses work related to moving facilities that are located in a public right-of-way and are in conflict with proposed highway or road work being done by various municipalities. The Large Government Job program is reserved for projects that will be equal to or exceed \$750K. Each project of this type will be tracked with a unique project structure. The Government Job program is a blanket program that contains all projects that are less than \$750K.
- Gas Meters: This program is for the purchase and installation of gas meters to replace existing, aged meters as they are removed from service as well as for new installations. Gas meters are exchanged for annual PSC required programs including statistical sampling, remediation programs and for other various reasons including relocation, load increases, meter damage, and special testing. The programs help to ensure accurate recording of customers usage and results in accurate customer billing. The costs included in this program do not include the installation of AMI equipment on existing meters.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 7.4 Gas Modernization Capital Investment Forecast

The Gas Modernization Capital Investment Forecast for NYSEG is shown in Table 29 and for RG&E is shown in Table 30, respectively.

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
1	<i>\$ in thousands</i>						
1	Modernization	\$ 7,233	\$ 6,695	\$ 2,829	\$ 2,954	\$ 639	\$ 20,349
2	Remote Telemetry Unit (RTU) Replace Prog	2,555	2,573	2,675	2,801	-	10,604
3	Gas Transportation Sys Software Upgrade	-	1,960	-	-	-	1,960
4	NYSEG Gas SCADA Control Room Upgrades	381	-	-	-	-	381
5	NYSEG OQ/Training Equipment	325	193	73	73	558	1,222
6	Networks ECTRM	490	490	-	-	-	980
7	NYSEG CGI Standardization Program	398	172	-	-	-	570
8	NYSEG Track & Traceability Functionality	1,359	120	-	-	-	1,479
9	NYSEG - Gas SCADA Upgrade	1,724	1,187	81	80	81	3,153
10	All Other Modernization	-	-	-	-	-	-
11	Total	\$ 7,233	\$ 6,695	\$ 2,829	\$ 2,954	\$ 639	\$ 20,349

Table 29 – NYSEG Gas Modernization Capital Investment Forecast

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
1	<i>\$ in thousands</i>						
1	Modernization	\$ 4,833	\$ 4,599	\$ 146	\$ 142	\$ 450	\$ 10,170
2	RGE Gas SCADA Control Room Upgrades	353	-	-	-	-	353
3	Gas Transportation Sys Software Upgrade	-	2,040	-	-	-	2,040
4	Networks ECTRM	260	260	-	-	-	520
5	RGE CGI Standardization Program	996	117	-	-	-	1,112
6	RGE Track & Traceability Functionality	100	1,031	-	-	-	1,131
7	RGE - Gas SCADA Upgrade	2,824	1,109	105	101	106	4,245
8	RGE OQ/Training Equipment	300	42	41	41	344	768
9	All Other Modernization	-	-	-	-	-	-
10	Total	\$ 4,833	\$ 4,599	\$ 146	\$ 142	\$ 450	\$ 10,170

Table 30 – RG&E Gas Modernization Capital Investment Forecast

The GIS Track and Traceability project in the Gas Modernization category allows for geospatial location and specification data to be collected and added to the GIS during the installation process thus allowing for on demand retrieval of this data for a variety of needs. Having a reliable historically accurate record of piping and related components facilitates not only system maintenance activities but is well suited to support organizational asset management efforts





April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

Section 7.5 Gas Reliability Capital Investment Forecast

The Gas Reliability Capital Investment Forecast for NYSEG is shown in Table 31 and Table 32 for RG&E, respectively.

A	B	C	D	E	F	G
<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1 Reliability	\$ 50,119	\$ 75,856	\$ 62,599	\$ 75,647	\$ 78,934	\$ 343,155
2 NYSEG Leak Prone Srv Repl Program	7,033	6,932	8,237	8,472	8,866	39,541
3 Town of Pendleton System Improvement	-	4,409	-	-	-	4,409
4 Low Pressure Relief Valve Program	548	549	664	684	-	2,445
5 Critical Valve Installations, Binghamton	190	190	234	241	250	1,105
6 Binghamton Anitec System Reinforcement	-	917	-	-	-	917
7 Norwich-DeRuyter Compressor Reliability	-	5,355	-	-	-	5,355
8 Goshen System Semi-Perm Peaking Tap	-	2,833	-	-	-	2,833
9 NYSEG Portable LNG Emergency Skid	530	-	-	-	-	530
10 CM 50, 52 & 53 (DeRuyter) Article VII	-	-	-	2,248	2,271	4,519
11 NYSEG Cathodic Protection on LPP	-	664	705	820	238	2,427
12 Lansing Low Pressure Contingency Plan	319	-	-	-	-	319
13 NYSEG Leak Prone Pipe Replace Prog - LPP	39,373	34,683	48,798	47,962	52,415	223,232
14 LPP Portageville Pennycook Rd Main	-	-	-	-	4,409	4,409
15 LPP Vestal Parkway East	-	-	-	3,193	-	3,193
16 LPP Line E Replacement	2,125	-	-	-	-	2,125
17 LPP_Slaterville Rd	-	7,133	-	-	-	7,133
18 Boswell Hill South	-	12,190	-	-	-	12,190
19 Walton Deposit Reservoir	-	-	3,961	12,028	10,484	26,473
20 All Other Reliability	-	-	-	-	-	-
21 Total	\$ 50,119	\$ 75,856	\$ 62,599	\$ 75,647	\$ 78,934	\$ 343,155

Table 31 – NYSEG Gas Reliability Capital Investment Forecast

A	B	C	D	E	F	G
<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1 Reliability	\$ 54,377	\$ 63,677	\$ 80,757	\$ 78,688	\$ 67,749	\$ 345,248
2 RG&E Leak Prone Srv Repl Program	5,346	5,434	6,448	6,539	6,711	30,479
3 MF60 SE Phase IV (Crowley Rd)	-	5,526	1,280	-	-	6,807
4 MF60 SE Phase III (Malone Rd)	5,671	-	-	-	-	5,671
5 MF60 SE Phase I (Mendon Gate - Rte 64)	-	7,607	-	-	-	7,607
6 Pavilion System Semi-Perm Peaking Tap	-	2,778	-	-	-	2,778
7 MF60 NW System Improvement - Phase I	-	-	10,788	-	-	10,788
8 MF60 NW System Improvement - Phase II	-	-	-	-	16,484	16,484
9 CM-2 Article VII	-	-	-	3,439	879	4,318
10 RGE Portable LNG Emergency Skid	492	-	-	-	-	492
11 RGE Cathodic Protection on LPP	-	657	775	889	252	2,573
12 RG&E Leak Prone Pipe Replace Prog - LPP	27,186	29,004	34,340	33,769	36,010	160,308
13 LPP_Paul Road	4,486	-	-	-	-	4,486
14 LPP_Maple St Phase I	-	4,893	-	-	-	4,893
15 LPP_Jay St	5,825	-	-	-	-	5,825
16 LPP_Fairport Rd	-	-	-	-	7,413	7,413
17 LPP_Monroe Ave Phase I	4,753	-	-	-	-	4,753
18 LPP_Winton Rd South	-	-	-	2,607	-	2,607
19 LPP_Empire Blvd	618	-	-	-	-	618
20 LPP_Buffalo Rd	-	-	-	21,119	-	21,119
21 LPP Paul Road (Airport)	-	-	21,855	-	-	21,855
22 LPP_East River Rd	-	-	-	10,326	-	10,326
23 LPP_Maple St Phase II	-	-	5,270	-	-	5,270
24 LPP_Ridgeway Ave Phase II	-	7,777	-	-	-	7,777
25 All Other Reliability	-	-	-	-	-	-
26 Total	\$ 54,377	\$ 63,677	\$ 80,757	\$ 78,688	\$ 67,749	\$ 345,248

Table 32 – RG&E Gas Reliability Capital Investment Forecast



Take care of the environment.
Print in black and white and only if necessary.



NYSEG and RG&E 5-Year Capital Investment Plan

The projects in this category include work being performed on mains and at regulator stations. Projects addressing Leak Prone Pipe (LPP) replacement at both the program (projects costing less than \$750K each) and major LPP projects (projects costing \$750K or greater). Projects to increase the automation at regulator stations and to upgrade regulator stations (not due to asset condition) are included in this category. Regulator station work that costs less than \$750K per project is included in the Regulator Modernization and Automation Program. The major projects and programs in this category are described below. The Companies also apply a screening criteria to determine if LPP projects are suitable for Non-Pipe Alternatives.

- Leak Prone Pipe Replacement Program: This program replaces leak prone gas mains identified as leak prone and includes mains replaced due to condition (Distribution Integrity Management Plan, DIMP, and leaks) and municipal projects. This work includes, but is not limited to, replacing gas services in conflict with street reconstruction projects in accordance with terms and conditions to occupy public right-of-way where the main being replaced also qualifies as leak prone; leak prone gas main replacements; tariff or code requirements; and actively leaking services. The Leak Prone Pipe replacement program improves distribution safety and reliability by replacing gas mains in poor asset condition at high risk for failure. The gas mains are prioritized for replacement in accordance with DIMP regulations and leak information. The gas main replacements result in a distribution system that is safer and more reliable. Projects that are included in the program have costs less than \$750K.
- Leak Prone Service Program: This program replaces services that are classified as Leak Prone and are required by various regulations to be replaced. This work includes, but is not limited to, replacing gas services in conflict with street reconstruction projects in accordance with terms and conditions to occupy public right-of-way; leak prone gas main replacements; tariff or code requirements; and actively leaking services.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 7.6 Gas AMI Capital Investment Forecast

The Gas Advanced Metering Infrastructure (AMI) Capital Investment Forecast for NYSEG is shown in Table 33 and for RG&E is shown in Table 34, respectively.

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
<i>\$ in thousands</i>							
1 AMI Project		\$ 1,348	\$ -	\$ -	\$ -	\$ -	\$ 1,348
2 NYSEG - AMI Project		978	-	-	-	-	978
3 AMI Project Growth		371	-	-	-	-	371
3 Total		\$ 1,348	\$ -	\$ -	\$ -	\$ -	\$ 1,348

Table 33 – NYSEG Gas AMI Capital Investment Forecast

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
<i>\$ in thousands</i>							
1 AMI		\$ 1,696	\$ -	\$ -	\$ -	\$ -	\$ 1,696
2 RGE - AMI Project		1,273	-	-	-	-	1,273
3 AMI Project Growth		423	-	-	-	-	423
3 Total		\$ 1,696	\$ -	\$ -	\$ -	\$ -	\$ 1,696

Table 34 – RG&E Gas AMI Capital Investment Forecast

The AMI category is the on-going installation of AMI in NYSEG and RG&E service territories. AMI will be an essential foundational system in realizing CLCPA goals to empower customers, through new tools and information, to effectively manage and reduce usage and minimize environmental impacts of energy consumption.





NYSEG and RG&E 5-Year Capital Investment Plan**Chapter 8 Common Capital Investment Forecast**

The common classification is for projects and programs which are applicable to both the electric and the gas lines of business. For projects that are applicable to both NYSEG and RG&E, the costs are first allocated to each Company based on factors that can vary by project. Once the amount has been established for each Company, an allocation factor is used to allocate the costs to the electric and gas lines of business. The lines of business allocation factors for common costs for NYSEG and RG&E included in the plan are shown in Figure 4.

Company	Allocation to Electric Line of Business	Allocation to Gas Line of Business
NYSEG	81.53%	18.47%
RG&E	74.64%	25.36%

Figure 4 – NYSEG and RG&E Common Allocation Factors

The amounts shown in all tables of this Chapter are unallocated amounts. The total allocation of common investment to each line of business is shown below each table. Table 35 and Table 36 show the unallocated capital investments for each of the areas within Common at each Company. The Sections that follow detail the specific projects within each of the seven areas.





April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	Buildings and Facilities	\$ 17,335	\$ 11,628	\$ 10,155	\$ 11,600	\$ 11,775	\$ 62,493
2	Customer Service	40,410	40,825	39,154	35,099	8,728	164,216
3	Fleet	37,512	22,082	20,904	19,362	20,326	120,187
4	Information Technology	18,246	17,954	21,633	13,712	20,656	92,201
5	Operational Smart Grids	55,884	69,257	60,728	61,553	55,692	303,115
6	Security	10,616	6,555	5,907	7,423	7,803	38,305
7	Training	589	230	291	241	303	1,654
8	Total	\$ 180,593	\$ 168,531	\$ 158,773	\$ 148,991	\$ 125,284	\$ 782,171
9							
10	Allocation to Electric Business	\$ 147,238	\$ 137,403	\$ 129,447	\$ 121,472	\$ 102,144	\$ 637,704
11	Allocation to Gas Business	\$ 33,356	\$ 31,128	\$ 29,325	\$ 27,519	\$ 23,140	\$ 144,467

Table 35 – NYSEG Common Capital Investment Forecast

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	Buildings and Facilities	\$ 8,802	\$ 3,080	\$ 1,818	\$ 2,095	\$ 1,525	\$ 17,320
2	Customer Service	19,508	19,545	18,630	16,922	4,690	79,296
3	Fleet	18,481	13,432	8,025	6,749	9,713	56,399
4	Information Technology	8,959	9,578	11,685	6,897	10,791	47,911
5	Operational Smart Grids	28,639	32,139	30,639	27,778	25,537	144,733
6	Security	4,979	2,687	2,358	3,180	3,367	16,572
7	Training	2	125	93	131	97	448
8	Total	\$ 89,369	\$ 80,588	\$ 73,250	\$ 63,753	\$ 55,721	\$ 362,680
9							
10	Allocation to Electric Business	\$ 66,705	\$ 60,151	\$ 54,674	\$ 47,585	\$ 41,590	\$ 270,704
11	Allocation to Gas Business	\$ 22,664	\$ 20,437	\$ 18,576	\$ 16,168	\$ 14,131	\$ 91,976

Table 36 – RG&E Common Capital Investment Forecast



Take care of the environment.
Print in black and white and only if necessary.



NYSEG and RG&E 5-Year Capital Investment Plan

Section 8.1 Buildings and Facilities Capital Forecast

The Building and Facilities area is responsible for maintaining and improving the Companies owned and leased facilities, which include office buildings, service centers, and training centers, ensuring they meet health and safety standards, code compliance and required upgrades to maximize asset life cycles.

The capital investments of the Building and Facilities area are needed to maintain, upgrade, or replace the Companies' facilities or equipment, due to asset condition, age, risk mitigation, efficiency loss, functional obsolescence, code compliance requirements, safety and/or environmental considerations. Project improvements typically include mechanical, electrical, building structure and envelope, and control systems. The facilities projects are aimed at providing safe working conditions, greater efficiencies and maximizing asset life cycles at all the Company's locations – office buildings, operation service centers and training facilities.

The projects in this area typically include upgrading HVAC systems to energy efficient models, (BMS) Building Management Systems upgrades/installations, LED lighting with controls, building envelope upgrades, environmental and site improvements (tanks, spill containment, etc.), back-up systems, UPS systems, generators, solar panels, installation of EV charges and consolidation projects to optimize our space utilization at Company facilities.

Building and Facilities collaborates with internal departments, to address requests for additional space, improvements to existing locations, expansion requests for new locations, and site-specific upgrades for operational benefits, which examples include new structures for covered parking or equipment storage.

Other types of projects include equipment replacement due to day to day wear and tear, roof replacements due to end of life or to mitigate cumulative repair costs, general replacement of material, systems and equipment required to keep the facilities in proper





NYSEG and RG&E 5-Year Capital Investment Plan

working order. The facility amounts for NYSEG and RG&E are shown in Table 37 and Table 38, respectively.

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	Buildings and Facilities	\$ 17,335	\$ 11,628	\$ 10,155	\$ 11,600	\$ 11,775	\$ 62,493
2	NYSEG Minor Projects	10,975	5,933	4,265	4,080	4,080	29,333
3	NYSEG EV Chargers	1,000	-	-	-	-	1,000
4	NYSEG Liberty Service Center Projects	-	-	-	-	100	100
5	NYSEG BMS System	500	-	-	-	-	500
6	NYSEG Auburn Service Center Projects	1,975	150	1,000	-	-	3,125
7	NYSEG Geneva Service Center Projects	-	-	-	250	2,870	3,120
8	NYSEG Brewster Service Center Projects	-	1,350	-	50	-	1,400
9	NYSEG Oneonta Service Center Projects	-	-	-	200	105	305
10	NYSEG Mechanicville Service Center Projects	300	-	1,600	-	650	2,550
11	NYSEG Hamburg Operations Center Projects	-	100	1,000	40	15	1,155
12	NYSEG ECC Projects	-	800	-	-	-	800
13	NYSEG KGO Projects	50	-	-	-	775	825
14	NYSEG Lancaster Service Center Projects	-	400	525	650	300	1,875
15	NYSEG Elmira Service Center Projects	800	700	-	2,410	200	4,110
16	NYSEG Long Lake Building Expansion	1,250	-	-	-	-	1,250
17	NYSEG Plattsburgh Service Center	410	-	-	-	-	410
18	NYSEG Lockport Service Center Projects	-	1,695	-	-	215	1,910
19	NYSEG Hornell Service Center Projects	-	-	-	-	1,750	1,750
20	NYSEG Geneva Service Center West Projects	-	-	-	3,905	200	4,105
21	NYSEG Lancaster Service Center Garage Projects	75	100	1,765	-	200	2,140
22	NYSEG Norwich Operations Center Projects	-	400	-	15	315	730
23	All Other Buildings and Facilities	-	-	-	-	-	-
24	Total	\$ 17,335	\$ 11,628	\$ 10,155	\$ 11,600	\$ 11,775	\$ 62,493
25							
26	Allocation to Electric Business	\$ 14,133	\$ 9,480	\$ 8,280	\$ 9,457	\$ 9,600	\$ 50,950
27	Allocation to Gas Business	\$ 3,202	\$ 2,148	\$ 1,876	\$ 2,143	\$ 2,175	\$ 11,542

Table 37 – NYSEG Building and Facilities Capital Investment Forecast

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	Buildings and Facilities	\$ 8,802	\$ 3,080	\$ 1,818	\$ 2,095	\$ 1,525	\$ 17,320
2	RGE Minor Projects	7,802	2,980	1,468	1,300	1,300	14,850
3	RGE BMS System	100	-	-	-	-	100
4	RGE 3 City Center	50	50	50	50	50	250
5	RGE Canandaigua Truck Garage Projects	100	-	-	-	75	175
6	RGE Fillmore Operations Center Projects	-	-	-	10	60	70
7	RGE Mushroom Blvd Projects	750	-	150	-	-	900
8	RGE Sodus Service Center Projects	-	-	150	735	-	885
9	All Other Buildings and Facilities	-	50	-	-	40	90
10	Total	\$ 8,802	\$ 3,080	\$ 1,818	\$ 2,095	\$ 1,525	\$ 17,320
11							
12	Allocation to Electric Business	\$ 6,570	\$ 2,299	\$ 1,357	\$ 1,564	\$ 1,138	\$ 12,928
13	Allocation to Gas Business	\$ 2,232	\$ 781	\$ 461	\$ 531	\$ 387	\$ 4,392

Table 38 – RG&E Building and Facilities Capital Investment Forecast

Building and Facilities some of the major projects being undertaken are:

- **Minor Projects** – The Companies' Minor Projects capital investment addresses various, core functions essential to its building portfolio needed to support all business functions. Minor Projects are relatively small dollar investments that include upgrades to facility systems due to end of life assets, failures associated





NYSEG and RG&E 5-Year Capital Investment Plan

with mechanical, electrical, building structures, control systems and the like. These projects improve efficiency, reduce energy consumption, reduce greenhouse emissions, and address security and safety issues. Minor projects typically range up to \$100,000 per project and are grouped to allow for faster responses and efficient funding approvals. Minor projects follow the Avangrid procurement guidelines and utilize framework agreements for awarding projects that have already gone through a procurement bidding process. Minor projects are required on an annual basis, due to planned and unplanned replacement of assets at the end of their useful life, unplanned failures, emergency replacement, security concerns, employee changes, storm support, and a multitude of emergency needs that can occur. These projects create savings in operational maintenance expenses with the installation of new and more efficient equipment. They enhance reliability and mitigate risks to provide safer working conditions, extends the life cycles of assets, avoid disruption to Electric Operations, and support green and sustainable initiatives, while creating an overall safer more efficient building to support operational needs, responses times and storm support. Minor project needs are prioritized based on impacts to the business, level of criticality, end-of-life assets, failures, employee changes, storm response, emergency needs and health, and safety related requirements. Priorities change on an annual basis and throughout any given budget year.

- Energy Efficiency Projects – The Companies are proposing projects related to energy efficiency improvements, such as the installation of solar panels, EV chargers, and Bio-Diesel fuel tanks for use by the Companies fleet at the facilities. These projects will reduce system demand and emissions and are in alignment with the state of New York and the Companies' Sustainability goals.
- NYSEG Emergency Control Center (ECC) Projects – These comprehensive projects consist of renovations to increase the building and systems life at the NYSEG Emergency Control Center, including: HVAC and LED upgrades, new





NYSEG and RG&E 5-Year Capital Investment Plan

backup generator, new UPS system, recircuiting, new communication cabling, wireless communication devices, new roof top unit, and new variable air units. These upgrades allow for increased efficiency, reduced maintenance and utility usage, and increase safety of employees.

- Building System Management (BSM) System – This project is designed to install a new system throughout high occupancy facilities across NYSEG and RG&E. The BMS system is the starting point for Smart Building Technology, providing local/remote access to control and monitor all buildings systems, including but not limited to: heating and cooling equipment, electrical load, Generators, lighting, elevators, fire panel and utility monitoring. The BMS system will allow the ability to monitor air quality, building system performance, and real-time alarming, resulting in more efficient energy management. The existing BMS works on an outdated operating system. The longer we rely on this setup increases the risk of rendering the system useless.
- Customer Service Call Center Projects – Pursuant to new legislation limiting New York utility's ability to send customer service calls outside of the Companies' service territory without approval from the Commission, the Companies' have included costs associated with bringing Customer Services Call Center staffing in-house, in order to meet this requirement. The scope includes but is not limited to the planning and assessment of the Customer Service Call Center current infrastructure to identify space and other specific needs. The project will also include the identification and build out of office space, HVAC system, new LED lighting, new furniture, and new IT systems (new cable data, racks, switches, fiber etc.) in accordance with Avangrid standards, necessary to accommodate space for the Call Center in the RG&E and NYSEG territories.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 8.2 Customer Service Capital Forecast

The Customer Service investments focus on providing customers with the systems and information they request when requested. These investments also help doing business with the Companies easy and efficient for the customer. The investments planned in the next five years are shown below in Table 39 for NYSEG and Table 40 for RG&E.

	A	B	C	D	E	F	G
	\$ in thousands						
	2026	2027	2028	2029	2030	Total 2026-2030	
1 Customer Service	\$ 40,410	\$ 40,825	\$ 39,154	\$ 35,099	\$ 8,728	\$ 164,216	
2 NYSEG - Regulatory Driven Efforts / Rate Case	1,563	1,563	1,042	1,073	1,105	6,345	
3 NYSEG CAPEX Lab Equipment	250	300	300	300	300	1,450	
4 IDP MFA Solution Implementation	350	-	-	-	-	350	
5 New IVR and Voice Solution	2,287	-	-	-	-	2,287	
6 S/4 HANA Implementation	25,859	30,369	30,531	26,906	-	113,664	
7 CRM Front Office Improvements - NY	491	-	-	-	-	491	
8 High Bill High Usage Customer Experience Redesign	1,258	1,023	-	-	-	2,281	
9 Digital Tech Stack Lifecycle and Upgrades	331	364	400	412	425	1,933	
10 Customer Journey Improvements	3,418	2,351	2,492	2,642	2,801	13,704	
11 NYSEG CapEx Software Subscriptions	753	785	819	854	892	4,104	
12 Customer Communications Platform RFP	-	1,064	-	-	-	1,064	
13 RPA Customer Service	412	424	437	450	464	2,187	
14 SAP Testing Automation and Enhancements	314	323	333	343	353	1,667	
15 Customer Service Generative AI	880	-	-	-	-	880	
16 eQuality Management System (QMS)	437	-	-	-	-	437	
17 Legacy Apps Technology Transformation-NY	-	-	-	-	207	207	
18 Mobile App Redesign	1,110	-	-	-	-	1,110	
19 IVR System Upgrades and Enhancements Program	-	1,074	1,568	1,127	1,160	4,929	
20 Generative AI Upgrades and Enhancements Program	-	440	440	454	467	1,802	
21 Customer Service Analytics	699	743	791	538	554	3,324	
22 All Other Customer Service	-	-	-	-	-	-	
23 Total	\$ 40,410	\$ 40,825	\$ 39,154	\$ 35,099	\$ 8,728	\$ 164,216	
24							
25 Allocation to Electric Business	\$ 32,947	\$ 33,285	\$ 31,922	\$ 28,617	\$ 7,116	\$ 133,885	
26 Allocation to Gas Business	\$ 7,464	\$ 7,540	\$ 7,232	\$ 6,483	\$ 1,612	\$ 30,331	

Table 39 – NYSEG Customer Service Capital Investment Forecast

	A	B	C	D	E	F	G
	\$ in thousands						
	2026	2027	2028	2029	2030	Total 2026-2030	
1 Customer Service	\$ 19,508	\$ 19,545	\$ 18,630	\$ 16,922	\$ 4,690	\$ 79,296	
2 RGE - Regulatory Driven Efforts / Rate Case	1,556	1,556	1,038	1,069	1,101	6,320	
3 RGE CAPEX Lab Equipment	250	300	300	300	300	1,450	
4 IDP MFA Solution Implementation	157	-	-	-	-	157	
5 S/4 HANA Implementation	11,697	13,836	14,025	12,491	-	52,049	
6 CRM Front Office Improvements - NY	460	-	-	-	-	460	
7 Digital Tech Stack Lifecycle and Upgrades	148	163	179	185	190	866	
8 Customer Journey Improvements	1,531	1,053	1,116	1,183	1,254	6,137	
9 SAP Testing Automation and Enhancements	145	149	154	158	163	770	
10 Customer Service Generative AI	394	-	-	-	-	394	
11 Legacy Apps Technology Transformation-NY	-	-	-	-	93	93	
12 RGE CapEx Software Subscriptions	435	454	475	496	518	2,378	
13 Customer Communications Platform RFP	-	477	-	-	-	477	
14 RPA Customer Service	184	190	196	201	208	979	
15 eQuality Management System (QMS)	256	-	-	-	-	256	
16 High Bill High Usage Customer Experience Redesign	563	458	-	-	-	1,022	
17 Mobile App Redesign	497	-	-	-	-	497	
18 IVR System Upgrades and Enhancements Program	-	378	597	395	407	1,777	
19 Generative AI Upgrades and Enhancements Program	-	197	197	203	209	807	
20 Customer Service Analytics	313	333	354	241	248	1,489	
21 New IVR and Voice Solution	922	-	-	-	-	922	
22 All Other Customer Service	-	-	-	-	-	-	
23 Total	\$ 19,508	\$ 19,545	\$ 18,630	\$ 16,922	\$ 4,690	\$ 79,296	
24							
25 Allocation to Electric Business	\$ 14,561	\$ 14,589	\$ 13,906	\$ 12,631	\$ 3,501	\$ 59,187	
26 Allocation to Gas Business	\$ 4,947	\$ 4,957	\$ 4,725	\$ 4,291	\$ 1,190	\$ 20,110	





NYSEG and RG&E 5-Year Capital Investment Plan

Table 40 – RG&E Customer Service Capital Investment Forecast

Customer Service some of the major projects being undertaken are:

- **Regulatory Driven Efforts:** This program covers software system upgrades and enhancements that are required by New York regulatory mandates and rate case initiatives. On an annual basis, there are anticipated regulatory requirements that require resources to develop and implement the necessary system changes. The work is anticipated to include system impacts to the areas of Billing, Retail Access, FICA/Credit and Collections.
- **S/4 HANA Implementation:** This project will replace the current customer care system with SAP S/4 HANA across the Companies which will allow harmonized business processes and increase operational efficiency. The current SAP standard maintenance is reaching end of life in 2027, and the software version will be unsupported by SAP. Which means SAP will not provide new enhancements or fixes to standard core product beyond 2027. This introduces risk to business. The conversion to S/4 HANA will accelerate innovation across business functions. It allows businesses to quickly connect, providing improved agility, enhanced decision-making, increased productivity, and cost savings.
- **Customer Journey Improvements:** This project will reimagine how customers interact with the Companies' most critical touchpoints. Through the development of a matrix, key journeys for redesign have been identified and prioritized based on the following criteria: customer satisfaction, cost reduction, strategic value, and complexity. Those journeys will include the end-to-end customer request experience, the Outage experience, the Move-In/Move-Out experience, Customer Contact experience and strategy (call reduction), the end-to-end EBILL experience, Alerts/Digital Communications, Regulatory-based web requests, and the end-to-end debt collection experience.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 8.3 Fleet Capital Forecast

Fleet Services' overall objective is to provide a safe, reliable, regulatory compliant and cost-effective fleet of vehicles and equipment for the Companies. The capital expenditures for Fleet are for the replacement of vehicles and equipment and are based on established life cycle criteria (years, mileage, and/or hours). Fleet Services supports noted objectives through the use of the following:

1. Cost-effective and timely processes for the acquisition, maintenance and disposal of fleet vehicles and equipment including light-, medium- and heavy-duty vehicles and equipment (e.g. trailers, backhoes, ATVs, etc.).
2. Replacements are based on established life cycle criteria (years, mileage, and/or hours). Each year the Companies review the existing fleet according to the established criteria and identify those vehicles that meet or exceed the replacement criteria. These are the units that are proposed for replacement.
3. Model year advancements by the vehicle and equipment manufacturers are factored into the acquisition process to ensure that the latest technical and safety features are included. Changes in operational requirements are also considered, based on feedback from the end-users of the fleet.
4. Supports sustainability efforts through the purchase of alternatively fueled vehicles.

The capital investment for Fleet at NYSEG and RG&E are shown in Table 41 and Table 42, respectively.





April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
1	<i>\$ in thousands</i>						
2	Fleet	\$ 37,512	\$ 22,082	\$ 20,904	\$ 19,362	\$ 20,326	\$ 120,187
3	NYSEG Fleet Replacement Program	36,758	22,009	20,904	19,362	20,326	119,360
4	NYSEG Global Telematics Solution	754	72	-	-	-	827
5	All Other Fleet	-	-	-	-	-	-
6	Total	\$ 37,512	\$ 22,082	\$ 20,904	\$ 19,362	\$ 20,326	\$ 120,187
7	Allocation to Electric Business	\$ 30,584	\$ 18,003	\$ 17,043	\$ 15,786	\$ 16,572	\$ 97,989
8	Allocation to Gas Business	\$ 6,928	\$ 4,078	\$ 3,861	\$ 3,576	\$ 3,754	\$ 22,199

Table 41 – NYSEG Fleet Capital Investment Forecast

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
1	<i>\$ in thousands</i>						
2	Fleet	\$ 18,481	\$ 13,432	\$ 8,025	\$ 6,749	\$ 9,713	\$ 56,399
3	RGE Fleet Replacement Program	18,239	13,388	8,025	6,749	9,713	56,114
4	RGE Global Telematics Solution	242	44	-	-	-	286
5	All Other Fleet	-	-	-	-	-	-
6	Total	\$ 18,481	\$ 13,432	\$ 8,025	\$ 6,749	\$ 9,713	\$ 56,399
7	Allocation to Electric Business	\$ 13,794	\$ 10,026	\$ 5,990	\$ 5,037	\$ 7,250	\$ 42,097
8	Allocation to Gas Business	\$ 4,687	\$ 3,406	\$ 2,035	\$ 1,711	\$ 2,463	\$ 14,303

Table 42 – RG&E Fleet Capital Investment Forecast



Take care of the environment.
Print in black and white and only if necessary.



NYSEG and RG&E 5-Year Capital Investment Plan

Section 8.4 Information Technology Capital Forecast

As technology advances, NYSEG and RG&E's goal is to implement solutions that enable the business to implement solutions that deliver value to the business and to our customers. The projects and programs included in this area are upgrades and updates to hardware, software applications, new digital applications and platforms, as well as asset condition-based replacements. The capital investments for Information Technology are shown in Table 43 and Table 44 for NYSEG and RG&E, respectively.

	A	B	C	D	E	F	G
	\$ in thousands						
	2026	2027	2028	2029	2030	Total 2026-2030	
1 Information Technology	\$ 18,246	\$ 17,954	\$ 21,633	\$ 13,712	\$ 20,656	\$ 92,201	
2 Client Project Requests and Integration Projects - NYSEG	1,103	1,103	2,836	3,034	3,247	11,323	
3 AGR - IOC-NET-END USER LC-NYSEG	2,216	1,549	1,009	1,844	1,005	7,623	
4 AGR - IOC-Microsoft Deployment LC - NYSEG	1,698	-	2,598	-	-	4,297	
5 AGR - IOC-WINTEL LC-NYSEG	853	868	882	899	908	4,411	
6 AGR - IOC-UNIX LC-NYSEG	1,140	980	396	1,049	1,060	4,626	
7 AGR - IOC-STORAGE LC-NYSEG	739	755	771	790	798	3,853	
8 AGR - IOC-NETENG LC-NYSEG	600	612	624	637	649	3,122	
9 AGR - IOC-NETSEC LC-NYSEG	283	286	293	301	304	1,469	
10 AGR-NET-23-SG-01-Esri UN Deployment-NYSEG	1,063	5,500	5,500	-	-	12,063	
11 AWS SW Cloud Subscription - NYSEG	-	-	2,713	-	11,203	13,916	
12 Azure SW Cloud Subscription - NYSEG	573	-	619	-	-	1,192	
13 AGR-TAS-25-PAT-SYSMNG_ControlM_EV-NYSEG	-	-	283	-	-	283	
14 Monitoring Improvement - NYSEG	312	-	-	319	-	631	
15 SUSE SLES SW Cloud Subscription - NYSEG	-	-	-	-	373	373	
16 ServiceNow ITIL-ITOM PPM SECOPS SW Cloud Subscription - NYSEG	-	-	-	496	-	496	
17 INSIGHT - RED HAT SW Cloud Subscription - NYSEG	-	-	664	-	-	664	
18 NTT - Liferay SW Cloud Subscription - NYSEG	379	-	-	455	-	834	
19 GIS Environment SW Cloud Subscriptions - NYSEG	1,615	-	-	1,714	-	3,330	
20 AGR-TAS-25-Nutanix_EV-NYSEG	346	355	364	373	382	1,819	
21 Infrastructure Security - NYSEG	396	405	413	422	426	2,062	
22 AGR-IOC-NET-END USER LC-MFD-NYSEG	396	323	215	407	222	1,562	
23 AGR-NET-24-IT-01-Global S4Hana-NYSEG	3,978	4,291	1,357	-	-	9,625	
24 Open Text Cloud Subscriptions - NYSEG	-	297	-	334	-	631	
25 Open Text Cloud Implementation - NYSEG	158	-	-	-	-	158	
26 Bentley Projectwise SW Cloud Subscription - NYSEG	-	467	-	495	-	962	
27 AGR-TAS-25-MOBILE TECH_LC-NYSEG	397	165	95	143	78	878	
28 All Other-1	-	-	-	-	-	-	
29 All Other-2	-	-	-	-	-	-	
30 Total	\$ 18,246	\$ 17,954	\$ 21,633	\$ 13,712	\$ 20,656	\$ 92,201	
31							
32 Allocation to Electric Business	\$ 14,876	\$ 14,638	\$ 17,637	\$ 11,180	\$ 16,841	\$ 75,172	
33 Allocation to Gas Business	\$ 3,370	\$ 3,316	\$ 3,996	\$ 2,533	\$ 3,815	\$ 17,030	

Table 43 – NYSEG Information Technology Investment Forecast





NYSEG and RG&E 5-Year Capital Investment Plan

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
1	<i>\$ in thousands</i>						
2	Information Technology	\$ 8,959	\$ 9,578	\$ 11,685	\$ 6,897	\$ 10,791	\$ 47,911
3	Client Project Requests and Integration Projects - RGE	561	561	1,442	1,543	1,651	5,759
4	AGR - IOC-NET-END USER LC-RGE	683	751	543	707	557	3,242
5	AGR - IOC-WINTEL LC-RGE	464	472	480	490	495	2,401
6	AGR - IOC-Microsoft Deployment LC - RGE	863	-	1,321	-	-	2,184
7	AGR - IOC-STORAGE LC-RGE	400	408	417	427	431	2,083
8	AGR - IOC-UNIX LC-RGE	569	499	198	534	539	2,339
9	AGR - IOC-NETSEC LC-RGE	363	367	375	384	387	1,876
10	AGR - IOC-NETENG LC-RGE	225	229	234	240	242	1,169
11	AGR-NET-23-SG-01-Esri UN Deployment-RGE	541	3,300	3,300	-	-	7,141
12	AWS SW Cloud Subscription - RGE	-	-	1,380	-	5,697	7,077
13	Azure SW Cloud Subscription - RGE	298	-	322	-	-	621
14	AGR-TAS-25-PAT-SYSMNG_ControlM_EV-RGE	-	-	144	-	-	144
15	SUSE SLES SW Cloud Subscription - RGE	-	-	-	-	190	190
16	ServiceNow ITIL-ITOM PPM SECOPS SW Cloud Subscription - RGE	-	-	-	252	-	252
17	INSIGHT - RED HAT SW Cloud Subscription - RGE	-	-	332	-	-	332
18	NTT - Liferay SW Cloud Subscription - RGE	190	-	-	228	-	417
19	GIS Environment SW Cloud Subscriptions - RGE	822	-	-	872	-	1,693
20	Bentley Projectwise SW Cloud Subscription - RGE	-	237	-	252	-	489
21	AGR-TAS-25-MOBILE TECH LC-RGE	418	105	50	55	44	672
22	AGR-TAS-25-Nutanix_EV-RGE	176	180	185	190	194	925
23	Monitoring Improvement - RGE	159	-	-	162	-	321
24	Infrastructure Security - RGE	227	231	236	241	243	1,179
25	AGR-IOC-NET-END USER LC-MFD-RGE	134	160	117	151	119	682
26	AGR-NET-24-IT-01-Global S4Hana-RGE	1,786	1,926	609	-	-	4,321
27	Open Text Cloud Subscriptions - RGE	-	151	-	170	-	321
28	Open Text Cloud Implementation - RGE	80	-	-	-	-	80
29	All Other-1	-	-	-	-	-	-
30	All Other-2	-	-	-	-	-	-
31	Total	\$ 8,959	\$ 9,578	\$ 11,685	\$ 6,897	\$ 10,791	\$ 47,911
32	Allocation to Electric Business	\$ 6,687	\$ 7,149	\$ 8,722	\$ 5,148	\$ 8,054	\$ 35,760
33	Allocation to Gas Business	\$ 2,272	\$ 2,429	\$ 2,963	\$ 1,749	\$ 2,736	\$ 12,150

Table 44 – RG&E Information Technology Investment Forecast

Information Technology some of the major projects being undertaken are:

- **Client Projects Requests and Integration Projects:** The program is for business initiatives identified by the Network's business areas for future projects. The Companies have a process for identifying the technological needs of the business, gathering information, vetting the project list and prioritizing based on need, business value and resource availability. The Project Demand Planning cycle runs annually and involves collating the requirements across all business areas for projects requiring IT expenditure. Projects are prioritized by the Leadership in each business area before completing the estimation and capacity planning process.
- **IOC-NET-End User Life Cycle (LC):** The program refreshes the computing devices issued to employees by the Company. Computing devices refresh lifecycle defined by the Companies is four years. This project also provides





NYSEG and RG&E 5-Year Capital Investment Plan

computing devices for new hires. Replacing aged equipment with new equipment will avoid service disruptions due to devices not working properly due to their age. New computers will provide higher computing capabilities.

- IOC-WINTEL LC: The purpose of this program is to refresh the Companies' Wintel infrastructure following the defined four-year refresh lifecycle. Wintel infrastructure includes primarily servers, chassis, and server blades. This infrastructure is primarily hosting applications and SQL databases and will provide Wintel Infrastructure that supports the Companies' organic growth. Hardware running beyond four years is more likely to have performance issues that may affect the applications hosted on it. Replace aged equipment with new Wintel equipment will avoid application performance issues or service disruptions due to hardware not working properly. New devices also provide higher performance and capabilities for better application and data management performance.
- AGR-NET-23-SG-01-Esri UN Deployment-NYSEG: This project will replace the Company's current GIS system with the Utility Network Model (UNM). The existing data model is to be retired by the vendor in a couple of years. This will change the data model used by the Gas line of business and move it to a more modern, utility-specific model. Upgrading will address the end of life and provide the Companies with a fully supported solution. Moving to the UNM will permit: a rule-based engine that supports and enforces higher quality data entry, reduced data latency between enterprise systems due to native service-oriented architecture, new branch versioning structure reduces performance impacts of long-running designs, and this addresses current GIS software's end-of-life timeline. For Asset Management, a higher fidelity data model enables more granular tracking of real-world assets, such as substation internals, SCADA, and AMI equipment and controllers as well as Gas devices and network assets. The





NYSEG and RG&E 5-Year Capital Investment Plan

Utility Network model allows for a programmatically created schematic view of the network.

- AGR-NET-24-IT-01-Global S4Hana-NYSEG: The S4/HANA transformation initiative is part of the Avangrid IT strategy, aiming to place technological platforms in a strategic position that enables the business to maximize digitalization, innovation and growth in an agile and efficient way. As per SAP product roadmap, the current version will reach end of support by the end of 2027. SAP is a key application to and must be supported by vendors to mitigate any interruption on our core process. As SAP is a vital application and the master repository for all assets, it is crucial to address any potential cybersecurity threats and avoid disruptions to our core processes. Therefore, upgrading to the new version is essential. Maintaining an obsolete system can jeopardize the integrity and reliability of our operations, making it imperative to stay current with the latest SAP version.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 8.5 Operational Smart Grids Capital Forecast

Projects in this category are aimed at building the backbone necessary to enable the Companies to effectively plan, monitor and control the electric distribution and transmission systems and the gas systems. These projects are intended to increase efficiency in accessing critical systems and information and ensure that communication between various devices on the networks and the Energy Control Center (ECC) is always available, efficient, and secure. The capital investments needed to ensure these aspects of the business are shown for NYSEG in Table 45 and for RG&E in Table 46.

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	Operational Smart Grids	\$ 55,884	\$ 69,257	\$ 60,728	\$ 61,553	\$ 55,692	\$ 303,115
2	NYSEG Data Center Consolidation	3,137	9,185	7,785	7,765	7,854	35,726
3	Telecomm Infrastructure	3,156	7,828	7,754	8,301	9,672	36,711
4	Telecomm Fiber	2,604	5,353	4,774	4,285	3,902	20,919
5	NY WAN Expansion	5,680	6,390	6,334	6,318	6,390	31,112
6	Avangrid Security Domain (ASD) OSG Telecommunications (NYSEG)	3,134	-	-	-	-	3,134
7	NYSEG OSG Communications Tower Shelter Facility Improvements	1,350	2,000	-	-	-	3,350
8	NYSEG FCC License Radio Spectrum purchase	-	500	500	-	-	1,000
9	ECS Infrastructure Firewalls NYSEG	174	906	51	405	296	1,832
10	NYSEG FAN +Mobile technology refresh and expansion	3,600	2,100	-	-	-	5,700
11	Telecomm Vertical Builds	858	3,167	2,849	2,841	2,875	12,591
12	NY Smart Metering Lifecycle	293	1,025	1,056	1,088	1,120	4,582
13	NYSEG ECC Life cycle	770	540	350	360	380	2,400
14	Historian and Analytic Upgrades Program (NYSEG CP Portion)	345	215	-	-	-	560
15	ASD Infrastructure Firewalls NYSEG	2,872	3,646	2,040	2,058	2,343	12,959
16	DRAGOS NYSEG	-	-	-	-	1,794	1,794
17	NMC Solar Winds NYSEG	254	254	254	254	254	1,268
18	NYSEG OMS Enhancements	375	375	375	375	375	1,875
19	NYSEG OMS Alignment Spectrum	250	250	250	-	-	750
20	Cyber Recovery Solution	-	1,102	1,102	1,102	-	3,305
21	Storm System (ARCOS improvement / Replacement)	2,848	1,366	-	-	-	4,213
22	Integrated Forecasting Solution	665	222	-	-	-	886
23	IT Datacenter (DR) - OT Connectivity - Phase 3 (Apps)	461	531	614	-	-	1,606
24	Carrier Ethernet Replacement	3,522	3,382	3,349	2,783	1,691	14,726
25	Sonet Replacement	1,115	1,071	1,060	1,057	958	5,262
26	Data Center Lifecycle	949	5,496	5,109	3,571	4,921	20,046
27	Networking Gear Lifecycle	1,738	775	2,668	3,856	4,569	13,605
28	Compliance Operations and Digital Identities	4,621	10,286	3,747	4,245	3,647	26,546
29	Platform Services Lifecycle	2,752	203	8,706	10,891	2,652	25,206
30	DC2 (Station 80) Relocation Project NYSEG	8,362	1,089	-	-	-	9,451
31	All Other Operational Smart Grids	-	-	-	-	-	-
32	Total	\$ 55,884	\$ 69,257	\$ 60,728	\$ 61,553	\$ 55,692	\$ 303,115
33							
34	Allocation to Electric Business	\$ 45,563	\$ 56,465	\$ 49,512	\$ 50,184	\$ 45,406	\$ 247,130
35	Allocation to Gas Business	\$ 10,322	\$ 12,792	\$ 11,216	\$ 11,369	\$ 10,286	\$ 55,985

Table 45 – NYSEG Operational Smart Grids Investment Forecast





NYSEG and RG&E 5-Year Capital Investment Plan

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
<i>\$ in thousands</i>							
1 Operational Smart Grids		\$ 28,639	\$ 32,139	\$ 30,639	\$ 27,778	\$ 25,537	\$ 144,733
2 RGE Data Center Consolidation		1,835	5,689	4,782	4,704	4,678	21,688
3 Telecomm Infrastructure		491	2,448	2,406	2,557	3,008	10,910
4 Telecomm NY WAN Buildout		2,253	2,529	2,486	2,443	2,428	12,139
5 Telecomm Fiber		1,153	1,192	1,054	1,036	1,029	5,464
6 RGE FAN + mobile technology refresh and expansion		1,666	-	-	-	-	1,666
7 Telecomm Vertical Builds		1,117	526	518	509	506	3,176
8 RGE OSG Communications Tower Shelter Facility Improvements		500	750	-	-	-	1,250
9 ECS Infrastructure Firewalls RGE		30	542	31	237	170	1,011
10 DRAGOS RGE		-	-	-	-	1,084	1,084
11 NY Smart Metering Lifecycle		172	691	712	733	755	3,064
12 Avangrid Security Domain (ASD) OSG Telecommunications (RGE)		1,623	-	-	-	-	1,623
13 Historian and Analytic Upgrades Program (RG&E CP Portion)		343	214	-	-	-	556
14 ASD Infrastructure Firewalls RGE		1,687	2,183	1,213	1,206	1,352	7,642
15 NMC Solar Winds RGE		204	204	204	204	204	1,020
16 RGE OMS Alignment Spectrum		83	83	83	-	-	249
17 RGE ECC Life cycle		700	170	170	170	174	1,384
18 Cyber Recovery Solution		-	666	666	666	-	1,998
19 DC2 (Station 80) Relocation Project RGE		4,818	647	-	-	-	5,465
20 RGE OMS Enhancements		125	304	125	125	125	804
21 Storm System (ARCOS improvement / Replacement)		1,390	683	-	-	-	2,073
22 IT Datacenter (DR) - OT Connectivity - Phase 3 (Apps)		266	314	359	-	-	938
23 Carrier Ethernet Replacement		1,128	1,109	1,089	881	531	4,738
24 Sonet Replacement		1,072	1,054	1,035	1,015	902	5,077
25 Data Center Lifecycle		555	3,282	3,018	1,942	2,795	11,592
26 Networking Gear Lifecycle		1,097	520	1,695	2,719	2,749	8,780
27 Compliance Operations and Digital Identities		2,671	6,085	2,199	2,454	2,071	15,479
28 Platform Services Lifecycle		1,157	87	6,794	4,178	975	13,190
29 Integrated Forecasting Solution		504	168	-	-	-	672
30 All Other Operational Smart Grids-1		-	-	-	-	-	-
31 All Other Operational Smart Grids-2		-	-	-	-	-	-
32 Total		\$ 28,639	\$ 32,139	\$ 30,639	\$ 27,778	\$ 25,537	\$ 144,733
33							
34 Allocation to Electric Business		\$ 21,376	\$ 23,989	\$ 22,869	\$ 20,734	\$ 19,061	\$ 108,029
35 Allocation to Gas Business		\$ 7,263	\$ 8,151	\$ 7,770	\$ 7,045	\$ 6,476	\$ 36,704

Table 46 – RG&E Operational Smart Grids Investment Forecast

Operational Smart Grids some of the major projects being undertaken are:

- **Data Center Consolidation:** This project aims to standardize hardware, software, and applications across all Operational Smart Grids (OSG) data centers while consolidating multiple Operational Technology (OT) facilities to improve asset management and enhance system reliability. By reducing the total number of data centers across the New York Companies, the initiative will simplify system architecture and improve connectivity between primary and backup sites. The project involves multi-year planning and execution, including asset and inventory assessments, business impact analyses, capacity forecasting, and technical evaluations of current data center operations. It will determine infrastructure needs, develop business cases for various operating models, and guide the design and selection of future data center sites. The scope also includes procuring and





NYSEG and RG&E 5-Year Capital Investment Plan

deploying infrastructure, migrating critical systems and applications, and decommissioning or repurposing legacy facilities. This consolidation will enable more efficient use of resources across the Companies and reduce the overall complexity of data center operations.

- Compliance Operations and Digital Identities: This program will continue to further the deployment, harmonize our environments while increasing our efficiency. At the present time the foundation applications are in specific areas but need to be pushed out to all areas of Operational Smart Grids. While this push is being completed, we will also include replacing legacy applications/hardware to reduce training, administration and renewal costs. It is important to continue this program now to increase our centralized management, standardize our tool offering and increase our efficacy and cyber diligence. Deploying this program allows us to safeguard the organization's digital assets and ensure the integrity, confidentiality, and availability of information through advanced security operations and robust digital identity management.
- Platform Services Lifecycle: This program supports the modernization and lifecycle management of critical IT infrastructure. This includes the deployment of Hyper Converged Infrastructure (HCI) using Dell VxRais to enable a Software Defined Data Center (SDDC), which virtualizes servers, networking, and security components, positioning the organization for future cloud integration. The program also manages the application lifecycle, covering Microsoft software, VMware ESXi, and Omnisia Horizon environments, with a focus on supporting high-performance Virtual Desktop Infrastructure (VDI). Video Wall systems in Energy Control Centers are maintained for operational awareness, including both display hardware and backend systems. Additionally, the program oversees the lifecycle of HP and Dell desktops and laptops, including their use as Transient Cyber Assets (TCAs) in field environments. Finally, it includes the management of Thin and Zero Clients from





NYSEG and RG&E 5-Year Capital Investment Plan

vendors like Clear Cube and Lenovo, which support centralized desktop environments in critical areas through VDI integration.

- Telecomm NY WAN Buildout: This program is intended to ensure the reliability and resiliency of the telecom network by means of providing new connectivity to unserved or underserved substations, service centers and distribution assets to support automation activities. This will involve deploying a new telecom cabinet (indoor or outdoor) with routing and switching equipment and connectivity to the Wide Area Network by means of cellular services, fiber optic, wireless broadband or wireless narrowband. This will also involve, when fiber optic cables are used, building the pathway into the station or the service center from the meet-me-point at the fence of the property, and upgrading the existing power plant to standard
- Telecomm Infrastructure: This program is intended to ensure the reliability of the existing telecom infrastructure by means of life cycle replacement or augmenting the diversity and redundancy of transport solutions. The program also supports battery backup and power solutions to enhance resiliency. Routers and ethernet switches will be deployed utilizing various protocols to support dynamic rerouting of traffic in the event of a transport or circuit failure. This project will also support the deployment of a lifecycle replace of the existing Private Land Mobile Radio Systems (LMR) with a new Digital Mobile Radio solution (DMR). The current LMR systems are at or beyond end-of-life.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 8.6 Security Capital Forecast

Security capital investments are required for both the physical safety and security of employees and Company assets as well to ensure that computer and communication systems are secure from cyber threats. These investments are required to meet various security mandates and regulations, such as the NERC Critical Infrastructure Protection (CIP) Standards as well as Executive Orders. The investment in Security are shown below in Table 47 for NYSEG and Table 48 for RG&E.

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
1	<i>\$ in thousands</i>						
2	Security	\$ 10,616	\$ 6,555	\$ 5,907	\$ 7,423	\$ 7,803	\$ 38,305
3	NYSEG FIRE PROTECTION COMMON	221	186	180	77	83	748
4	SOC Program-NYSEG	11	23	45	113	371	563
5	Physical Security Lifecycle Management Program-NYSEG	5,392	5,527	5,638	5,751	5,866	28,174
6	OT Cybersecurity - Architecture NYSEG	4,991	820	44	1,483	1,483	8,820
7	All Other Security	-	-	-	-	-	-
8	Total	\$ 10,616	\$ 6,555	\$ 5,907	\$ 7,423	\$ 7,803	\$ 38,305
9	Allocation to Electric Business	\$ 8,655	\$ 5,345	\$ 4,816	\$ 6,052	\$ 6,362	\$ 31,230
10	Allocation to Gas Business	\$ 1,961	\$ 1,211	\$ 1,091	\$ 1,371	\$ 1,441	\$ 7,075

Table 47 – NYSEG Security Investment Forecast

	A	B	C	D	E	F	G
		2026	2027	2028	2029	2030	Total 2026-2030
1	<i>\$ in thousands</i>						
2	Security	\$ 4,979	\$ 2,687	\$ 2,358	\$ 3,180	\$ 3,367	\$ 16,572
3	RG&E FIRE PROTECTION COMMON	228	-	-	-	-	228
4	SOC Program-RGE	6	11	23	57	188	284
5	OT Cybersecurity - Architecture RGE	2,538	417	22	754	754	4,486
6	Physical Security Lifecycle Management Program-RGE	2,206	2,259	2,313	2,369	2,426	11,573
7	All Other Security	-	-	-	-	-	-
8	Total	\$ 4,979	\$ 2,687	\$ 2,358	\$ 3,180	\$ 3,367	\$ 16,572
9	Allocation to Electric Business	\$ 3,716	\$ 2,006	\$ 1,760	\$ 2,373	\$ 2,513	\$ 12,369
10	Allocation to Gas Business	\$ 1,263	\$ 681	\$ 598	\$ 806	\$ 854	\$ 4,203

Table 48 – RG&E Security Investment Forecast

Some of the major Security projects being undertaken are:

- Physical Security Lifecycle Management Program: This program, formerly known as projects “System Cutover” or “AVANGRID Secure Domain (ASD) Security System Installation,” relates to security work on various facilities and assets. Investment decisions are based on a combination of risk assessments and regulatory requirements. Sites with the most risk and highest regulatory ratings (e.g., bulk electric substations) receive protections such as but not limited to card access control systems, disturbance sensors, Public Address (PA)





NYSEG and RG&E 5-Year Capital Investment Plan

systems, enhanced fencing, video surveillance, video analytics and thermal cameras. Occupied facilities and other assets which may not be identified as regulatory requirements but have unique risk profiles (e.g., large office/service center with employee life safety concerns, cash offices or public-facing facilities certain above-ground gas appurtenances or attractive nuisance sites) receive protections such as but not limited to card access control systems, video surveillance, disturbance sensors, and video analytics. Additional work includes the enhancement of communication networks to allow for the transport of video back to the Security Operations Center (SOC) for remote monitoring of security network, access control and video monitoring systems to allow for the transport of video back to the SOC for remote monitoring of security network, access control and video monitoring systems.

- Fire Protection: This program addresses fire protection system projects to ensure the safety of our facilities as well as ensuring our systems are up to date and in compliance with local, state and federal requirements as well as the National Fire Protection Association (NFPA) Standards, the Fire Code of New York State and OSHA Regulations. Fire protection projects include the design and installation and/or replacement of smoke detector/fire alarm systems, mass notification systems, automated extinguisher monitoring systems and fire suppression systems. Compliance with local and federal laws as well as applicable NFPA Standards reduces fire risk and loss to Company infrastructure by increasing resiliency to maintain operations.





NYSEG and RG&E 5-Year Capital Investment Plan

Section 8.7 Training Capital Forecast

The Companies' existing training facilities are outdated, are not technologically current and do not have enough capacity to safely provide increasing training needs. To address the training needs, the Companies are improving the facilities, program and methodologies of training. The capital projects needed to improve these facilities are shown below in Table 49 and Table 50 for NYSEG and RG&E, respectively.

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	Training	\$ 589	\$ 230	\$ 291	\$ 241	\$ 303	\$ 1,654
2	NYSEG HR Training Equipment & Tools	192	105	267	109	278	951
3	NYSEG HR Training Technology Projects	23	125	24	131	25	328
4	GS - Training Facilities (HR) NYSEG Johnson City Reynolds Trng Yard	375	-	-	-	-	375
5	All Other Training	-	-	-	-	-	-
6	Total	\$ 589	\$ 230	\$ 291	\$ 241	\$ 303	\$ 1,654
7							
8	Allocation to Electric Business	\$ 480	\$ 187	\$ 237	\$ 196	\$ 247	\$ 1,349
9	Allocation to Gas Business	\$ 109	\$ 42	\$ 54	\$ 44	\$ 56	\$ 306

Table 49 – NYSEG Training Investment Forecast

	A	B	C	D	E	F	G
	<i>\$ in thousands</i>	2026	2027	2028	2029	2030	Total 2026-2030
1	Training	\$ 2	\$ 125	\$ 93	\$ 131	\$ 97	\$ 448
2	RGE HR Training Equipment & Tools	-	42	85	44	89	260
3	RGE HR Training Technology Projects	2	84	7	88	8	188
4	All Other Training	-	-	-	-	-	-
5	Total	\$ 2	\$ 125	\$ 93	\$ 131	\$ 97	\$ 448
6							
7	Allocation to Electric Business	\$ 1	\$ 94	\$ 69	\$ 98	\$ 72	\$ 335
8	Allocation to Gas Business	\$ 1	\$ 32	\$ 24	\$ 33	\$ 25	\$ 114

Table 50 – RG&E Training Investment Forecast

Training some of the major projects being undertaken are:

- **Training Equipment & Tools and Fleet:** Equipment and tooling project will secure tools equivalent to those being used in the field by operational groups. The fleet project supplements the tooling project with the addition of fleet vehicles equivalent to those used in the field. Current training fleet is outdated with different controls and functionality than vehicles used in day to day operations. Acquisition of these tools and fleet will allow for replication of real world scenarios within the training environment. Time to mastery is reduced through precise replication of field scenarios creating a safer more efficient workforce.





NYSEG and RG&E 5-Year Capital Investment Plan

- Training Technology Projects: Emerging technologies such as Augmented Reality (AR) and Virtual Reality (VR) require capital investment for deployment. Hardware to execute initiatives include headsets, computing equipment, sensors, and other items to create a fully safe and immersive mixed reality experience.





NYSEG and RG&E 5-Year Capital Investment Plan

Appendix A - Capital Investment Forecast

NYSEG Electric Projects	
RG&E Electric Projects	
NYSEG Gas Projects	
RG&E Gas Projects	
NYSEG Common Projects	
RG&E Common Projects	





April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

NYSEG Electric Projects

NYSEG - Electric Projects (\$000's)	2025	2026	2027	2028	2029	Total
Asset Condition	148,534	189,649	397,242	497,177	465,004	1,697,605
Reliability	87,937	84,008	135,889	226,559	453,198	987,590
Resiliency	115,075	156,807	138,387	109,865	56,335	576,469
Compliance	60,828	66,317	80,730	167,796	273,902	649,573
Electric Clean Energy	119,276	211,027	405,182	370,743	267,954	1,374,182
Customer Focus	162,923	175,494	208,888	231,358	227,929	1,006,592
Modernization	10,628	2,219	22,441	12,324	11,919	59,531
Innovation	10,902	6,568	-	-	-	17,470
Hydro-Generation	19,800	27,115	41,115	29,676	29,638	147,344
AMI	44,079	6,651	-	-	-	50,730
Total	779,981	925,856	1,429,874	1,645,498	1,785,878	6,567,088



Take care of the environment.
Print in black and white and only if necessary.



April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

RG&E Electric Projects

RG&E - Electric Projects (\$000's)	2025	2026	2027	2028	2029	Total
Asset Condition	66,211	62,471	66,960	61,231	119,764	376,637
Reliability	62,070	80,135	162,231	373,073	544,471	1,221,980
Resiliency	20,080	19,882	30,032	22,382	43,201	135,575
Compliance	46,525	41,613	28,805	29,458	55,203	201,604
Customer Focus	70,267	83,074	104,255	70,379	71,174	399,150
Modernization	4,427	1,145	601	2,876	2,883	11,932
Innovation	5,182	2,661	-	-	-	7,843
Hydro-Generation	14,440	14,431	27,688	50,194	36,700	143,453
AMI	22,704	3,002	-	-	-	25,707
Total	311,907	308,414	420,571	609,593	873,396	2,523,880



Take care of the environment.
Print in black and white and only if necessary.



April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

NYSEG Gas Projects

NYSEG - Gas Projects (\$000's)	2025	2026	2027	2028	2029	Total
Asset Condition	12,169	23,078	12,056	19,485	15,543	82,331
Mandatory	21,463	16,258	17,247	19,981	20,784	95,733
Modernization	239	7,233	6,695	2,829	2,954	19,949
Reliability	64,277	53,326	72,498	62,599	77,250	329,951
AMI	7,720	1,348	-	-	-	9,069
Total	105,868	101,243	108,496	104,894	116,531	537,032



Take care of the environment.
Print in black and white and only if necessary.



April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

RG&E Gas Projects

RG&E - Gas Projects (\$000's)	2025	2026	2027	2028	2029	Total
Asset Condition	21,962	24,925	16,206	14,385	37,856	115,334
Mandatory	18,158	16,282	26,499	23,529	22,603	107,071
Modernization	118	4,833	4,599	146	142	9,838
Reliability	40,554	57,531	60,898	80,757	80,186	319,926
AMI	7,719	1,696	-	-	-	9,415
Total	88,511	105,267	108,202	118,818	140,787	561,584



Take care of the environment.
Print in black and white and only if necessary.



April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

NYSEG Common Projects

NYSEG - Common Projects (\$000's)	2025	2026	2027	2028	2029	Total
Buildings and Facilities	19,488	23,725	11,628	10,155	11,600	76,595
Customer Service	28,525	41,859	44,210	45,440	39,612	199,647
Fleet	18,875	37,512	22,082	20,904	19,362	118,736
Information Technology	13,490	18,787	18,411	21,633	13,712	86,032
Operational Smart Grids	44,287	55,884	69,257	60,728	61,553	291,710
Training	7,595	589	230	291	241	8,946
Security	6,798	11,956	7,931	7,289	8,908	42,883
Total	139,058	190,312	173,749	166,440	154,989	824,548



Take care of the environment.
Print in black and white and only if necessary.



April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

RG&E Common Projects

RG&E - Common Projects (\$000's)	2025	2026	2027	2028	2029	Total
Buildings and Facilities	4,390	11,292	3,080	1,818	2,095	22,675
Customer Service	15,508	20,099	21,010	21,384	18,870	96,870
Fleet	5,500	18,481	13,432	8,025	6,749	52,186
Information Technology	7,222	9,278	9,847	11,685	6,897	44,929
Operational Smart Grids	23,036	28,639	32,139	30,639	27,778	142,232
Training	101	2	125	93	131	453
Security	2,390	4,978	2,915	2,587	3,408	16,279
Total	58,147	92,768	82,549	76,231	65,929	375,624



Take care of the environment.
Print in black and white and only if necessary.



April 1, 2026

NYSEG and RG&E 5-Year Capital Investment Plan

Appendix B - Capital Project Summaries



Take care of the environment.
Print in black and white and only if necessary.

Appendix B - Capital Project Summaries

NYSEG Electric Asset Condition.....	117
TLD Replacements NYSEG.....	118
TLD Replacements-NYSEG-L47	120
TLD Replacements-NYSEG-L48	122
TLD Replacements-NYSEG-L994	124
TLD Replacements-NYSEG-L805	126
TLD Replacements-NYSEG-L957	128
TLD Replacements-NYSEG-L349	130
TLD Replacements-NYSEG-L810	132
TLD Replacements-NYSEG-L813	134
TLD Replacements-NYSEG-L991	136
TLD Replacements-NYSEG-L350	138
TLD Replacements-NYSEG-L997	140
TLD Replacements-NYSEG-L517	142
TLD Replacements-NYSEG-L819	144
TLD Replacements-NYSEG-L916	146
TLD Replacements-NYSEG-L954	148
TLD Replacements-NYSEG-L959	150
TLD Replacements-NYSEG-L911	152
TLD Replacements-NYSEG-L914	154
TLD Replacements-NYSEG-L31	156
TLD Replacements-NYSEG-L417	158
TLD Replacements-NYSEG-L531	160
TLD Replacements-NYSEG-L555	162
TLD Replacements-NYSEG-L912	164
TLD Replacements-NYSEG-L998	166
TLD Replacements-NYSEG-L522 (Ithaca)	168
TLD Replacements-NYSEG-L520	170
TLD Replacements-NYSEG-L814	172
TLD Replacements-NYSEG-L422	174
TLD Replacements-NYSEG-L455	176
TLD Replacements-NYSEG-L535	178
TLD Replacements-NYSEG-L974	180
TLD Replacements-NYSEG-L508	182
TLD Replacements-NYSEG-L341	184
TLD Replacements-NYSEG-L884	186
TLD Replacements-NYSEG-L342	188
TLD Replacements-NYSEG-L806	190
TLD Replacements-NYSEG-L441	192
TLD Replacements-NYSEG-L955	194
TLD Replacements-NYSEG-L917	196
TLD Replacements-NYSEG-L802	198
TLD Replacements-NYSEG-L589	200
TLD Replacements-NYSEG-L65	202
TLD Replacements-NYSEG-L549	204
Line 880 Rebuild	206
TLD Replacements-NYSEG-L943	208

NYSEG Substation Modernization - Noyes Island D	240
Line 890 Rebuild	243
NYSEG - Battery Program	247
Cobble Hill Transformer Replacement.....	255
RG&E Electric Asset Condition.....	315
Station 29 Modernization Project	320
Station 37 Modernization Project	328
Station 43 Circuit Upgrades	333
Station 43 Modernization Project	335
Station 192 Circuit Upgrades	340
Station 192 Trans Facilities Upgrade	342
Station 5 Substation Mod D	345
TLD Replacements-RGE-L701	363
TLD Replacements-RGE-L795	365
RGE Station 5 - Transmission Line Upgrades	369
NYSEG Electric Reliability	399
Circuit Breaker Replacement - Northside 115 kV	404
Circuit Breaker Replacement - Locus St.....	408
Circuit Breaker Replacement - Milliken	412
Circuit Breaker Replacement - Morgan Road	416
Circuit Breaker Replacement - New Berlin	420
Circuit Breaker Replacement - North Endicott 115 kV	424
Circuit Breaker Replacement - Orchard Park	428
Circuit Breaker Replacement - River Road	432
Circuit Breaker Replacement - Sand Street	436
Circuit Breaker Replacement - Sleigh Road	441
Circuit Breaker Replacement - Stilesville	445
Circuit Breaker Replacement - Legion Drive.....	452
Circuit Breaker Replacement - Lake Ave	456
Circuit Breaker Replacement - Ferndale.....	460
Circuit Breaker Replacement - Dick Rd	464
Circuit Breaker Replacement - Caton Avenue	468
Circuit Breaker Replacement - Bulkhead	476
Circuit Breaker Replacement - Cadyville	480
Circuit Breaker Replacement - Cooperstown.....	484
Circuit Breaker Replacement - Macedon	488
Circuit Breaker Replacement - Mohansic	492
Circuit Breaker Replacement - Mulberry	496
Circuit Breaker Replacement - Pound Ridge	500
Circuit Breaker Replacement - Roll Rd	504
W. Winfield 12.5KV Load Relief.....	508
New Centerport Substation (Port Byron - Load relief)	510
NYSEG Transmission Reinforcement Program	555
Afton Sub - Add new 34.5kV Circuit.....	574
NYSEG Wales 325	607
NYSEG Stolle Rd 551	610
NYSEG Raylinski Tap 606(635T606)	613
NYSEG Pound Ridge 457.....	616

NYSEG Worst Performing Zones of Protection	619
RGE Overloaded Step Banks	625
NYSEG Mapleton 520.....	628
NYSEG Roll Road 545.....	631
NYSEG Sylvan Lake 481.....	634
NYSEG Warners 526.....	637
NYSEG Crellin 615 (615T630).....	640
Circuit Breaker Replacement - Brothertown Road.....	643
Circuit Breaker Replacement - Hancock.....	647
Circuit Breaker Replacement - West Elmira	651
RG&E Electric Reliability	656
Circuit Breaker Replacement - Station 112.....	697
Circuit Breaker Replacement - Station 85.....	705
Circuit Breaker Replacement - Station 33.....	709
Circuit Breaker Replacement - Station 86.....	713
Circuit Breaker Replacement - Station 418.....	717
Circuit Breaker Replacement - Station 67.....	721
Circuit Breaker Replacement - Station 48.....	725
Circuit Breaker Replacement - Station 13A	729
Replace DC Pilot Wire System	737
New TL 812 & DL 418.....	739
Line 798 Uprate	741
Station 73 Distribution Upgrades	743
Webster Project - Station 55	745
Line 778 Uprate - Station 42 to 43	747
Line 799 Uprate	749
Webster Project - Station 73	751
Webster Project - Station 62	753
Webster Project - Station 42	755
Webster Project - Station 420	759
Station 46 - Circuit 261	763
Station 51.....	766
Circuit Breaker Replacement - Station 114.....	772
NYSEG Electric Resiliency	788
NYSEG - SCADA/Automation.....	789
Resiliency.....	793
Lancaster Project - Losson Road Substation 34.5/12.5 kV GIS Upgrade	796
Lancaster Project - Blossom Road Substation 34.5/12.5 kV GIS Upgrade	800
Lancaster Project - Sloan - Distribution Center.....	804
Lancaster Project - Losson Road - Distribution Center.....	808
Lancaster Project - Walden Ave to Sloan - Distribution Express feeder	812
Lancaster Project - Sloan to Losson - Distribution Express feeder.....	816
Lancaster Project - Losson - Distribution Express feeder	820
Lancaster Project - Blossom to Losson - Distribution Express feeder	824
Lancaster Project - Line 532 - Reroute	828
Lancaster Project - Walden Ave & Sloan - Distribution upgrades.....	832
Lancaster Project - Losson Road - Distribution upgrades	836
Kline Kill 630 - 631	840

NYSEG Resiliency - Shandaken 501.....	843
NYSEG Automation - Liberty	846
NYSEG Automation - Binghamton	849
NYSEG Automation - Auburn	852
NYSEG Resiliency - Greenidge 596	855
NYSEG Resiliency - Kattleville 422	858
New York 21st Century Grid Plan (Cheektowaga).....	863
Lancaster Project - North Broadway - Expansion	867
Lancaster Project - Blosson Road - Distribution upgrades	871
NYSEG Resiliency Cemetery Rd 490/ North Broadway 535	890
RG&E Electric Resiliency.....	918
Resiliency.....	919
RGE Resiliency 0104RO5156	922
RGE Resiliency 0230RO5163	925
RGE Resiliency 0056RO5180	928
RGE Resiliency 0195LS5153	932
RGE Resiliency 0143CF5146	935
SCADA/Automation RGE.....	938
Distribution Automation - RGE	947
RGE Automation - Central	950
Automation RGE Canandaigua.....	953
NYSEG Electric Compliance.....	956
BES - Ten Mile River to	983
BES - Ten Mile to Pleasant Valley New 115 kV Line	998
NERC Compliance Program - NYSEG	1018
NERC Alert Priority III	1021
NERC Alert Priority III-NYSEG-Line 929	1023
NERC Alert Priority III-NYSEG-Line 936	1025
NERC Alert Priority III-NYSEG-Line 991	1027
NERC Alert Priority III-NYSEG-Line 951	1029
NERC Alert Priority III-NYSEG-Line 969	1031
NERC Alert Priority III-NYSEG-Line 973	1033
NERC Alert Priority III-NYSEG-Line 974	1035
NERC Alert Priority III-NYSEG-Line 975	1037
NERC Alert Priority III-NYSEG-Line 979	1039
NERC Alert Priority III-NYSEG-Line 994	1041
NERC Alert Priority III-NYSEG-Line 998	1043
NERC Alert Priority III-NYSEG-Line 958	1045
NERC Alert Priority III-NYSEG-Line 964	1047
RG&E Electric Compliance.....	1058
BES - 947 Line Upgrade	1061
BES NY.L946.....	1063
BES NY.L917	1065
BES NY.L945.....	1067
RG&E FERC 2222	1069
FERC 881 Regulatory Compliance RGE	1072
BES - Station 056 Reconfiguration	1075

NYSEG Electric Electric Clean Energy	1078
CLCPA Phase 1 - Lounsberry 115/12.5 kV Substation Full Rebuild	1088
CLCPA Phase 1 - Trans Line - 946 Rebuild	1091
CLCPA Phase 1 - Clarks Corners.....	1093
CLCPA Phase 1 - Trans Line - 982 Rebuild	1095
CLCPA Phase 1 - Oakdale Westover Solution	1097
CLCPA Phase 1 - Trans Line - 945 Reroute.....	1100
Robinson Road 230/115/34.5 kV Substation Upgrades	1102
Stolle Road 345/230/115/34.5 kV Substation Upgrades.....	1105
Coddington 115/34.5 kV Substation Upgrades	1108
Etna 115/34.5/4.8 kV Substation Full Rebuild	1111
CLCPA - South Owego Upgrades	1114
West Hill SS	1117
Trumansburg SS.....	1119
Cayuga Heights SS.....	1121
Fourth St SS	1123
NYSEG Electric Customer Focus.....	1125
RG&E Electric Customer Focus	1157
Town of Brighton Arc-Lighting Circuit	1170
Aqueduct Re-Imagined	1178
NYSEG Electric Modernization.....	1195
EMS/ADMS Deployment.....	1196
MV90/IEE Service Mode	1199
Java SS Microgrid BESS	1201
RG&E Electric Modernization	1204
NYSEG Electric Innovation	1210
Stephentown BESS NYSEG	1214
RG&E Electric Innovation	1221
NYSEG Electric Hydro-Generation.....	1228
RG&E Electric Hydro-Generation.....	1324
NYSEG Gas Asset Condition.....	1408
NYSEG Dist Main Replacement	1409
NYSEG Gas Operations Departmental.....	1411
NYSEG Reg Mod & Auto Pgm GRMP.....	1413
Vienna Road Regulator Station GRMP	1415
Baltimore Ave DRS Relocation	1417
Border City DRS Rebuild	1419
RG&E Gas Asset Condition	1421
Caledonia Station Rebuild	1422
CM-1 Pipeline: Section 4 Chili GS to Bal	1425
RGE Dist Main Replacement	1427
Mt Read (SF115 psig) Main Replacement.....	1429
RGE Reg Mod & Auto Pgm GRMP.....	1432
RS 369 East Station Rebuild GRMP.....	1434
Industrial Gas Service Replacement - RGE.....	1436
Rebuild Station 449 - Valentown Rd & CR9	1438

NYSEG Gas Mandatory	1440
NYSEG New Services	1441
NYSEG Dist Mains New Business	1443
NYSEG Non LP Srv Repl Program	1445
NYSEG CAPEX Gas Meters	1447
NYSEG Government Jobs	1449
Large Government Jobs - NYSEG	1451
RG&E Gas Mandatory	1453
RGE Dist Mains New Business	1454
RGE CAPEX Gas Meters	1456
RGE New Services	1458
Large Government Jobs - RG&E	1460
RGE Non LP Srv Repl Program	1462
RGE Government Jobs	1464
Rt 15 Corridor Safety Enhancements	1466
Thruway Park/Hendrix Rd Short Segment	1468
Burben Way Short Segment	1470
900, 920 Penfield-Walworth Rd Short Seg	1472
NYSEG Gas Modernization	1474
Remote Telemetry Unit (RTU) Replace Prog	1475
Gas Transportation Sys Software Upgrade	1478
NYSEG OQ Training Equipment	1481
Networks ECTRM	1483
NYSEG Track & Traceability Functionality	1486
RG&E Gas Modernization	1490
Gas Transportation Sys Software Upgrade	1491
RGE CGI Standardization Program	1494
RGE Track & Traceability Functionality	1496
RGE OQ Training Equipment	1500
NYSEG Gas Reliability	1502
NYSEG Leak Prone Pipe Replace Prog - LPP	1503
LPP Portageville Pennycook Rd Main	1505
LPP Vestal Parkway East	1507
LPP Line E Replacement	1509
LPP_Slaterville Rd	1511
Boswell Hill South	1513
Walton Deposit Reservoir	1515
NYSEG Leak Prone Srv Repl Program	1517
Town of Pendleton System Improvement	1519
Binghamton Anitec System Reinforcement	1522
Norwich-DeRuyter Compressor Reliability	1525
Goshen System Semi-Perm Peaking Tap	1527
CM 50, 52 & 53 (DeRuyter) Article VII	1529
NYSEG Cathodic Protection on LPP	1531
RG&E Gas Reliability	1533
LPP_Paul Road	1536
LPP_Paul Road	1538

LPP_Maple St Phase I	1540
LPP_Jay St	1542
LPP_Fairport Rd	1544
LPP_Monroe Ave Phase I	1546
LPP_Winton Rd South	1548
LPP_Buffalo Rd	1550
LPP Paul Road (Airport)	1552
LPP_East River Rd	1554
LPP_Maple St Phase II	1556
LPP_Ridgeway Ave Phase II	1558
RG&E Leak Prone Srv Repl Program	1560
MF60 SE Phase IV (Crowley Rd)	1562
MF60 SE Phase III (Malone Rd)	1564
MF60 SE Phase I (Mendon Gate - Rte 64)	1566
Pavilion System Semi-Perm Peaking Tap	1568
MF60 NW System Improvement - Phase I	1570
MF60 NW System Improvement - Phase II	1572
CM-2 Article VII	1574
RGE Cathodic Protection on LPP	1577
NYSEG Common Buildings and Facilities	1578
NYSEG Minor Projects	1580
NYSEG EV Chargers	1582
NYSEG Auburn Service Center Projects	1584
NYSEG Geneva Service Center Projects	1586
NYSEG Brewster Service Center Projects	1588
NYSEG Mechanicville Service Center Projects	1590
NYSEG Hamburg Operations Center Projects	1592
NYSEG ECC Projects	1594
NYSEG KGO Projects	1596
NYSEG Elmira Service Center Projects	1598
NYSEG Long Lake Building Expansion	1600
NYSEG Lockport Service Center Projects	1602
NYSEG Hornell Service Center Projects	1604
NYSEG Geneva Service Center West Projects	1606
NYSEG Lancaster Service Center Garage Projects	1608
Common	1579
RG&E Common Buildings and Facilities	1610
RGE Minor Projects	1611
Common	1610
NYSEG Common Customer Service	1619
NYSEG - Regulatory Driven Efforts / Rate Case	1620
New IVR and Voice Solution	1624
S/4 HANA Implementation	1626
CRM Front Office Improvements - NY	1629
Customer Service Generative AI	1637
eQuality Management System (QMS)	1640
IVR System Upgrades and Enhancements Program	1644

Customer Service Analytics	1646
NYSEG Common.....	1619
Customer Service	1619
S/4 HANA Implementation	1626
RG&E Common Customer Service	1651
RGE - Regulatory Driven Efforts / Rate Case	1652
S/4 HANA Implementation	1654
CRM Front Office Improvements - NY	1657
Customer Service Generative AI	1661
eQuality Management System (QMS)	1664
New IVR and Voice Solution	1666
RG&E Common.....	1651
Customer Service	1651
NSYEG Common Fleet	1674
NYSEG Fleet Replacement Program	1675
NYSEG Global Telematics Solution.....	1677
NSYEG Common Fleet	1674
RG&E Common Fleet	1679
RGE Fleet Replacement Program	1680
RG&E Common Fleet	1679
NYSEG Common Information Technology.....	1682
Client Project Requests and Integration Projects - NYSEG.....	1683
AGR-NET-23-SG-01-Esri UN Deployment-NYSEG	1685
AWS SW Cloud Subscription - NYSEG	1687
GIS Environment SW Cloud Subscriptions - NYSEG	1689
AGR-NET-24-IT-01-Global S4Hana-NYSEG.....	1691
AGR - IOC-NET-END USER LC-NYSEG	1693
AGR - IOC-Microsoft Deployment LC - NYSEG	1695
AGR - IOC-WINTEL LC-NYSEG	1697
AGR - IOC-UNIX LC-NYSEG	1699
AGR - IOC-STORAGE LC-NYSEG	1701
Common	1682
RG&E Common Information Technology.....	1706
Client Project Requests and Integration Projects - RGE	1707
AGR-NET-23-SG-01-Esri UN Deployment-RGE	1709
AWS SW Cloud Subscription - RGE.....	1711
GIS Environment SW Cloud Subscriptions - RGE.....	1713
AGR-NET-24-IT-01-Global S4Hana-RGE	1715
AGR - IOC-NET-END USER LC-RGE.....	1717
AGR - IOC-Microsoft Deployment LC - RGE	1719
Common	1706
NSYEG Common Operational Smart Grids	1720
NYSEG ECC Life cycle	1722
NYSEG OMS Alignment Spectrum	1725
ECS Infrastructure Firewalls NYSEG.....	1727

Cyber Recovery Solution	1729
Data Center Lifecycle.....	1731
Networking Gear Lifecycle	1733
Compliance Operations and Digital Identities	1735
Platform Services Lifecycle	1738
ASD Infrastructure Firewalls NYSEG.....	1740
DRAGOS NYSEG	1742
NY Smart Metering Lifecycle	1745
Telecomm Infrastructure	1747
Telecomm Fiber	1749
NY WAN Expansion.....	1751
NYSEG OSG Communications Tower Shelter Facility Improvements	1753
NYSEG FCC License Radio Spectrum purchase	1755
NYSEG FAN +Mobile technology refresh and expansion.....	1757
Telecomm Vertical Builds	1759
Avangrid Security Domain (ASD) OSG Telecommunications (NYSEG).....	1765
NYSEG Data Center Consolidation	1767
Storm System (ARCOS improvement / Replacement)	1769
DC2 (Station 80) Relocation Project NYSEG	1771
Integrated Forecasting Solution	1774
Common	1721
RG&E Common Operational Smart Grids	1776
Cyber Recovery Solution	1777
Data Center Lifecycle.....	1779
Networking Gear Lifecycle	1781
Compliance Operations and Digital Identities	1783
Platform Services Lifecycle	1786
DRAGOS RGE.....	1788
ASD Infrastructure Firewalls RGE	1791
NY Smart Metering Lifecycle	1793
Telecomm Infrastructure	1795
Telecomm Fiber	1797
Telecomm NY WAN Buildout.....	1800
RGE OSG Communications Tower Shelter Facility Improvements	1802
RGE FAN + mobile technology refresh and expansion	1804
Telecomm Vertical Builds	1806
Sonet Replacement	1810
Avangrid Security Domain (ASD) OSG Telecommunications (RGE)	1812
RGE Data Center Consolidation	1814
Storm System (ARCOS improvement / Replacement)	1817
DC2 (Station 80) Relocation Project RGE	1819
Common	1776
NYSEG Common Security	1822
Physical Security Lifecycle Management Program-NYSEG	1823
OT Cybersecurity - Architecture NYSEG	1825
NYSEG Common Security	1822
RG&E Common Security	1828

OT Cybersecurity - Architecture RGE	1829
Physical Security Lifecycle Management Program-RGE	1832
RG&E Common Security	1828
NYSEG Common Training	1834
NYSEG Common Training	1834
GS - Training Facilities (HR) NYSEG Johnson City Reynolds Trng Yard.....	1835



NYSEG Electric Asset Condition

TLD Replacements NYSEG

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-002963	Charge Code: Electric Distribution	Project Sponsor: Malone, Chris	Project Type: Annual Program
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: H1 2025	In-Service Date: H2 2025

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program). Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The TLD NYSEG Program spans the Upstate New York area, serving over 900,000 electricity customers. This initiative addresses an estimated 6,500+ deficiency notifications classified as Level 2 and Level 3, which require capital processing and are ranked within the highest Operational Prioritization Rankings.

All notifications will undergo an engineering review before construction begins, focusing on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements, utilizing wood poles and/or light-duty steel poles based on engineering recommendations.

Over the past several years, outages on these transmission and sub-transmission lines have affected thousands of customers. This program aims to address the highest-ranked notifications, thereby enhancing service reliability and reducing the frequency and duration of outages. By improving the structural integrity of the network, the TLD NYSEG Program will ensure a more consistent power supply, ultimately leading to higher customer satisfaction and compliance with regulatory standards.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow the continued decay of an aging transmission system, increasing the risk of outages due to asset condition and compromising service reliability. By proactively addressing these issues, the TLD Program ensures a more resilient and reliable transmission network, ultimately benefiting its customers.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 1,877	\$ -	\$ -	\$ 152	\$ 772	\$ 953		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 23,613	\$ -	\$ -	\$ 6,028	\$ 9,681	\$ 7,904		
# Internal - Non-AC	\$ 160	\$ -	\$ -	\$ 103	\$ 31	\$ 27		
# Internal, Labor	\$ 949	\$ -	\$ -	\$ 330	\$ 373	\$ 246		
# Internal, Overheads	\$ 3,381	\$ -	\$ -	\$ 798	\$ 1,385	\$ 1,198		
# Materials	\$ 2,467	\$ -	\$ -	\$ 358	\$ 1,466	\$ 643		
# Overheads - External	\$ 6,135	\$ -	\$ -	\$ 1,347	\$ 2,866	\$ 1,921		
Total	\$ 38,582	\$ -	\$ -	\$ 9,116	\$ 16,574	\$ 12,892		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ 1	\$ -	\$ -	\$ -	\$ 1	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ 1	\$ -	\$ -	\$ -	\$ 1	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 18,774	\$ 223	\$ -	\$ -	\$ 44	\$ 3,598	\$ 6,935	\$ 7,975
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 176,497	\$ 28,085	\$ -	\$ -	\$ 352	\$ 28,780	\$ 55,480	\$ 63,800
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 17,981	\$ -570	\$ -	\$ -	\$ 44	\$ 3,598	\$ 6,935	\$ 7,975
# Internal, Overheads	\$ 24,857	\$ 1,245	\$ -	\$ -	\$ 49	\$ 3,908	\$ 8,196	\$ 11,459
# Materials	\$ 124,778	\$ -1,372	\$ -	\$ -	\$ 299	\$ 24,463	\$ 47,158	\$ 54,230
# Overheads - External	\$ 26,837	\$ 662	\$ -	\$ -	\$ 54	\$ 4,332	\$ 9,085	\$ 12,703
Total	\$ 389,725	\$ 28,273	\$ -	\$ -	\$ 842	\$ 68,678	\$ 133,789	\$ 158,142

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L47

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007336	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2025

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 345kV L47 is located in Pennsylvania Division. This TLD Project involves addressing 52 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings.

All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 0 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 300	\$ 100	\$ 100	\$ 100	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,400	\$ 800	\$ 800	\$ 800	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 300	\$ 100	\$ 100	\$ 100	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 429	\$ 140	\$ 162	\$ 127	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 2,040	\$ 680	\$ 680	\$ 680	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 500	\$ 180	\$ 179	\$ 141	\$ -	\$ -	\$ -	\$ -
Total	\$ 5,969	\$ 2,000	\$ 2,020	\$ 1,948	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L48

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007337	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2025

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 345kV L48 is located in LPennsylvania Division. This TLD Project involves addressing 52 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings.

All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 0 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 300	\$ 100	\$ 100	\$ 100	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,400	\$ 800	\$ 800	\$ 800	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 300	\$ 100	\$ 100	\$ 100	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 429	\$ 140	\$ 162	\$ 127	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 2,040	\$ 680	\$ 680	\$ 680	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 500	\$ 180	\$ 179	\$ 141	\$ -	\$ -	\$ -	\$ -
Total	\$ 5,969	\$ 2,000	\$ 2,020	\$ 1,948	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L994

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007338	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 115kV L994 is located in Brewster Division. This TLD Project involves addressing 49 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings.

All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 6,279 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 275	\$ 80	\$ 195	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,200	\$ 640	\$ 1,560	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 275	\$ 80	\$ 195	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 427	\$ 112	\$ 315	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,870	\$ 544	\$ 1,326	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 493	\$ 144	\$ 349	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 5,540	\$ 1,600	\$ 3,940	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L805

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007339	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 46 kV L805 is located in Brewster Division. This TLD Project involves addressing 18 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 56,380 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 70	\$ 15	\$ 55	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 560	\$ 120	\$ 440	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 70	\$ 15	\$ 55	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 110	\$ 21	\$ 89	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 476	\$ 102	\$ 374	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 125	\$ 27	\$ 98	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,411	\$ 300	\$ 1,111	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L957

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007341	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 115kV L957 is located in Liberty Division. This TLD Project involves addressing 55 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings.

All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 2,270 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 300	\$ 240	\$ 60	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,400	\$ 1,920	\$ 480	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 300	\$ 240	\$ 60	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 433	\$ 336	\$ 97	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 2,040	\$ 1,632	\$ 408	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 539	\$ 432	\$ 107	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 6,012	\$ 4,800	\$ 1,212	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L349

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007342	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L349 is located in Liberty Division. This TLD Project involves addressing 44 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 9,408 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 225	\$ 50	\$ 175	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,800	\$ 400	\$ 1,400	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 225	\$ 50	\$ 175	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 353	\$ 70	\$ 283	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,530	\$ 340	\$ 1,190	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 403	\$ 90	\$ 313	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 4,536	\$ 1,000	\$ 3,536	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L810

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007345	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 46 kV L810 is located in Brewster Division. This TLD Project involves addressing 14 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 11,106 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 50	\$ 20	\$ 30	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 400	\$ 160	\$ 240	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 50	\$ 20	\$ 30	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 76	\$ 28	\$ 48	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 340	\$ 136	\$ 204	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 90	\$ 36	\$ 54	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,006	\$ 400	\$ 606	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L813

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007346	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 46 kV L813 is located in Brewster Division. This TLD Project involves addressing 35 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 23,165 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 191	\$ 15	\$ 176	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,528	\$ 120	\$ 1,408	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 191	\$ 15	\$ 176	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 305	\$ 21	\$ 284	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,299	\$ 102	\$ 1,197	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 342	\$ 27	\$ 315	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 3,856	\$ 300	\$ 3,556	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L991

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007347	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 115kV L991 is located in Brewster Division. This TLD Project involves addressing 47 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 9,039 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 257	\$ 35	\$ 222	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,052	\$ 280	\$ 1,772	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 257	\$ 35	\$ 222	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 407	\$ 49	\$ 358	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,744	\$ 238	\$ 1,506	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 459	\$ 63	\$ 396	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 5,175	\$ 700	\$ 4,475	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L350

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007348	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L350 is located in Liberty Division. This TLD Project involves addressing 228 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 32,128 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,240	\$ 175	\$ 800	\$ 265	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 9,920	\$ 1,400	\$ 6,400	\$ 2,120	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 1,240	\$ 175	\$ 800	\$ 265	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 1,875	\$ 245	\$ 1,293	\$ 338	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 8,432	\$ 1,190	\$ 5,440	\$ 1,802	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 2,120	\$ 315	\$ 1,431	\$ 374	\$ -	\$ -	\$ -	\$ -
Total	\$ 24,827	\$ 3,500	\$ 16,164	\$ 5,163	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L997

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007349	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 115kV L997 is located in Liberty Division. This TLD Project involves addressing 38 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 5,697 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 190	\$ 25	\$ 165	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,520	\$ 200	\$ 1,320	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 190	\$ 25	\$ 165	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 302	\$ 35	\$ 267	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,292	\$ 170	\$ 1,122	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 340	\$ 45	\$ 295	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 3,834	\$ 500	\$ 3,334	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L517

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007350	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L517 is located in Lancaster Division. This TLD Project involves addressing 69 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 13,058 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 395	\$ 10	\$ 385	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,160	\$ 80	\$ 3,080	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 395	\$ 10	\$ 385	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 636	\$ 14	\$ 622	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 2,686	\$ 68	\$ 2,618	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 707	\$ 18	\$ 689	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 7,979	\$ 200	\$ 7,779	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L819

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007351	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 46 KV L819 is located in Oneonta Division. This TLD Project involves addressing 96 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 9,700 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 550	\$ 10	\$ 50	\$ 490	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 4,400	\$ 80	\$ 400	\$ 3,920	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 550	\$ 10	\$ 50	\$ 490	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 719	\$ 14	\$ 81	\$ 624	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 3,740	\$ 68	\$ 340	\$ 3,332	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 799	\$ 18	\$ 89	\$ 691	\$ -	\$ -	\$ -	\$ -
Total	\$ 10,758	\$ 200	\$ 1,010	\$ 9,547	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L916

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007352	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 115kV L916 is located in Oneonta Division. This TLD Project involves addressing 170 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 3,997 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 975	\$ 15	\$ 100	\$ 860	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 7,800	\$ 120	\$ 800	\$ 6,880	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 975	\$ 15	\$ 100	\$ 860	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 1,278	\$ 21	\$ 162	\$ 1,096	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 6,630	\$ 102	\$ 680	\$ 5,848	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 1,419	\$ 27	\$ 179	\$ 1,213	\$ -	\$ -	\$ -	\$ -
Total	\$ 19,077	\$ 300	\$ 2,020	\$ 16,757	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L954

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007353	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L349 is located in Liberty Division. This TLD Project involves addressing 135 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings.

All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 9,408 customers. L349 is classified in the TLD Operational Prioritization Rankings as 15, 54, 60, 179, 297 and 578. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 765	\$ 15	\$ 100	\$ 650	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 6,120	\$ 120	\$ 800	\$ 5,200	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 765	\$ 15	\$ 100	\$ 650	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 1,011	\$ 21	\$ 162	\$ 828	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 5,202	\$ 102	\$ 680	\$ 4,420	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 1,123	\$ 27	\$ 179	\$ 917	\$ -	\$ -	\$ -	\$ -
Total	\$ 14,985	\$ 300	\$ 2,020	\$ 12,665	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L959

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007354	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 115kV L959 is located in Liberty Division. This TLD Project involves addressing 31 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected multiple customers in this division. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 180	\$ -	\$ 25	\$ 155	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,440	\$ -	\$ 200	\$ 1,240	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 180	\$ -	\$ 25	\$ 155	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 238	\$ -	\$ 40	\$ 197	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,224	\$ -	\$ 170	\$ 1,054	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 263	\$ -	\$ 45	\$ 219	\$ -	\$ -	\$ -	\$ -
Total	\$ 3,525	\$ -	\$ 505	\$ 3,020	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L911

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007355	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 115kV L911 is located in Plattsburgh Division. This TLD Project involves addressing 21 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 7,996 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 110	\$ 10	\$ 10	\$ 90	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 880	\$ 80	\$ 80	\$ 720	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 110	\$ 10	\$ 10	\$ 90	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 145	\$ 14	\$ 16	\$ 115	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 748	\$ 68	\$ 68	\$ 612	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 163	\$ 18	\$ 18	\$ 127	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,156	\$ 200	\$ 202	\$ 1,754	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L914

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007356	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 115kV L914 is located in Plattsburgh Division. This TLD Project involves addressing 235 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 715 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,325	\$ 15	\$ 134	\$ 590	\$ 586	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 10,600	\$ 120	\$ 1,072	\$ 4,718	\$ 4,690	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 1,325	\$ 15	\$ 134	\$ 590	\$ 586	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 1,689	\$ 21	\$ 216	\$ 751	\$ 700	\$ -	\$ -	\$ -
# Materials	\$ 9,010	\$ 102	\$ 911	\$ 4,010	\$ 3,987	\$ -	\$ -	\$ -
# Overheads - External	\$ 1,874	\$ 27	\$ 240	\$ 832	\$ 775	\$ -	\$ -	\$ -
Total	\$ 25,823	\$ 300	\$ 2,707	\$ 11,491	\$ 11,325	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L31

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007357	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 345kV L31 is located in Binghamton & Elmira Division. This TLD Project involves addressing 85 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings.

All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 0 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 490	\$ 15	\$ 30	\$ 100	\$ 345	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,920	\$ 120	\$ 240	\$ 800	\$ 2,760	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 490	\$ 15	\$ 30	\$ 100	\$ 345	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 609	\$ 21	\$ 48	\$ 127	\$ 412	\$ -	\$ -	\$ -
# Materials	\$ 3,332	\$ 102	\$ 204	\$ 680	\$ 2,346	\$ -	\$ -	\$ -
# Overheads - External	\$ 678	\$ 27	\$ 54	\$ 141	\$ 456	\$ -	\$ -	\$ -
Total	\$ 9,519	\$ 300	\$ 606	\$ 1,948	\$ 6,664	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L417

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007358	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L417 is located in Binghamton Division. This TLD Project involves addressing 100 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings.

All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 26,966 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 575	\$ 15	\$ 40	\$ 100	\$ 420	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 4,600	\$ 120	\$ 320	\$ 800	\$ 3,360	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 575	\$ 15	\$ 40	\$ 100	\$ 420	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 715	\$ 21	\$ 65	\$ 127	\$ 502	\$ -	\$ -	\$ -
# Materials	\$ 3,910	\$ 102	\$ 272	\$ 680	\$ 2,856	\$ -	\$ -	\$ -
# Overheads - External	\$ 795	\$ 27	\$ 72	\$ 141	\$ 555	\$ -	\$ -	\$ -
Total	\$ 11,170	\$ 300	\$ 808	\$ 1,948	\$ 8,113	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L531

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007359	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L531 is located in Lancaster Division. This TLD Project involves addressing 58 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings.

All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 25,275 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 335	\$ 10	\$ 20	\$ 50	\$ 255	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,680	\$ 80	\$ 160	\$ 400	\$ 2,040	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 335	\$ 10	\$ 20	\$ 50	\$ 255	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 415	\$ 14	\$ 32	\$ 64	\$ 305	\$ -	\$ -	\$ -
# Materials	\$ 2,278	\$ 68	\$ 136	\$ 340	\$ 1,734	\$ -	\$ -	\$ -
# Overheads - External	\$ 462	\$ 18	\$ 36	\$ 71	\$ 337	\$ -	\$ -	\$ -
Total	\$ 6,504	\$ 200	\$ 404	\$ 974	\$ 4,926	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L555

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007360	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L555 is located in Ithaca Division. This TLD Project involves addressing 88 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 22,278 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 505	\$ 10	\$ 25	\$ 100	\$ 370	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 4,040	\$ 80	\$ 200	\$ 800	\$ 2,960	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 505	\$ 10	\$ 25	\$ 100	\$ 370	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 624	\$ 14	\$ 40	\$ 127	\$ 442	\$ -	\$ -	\$ -
# Materials	\$ 3,434	\$ 68	\$ 170	\$ 680	\$ 2,516	\$ -	\$ -	\$ -
# Overheads - External	\$ 693	\$ 18	\$ 45	\$ 141	\$ 489	\$ -	\$ -	\$ -
Total	\$ 9,801	\$ 200	\$ 505	\$ 1,948	\$ 7,147	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L912

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007361	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 115kV L912 is located in Plattsburgh Division. This TLD Project involves addressing 17 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected multiple customers in this division. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 100	\$ -	\$ 10	\$ 10	\$ 80	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 800	\$ -	\$ 80	\$ 80	\$ 640	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 100	\$ -	\$ 10	\$ 10	\$ 80	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 124	\$ -	\$ 16	\$ 13	\$ 96	\$ -	\$ -	\$ -
# Materials	\$ 680	\$ -	\$ 68	\$ 68	\$ 544	\$ -	\$ -	\$ -
# Overheads - External	\$ 138	\$ -	\$ 18	\$ 14	\$ 106	\$ -	\$ -	\$ -
Total	\$ 1,942	\$ -	\$ 202	\$ 195	\$ 1,545	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L998

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007364	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 115kV L998 is located in Ithaca Division. This TLD Project involves addressing 11 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected multiple customers in this division. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 50	\$ 10	\$ 40	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 400	\$ 80	\$ 320	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 50	\$ 10	\$ 40	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 79	\$ 14	\$ 65	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 340	\$ 68	\$ 272	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 90	\$ 18	\$ 72	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,008	\$ 200	\$ 808	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L522 (Ithaca)

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007447	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L522 is located in Ithaca Division. This TLD Project involves addressing 19 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 43,378 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 109	\$ -	\$ 10	\$ 10	\$ 89	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 874	\$ -	\$ 80	\$ 80	\$ 714	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 109	\$ -	\$ 10	\$ 10	\$ 89	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 136	\$ -	\$ 16	\$ 13	\$ 107	\$ -	\$ -	\$ -
# Materials	\$ 743	\$ -	\$ 68	\$ 68	\$ 607	\$ -	\$ -	\$ -
# Overheads - External	\$ 150	\$ -	\$ 18	\$ 14	\$ 118	\$ -	\$ -	\$ -
Total	\$ 2,121	\$ -	\$ 202	\$ 195	\$ 1,724	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L520

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007448	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L520 is located in Lancaster Division. This TLD Project involves addressing 20 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 5,706 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 115	\$ -	\$ 10	\$ 10	\$ 95	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 920	\$ -	\$ 80	\$ 80	\$ 760	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 115	\$ -	\$ 10	\$ 10	\$ 95	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 142	\$ -	\$ 16	\$ 13	\$ 113	\$ -	\$ -	\$ -
# Materials	\$ 782	\$ -	\$ 68	\$ 68	\$ 646	\$ -	\$ -	\$ -
# Overheads - External	\$ 158	\$ -	\$ 18	\$ 14	\$ 126	\$ -	\$ -	\$ -
Total	\$ 2,232	\$ -	\$ 202	\$ 195	\$ 1,835	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L814

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007449	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 46kV L814 is located in Brewster Division. This TLD Project involves addressing 85 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 24,719 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 489	\$ -	\$ 20	\$ 50	\$ 419	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,910	\$ -	\$ 160	\$ 400	\$ 3,350	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 489	\$ -	\$ 20	\$ 50	\$ 419	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 596	\$ -	\$ 32	\$ 64	\$ 500	\$ -	\$ -	\$ -
# Materials	\$ 3,324	\$ -	\$ 136	\$ 340	\$ 2,848	\$ -	\$ -	\$ -
# Overheads - External	\$ 660	\$ -	\$ 36	\$ 71	\$ 554	\$ -	\$ -	\$ -
Total	\$ 9,467	\$ -	\$ 404	\$ 974	\$ 8,089	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L422

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007450	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L422 is located in Binghamton Division. This TLD Project involves addressing 69 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 63,543 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 397	\$ -	\$ 20	\$ 50	\$ 327	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,174	\$ -	\$ 160	\$ 400	\$ 2,614	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 397	\$ -	\$ 20	\$ 50	\$ 327	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 486	\$ -	\$ 32	\$ 64	\$ 390	\$ -	\$ -	\$ -
# Materials	\$ 2,698	\$ -	\$ 136	\$ 340	\$ 2,222	\$ -	\$ -	\$ -
# Overheads - External	\$ 538	\$ -	\$ 36	\$ 71	\$ 432	\$ -	\$ -	\$ -
Total	\$ 7,690	\$ -	\$ 404	\$ 974	\$ 6,312	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L455

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007451	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L455 is located in Binghamton Division. This TLD Project involves addressing 58 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 99.058 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 334	\$ -	\$ 20	\$ 50	\$ 264	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,668	\$ -	\$ 160	\$ 400	\$ 2,108	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 334	\$ -	\$ 20	\$ 50	\$ 264	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 411	\$ -	\$ 32	\$ 64	\$ 315	\$ -	\$ -	\$ -
# Materials	\$ 2,268	\$ -	\$ 136	\$ 340	\$ 1,792	\$ -	\$ -	\$ -
# Overheads - External	\$ 455	\$ -	\$ 36	\$ 71	\$ 349	\$ -	\$ -	\$ -
Total	\$ 6,468	\$ -	\$ 404	\$ 974	\$ 5,090	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L535

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007452	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L535 is located in Elmira Division. This TLD Project involves addressing 49 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings.

All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements . Poles will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 23,770 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 282	\$ -	\$ 15	\$ 35	\$ 232	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,254	\$ -	\$ 120	\$ 280	\$ 1,854	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 282	\$ -	\$ 15	\$ 35	\$ 232	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 346	\$ -	\$ 24	\$ 45	\$ 277	\$ -	\$ -	\$ -
# Materials	\$ 1,916	\$ -	\$ 102	\$ 238	\$ 1,576	\$ -	\$ -	\$ -
# Overheads - External	\$ 383	\$ -	\$ 27	\$ 49	\$ 307	\$ -	\$ -	\$ -
Total	\$ 5,462	\$ -	\$ 303	\$ 682	\$ 4,477	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L974

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007453	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 115kV L974 is located in Ithaca Division. This TLD Project involves addressing 183 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected multiple customers in this division. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,052	\$ -	\$ 25	\$ 100	\$ 927	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 8,418	\$ -	\$ 200	\$ 800	\$ 7,418	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 1,052	\$ -	\$ 25	\$ 100	\$ 927	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 1,275	\$ -	\$ 40	\$ 127	\$ 1,108	\$ -	\$ -	\$ -
# Materials	\$ 7,155	\$ -	\$ 170	\$ 680	\$ 6,305	\$ -	\$ -	\$ -
# Overheads - External	\$ 1,412	\$ -	\$ 45	\$ 141	\$ 1,226	\$ -	\$ -	\$ -
Total	\$ 20,365	\$ -	\$ 505	\$ 1,948	\$ 17,912	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L508

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007454	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L508 is located in Ithaca Division. This TLD Project involves addressing 38 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 14,818 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 201	\$ -	\$ 15	\$ 30	\$ 156	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,610	\$ -	\$ 120	\$ 240	\$ 1,250	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 201	\$ -	\$ 15	\$ 30	\$ 156	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 249	\$ -	\$ 24	\$ 38	\$ 187	\$ -	\$ -	\$ -
# Materials	\$ 1,369	\$ -	\$ 102	\$ 204	\$ 1,063	\$ -	\$ -	\$ -
# Overheads - External	\$ 276	\$ -	\$ 27	\$ 42	\$ 207	\$ -	\$ -	\$ -
Total	\$ 3,906	\$ -	\$ 303	\$ 585	\$ 3,018	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L341

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007455	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L341 is located in Liberty Division. This TLD Project involves addressing 39 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 5,907 customers in this division. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 224	\$ -	\$ 15	\$ 30	\$ 179	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,794	\$ -	\$ 120	\$ 240	\$ 1,434	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 224	\$ -	\$ 15	\$ 30	\$ 179	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 277	\$ -	\$ 24	\$ 38	\$ 214	\$ -	\$ -	\$ -
# Materials	\$ 1,525	\$ -	\$ 102	\$ 204	\$ 1,219	\$ -	\$ -	\$ -
# Overheads - External	\$ 306	\$ -	\$ 27	\$ 42	\$ 237	\$ -	\$ -	\$ -
Total	\$ 4,350	\$ -	\$ 303	\$ 585	\$ 3,463	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L884

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007460	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 46kV L884 is located in Plattsburgh Division. This TLD Project involves addressing 30 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 21,502 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 173	\$ -	\$ -	\$ 13	\$ 25	\$ 135	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,380	\$ -	\$ -	\$ 100	\$ 200	\$ 1,080	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 173	\$ -	\$ -	\$ 13	\$ 25	\$ 135	\$ -	\$ -
# Internal, Overheads	\$ 204	\$ -	\$ -	\$ 16	\$ 30	\$ 158	\$ -	\$ -
# Materials	\$ 1,173	\$ -	\$ -	\$ 85	\$ 170	\$ 918	\$ -	\$ -
# Overheads - External	\$ 226	\$ -	\$ -	\$ 18	\$ 33	\$ 175	\$ -	\$ -
Total	\$ 3,328	\$ -	\$ -	\$ 244	\$ 483	\$ 2,601	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L342

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007462	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L342 is located in Liberty Division. This TLD Project involves addressing 11 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements , poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 2,595 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 63	\$ -	\$ -	\$ 8	\$ 56	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 506	\$ -	\$ -	\$ 60	\$ 446	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 63	\$ -	\$ -	\$ 8	\$ 56	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 76	\$ -	\$ -	\$ 10	\$ 67	\$ -	\$ -	\$ -
# Materials	\$ 430	\$ -	\$ -	\$ 51	\$ 379	\$ -	\$ -	\$ -
# Overheads - External	\$ 84	\$ -	\$ -	\$ 11	\$ 74	\$ -	\$ -	\$ -
Total	\$ 1,223	\$ -	\$ -	\$ 146	\$ 1,077	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L806

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007463	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 46kV L806 is located in Oneonta Division. This TLD Project involves addressing 50 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements . Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 15,161 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 288	\$ -	\$ -	\$ 5	\$ 15	\$ 268	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,300	\$ -	\$ -	\$ 40	\$ 120	\$ 2,140	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 288	\$ -	\$ -	\$ 5	\$ 15	\$ 268	\$ -	\$ -
# Internal, Overheads	\$ 337	\$ -	\$ -	\$ 6	\$ 18	\$ 313	\$ -	\$ -
# Materials	\$ 1,955	\$ -	\$ -	\$ 34	\$ 102	\$ 1,819	\$ -	\$ -
# Overheads - External	\$ 374	\$ -	\$ -	\$ 7	\$ 20	\$ 347	\$ -	\$ -
Total	\$ 5,541	\$ -	\$ -	\$ 97	\$ 290	\$ 5,154	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L441

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007464	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L441 is located in Binghamton Division. This TLD Project involves addressing 12 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include poles replacement and crossarms replacement . Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 4,318 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 69	\$ -	\$ -	\$ 8	\$ 62	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 552	\$ -	\$ -	\$ 60	\$ 492	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 69	\$ -	\$ -	\$ 8	\$ 62	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 83	\$ -	\$ -	\$ 10	\$ 73	\$ -	\$ -	\$ -
# Materials	\$ 469	\$ -	\$ -	\$ 51	\$ 418	\$ -	\$ -	\$ -
# Overheads - External	\$ 92	\$ -	\$ -	\$ 11	\$ 81	\$ -	\$ -	\$ -
Total	\$ 1,334	\$ -	\$ -	\$ 146	\$ 1,188	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L955

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007465	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 115 kV L955 is located in Liberty Division. This TLD Project involves addressing 101 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 0 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 581	\$ -	\$ -	\$ 8	\$ 15	\$ 558	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 4,646	\$ -	\$ -	\$ 60	\$ 120	\$ 4,466	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 581	\$ -	\$ -	\$ 8	\$ 15	\$ 558	\$ -	\$ -
# Internal, Overheads	\$ 681	\$ -	\$ -	\$ 10	\$ 18	\$ 654	\$ -	\$ -
# Materials	\$ 3,949	\$ -	\$ -	\$ 51	\$ 102	\$ 3,796	\$ -	\$ -
# Overheads - External	\$ 754	\$ -	\$ -	\$ 11	\$ 20	\$ 724	\$ -	\$ -
Total	\$ 11,192	\$ -	\$ -	\$ 146	\$ 290	\$ 10,756	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L917

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007467	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 115kV L917 is located in Oneonta Division. This TLD Project involves addressing 157 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarms replacements . Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 25,226 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 903	\$ -	\$ -	\$ 25	\$ 100	\$ 778	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 7,222	\$ -	\$ -	\$ 200	\$ 800	\$ 6,222	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 903	\$ -	\$ -	\$ 25	\$ 100	\$ 778	\$ -	\$ -
# Internal, Overheads	\$ 1,062	\$ -	\$ -	\$ 32	\$ 119	\$ 910	\$ -	\$ -
# Materials	\$ 6,139	\$ -	\$ -	\$ 170	\$ 680	\$ 5,289	\$ -	\$ -
# Overheads - External	\$ 1,176	\$ -	\$ -	\$ 35	\$ 132	\$ 1,008	\$ -	\$ -
Total	\$ 17,404	\$ -	\$ -	\$ 487	\$ 1,932	\$ 14,985	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L802

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007468	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 46kV L802 is located in Oneonta Division. This TLD Project involves addressing 72 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings.

All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 27,562 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 414	\$ -	\$ -	\$ 5	\$ 15	\$ 394	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,312	\$ -	\$ -	\$ 42	\$ 120	\$ 3,150	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 414	\$ -	\$ -	\$ 5	\$ 15	\$ 394	\$ -	\$ -
# Internal, Overheads	\$ 486	\$ -	\$ -	\$ 7	\$ 18	\$ 461	\$ -	\$ -
# Materials	\$ 2,815	\$ -	\$ -	\$ 36	\$ 102	\$ 2,678	\$ -	\$ -
# Overheads - External	\$ 538	\$ -	\$ -	\$ 7	\$ 20	\$ 510	\$ -	\$ -
Total	\$ 7,978	\$ -	\$ -	\$ 102	\$ 290	\$ 7,586	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L589

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007469	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L589 is located in Geneva Division. This TLD Project involves addressing 16 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements . Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 14,825 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 92	\$ -	\$ -	\$ 10	\$ 20	\$ 62	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 736	\$ -	\$ -	\$ 80	\$ 160	\$ 496	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 92	\$ -	\$ -	\$ 10	\$ 20	\$ 62	\$ -	\$ -
# Internal, Overheads	\$ 109	\$ -	\$ -	\$ 13	\$ 24	\$ 73	\$ -	\$ -
# Materials	\$ 626	\$ -	\$ -	\$ 68	\$ 136	\$ 422	\$ -	\$ -
# Overheads - External	\$ 121	\$ -	\$ -	\$ 14	\$ 26	\$ 80	\$ -	\$ -
Total	\$ 1,776	\$ -	\$ -	\$ 195	\$ 386	\$ 1,195	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L65

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007470	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 230kV L65 is located in Lancaster Division. This TLD Project involves addressing 42 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected multiple customers in this division. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 242	\$ -	\$ -	\$ 15	\$ 25	\$ 202	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,932	\$ -	\$ -	\$ 120	\$ 200	\$ 1,612	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 242	\$ -	\$ -	\$ 15	\$ 25	\$ 202	\$ -	\$ -
# Internal, Overheads	\$ 285	\$ -	\$ -	\$ 19	\$ 30	\$ 236	\$ -	\$ -
# Materials	\$ 1,642	\$ -	\$ -	\$ 102	\$ 170	\$ 1,370	\$ -	\$ -
# Overheads - External	\$ 315	\$ -	\$ -	\$ 21	\$ 33	\$ 261	\$ -	\$ -
Total	\$ 4,657	\$ -	\$ -	\$ 292	\$ 483	\$ 3,882	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L549

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007472	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L549 is located in Hornell Division. This TLD Project involves addressing 10 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 0 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 58	\$ -	\$ -	\$ 8	\$ 50	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 460	\$ -	\$ -	\$ 60	\$ 400	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 58	\$ -	\$ -	\$ 8	\$ 50	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 69	\$ -	\$ -	\$ 10	\$ 60	\$ -	\$ -	\$ -
# Materials	\$ 391	\$ -	\$ -	\$ 51	\$ 340	\$ -	\$ -	\$ -
# Overheads - External	\$ 77	\$ -	\$ -	\$ 11	\$ 66	\$ -	\$ -	\$ -
Total	\$ 1,112	\$ -	\$ -	\$ 146	\$ 966	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Line 880 Rebuild

PROJECT INFORMATION

OpCo: NYSEG	Project ID: UH-N0000414-NYSEG-ET	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

Line 880 has been identified by Asset Management as a line that needs replacement. The 15.4 miles of 46kV line from the Rainbow Falls Substation to the Cabot Substation provide Services for more than 2300 customers in the area. These upgrades will increase reliability to the Line which is still experiencing regular outages; In 2021, 2634 customers were impacted by outages associated with this Line. There is presently no static wire existing for this line. Without a static wire, this line is at higher risk for lightning related outages and does not meet Avangrid's standards for lightning protection. The Line's poles have also been rated from poor to fair condition, with the many of the poles being installed between 1947 and 1950 with an average age of 51 years.

Project Scope:

The total project is rebuild of 15.4 miles of 46kV line from the Rainbow Falls Substation to the Cabot Substation, all but the final North Phase (5.75 miles), has been constructed and put in service. To date, we have added \$29.56M to Rate Base, and this final phase will add an additional \$20.2M to Rate Base.

This project includes erecting new wood poles, with self-supporting laminated wood and steel poles on angles and dead-ends. Transmission lines will be completely reconducted and replaced with 477 conductor cable and OPGW static wire. Underbuilt replacement and transfers will be required along select areas of the line. The project was approved in March 2022 to split into two phases, with three distinct WBSs. The original WBS is Phase 1, which was the area identified as the most need. This is from new structure 127 to structure 290 and is a total of 8.32 miles, with approximately 1.1 Miles roadside and 7.22 Miles backlot. The remaining 7.08 miles is Phase 2, which consists two sections North and South of Phase 1. Phase 2 South (1.25 mi) and the remainder of Phase 1 (1.03 mi) was energized in August 2023. The project was ready to pick up Phase 2 North construction but due to rate case reduction Phase 2 North (5.75 mi) construction has tentatively pushed to 2027 rate cycle. Project has received the Phase 2 North materials, which is currently in storage and is ready to use when project resumes.

Project Benefits:

This rebuild will increase reliability to the line which is still experiencing regular outages. There was no static wire on this line and without a static wire, this line is at higher risk for lightning related outages and does not meet Avangrid's standards for lightning protection.

Project Risks and Mitigation Plan:

Phase 2 North will need to acquire or retrieve all the permits when Project will resume for construction in future.

Risk of No Action:

The line will continue to experience regular outages due to asset conditions. Also, we have all of the materials (poles, conductor, insulators, etc.) in storage to complete the work, these will need to be moved back to inventory and the laydown yard rental cancelled.

Project Alternatives:

Line 880 Phase 2 North 2023 Re-assessment Summary

- The TLD Notifications Dashboard shows there are 13 TLDs (7-high priority and 6-medium priority) on L880 Phase-2 North.
 - Since 2020, there have been 4 outages that have affected line 880.
 - Comprehensive re-assessment performed using SAP data to confirm age of pole and conductors.
 - Comprehensive Visual Inspection (CVI) walking the line and drone inspection using internal NY ISP (Asset Management and Planning) resources was conducted for L880 Phase-2 North in August 2023 with the lead engineer and construction manager of the project. A total of 128 poles were inspected.
 - Significantly more TLDs and DLDs of varying severity were identified (total transmission and distribution deficiencies 257)
 - Of the 105 Pole TLDs 66 were identified to be replaced (52%)
 - Based on visual inspections, a predominant number of insulators are brown glass and therefore recommended for replacement.
 - Transmission conductor is comprised of AAAC, ACSR and Copper with an installation date of 1950. When paired with the structure deficiencies, the conductor is considered in need of replacement.
 - The average conductor age on poles with level 1 & 2 TLDs is 72 years old.
- Recommendation:
- More than 50% of the poles needs to be replaced therefore, line rebuild is recommended.
 - Rebuild of the line including installation of the static wire will improve reliability/resiliency.

Basis for Project Estimates

Estimate based on bid/construction award from 2021 and first two phases of the project.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 2,502	\$ 55	\$ 266	\$ 811	\$ 1,063	\$ 306		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 16,895	\$ 177	\$ 4,600	\$ 6,048	\$ 6,071	\$ -0		
# Internal - Non-AC	\$ 243	\$ 52	\$ 67	\$ 90	\$ 22	\$ 12		
# Internal, Labor	\$ 601	\$ 46	\$ 184	\$ 211	\$ 160	\$ 0		
# Internal, Overheads	\$ 3,167	\$ 33	\$ 1,230	\$ 745	\$ 1,147	\$ 12		
# Materials	\$ 4,970	\$ -	\$ 2,382	\$ 160	\$ 2,360	\$ 68		
# Overheads - External	\$ 4,848	\$ 58	\$ 1,576	\$ 1,260	\$ 1,941	\$ 13		
Total	\$ 33,225	\$ 421	\$ 10,305	\$ 9,325	\$ 12,765	\$ 410		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 2,322	\$ 335	\$ 365	\$ 640	\$ 982	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 10,434	\$ -	\$ -	\$ 6,722	\$ 3,671	\$ 41	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 120	\$ -	\$ -	\$ 63	\$ 57	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 697	\$ 5	\$ 5	\$ 450	\$ 234	\$ 2	\$ -	\$ -
# Materials	\$ 200	\$ 50	\$ 50	\$ 50	\$ 50	\$ -	\$ -	\$ -
# Overheads - External	\$ 741	\$ 4	\$ 5	\$ 478	\$ 252	\$ 3	\$ -	\$ -
Total	\$ 14,514	\$ 394	\$ 425	\$ 8,403	\$ 5,246	\$ 46	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L943

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007363	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 115kV L943 is located in Binghamton Division. This TLD Project involves addressing 132 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include pole replacements and of crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 1,131 customers. This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 755	\$ 15	\$ 400	\$ 340	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 6,040	\$ 120	\$ 3,200	\$ 2,720	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 755	\$ 15	\$ 400	\$ 340	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 1,100	\$ 21	\$ 646	\$ 433	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 5,134	\$ 102	\$ 2,720	\$ 2,312	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 1,222	\$ 27	\$ 716	\$ 480	\$ -	\$ -	\$ -	\$ -
Total	\$ 15,007	\$ 300	\$ 8,082	\$ 6,625	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG - Electric Ops (Line Insp CAP)

PROJECT INFORMATION

OpCo: NYSEG	Project ID: UI-N5075-RGE-ED	Charge Code: Electric Distribution	Project Sponsor: Shail, Joshua	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Distribution Line Inspection program at NYSEG is a New York State Public Service Commission (PSC) mandated visual inspection order. The entire distribution system is inspected on a five-year cycle. The program involves replacing poles, cross arms, cutouts, transformers, and any other units of property identified during the annual inspection. Additionally, the program includes other maintenance inspection initiatives such as infrared and helicopter inspections.

Program initiatives have created division-specific work plans focused on two phases of priority:

Phase 1: Includes all DLI Level II notifications that will be found during the 2024-2030 inspection cycles. These notifications are addressed based on their due dates.

Phase 2: Includes DLI Level III notifications and all other maintenance deficiency programs. These notifications are prioritized based on their impact on customer reliability and System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) scores.

All Level I notifications are immediately vetted and prioritized at the division level due to the immediate concerns identified during inspections.

Project Scope:

The program involves replacing poles, cross arms, cutouts, transformers, and any other units of property identified during the annual inspection.

The DLD program consists of a field inspection that generates notifications for execution of work on company equipment. The execution happens following a workplan based on the notification priority and a reliability score that includes asset data, customer exposure and historical reliability variables. At NYSEG an average of 136,000 customers were interrupted annually by company equipment failure causes over the past 3 years.

The following units and average unit costs will be addressed between 2025-2031:

2025 - 7,619 (units) / \$2,060 (unit cost)
2026 - 6,895 (units) / \$2,121 (unit cost)
2027 - 7,045 (units) / \$2,185 (unit cost)
2028 - 7,197 (units) / \$2,251 (unit cost)
2029 - 7,353(units) / \$2,318 (unit cost)
2030 - 7,495 (units) / \$2,388 (unit cost)
2031 - 7,656 (units) / \$2,459 (unit cost)

Project Benefits:

Replacing deficient poles and equipment will rejuvenate an aging system, thereby increasing reliability and reducing customer outages. This proactive approach will also minimize the need for costly emergency repairs, lessening the potential for accidents and injuries to both customers and employees.

The program ensures compliance with safety standards and maintains safety for the public and utility workers. By replacing poles using current standards and as determined by pole loading analysis per the National Electrical Safety Code (NESC) Northeast wind and radial ice modeling parameters, the reliability and resiliency of the NYSEG distribution system are improved.

Project Risks and Mitigation Plan:

Potential increased power losses due to degraded conductors, risk of outages from weakened components, increased maintenance needs, potential for sagging or breaking wires, and a reduced capacity to transmit electricity efficiently could affect reliability and stability. Regular inspections and maintenance of the lines are essential to promptly identify and address these potential issues.

Risk of No Action:

If no action is taken and deteriorated poles and equipment are not replaced, this will result in non-compliance with NESC requirements and put the safety of the public and utility workers at risk.

Project Alternatives:

This program aims to replace outage equipment using an “in-kind” replacement strategy.

Basis for Project Estimates

Future annual spending targets are determined through an annual analysis that considers historical itemized component upgrades (such as poles, transformers, and conductors) and overall spending from prior years. Projections for P25 spending are based on prior actuals by component upgrade type, with a current and justified escalation factor used to inform each subsequent out-year.

FINANCIAL INFORMATION**Actual Capital Spent, all amounts shown below in thousands (\$000's)**

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 1,311	\$ 230	\$ 404	\$ 242	\$ 203	\$ 231		
# CIAC	\$ -2,334	\$ -229	\$ -323	\$ -200	\$ -610	\$ -972		
# External Services	\$ 55,326	\$ 12,690	\$ 17,389	\$ 10,867	\$ 8,053	\$ 6,328		
# Internal - Non-AC	\$ 28	\$ 22	\$ 1	\$ -	\$ 3	\$ 3		
# Internal, Labor	\$ 6,610	\$ 1,866	\$ 1,310	\$ 648	\$ 1,333	\$ 1,452		
# Internal, Overheads	\$ 9,546	\$ 2,271	\$ 2,778	\$ 1,408	\$ 1,582	\$ 1,508		
# Materials	\$ 14,520	\$ 3,855	\$ 3,305	\$ 1,565	\$ 2,589	\$ 3,206		
# Overheads - External	\$ 14,312	\$ 3,118	\$ 3,906	\$ 2,142	\$ 2,713	\$ 2,433		
Total	\$ 99,319	\$ 23,824	\$ 28,769	\$ 16,673	\$ 15,866	\$ 14,188		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ 7,227	\$ 1,492	\$ 2,239	\$ 1,723	\$ 1,015	\$ 757		
Materials	\$ 717	\$ 165	\$ 127	\$ 132	\$ 144	\$ 150		
Other O&M	\$ 112	\$ 13	\$ 59	\$ 27	\$ 4	\$ 9		
Total	\$ 8,056	\$ 1,670	\$ 2,425	\$ 1,882	\$ 1,163	\$ 915		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,468	\$ 176	\$ 190	\$ 199	\$ 209	\$ 220	\$ 231	\$ 243
# CIAC	\$ -6,422	\$ -971	\$ -874	\$ -883	\$ -892	\$ -901	\$ -946	\$ -955
# External Services	\$ 103,501	\$ 14,527	\$ 13,081	\$ 13,735	\$ 14,422	\$ 15,143	\$ 15,900	\$ 16,695
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 8,448	\$ 741	\$ 1,133	\$ 1,190	\$ 1,249	\$ 1,312	\$ 1,377	\$ 1,446
# Internal, Overheads	\$ 9,252	\$ 1,087	\$ 1,442	\$ 1,194	\$ 1,175	\$ 1,211	\$ 1,380	\$ 1,764
# Materials	\$ 8,686	\$ 1,219	\$ 1,098	\$ 1,153	\$ 1,210	\$ 1,271	\$ 1,334	\$ 1,401
# Overheads - External	\$ 11,004	\$ 1,179	\$ 1,735	\$ 1,436	\$ 1,414	\$ 1,457	\$ 1,660	\$ 2,122
Total	\$ 135,937	\$ 17,959	\$ 17,804	\$ 18,023	\$ 18,788	\$ 19,712	\$ 20,936	\$ 22,715

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 6,281	\$ 821	\$ 863	\$ 882	\$ 900	\$ 919	\$ 938	\$ 958
Materials	\$ 623	\$ 82	\$ 86	\$ 88	\$ 89	\$ 91	\$ 93	\$ 95
Other O&M	\$ 97	\$ 13	\$ 13	\$ 14	\$ 14	\$ 14	\$ 15	\$ 15
Total	\$ 7,002	\$ 915	\$ 962	\$ 983	\$ 1,003	\$ 1,025	\$ 1,046	\$ 1,068

NYSEG - Pole Replace (WPIT) Program CAP

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-001577	Charge Code: Electric Distribution	Project Sponsor: Shail, Joshua	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

Wood Pole Inspect and Treat (WPIT) program was established in 2021 to address the growing number of asset condition needs identified among NYSEG's fleet of wooden type distribution and transmission poles as part of routine field inspections.

Field inspections are performed across all NYSEG divisions (13 total), on a yearly basis, to identify wood poles that are deemed in need of replacement or repairs. Inspections include ground line evaluations to identify instances of wood decay, excavation and boring techniques to identify decay at-or-below ground line, and "Sounding" the pole which includes striking the pole with a mallet and listening for signs of a hollow structure.

Inspections include the visual observation of the pole from top to bottom and looking for signs such as: woodpecker holes, split tops, excessive leaning, structural damage. The following determines which inspection technique is used:

Age of Pole (0-10 Years) - Visual

Age of Pole (11+) - Sound, Boring, and partial excavation

Inspections occur from March to December and are used to inform a larger set of system needs including those that were identified in prior years but have not yet been addressed.

In Q4 of each calendar year, Electric Operations reviews the system needs identified through field inspections and prioritize the subsequent year's deployment based on the severity of the need.

Once the overall prioritization has been established, the annual plan is communicated to the local division for execution in the following calendar year.

Project Scope:

The WPIT program consists of a field inspection that generates notifications for work execution on decayed poles. The execution happens following a workplan based on the notification priority and a reliability score that includes asset data, customer exposure and historical reliability variables. At NYSEG an average of 55,000 customers were interrupted annually by pole decay and insulator related causes over the past 3 years.

The following units and average unit costs will be addressed between 2025-2031:

2025 - 2,246 (units) / \$9,851 (unit cost)

2026 - 1,969 (units) / \$10,147 (unit cost)

2027 - 2,009 (units) / \$10,451 (unit cost)

2028 - 2,049 (units) / \$10,765 (unit cost)

2029 - 2,091 (units) / \$11,088 (unit cost)

2030 - 2,131 (units) / \$11,420 (unit cost)

2031 - 2,174 (units) / \$11,763 (unit cost)

Project Benefits:

Pole replacements and repairs serve to mitigate safety risks and have been shown to improve overall system reliability metrics (e.g., SAIFI).

Project Risks and Mitigation Plan:

The Company must align with State and Federal reliability standards which is evidence of the Company's commitment to these standards through a well executed program. The program identifies tasks within same reach to help reduce operational costs and improve the timeliness of the execution plan. As this program matures, the expectation is that all distribution poles are to be inspected on a 10-year cycle, which would equate to 10% of the Company's distribution poles being inspected annually.

NYSEG use internal designations and specify WPIT severity levels based on the following internal nomenclature.

WPIT Level 2A: Recommended replacement within 30 days.

WPIT Level 2: Recommended replacement within one year.

Level 2A poles are missing a substantial level of strength and are likely to come down in the next storm. The remaining notifications were ranked by reliability impact for NYSEG, by the number of customers downstream of the specific location, the historical customer impact, the device type, the notifications per specific FLOC and the historical incident count.

Risk of No Action:

The WPIT program proactively inspects and treats wood poles to prevent potential increases in outage frequency. Without this proactive work, the system may experience more frequent outages. Additionally, there are risks of negatively impacting SAIFI goals, environmental factors, supply chain stability, public perception, and facing regulatory penalties.

Project Alternatives:

The WPIT program aims to replace one-for-one assets that are in poor condition. Alternatives are considered on a case-by-case basis to ensure the most effective solutions are implemented.

Basis for Project Estimates

The financial plan is based on an average cost per pole replacement. The average cost is determined by the cost of construction crews, internal labor costs, material costs, and overheads applicable to replacing a pole.

FINANCIAL INFORMATION**Actual Capital Spent, all amounts shown below in thousands (\$000's)**

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 408	\$ -	\$ 38	\$ 90	\$ 87	\$ 193		
# CIAC	\$ -750	\$ -	\$ -4	\$ -28	\$ -382	\$ -336		
# External Services	\$ 25,219	\$ -	\$ 3,037	\$ 7,937	\$ 5,698	\$ 8,547		
# Internal - Non-AC	\$ 0	\$ -	\$ -	\$ -	\$ 0	\$ -		
# Internal, Labor	\$ 2,420	\$ -	\$ 150	\$ 633	\$ 644	\$ 993		
# Internal, Overheads	\$ 4,746	\$ -	\$ 560	\$ 1,227	\$ 1,102	\$ 1,857		
# Materials	\$ 7,730	\$ -	\$ 736	\$ 1,581	\$ 1,889	\$ 3,525		
# Overheads - External	\$ 7,255	\$ -	\$ 779	\$ 1,855	\$ 1,826	\$ 2,795		
Total	\$ 47,028	\$ -	\$ 5,295	\$ 13,294	\$ 10,865	\$ 17,574		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ 1,369	\$ -	\$ 159	\$ 461	\$ 318	\$ 432		
Materials	\$ 382	\$ -	\$ 27	\$ 85	\$ 102	\$ 169		
Other O&M	\$ 19	\$ -	\$ 15	\$ 2	\$ -	\$ 3		
Total	\$ 1,771	\$ -	\$ 200	\$ 548	\$ 420	\$ 603		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,923	\$ 177	\$ 258	\$ 269	\$ 283	\$ 297	\$ 312	\$ 328
# CIAC	\$ -3,186	\$ -483	\$ -434	\$ -438	\$ -442	\$ -447	\$ -469	\$ -474
# External Services	\$ 131,207	\$ 18,450	\$ 16,577	\$ 17,406	\$ 18,276	\$ 19,190	\$ 20,150	\$ 21,157
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 6,934	\$ 975	\$ 876	\$ 920	\$ 966	\$ 1,014	\$ 1,065	\$ 1,118
# Internal, Overheads	\$ 11,940	\$ 1,120	\$ 1,911	\$ 1,582	\$ 1,557	\$ 1,605	\$ 1,828	\$ 2,337
# Materials	\$ 21,379	\$ 3,006	\$ 2,701	\$ 2,836	\$ 2,978	\$ 3,127	\$ 3,283	\$ 3,447
# Overheads - External	\$ 13,344	\$ 1,230	\$ 2,139	\$ 1,771	\$ 1,744	\$ 1,797	\$ 2,047	\$ 2,617
Total	\$ 183,541	\$ 24,476	\$ 24,028	\$ 24,346	\$ 25,362	\$ 26,583	\$ 28,216	\$ 30,530

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031

Outside Services	\$ 5,934	\$ 776	\$ 815	\$ 833	\$ 850	\$ 868	\$ 887	\$ 905
Materials	\$ 1,657	\$ 217	\$ 228	\$ 233	\$ 237	\$ 242	\$ 248	\$ 253
Other O&M	\$ 83	\$ 11	\$ 11	\$ 12	\$ 12	\$ 12	\$ 12	\$ 13
Total	\$ 7,675	\$ 1,003	\$ 1,054	\$ 1,077	\$ 1,100	\$ 1,123	\$ 1,147	\$ 1,171

New Gardenville Substation Rebuild

PROJECT INFORMATION

OpCo:	Project ID:	Charge Code:	Project Sponsor:	Project Type:
NYSEG	UH-N0000204-NYSEG-ET	Electric Transmission	Malone, Chris	Project
Business Area:	Rate Case Category	Project Stage:	Start Date:	In-Service Date:
Projects	Asset Condition	IP4 Change	H1 2025	H2 2030

Project description:

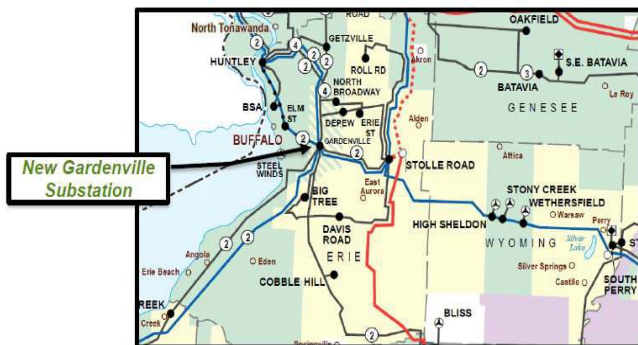
New Gardenville is a 230/115/34.5 kV substation located in NYSEG's Lancaster Division, southeast of Buffalo, NY, originally built in 1959. Today, New Gardenville's 230 kV facilities are designated as [REDACTED] important hub for the 115 kV transmission network within the Lancaster Division. Additionally, New Gardenville is a major source of power for the underlying 34.5 kV sub-transmission and distribution systems. To determine the full scope of needs within the substation yard, a comprehensive needs assessment was conducted, including a Transmission System steady-state power-flow analysis, as well as an asset condition, and historical reliability analysis. The assessment identified several key needs:

Reliability-Capacity:

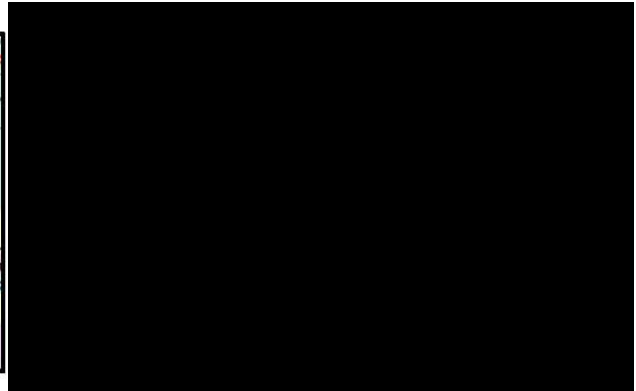
Asset Condition: Widespread structural and footing deficiencies indicate a risk of failures of the supporting yard structures under the required NESC loading conditions. The control house has code violations due to clearances, ventilation, and fire ratings. Obsolete electromechanical relays, unsupported by the manufacturer, require parts from retired relays when failures occur. All 230 & 115 kV breakers (3-230 kV & 6-115 kV) were determined to be in poor condition and in need of replacement according to the latest Asset Management breaker assessment data. Lastly, the substation yard has very poor drainage which can result in standing water near the control house. It has been reported that water has penetrated the interior of the control house building posing a threat to the electrical equipment.

Customer Reliability: Several outages occurred at New Gardenville that directly impacted customers fed off the 34.5 kV system. In 2020, two major outages faulted the 34.5 kV bus due to the failure of brown-glass insulators. In general, the 230 kV, 115 kV, and 34.5 kV straight bus configurations are an undesirable design and pose a risk to customers following single-element contingencies.

The objective of this project is to completely upgrade the substation design to mitigate known thermal and voltage violations, replace facilities that are beyond their useful operating life and could cause major outages if they were to fail, and ensure compliance with NPCC Directory #4 requirements. Due to the overall condition, compliance obligations, and customer outage risks, it is important for this project to proceed.



Geographical Overview - New Gardenville



Existing One-Line

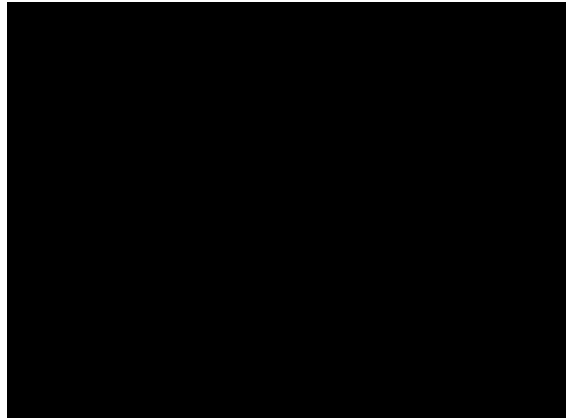
Project Scope:

The scope of work for the NYSEG New Gardenville Substation includes a complete rebuild of the 230/115/34.5 kV facility. The 230 kV yard will be reconstructed as an open air insulated (AIS) 3-breaker ring bus design, connecting to two 230 kV lines and a new 230/115/34.5 kV autotransformer. The layout will also allow for the future addition of a fourth 230 kV breaker if expansion is needed.

The 115 kV yard will be rebuilt as a gas insulated (GIS) 4-bay breaker-and-a-half design (BAAH), incorporating eleven breakers. This will connect four 115 kV lines, a new 230/115/34.5 kV autotransformer, and two new 115/34.5 kV transformers, with space for a twelfth breaker to accommodate future expansion.

The 34.5 kV yard will be redesigned as a medium voltage GIS straight bus configuration with two bus-tie breakers. All 34.5 kV circuit connections will be terminated through dedicated line breakers, and the two 115/34.5 kV transformers will have dedicated low-side breakers.

[REDACTED] The execution timeline for this project is expected to span five years, although this may be accelerated since the project was previously in execution but subsequently placed on hold. Below is a one-line depicting the final scope of work for this project:



Post-Project One-Line

Project Benefits:

This project aims to address known thermal and voltage needs affecting the Bulk Electric System (BES) as well as the 34.5 kV sub-transmission and distribution systems. While asset condition was the primary driver for this project, the improved (more resilient) electrical design and higher capacity transformers will significantly improve reliability for our customers and support future load growth within the Lancaster Division. The design is also prepared to accommodate future expansion, which will allow the company to align with New York State's clean energy goals and anticipated electrification needs (if needed).

The newly designed control house will feature advanced microprocessor relays with full DC separation, ensuring compliance with NPCC Directory #4 requirements. Replacing poorly rated electrical equipment, such as circuit breakers and brown glass insulators, will greatly reduce the risk of future equipment failures that could impact NYSEG customers. Additionally, the inclusion of 34.5 kV bus-tie breakers will enhance operational flexibility and limit outage exposure in the event of a single (N-1) contingency. This project is in line with NYSEG's overall strategy to improve system reliability by modernizing legacy facilities and replacing equipment that is deemed to be beyond its useful operating life. New Gardenville is considered a critical source of power and a key component of the 230 kV east-to-west power flow within the Lancaster Region and these upgrades will help to ensure BES and local system reliability.

Project Risks and Mitigation Plan:

Given the constraints of this site, special safety precautions are necessary while working in an energized yard. Construction and outage sequencing will be required to ensure that existing energized equipment remains uninterrupted during the work. According to the needs assessment, there is a risk of standing water in the yard, so de-watering equipment will likely be needed to ensure worker safety. Central to the efficient and safe execution of the construction project will be the use of Ground Penetrating Radar (GPR), dig safe practices, and hand digging to review areas of concern. Additionally, the project is being constructed in a phased approach, which will allow for quicker recovery in the event of an unforeseen incident.

Risk of No Action:

This project has been on [REDACTED] Given the condition of electrical and structural assets, there is a greater risk of equipment failures without intervention. The undesirable straight-bus design would likely cause unplanned customer interruptions, further degrading NYSEG's reliability statistics. The project began execution activities several years ago and has accumulated a sizable amount of construction work in progress (CWIP). Therefore, it is still accumulating Allowance for Funds Used During Construction (AFUDCs), making it important to complete the work already started to reduce overall project costs. Additionally, the control house has code violations due to clearances, ventilation, and fire ratings, posing a safety risk.

Project Alternatives:

To address the needs identified at New Gardenville, three competing solution alternatives were developed. These solution alternatives (high-level descriptions) were evaluated based on cost estimates developed in Q1 2021, and other variables, such as execution timeline and expandability to compare options at the time of project selection. The selected alternative (described in the project scope section) was selected based primarily on the fact that it is expected to have the least-complex construction sequence, greatly improves electrical performance, and was the second lowest cost solution.

Alternative 1: Proposed a 230 kV AIS Ring Bus, a 115 kV GIS Breaker-and-a-Half (BAAH) design, and a 34.5 kV GIS straight bus. This alternative utilizes two 230/115/34.5 kV transformers and one 115/34.5 kV transformer, with a total estimated cost of \$131 million (+50/-25%). However, it was dismissed due to physical constraints at the site, cost, 34.5 kV short-circuit impacts, and a more complex construction outage sequence.

Alternative 2: Proposed a GIS BAAH rebuild of the 115 kV and 34.5 kV straight bus, utilizing three 115/34.5 kV transformers and retiring the existing 230 kV transformation. The total estimated cost for this alternative was \$115 million (+50/-25%). It was dismissed due to its less than stellar electrical performance and the adverse impact it would have caused on N-Grid facilities.

Alternative 3: Proposed a GIS BAAH rebuild of both the 230 kV and 115 kV systems, along with a 34.5 kV GIS straight bus. This alternative utilized three 230/115/34.5 kV transformers, with a total estimated cost of \$177 million (+50/-25%). It was dismissed due to cost, 34.5 kV short-circuit impacts, and the most complex construction outage sequence among the alternatives.

Basis for Project Estimates

These estimates are derived from multiple sources. A number of the efforts were in the bid process or had been awarded and we used the contract/bid values received escalated for inflation. Other items were estimated based on costs for similar items. Project estimates are routinely reviewed and updated as the project progresses.

FINANCIAL INFORMATION**Actual Capital Spent, all amounts shown below in thousands (\$000's)**

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 1,303	\$ 114	\$ 162	\$ 189	\$ 311	\$ 526		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 3,543	\$ 401	\$ 343	\$ 350	\$ 1,618	\$ 832		
# Internal - Non-AC	\$ 755	\$ 178	\$ 200	\$ 197	\$ 133	\$ 46		
# Internal, Labor	\$ 56	\$ -	\$ 0	\$ 2	\$ 16	\$ 38		
# Internal, Overheads	\$ 735	\$ 65	\$ 88	\$ 138	\$ 301	\$ 142		
# Materials	\$ 1,188	\$ -	\$ 48	\$ 427	\$ 621	\$ 93		
# Overheads - External	\$ 1,211	\$ 103	\$ 122	\$ 186	\$ 578	\$ 221		
Total	\$ 8,790	\$ 862	\$ 964	\$ 1,488	\$ 3,578	\$ 1,898		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ 7	\$ -	\$ -	\$ -	\$ -	\$ 7		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ 7	\$ -	\$ -	\$ -	\$ -	\$ 7		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 13,247	\$ 710	\$ 737	\$ 834	\$ 1,440	\$ 3,450	\$ 6,076	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 56,901	\$ -	\$ -	\$ 373	\$ 2,865	\$ 15,615	\$ 36,295	\$ 1,754
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 540	\$ -	\$ -	\$ 110	\$ 125	\$ 126	\$ 126	\$ 54
# Internal, Overheads	\$ 7,329	\$ -	\$ -	\$ 234	\$ 1,091	\$ 2,398	\$ 3,271	\$ 335
# Materials	\$ 44,987	\$ -	\$ -	\$ 2,381	\$ 11,489	\$ 18,760	\$ 10,501	\$ 1,856
# Overheads - External	\$ 7,121	\$ -	\$ -	\$ 230	\$ 1,008	\$ 2,278	\$ 3,276	\$ 329
Total	\$ 130,125	\$ 710	\$ 737	\$ 4,161	\$ 18,018	\$ 42,627	\$ 59,544	\$ 4,328

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Materials	\$ 56	\$ 7	\$ 8	\$ 8	\$ 8	\$ 8	\$ 8	\$ 9
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 56	\$ 7	\$ 8	\$ 8	\$ 8	\$ 8	\$ 8	\$ 9

NYSEG T&S Asset Condition Replacement Program

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-003022	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2027

Project description:

The T&S Asset Condition Replacement Program aims to enhance the health of NYSEG systems through comprehensive facility surveys and a long-term mitigation strategy. The 5-year plan focuses on assessing underground cable facilities, prioritizing needs based on failure risk and customer impact, and developing projects to replace cables beyond their useful life. Additionally, the plan includes rejuvenating cables that show signs of aging but are still within their useful life.

The investment plan allocates small expenditures in 2026 and larger investments from 2027 onwards for specific underground replacement and rejuvenation projects. Approximately 17.39% of NYSEG customers rely on aging underground cable systems, spanning 3,146 cable miles with average ages ranging from 25 to over 100 years. Increased underground cable failures over the past four years highlight the urgent need for detailed assessments to identify asset conditions, maintenance, and operational needs.

The project's primary objective is to conduct a comprehensive needs assessment of NYSEG's underground cable systems, evaluating asset conditions and identifying maintenance and operational needs. This assessment aims to develop a prioritized plan for cable replacement, rejuvenation, and maintenance, mitigating risks associated with aging infrastructure and ensuring reliable electric service.

Improving data accuracy in the SAP database is also a key goal. Accurate data is essential for effective asset management and decision-making. The assessment will verify and correct existing data, gather new information through field inspections and testing, and support the development of a robust prioritization algorithm for resource allocation.

Following the assessments, the project will implement cable replacements and rejuvenation based on the prioritized plan. These interventions will optimize capital expenditures for reliability improvements, enhancing the performance and sustainability of the underground infrastructure. This project is a critical step towards modernizing NYSEG's underground cable systems, addressing aging infrastructure, and improving data accuracy. The successful completion of this project will benefit both the utility company and its customers, providing a more resilient and dependable electric service across NYSEG.

Project Scope:

The scope of the project involves engaging a contractor to perform a detailed assessment of the underground transmission and distribution cable systems. This includes using cable system assessment technologies such as TDR, Tan-Delta, and Partial Discharge. Where needed, the contractor will correct or update erroneous mapping of the underground cable system, verify cable age, type, length, and in-service dates, assess cable loading and termination conditions, evaluate gas usage for nitrogen-filled cables, conduct oil testing for high-pressure oil-filled cables, and assess cathodic protection, among other tasks. Based on the assessment results, a prioritization algorithm will be developed to guide resource allocation for cable replacement, rejuvenation, and maintenance efforts.

In addition to the assessment and prioritization, the scope of work will include the actual replacement or rejuvenation of the identified cables as part of the project. This means that the contractor will not only identify the cables that need attention but, together with internal resources, they will also carry out the necessary interventions to ensure the reliability and safety of the underground cable systems. This comprehensive approach ensures that the project addresses both the diagnostic and corrective aspects of cable management.

The project deliverables include a comprehensive assessment report detailing the condition of the underground cable systems, a prioritized list of recommended interventions, updated and accurate data in the SAP database, and recommendations for improving system reliability and safety. The inclusion of actual replacement or rejuvenation activities as part of the deliverables ensures that the project outcomes are actionable and lead to tangible improvements in the cable infrastructure.

The project is expected to commence in 2026, with the assessment and prioritization phase taking approximately 24 months. The remaining work, including the actual replacement or rejuvenation of cables, will span a period of 20+ years, contingent on funding approval. Currently, the estimated per mile cost of underground (UG) cable replacements is \$3.6 million per mile for transmission cables and \$2 million per mile for distribution cables.

For NYSEG, we plan to replace 1 transmission mile every 3 years. Distribution underground starts with 15-17 miles per year and increases to 20 miles per year after 2028.

Project Benefits:

This project provides five (5) distinct benefits:

(1) Improve system reliability. By conducting a comprehensive needs assessment and identifying the condition of the underground cables, the project will help mitigate the risks associated with aging infrastructure. This proactive approach will reduce the frequency of outages and failures, ensuring a more consistent and dependable electric service for customers.

(2) Optimize capital expenditures. By developing a prioritized plan for cable replacement, rejuvenation, and maintenance, the project will ensure that resources are allocated efficiently. This targeted approach will maximize the impact of investments, leading to cost-effective improvements in the underground systems' performance and longevity.

(3) Enhance data accuracy. By verifying and correcting existing data in the SAP database and gathering new information through field inspections and testing, the project will improve the quality of data used for asset management and decision-making. Accurate data is crucial for developing effective maintenance strategies and ensuring the long-term sustainability of the underground infrastructure.

(4) Improve safety. By addressing the aging underground cables and implementing necessary interventions, the project will reduce the risk of cable failures that could pose safety hazards. This will create a safer environment for both utility workers and the general public.

(5) Support future growth and demand. By modernizing the underground cable systems and ensuring they can meet current and future demands, the project will provide a robust foundation for the continued development of the electric grid. This will support economic growth and development in the region, benefiting both the utility company and its customers.

Overall, this project represents a critical investment in the future of NYSEG's underground cable systems, delivering significant benefits in terms of reliability, cost-efficiency, data accuracy, safety, and capacity to meet future demands.

Project Risks and Mitigation Plan:

The project to assess and upgrade NYSEG's underground cable systems carries several risks that need to be addressed to ensure its success. Here are the key risks and their corresponding mitigation plans:

Risk

Incomplete or Inaccurate Data Collection: The project relies heavily on accurate data to assess the condition of the underground cables. Inaccurate or incomplete data can lead to incorrect assessments and suboptimal decision-making.

Mitigation

Implement a robust data verification process that includes cross-referencing existing data with field inspections and testing. Utilize advanced data collection technologies and methodologies to ensure comprehensive and accurate data gathering. Regular audits and quality checks should be conducted throughout the project to maintain data integrity.

Risk

Unanticipated Cable Failures During Assessment: Given the aging infrastructure, there is a risk that cables may fail unexpectedly during the assessment phase, causing service disruptions.

Mitigation

Develop a contingency plan that includes rapid response teams and backup systems to address any unexpected failures promptly. Ensure that all assessment activities are closely monitored and that any signs of potential failure are addressed immediately. Additionally, communicate with customers about the potential for temporary disruptions and the measures being taken to minimize them.

Risk of Insufficient Funding or Resource Allocation: The project requires significant investment in terms of capital and resources. Insufficient funding or misallocation of resources can hinder the project's progress and effectiveness.

Mitigation

Secure funding commitments from stakeholders and ensure a detailed budget plan is in place. Prioritize project activities based on criticality and potential impact on system reliability. Regularly review and adjust the budget and resource allocation to align with project needs and progress.

Risk

Delays in Project Implementation: Delays in the assessment and subsequent implementation phases can extend the period during which the aging infrastructure remains vulnerable, increasing the risk of failures.

Mitigation

Develop a detailed project timeline with clear milestones and deadlines. Implement project management best practices, including regular progress reviews, risk assessments, and contingency planning. Engage experienced project managers and ensure effective communication and coordination among all project teams.

Risk

Stakeholder Resistance or Lack of Support: Resistance from stakeholders, including utility employees, regulatory bodies, and customers, can impede project progress and acceptance.

Mitigation

Engage stakeholders early in the project to build support and address concerns. Provide transparent and regular updates on project progress and benefits. Conduct training and awareness programs for utility employees to ensure they understand the project's importance and their role in its success. Foster a collaborative environment where stakeholder feedback is valued and incorporated into project planning and execution.

By addressing these risks with comprehensive mitigation plans, the project can proceed smoothly and achieve its objectives of improving the reliability, safety, and sustainability of NYSEG's underground cable systems.

Risk of No Action:

If no action is taken to address the aging underground systems, the risks to the reliability and performance of electric service will continue to escalate. With 17.39% of NYSEG customers relying on these aging systems, the potential for widespread service disruptions is significant. The underground systems, spanning 3146 cable miles include cables that are over 100 years old. The increasing frequency of underground cable failures over the past four years underscores the urgent need for a detailed assessment to identify asset conditions, maintenance, and operational needs.

Without a comprehensive needs assessment, the condition of the underground cables will remain uncertain, leading to unanticipated failures and outages. The lack of a prioritized plan for cable replacement, rejuvenation, and maintenance will result in a reactive approach to infrastructure management, which is less efficient and more costly. The continued degradation of the underground systems will compromise the reliability of electric service, causing inconvenience and potential safety hazards for customers.

Inaccurate and outdated data in the SAP database will further exacerbate the challenges of managing the underground cable systems. Without verifying and correcting existing data, and gathering new information through field inspections and testing, the utility companies will struggle to make informed decisions about asset management. This lack of accurate data will hinder the development of effective maintenance strategies and resource allocation, leading to suboptimal use of capital expenditures and increased operational risks.

The absence of a proactive approach to addressing the aging infrastructure will also pose significant safety risks. Aging cables are more prone to failures, which can lead to hazardous situations for both utility workers and the public. Without timely interventions, the risk of accidents and injuries will increase, compromising the safety of the electric service environment.

Ultimately, failing to modernize NYSEG's underground cable systems will jeopardize the long-term sustainability of the electric grid. The inability to meet current and future demands will hinder economic growth and development in the region. The continued reliance on outdated infrastructure will result in higher maintenance costs, reduced system reliability, and increased customer dissatisfaction. Taking no action will not only affect the utility companies' performance but also negatively impact the quality of life for their customers.

Project Alternatives:

When considering alternatives to the proposed project for assessing and upgrading NYSEG's underground cable systems, several options emerge, each with its own set of benefits and drawbacks.

One alternative is to continue with the current reactive maintenance approach. This would involve addressing cable failures as they occur without a comprehensive needs assessment or proactive replacement plan. While this option may initially seem cost-effective, it carries significant risks. The increasing frequency of underground cable failures suggests that this approach will likely lead to higher long-term costs due to emergency repairs and service disruptions. Additionally, the reliability and performance of the electric service will continue to degrade, causing inconvenience and potential safety hazards for customers.

Another alternative is to implement a partial upgrade focused on the most critical areas. This would involve identifying and replacing only the most at-risk cables based on available data. While this targeted approach could improve reliability in the short term, it may not address the underlying issues of aging infrastructure comprehensively. The lack of accurate and up-to-date data in the SAP database could lead to suboptimal decisions about which cables to prioritize, potentially leaving significant vulnerabilities unaddressed.

A third alternative is to invest in advanced monitoring and diagnostic technologies to continuously assess the condition of the underground cables. This approach would involve installing sensors and other monitoring equipment to detect early signs of cable degradation and failures. While this could provide valuable real-time data and help prevent unexpected outages, it would still require significant investment and may not fully address the need for a comprehensive replacement and rejuvenation plan. Additionally, the effectiveness of this approach depends on the accuracy and reliability of the monitoring technologies.

A fourth alternative is to outsource the entire assessment and upgrade process to a specialized third-party contractor. This could leverage the expertise and resources of a company experienced in managing underground cable systems. While this option could potentially expedite the project and ensure high-quality results, it may also involve higher costs and require careful oversight to ensure alignment with NYSEG and RG&E's specific needs and standards.

Another option is to implement a phased replacement over an extended period. This approach involves spreading the replacement and rejuvenation of underground cables over a longer time frame, such as 10-20 years. While this can help manage costs and resource allocation more effectively, it also means that many aging cables will remain in service for an extended period, increasing the risk of failures and outages. The prolonged timeline may also lead to higher cumulative costs due to inflation and the need for ongoing emergency repairs.

An enhanced preventive maintenance program is another alternative. Instead of a full-scale replacement, this approach focuses on significantly ramping up preventive maintenance activities, such as regular inspections, testing, and minor repairs. While this can help extend the lifespan of existing cables and reduce the frequency of failures, it may not be sufficient to address the fundamental issues of aging infrastructure. The effectiveness of preventive maintenance is limited, and it may only delay the inevitable need for major replacements.

Selective use of cable rejuvenation technologies is another option. Cable rejuvenation involves injecting a fluid into the insulation of aging cables to restore their dielectric properties and extend their lifespan. This can be a cost-effective alternative to full replacement. However, rejuvenation is not suitable for all types of cables or all conditions, and its effectiveness can vary. There is also a risk that rejuvenated cables may still fail prematurely, leading to unexpected outages and additional costs.

Each of these alternatives offers potential benefits but also comes with significant risks. The proposed comprehensive needs assessment and prioritized replacement plan remains the most balanced approach, addressing the aging infrastructure holistically while mitigating risks and optimizing resource allocation.

These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, Avangrid Master Service Agreement rates from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Escalation rates are based upon current U.S. inflation rates. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

[illegible]

NYSEG PCB Transformer Replacements

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-003650	Charge Code: Electric Distribution	Project Sponsor: Potter, George	Project Type: Project
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The NYSEG PCB Transformer Replacement Program is a focused initiative to identify and replace distribution transformers containing Polychlorinated Biphenyls (PCBs) as part of NYSEG's commitment to environmental compliance and public safety. By addressing these aging assets, the program not only ensures compliance with environmental regulations but also reduces risks associated with transformer failures, ultimately supporting the reliability and safety of the electric distribution system.

Project Scope:

The program is designed to target transformers identified as containing PCBs. Field reviews and site assessments will guide the design and planning for replacements, ensuring a systematic and effective approach. Decommissioned transformers will be removed and disposed of in accordance with NYSEG standards.

The following units and average unit costs will be addressed between 2025-2031:

2025 - 400 (units) / \$8,000 (unit cost)
 2026 - 395 (units) / \$8,240 (unit cost)
 2027 - 405 (units) / \$8,487 (unit cost)
 2028 - 417 (units) / \$8,742 (unit cost)
 2029 - 436 (units) / \$9,004 (unit cost)
 2030 - 454 (units) / \$9,274 (unit cost)
 2031 - 471 (units) / \$9,552 (unit cost)

Project Benefits:

The primary benefit of the NYSEG PCB Transformer Replacement Program is the removal and proper disposal of PCB-containing transformers and reducing environmental risks. The program also underscores NYSEG's commitment to sustainability, regulatory compliance, and the responsible modernization of its electric distribution infrastructure.

Project Risks and Mitigation Plan:

The Company must align with State and Federal reliability standards which is evidence of the Company's commitment to these standards through a well executed program. The program identifies tasks within same reach to help reduce operational costs and improve the timeliness of the execution plan. As this program matures, the expectation is that all PCB Transformers are to be replaced.

Risk of No Action:

The PCB Transformer replacement program proactively replaces PCB transformers to prevent potential increases in environmental risks. Without this proactive work, the system may experience more environmental exposure. Additionally, there are risks of negatively impacting SAIFI goals, environmental factors, supply chain stability, public perception, and facing regulatory penalties.

Project Alternatives:

The PCB transformer replacement program aims to replace one-for-one assets that identified as containing PCB's. Alternatives are considered on a case-by-case basis to ensure the most effective solutions are implemented.

Basis for Project Estimates

The financial plan is based on an average cost per transformer replacement. The average cost is determined by the cost of construction crews, internal labor costs, material costs, disposal, and overheads applicable to replacing a transformer.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:		Total	2020	2021	2022	2023	2024
	Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 250	\$ -	\$ -	\$ 39	\$ 47	\$ 51	\$ 55	\$ 58
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 13,631	\$ 1,761	\$ 1,690	\$ 1,842	\$ 1,919	\$ 2,031	\$ 2,141	\$ 2,248
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 2,889	\$ 375	\$ 347	\$ 392	\$ 408	\$ 432	\$ 456	\$ 478
# Internal, Overheads	\$ 2,230	\$ 298	\$ 332	\$ 272	\$ 271	\$ 286	\$ 334	\$ 435
# Materials	\$ 9,391	\$ 1,064	\$ 1,217	\$ 1,165	\$ 1,271	\$ 1,409	\$ 1,556	\$ 1,711
# Overheads - External	\$ 2,702	\$ 345	\$ 402	\$ 337	\$ 333	\$ 351	\$ 407	\$ 527
Total	\$ 31,094	\$ 3,844	\$ 3,988	\$ 4,048	\$ 4,249	\$ 4,560	\$ 4,948	\$ 5,458

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

South Perry New Sub & Trans Line Upgrade

PROJECT INFORMATION

OpCo: NYSEG	Project ID: UH-N0000106-NYSEG-ET	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

South Perry is an existing 230/115/69/34.5 kV substation located at Middle Reservation Road, Castile, NY within the Hornell Division. It consists of two separate yards for 230 kV constructed in 2018, and a 115/69/34.5 kV yard initially constructed in 1955.

South Perry substation directly serves roughly 30 MW of load to approximately 8,218 customers.

The newly built 230 kV yard is configured as a 230kV ring bus, connected to two (2) incoming 230 kV lines (L87 to Meyer and L85 to Wethersfield (NG)), and to one (1) 230/115/34.5 kV 224 MVA transformer (4T) currently energized but not connected to the 115 kV bus (no-load condition).

The load at potential risk is 30.5 MW (unacceptable loss under N-1 according to Loss of Load criteria) and customer count is 8,218, including the Town of Castile.

A comprehensive needs assessment conducted in 2021/22 identified many assets health issues including structural deficiencies, foundations beyond repair, and equipment in poor condition.

Project Scope:

The selected solution for South Perry substation is a full rebuild with a 115 kV GIS 4-BAY BAAH, 34.5 kV GIS straight bus and 69 kV AIS straight bus. This alternative retires the existing RGE STA 162 substation to merge with South Perry. The full scope details are as follows:

1. Rebuild 115 kV AIS bus as a GIS 4-bay BAAH
2. Connect the 230/115 kV transformer Bank 4 to 115 kV BAAH (temporarily run the low side disconnect switch on normally open position until Line 934 is reconductored)
3. Decommission Station 162 and re-route lines to the 115 kV BAAH
4. Add one new 115/34.5 kV transformer (50 MVA)
5. Reguild the 34.5 kV AIS bus to a GIS straight bus with a tie breaker
6. Interconnect a solar project
7. Replace a 34.5 kV ground bank

Project Benefits:

Reliability: System deficiencies that result from the application of regional and local planning standards (e.g. voltage, thermal etc.).

Asset Condition – Structural: Deficiencies based on visual and structural loading assessment.

Asset Condition – Other: A broad range of deficiencies such as NPCC requirements, obsolete or unsupported equipment at or near its end of life, poor operating or maintenance history, known operational issues or complexities, etc.

The core benefits of scope above was to relieve N-1 loss of load exposure in the area and improve system reliability in the Hornell area.

Project Risks and Mitigation Plan:

The main project risks are:

- Awarding of 115kV and 34.5 kV GIS equipment.

34.5 kV GIS supply has already been awarded and 115kV GIS supply will be awarded in the summer.

- Long lead times for materials.

Anticipate Detailed Engineering and work with standard materials and suppliers frameworks.

- Avoiding extending the yard and/or changing any existing easement or property limit.

Anticipate Detailed Engineering and make a proper analysis of the layout involving the GIS supplier to reduce the yard print.

Work with Operations to make sure the proposed lines design is acceptable. The proposed yard extension and line deviation is within our property limits.

- Avoid disconnecting the substation and having long outages.

Coordinate the works with Operations and anticipate Detailed Engineering. We will try to execute most of the work without an outage if we manage to make a temporary reroute of the existing line.

Risk of No Action:

Asset Condition:

- Circuit Breakers: 2 out of 5 (40%) 115 kV breakers, 2 out of 6 (33%) of the 34.5 kV breakers, and the only dedicated 69 kV breaker are rated1 poor/very poor in asset health condition.

- Ground Bank: The 34.5kV ground transformer is rated2 poor in asset health condition.

- Switches: 45% of 115kV switches, 85% of 34.5kV switches, 100% of 69kV switches are determined3 to be poor in condition.

- Insulators: The majority of 115kV switches and strain bus insulators are aged brown glass types that are obsolete and prone to failure.

- SP&C: Substation relies mostly on obsolete electromechanical relays and SCADA automation with limited capabilities and are unsupported by their manufacturers.

- Control House: The 115kV control building has very limited/no room for any major upgrade. Building interior and exterior finishes do not meet building NEC/NFPA 70 code requirements for fire barrier and propagation.

- Additional equipment: Station service transformers, 69kV instrument transformers are determined to be poor in condition.

Other Needs (Thermal Ratings):

- [REDACTED]

Project Alternatives:

Alternative 1:

Full rebuild 115 kV GIS 4-BAY BAAH, 34.5 kV GIS straight bus, and 69 kV AIS straight bus. This alternative utilizes one new 115/34.5 kV 56 MVA transformer, one existing 115/34.5 kV 56 MVA transformer, and one existing 115/69 kV 50 MVA transformer. This alternative retains the existing RGE STA 162 substation.

Alternative 2:

Full rebuild 115 kV AIS 4-BAY BAAH, 34.5 kV GIS straight bus, and 69 kV AIS straight bus. This alternative utilizes one new 115/34.5 kV 56 MVA transformer, one existing 115/34.5 kV 56 MVA transformer, and one existing 115/69kV 50 MVA transformer. This alternative retains the existing RGE STA 162 substation.

Alternative 3:

Full rebuild 115 kV AIS 4-BAY BAAH, 34.5 kV GIS straight bus, and 69 kV AIS straight bus. This alternative utilizes one new 115/34.5 kV 56 MVA transformer, one existing 115/34.5 kV 56 MVA transformer, and one existing 115/69 kV 50 MVA transformer. This alternative retires the existing RGE STA 162 substation and merges with South Perry Substation.

Alternatives 1 and 2, which retain Station 162, were not selected since they would keep a substation with equipment in poor condition & with straight a bus configuration. Keeping the three (3) separate station yards makes O&M undesirable as well as increases the cost. The selected solution has the lowest construction complexity, fastest schedule, and lowest cost of all the alternatives.

Basis for Project Estimates

Estimate based on historical projects:

1. Pequannock Substation (Similar GIS layout).

2. Existing GIS proposals.

3. Current framework agreements for different materials and engineering costs.

4. Working together with Meyer SS rebuild (similar configuration).

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 339	\$ 26	\$ 45	\$ 54	\$ 85	\$ 129		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 1,215	\$ 180	\$ 122	\$ 149	\$ 294	\$ 471		
# Internal - Non-AC	\$ 3	\$ 0	\$ 0	\$ 0	\$ 1	\$ 2		
# Internal, Labor	\$ 324	\$ 83	\$ 12	\$ 36	\$ 106	\$ 86		
# Internal, Overheads	\$ 295	\$ 33	\$ 20	\$ 22	\$ 56	\$ 165		
# Materials	\$ 443	\$ -	\$ -76	\$ -	\$ 43	\$ 476		
# Overheads - External	\$ 508	\$ 63	\$ 30	\$ 43	\$ 133	\$ 239		
Total	\$ 3,128	\$ 385	\$ 152	\$ 304	\$ 718	\$ 1,568		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:		Total	2020	2021	2022	2023	2024
	Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 10,380	\$ 303	\$ 815	\$ 1,617	\$ 7,644	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 20,349	\$ 586	\$ 3,349	\$ 5,752	\$ 10,662	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 449	\$ 80	\$ 100	\$ 85	\$ 184	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 4,077	\$ 341	\$ 1,175	\$ 1,037	\$ 1,523	\$ -	\$ -	\$ -
# Materials	\$ 29,954	\$ 3,029	\$ 8,319	\$ 7,775	\$ 10,830	\$ -	\$ -	\$ -
# Overheads - External	\$ 3,863	\$ 301	\$ 1,100	\$ 987	\$ 1,475	\$ -	\$ -	\$ -
Total	\$ 69,072	\$ 4,641	\$ 14,858	\$ 17,254	\$ 32,318	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Meyer Substation Rebuild

PROJECT INFORMATION

OpCo: NYSEG	Project ID: UH-N0000064-NYSEG-ET	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

The intent of the Meyer Substation Rebuild Project is to completely replace the 115 kV, 34 kV and 12 kV sections of the existing station with a modern Gas Insulated Switchgear (GIS) solution and upgrade all distribution circuits to 12.5 kV for the purpose of addressing asset condition and reliability needs. The use of GIS to replace the transmission and distribution elements offers a compact, modern, safe, and efficient alternative to the conventional Air Insulated Switchgear (AIS) configuration. A new control building is included in the plan to enclose the protection and control cabinets, telecommunication equipment, and battery banks for the entire substation. The new GIS yard requires the acquisition of 4 acres of new land so its construction can begin while the existing substation is in service.

Meyer substation is an existing 230/115/34.5/12.5/4.8 kV BPS station, initially constructed in 1948, located at 9740 Frontage Rd, N Dansville NY, within the Hornell Division. It serves roughly 60 MW of load to approximately 6,740 customers.

Due to asset condition concerns, the existing 230 kV Air Insulated Switchgear (AIS) will be updated with a new circuit breaker protected 230/121/36.2 KV 268.8/358.4/448 MVA TER 39/52/65 MVA auto transformer. The assets' poor health makes it prudent to execute this phase of the work with due urgency. The new bank and breakers will be isolatable with disconnects on both sides of the respective equipment. Bank 6 will be replaced adjacent to the existing 230kV bank such that the installation can be made while the existing transformer is operational. The Bank 6 replacement requires the expansion of the existing yard and the realignment of existing bus work.

All of the decommissioned elements will be demolished and disposed of.

Project Scope:

1. Land purchase and yard expansion.
2. New fence and security.
3. Upgrade 230 kV Transformer with new breaker protection and disconnect isolation.
4. Upgrade 230 kV bus, transformer, breaker protection, and control scheme within the existing control house, adding three additional cabinets.
5. Install one (1) Protection and Control building with A and B systems and battery backup complete with foundation, AC/DC power, HVAC, and security.
6. Install two (2) new 115/34.5 kV LTC 30/40/50 MVA YΔ transformer banks protected by the 115 kV GIS.
7. Install 115 kV GIS comprised of foundation, building, GIS, and Local Control Cabinets feeding lines 966, 724 and 934. Includes a capacitor bank breaker.
8. Refurbish/Reuse an existing PH 12/16/20 MVA 34.5 - 13.09Y/7.56 KV W/LTC protected by the 34kV GIS.
9. Install two (2) 34.5 kV GIS comprised of foundation, building, GIS, and Local Control Cabinets feeding lines 549 and 565. Includes mobile tap breakers.
10. Install one (1) 12.5 kV compact enclosure GIS feeding circuits 350, 351, 352 and 353. Includes a mobile tap breaker.
11. Upgrade and convert existing 4.8 kV circuits to 12.5 kV. Maintain Bank 5.

Project Benefits:

Voltage and thermal violations are revealed under N-1-1 contingency:

The core benefit of this scope is to allow for adequate voltages and thermal conditions to be maintained in the area and improve system capacity & reliability.

The rebuild and enhancement of the substation provides increased reliability to the customer base. Gas Insulated Switchgear (GIS) offers several benefits including: compact size, reduced maintenance needs, high reliability, enhanced safety due to its enclosed design, suitability for harsh environments, and the ability to minimize space requirements compared to traditional air-insulated switchgear. The replacement of deteriorated structures and equipment also improves reliability by preventing asset condition related failures.

Project Risks and Mitigation Plan:

Sudden failure of Bank 6

- Development of a coordination plan to have a trailer mounted mobile transformer available for rapid restoration and continued operation of the station.
- Expedite the replacement of Bank 6. Use of the transformer that was procured for New Gardenville saving time of procurement. Expedited design and issuance of contracts associated with Bank 6.

Inferior subsurface conditions

- Performance of geotechnical studies and preemptive mitigation plans to stabilize the subsurface soils and achieve the required loading capacities.

Integration of the 115 kV GIS

- Issuance of a Design Build Contract for the 115 kV GIS thereby minimizing the risk that the foundation and building will not accommodate the appurtenances of the GIS and streamlining the design, manufacture, and installation.

Supply Chain and Long Lead Times

- Purchase standardized equipment.
- Prioritize and advance the specification of equipment.
- Include Liquidated Damages clause in contracts for missed milestones.

Risk of No Action:

The decision to take no action would result in the continued operation of aged equipment in poor health, lacking modern protection and control. Bank 6 will inevitably fail causing a significant outage and requiring the use of vital mobile transformer. System deficiencies that result from the application of regional and local planning standards will remain unaddressed negatively affecting reliability. Asset condition deficiencies such as NPCC requirements, obsolete or unsupported equipment at or near its end of life, poor operating or maintenance history, known operational issues or complexities, etc. will remain unaddressed leading to failure, interruption of service and safety infringements.

Project Alternatives:

1. 230/115/34.5 kV transformer replacement, and full rebuild 115 kV GIS 3-BAY BAAH, 34.5 kV GIS straight bus, in-kind 12.5 kV AIS breaker replacement. This alternative re-purposes South Perry 230/115/34.5 kV transformer (bank #4) and reuses it at Meyer; utilizes two new 115/34.5 kV 50 MVA transformers, and one existing 34.5/12.5 kV 22.4 MVA transformer. This alternative also retires the existing 34.5/4.8 kV transformer and converts existing 4.8 kV circuit to 12.5 kV.
2. 230/115/34.5 kV transformer replacement, and full rebuild 115 kV AIS 3-BAY BAAH, 34.5 kV & 12.5 kV GIS straight bus. This alternative re-purposes South Perry 230/115/34.5 kV transformer (bank #4) and reuses it at Meyer; utilizes two new 115/34.5 kV 50 MVA transformers, and one existing 34.5/12.5 kV 22.4 MVA transformer. This alternative also retires the existing 34.5/4.8 kV transformer and converts existing 4.8kV circuit to 12.5kV.
3. Full rebuild to 230 kV GIS Ring, 115 kV GIS 3-BAY BAAH, 34.5 kV & 12 kV GIS straight bus. This alternative re-purposes South Perry 230/115/34.5 kV transformer (bank #4) and reuses it at Meyer; utilizes two new 115/34.5 kV 50 MVA transformers, and one existing 34.5/12.5 kV 22.4 MVA transformer. This alternative also retires the existing 34.5/4.8 kV transformer and converts existing 4.8kV circuit to 12.5kV.

While the first alternative had the lowest cost, the selected solution had a more flexible construction schedule, shorter expected outage durations, and lower construction complexity. Alternative 2 was dismissed due to significant real estate constraints. Alternative 3 was not selected because it was the highest cost, least flexible, and most complex of the different solutions.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 3,646	\$ 516	\$ 624	\$ 609	\$ 760	\$ 1,136		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 2,178	\$ 256	\$ 249	\$ 146	\$ 397	\$ 1,130		
# Internal - Non-AC	\$ 2	\$ 0	\$ -	\$ 0	\$ 1	\$ 1		
# Internal, Labor	\$ 318	\$ 28	\$ 9	\$ 40	\$ 99	\$ 142		
# Internal, Overheads	\$ 1,473	\$ 33	\$ 37	\$ 22	\$ 451	\$ 930		
# Materials	\$ 6,326	\$ -	\$ -	\$ -	\$ 2,354	\$ 3,972		
# Overheads - External	\$ 2,049	\$ 56	\$ 54	\$ 44	\$ 720	\$ 1,175		
Total	\$ 15,992	\$ 890	\$ 974	\$ 862	\$ 4,781	\$ 8,485		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 19,080	\$ 1,993	\$ 2,131	\$ 3,525	\$ 11,431	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 21,726	\$ 4,214	\$ 966	\$ 4,191	\$ 12,356	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 515	\$ 251	\$ 88	\$ 33	\$ 144	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 5,223	\$ 793	\$ 1,505	\$ 1,217	\$ 1,708	\$ -	\$ -	\$ -
# Materials	\$ 41,148	\$ 4,780	\$ 13,287	\$ 11,181	\$ 11,900	\$ -	\$ -	\$ -
# Overheads - External	\$ 4,865	\$ 745	\$ 1,355	\$ 1,118	\$ 1,647	\$ -	\$ -	\$ -
Total	\$ 92,557	\$ 12,775	\$ 19,331	\$ 21,265	\$ 39,186	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit 590 Rebuild

PROJECT INFORMATION

OpCo: NYSEG	Project ID: UH-N0005680-NYSEG-ET	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP2 Partial Approval	Start Date: Ongoing	In-Service Date: H2 2031

Project description:

Circuit 590 is a 12.7 mile Transmission Line Operating at 34.5kV. Circuit 590 contains 9.25 miles of Distribution under-build. The Transmission Line is comprised of approximately 393 wood poles. Current field conditions indicate the wood poles are of various age, length, class, and design configurations. A drone inspection was performed for the entirety of the transmission line. Asset condition was assessed for each structure based upon the drone photos. Circuit 590 is located near Perry, NY and currently connects South Perry SS to Silver Springs SS and ends at the Warsaw SS. Over 26% of the 399 wood poles are 70 years old or greater.

A structural analysis of the circuit was performed and found the following number of overstressed structures according to National Electric Safety Code 1961 (NESC) load cases:

9-Wood Poles Fail Under 1961 NESC 250B Grade B Construction.

7-Wood Poles Fail Under 1961 NESC 250B Grade C Construction.

In addition to age degradation, other criteria that contribute to reduced strength of the poles are pole weathering, pole top and pole base rot, cracks, checks, insect, and woodpecker damage. Many of the span guys and down guys have become loose over the years and no longer provide adequate structural support.

A drone inspection was commissioned so that a visual assessment of the transmission line could be performed. 214 out of 393 wood poles were deemed to be in poor condition (54%).

75% of the transmission line does not have lightning protection.

The following Distribution under-build concerns were also observed:

- Significant difficulty to avoid distribution when needing to work on transmission above.
- Cannot get bucket mounted conductor lift tool in between to work on pole or change insulators or arms.
- Insufficient vertical clearances in many cases to use hot stick methods without also moving distribution conductors.

This project will mitigate the asset condition needs identified on Circuit 590.

Project Scope:

Full Rebuild, Open Wire (\$67.1 M, ISD 2031) - Rebuild to meet NESC & current Avangrid standards. The scope of work includes

- Replacing existing distribution and transmission facilities and transfer distribution conductor.
- Existing structures that meet current specifications are to have all hardware replaced.
- ROW width shall be optimized through use of a Delta Circuit Configuration.
- Designing a Terminal Structure to prevent Cascade Failures.

Avangrid Wood Pole Structure Types for Rebuild:

- Wood Poles utilized for Tangent Structure Design.
- Light Duty Steel Poles for Angled and Strain Structure Design
- Engineered Steel Poles for Switch & Reclosure Design.

Conductor Specification:

- 12.7 miles for 477 kcmil 18/1 "Pelican" ACSR
- 12.7 miles DNO-8155- 36 count fiber OPGW

Reroute Alignment to NY RTE:

- Eliminates the difficult access between 0138-Gainsville to Warsaw-0199 for multiple stream crossings.
- Eliminates the need to grade each structure location between 0160-WARSAW and 0199-Warsaw.

Project Benefits:

This project will address all aging infrastructure on the circuit and the line will be built in accordance with Avangrid standards. Installing OPGW provides an enhanced future communication path for protection and control system upgrades. The newly rebuilt line will reduce outage risks due to increased structural resiliency and vegetation clearing during construction.

Project Risks and Mitigation Plan:

The top risk associated with the project would be worker injury during construction. This risk can be mitigated by instituting a Health and Safety Plan (HASP).

This project is in the pre-conceptual stage; a risk register has not been created for this project.

Risk of No Action:

The risks of no action on this circuit are continued outages and customer interruptions due to failed equipment, downed trees, or lightning strikes.

The operational constraints of the Distribution under-build will also continue to exist, increasing the possibility of safety events when performing work on the line.

- Significant difficulty to avoid distribution when needing to work on transmission above.
- Cannot get bucket mounted conductor lift tool in between to work on pole or change insulators or arms
- Insufficient vertical clearances in many cases to use hot stick methods without also moving distribution conductors.

Project Alternatives:

Reconductor & Selected Structure Replacements (\$47.4 M, ISD 2031):

Reconductor Line 590 with a similarly sized ACSR or ACCR. Perform structure replacements as required to mitigate visual, structural or clearance failures. Selected structures would be rebuilt with wood poles in the existing structure configuration. Angle and dead-end structures would employ the use of guy wires. The 75% of the transmission line without lightning protection would remain without lightning protection.

This alternative was dismissed because it does not address the lightning protection concerns, leaves aged assets in-service, and does not address the operational issues noted above.

Basis for Project Estimates

The estimate is derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, Avangrid Master Service Agreement rates from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Escalation rates are based upon current U.S. inflation rates. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 873	\$ 129	\$ 346	\$ 334	\$ 63	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 1,606	\$ 1,515	\$ 7	\$ 84	\$ -	\$ -		
# Internal - Non-AC	\$ 1	\$ 1	\$ 0	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 67	\$ 46	\$ 20	\$ 1	\$ -	\$ -		
# Internal, Overheads	\$ 524	\$ 489	\$ 24	\$ 11	\$ -	\$ -		
# Materials	\$ 1,788	\$ 1,702	\$ 86	\$ -	\$ -	\$ -		
# Overheads - External	\$ 713	\$ 666	\$ 30	\$ 18	\$ -	\$ -		
Total	\$ 5,573	\$ 4,548	\$ 514	\$ 448	\$ 63	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 673	\$ -	\$ -	\$ 100	\$ 108	\$ 111	\$ 221	\$ 133
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 35,650	\$ -	\$ -	\$ 5,291	\$ 5,717	\$ 5,884	\$ 11,724	\$ 7,034
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 4,622	\$ -	\$ -	\$ 673	\$ 682	\$ 689	\$ 1,490	\$ 1,088
# Materials	\$ 22,197	\$ -	\$ -	\$ 3,294	\$ 3,560	\$ 3,664	\$ 7,300	\$ 4,380
# Overheads - External	\$ 4,512	\$ -	\$ -	\$ 657	\$ 666	\$ 673	\$ 1,454	\$ 1,062
Total	\$ 67,655	\$ -	\$ -	\$ 10,015	\$ 10,732	\$ 11,020	\$ 22,190	\$ 13,697

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG - Subst Minor Capital

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-000877	Charge Code: Electric Distribution	Project Sponsor: Kuhn, Dennis	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Substation Capital Minors program is the primary capital budget is a hybrid reactive and proactive program supporting 467 substations. The program is used to replace minor failed equipment in substations in order to provide continual reliable service to our customers and to support minor betterment projects that target increased system reliability, security, as well as equipment restorations/replacements required to meet NERC regulatory requirements including PRC-005 such as relay replacements and protective communication system upgrades.

Project Scope:

The Substation Minors Betterments program covers work at substations < \$500K threshold for a major project addressing unplanned failures and planned events as a result of inspections.

Below are the 2025-2031 estimated annual work type components and average unit rates excluding overheads based on a work type cost basis historical average.

Animal Prevention - 23 @ \$51,700/each.

--Supports new installations where there are no animal fences currently and replacements of old and/or failed animal fences. Also supports installation of animal guards on bushings, bus, line exits.

Capacity Upgrades - 24 @ \$16,700/each.

- Supports requests from distribution planning - annual summer load preparedness jobs. Example - adding fans to substation transformers.

Grounds/Driveway/Control House Improvements - 13 @ \$16,700/each.

--Supports physical grounds and control house upkeep and betterments at substations. Includes driveway paving/new driveways, control house door, roof, lighting replacements, spill prevention measures.

HVAC - 13 @ \$14,200/each.

--Supports new HVAC installations at control houses that do not have them as well as failure of HVAC units at existing locations.

Instrument Transformer Replacement - 10 @ \$20,800/each

--Supports replacement of failed instrument transformers (CT's, PT's, CCVT's) in substations

Insulator Replacement - 9 @ \$41,600/each

--Supports brown glass replacements at substations as well as failures of insulators.

Lightning Replacement - 11 @ \$12,500/each.

--Supports lightning arrester replacements due to failures.

Regulator Replacement - 13 @ \$42,500/each.

--Supports regulator replacements due to load increases due to customer requests that are non-customer funded. Also supports regulator replacements due to failures

Relay/Meter/RTU/DME/Control Upgrades 13 @ \$17,500.

--Supports relay replacements, meter replacements, transformer LTC control upgrades, RTU replacements, DME replacements; mostly due to failure conditions or when required to meet a compliance activity or upgrade due to obsolete parts availability or support.

Security Fence - Gates - 11 @ \$7,500/each.

-- Supports substation gate replacements. These deteriorate due to wear and tear, new gates establish efficient entry/exit and improve security.

Security Fence - Fence - 8 @ \$68,300/each.

-- Supports replacement of perimeter fence at substations - due to security issues at substations or deterioration/failure of the fence.

Station Service - 1 @ 41,700/each.

--Supports control house AC/DC panel upgrades or replacement of obsolete. Supports upgrades/replacements of station service transformers due to failures or other identified requirements.

Switch Replacement - 13 @ \$32,000/each

--Supports replacement of switches upon failure.

Misc Costs not Detailed in Work Type \$13K.

--Examples: capacitor can replacements, mobile substation cables, ltc transformer filter system replacements as required.

The average costs were escalated by P25 - 3%; P26-P30 - 6% and P31 - 4.5%.

Refer to the 'The RC_Historical Analysis' tab for year-by-year breakdown of estimated units and average unit rate of components.

Project Benefits:

This program provides the ability to maintain and improve substation equipment and facilities that allow for the continual safe and reliable operation of the electric system as required by regulatory requirements and targets identified by the NY PSC. This program provides the company with the agility path to correct what is negatively impacting reliability in a proactive way. It additionally allows for the timely replacement of failed equipment and thus increases system reliability by limiting the duration primary equipment is out of service. Security of substations and substation equipment is heavily reliant on the substations minors budget to replace fencing, add lighting and cameras across 13 NYSEG divisions and 467 substations.

Project Risks and Mitigation Plan:

Inadequate funding, on an annual basis, has been the primary risk associated with this program. Program tracking and monitoring of available budget is continually balanced with remaining/anticipated workload, and in many cases, financial offsets are required from other planned work to fund this mandatory work throughout the year. These offsets create downstream consequences since prioritized work can no longer be executed as planned which can affect any number of factors, mainly system reliability.

Risk of No Action:

The consequences of not undertaking this project will lead to system abnormal conditions and unsafe conditions for the public and workforce. Not addressing emergent failures will have a negative impact on reliability (CAIDI) and lead to legal and regulatory scrutiny. Connecting customers and ensuring reliable service is our fundamental goal; taking no action to restore customers after equipment failure is not an option. Delayed or non-execution of customer restoration could result in fines, penalties and reputational damage. The scheduled replacement contributes to the reduction of outages because of substation equipment failures, which has been identified as the main root cause of substation outages.

Substation Minors Betterments contributes to the reduction of System Average Interruption Frequency Index (SAIFI).

Project Alternatives:

This program aims to replace outage equipment using an "in-kind" replacement strategy and therefore project alternatives are not applicable within this program.

Basis for Project Estimates

Future annual spending targets are informed by an annual analysis which considers historical itemized components and overall spending from prior years. Using prior actuals, by work type component, is the basis for future spending projections and a current and justified escalation factor is used to inform each subsequent out-year.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 2,787	\$ 576	\$ 742	\$ 496	\$ 442	\$ 531		
# CIAC	\$ -170	\$ -	\$ -156	\$ -	\$ -12	\$ -2		
# External Services	\$ 10,778	\$ 3,547	\$ 1,531	\$ 1,989	\$ 1,790	\$ 1,922		
# Internal - Non-AC	\$ 8	\$ 7	\$ -	\$ 0	\$ -	\$ 1		
# Internal, Labor	\$ 4,326	\$ 1,050	\$ 1,093	\$ 708	\$ 597	\$ 877		
# Internal, Overheads	\$ 3,470	\$ 1,055	\$ 778	\$ 546	\$ 417	\$ 674		
# Materials	\$ 7,720	\$ 2,699	\$ 1,618	\$ 1,223	\$ 778	\$ 1,401		
# Overheads - External	\$ 5,706	\$ 1,628	\$ 1,140	\$ 904	\$ 914	\$ 1,120		
Total	\$ 34,626	\$ 10,563	\$ 6,746	\$ 5,866	\$ 4,927	\$ 6,524		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ 6	\$ -	\$ -	\$ -	\$ 6	\$ -		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ 6	\$ -	\$ -	\$ -	\$ 6	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 542	\$ 65	\$ 73	\$ 71	\$ 76	\$ 81	\$ 86	\$ 90
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 18,216	\$ 2,113	\$ 2,367	\$ 2,486	\$ 2,610	\$ 2,741	\$ 2,878	\$ 3,021
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 6,965	\$ 848	\$ 946	\$ 974	\$ 1,003	\$ 1,033	\$ 1,064	\$ 1,096
# Internal, Overheads	\$ 3,248	\$ 392	\$ 487	\$ 409	\$ 408	\$ 427	\$ 495	\$ 629
# Materials	\$ 14,909	\$ 1,566	\$ 1,748	\$ 1,922	\$ 2,115	\$ 2,326	\$ 2,559	\$ 2,674
# Overheads - External	\$ 4,422	\$ 517	\$ 685	\$ 569	\$ 562	\$ 581	\$ 665	\$ 842
Total	\$ 48,302	\$ 5,501	\$ 6,306	\$ 6,431	\$ 6,774	\$ 7,189	\$ 7,747	\$ 8,353

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

General Equipment - OPS-T&D

PROJECT INFORMATION

OpCo: NYSEG	Project ID: UI-50004-NYSEG-ED	Charge Code: Electric Distribution	Project Sponsor: Shail, Joshua	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The NYSEG General Equipment Program is dedicated to the replacement of tools and equipment, specifically for Transmission and Distribution (T&D) Operations. This program ensures that employees have access to the necessary tools and equipment to perform their duties efficiently and safely. Additionally, it includes the outfitting of trucks with the required equipment to support field operations.

Project Scope:

The NYSEG General Equipment Program is designed to provide essential electrical equipment, tools, and safety gear for new employees, ensuring compliance with safety and Occupational Safety and Health Administration (OSHA) requirements. This program focuses on the replacement of tools and equipment at the end of their useful lives to maintain high safety standards. The tools and equipment covered include, but are not limited to, hammers, wrenches, pliers, gloves, climbing ropes, harnesses, equipment bags, and rubber goods.

In addition to standard tools, the program also includes the purchase of specialty tools and multi-functional testing devices to outfit vehicles for craft workers. These specialty tools include high-speed pumps, hydraulic-operated cutters and drills, Arc Flash Blankets, fault locating equipment, climbing gear, and saws.

Below are the 2025-2031 estimated annual units and average unit rates excluding overheads based on a 3-year historical average (2022 - 2024):

Hand Tools (estimated units/purchase orders = 414) \$5,068/unit*

Work Clothes (estimated units/purchase orders = 8) \$64,594/unit*

Spare Parts (estimated units/purchase orders = 7) \$7,712/unit**

Health & Safety (estimated units/purchase orders = 129) \$4,890/unit*

Grounding Kits (estimated units = 32) \$10,000/unit* - Begins in 2026

Wire Stripping Tool (estimated units = 250) \$3,040/unit - One-time purchase in 2026

In addition to the above units and average costs, the budget includes \$876K for miscellaneous items.

*Unit rates are calculated with a 3% annual escalation for 2025- 2031

Refer to the 'The RC_Historical Analysis' tab for year-by-year breakdown of estimated units and average unit rates.

Project Benefits:

Tools and equipment periodically break down and therefore it is necessary to replace them. Safety has also improved over the years due to more ergonomic tools that are lighter and have safety measures integrated to protect employees during use when performing heavy construction work.

Project Risks and Mitigation Plan:

The most common risks associated with this work are: workers may lack the necessary tools to perform construction and maintenance tasks; frequent use of manual equipment can lead to increased muscle fatigue and injuries; and insufficient personal protective equipment (PPE) for arc flash, electrical testing tools, hazardous gas sensors, blast blankets, and confined space entry equipment can result in injuries or fatalities.

Mitigation Plan: Continue to invest in safety gear, mechanized tools, and updated technology to stay current with industry advancements.

Risk of No Action:

High-risk tasks such as confined space entry, working at heights, working on live parts, using critical mechanical tools and lifts, performing hot work, line breaking or hot tapping, and working near unguarded moving parts all pose significant risks to workers. Without the proper safety gear, tools, and testing equipment, these activities can lead to serious injuries or fatalities.

Project Alternatives:

The Company sources gear and equipment through framework agreements and trusted suppliers to ensure both quality and cost-effectiveness.

There are no viable alternatives to working safely without the proper safety gear and tools. Ensuring the availability of high-quality safety equipment is essential for protecting workers and maintaining a safe working environment.

Basis for Project Estimates

The budget for this program is typically determined based on the average actual costs over the past three years.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 4,927	\$ 522	\$ 1,125	\$ 572	\$ 1,509	\$ 1,200		
# Internal - Non-AC	\$ 23	\$ 3	\$ -	\$ -	\$ 21	\$ -1		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ 9,647	\$ 2,121	\$ 1,740	\$ 1,942	\$ 1,912	\$ 1,933		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ 14,596	\$ 2,645	\$ 2,864	\$ 2,513	\$ 3,441	\$ 3,132		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 11,143	\$ 1,646	\$ 1,468	\$ 1,512	\$ 1,558	\$ 1,604	\$ 1,653	\$ 1,702
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 15,182	\$ 2,594	\$ 2,369	\$ 1,925	\$ 1,983	\$ 2,042	\$ 2,103	\$ 2,166
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 26,325	\$ 4,240	\$ 3,837	\$ 3,437	\$ 3,540	\$ 3,646	\$ 3,756	\$ 3,868

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

NYSEG - Subst Major Capital

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-001578	Charge Code: Electric Distribution	Project Sponsor: Kuhn, Dennis	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

Substation Majors is a program for substation capital improvements & upgrades that addresses emergent failures of major equipment and packages. Including but not limited to relay upgrades, breaker replacements, transformer replacements, battery replacements. All upgrades are meant to maintain and improve system reliability and area load growth across all NYSEG substation areas.

Substation Majors includes improvements of major equipment and packages, planned & unplanned to all substation equipment due to age or condition at transmission voltages.

Project Scope:

This program encompasses all needed substation capital upgrades or replacements mostly generated by failure or imminent failure but can include work related to reliability, customer load growth, age and condition of substation equipment.

Project Benefits:

Substation majors investment is needed to complete critical capital improvements to all NYSEG substations and their equipment to improve customer reliability, system stability and to identify, replace or improve equipment due to age or condition. The risk of not having this program available for needed upgrades is failing substation equipment which would directly impact system stability, customer reliability, regulatory relations and reputational risks along with exposure to larger NRA's.

Project Risks and Mitigation Plan:

Inadequate funding, on an annual basis, has been the primary risk associated with this program. Program tracking and monitoring of available budget is continually balanced with remaining/anticipated workload, and in many cases, financial offsets are required from other planned work to fund this mandatory work throughout the year. These offsets create downstream consequences since prioritized work can no longer be executed as planned which can affect any number of factors, mainly system reliability.

Risk of No Action:

The consequences of not undertaking this project will lead to system abnormal conditions and unsafe conditions for the public and workforce. Not addressing emergent failures will have a negative impact on reliability (CAIDI) and lead to legal and regulatory scrutiny. Connecting customers and ensuring reliable service is our fundamental goal; taking no action to restore customers after equipment failure is not an option. Delayed or non-execution of customer restoration could result in fines, penalties and reputational damage.

Project Alternatives:

This program aims to replace outaged equipment using an "in-kind" replacement strategy and therefore project alternatives are not applicable within this program.

Basis for Project Estimates

If project estimates are known at the time of the annual budget planning process, those costs will be used as the basis for planned funding. Typically, however, the cost of this program is based on the historical average expenditure by the Company per year, or a combination of both historical and estimated known project costs.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 201	\$ -	\$ -	\$ 33	\$ 56	\$ 112		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 2,787	\$ -	\$ -	\$ -	\$ 675	\$ 2,113		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 201	\$ -	\$ -	\$ 5	\$ 105	\$ 92		
# Internal, Overheads	\$ 818	\$ -	\$ -	\$ 162	\$ 225	\$ 431		
# Materials	\$ 2,402	\$ -	\$ -	\$ 905	\$ 803	\$ 694		
# Overheads - External	\$ 1,225	\$ -	\$ -	\$ 179	\$ 410	\$ 636		
Total	\$ 7,635	\$ -	\$ -	\$ 1,284	\$ 2,273	\$ 4,079		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:		Total	2020	2021	2022	2023	2024
	Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 217	\$ 39	\$ 37	\$ 25	\$ 26	\$ 28	\$ 30	\$ 32
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 8,430	\$ 1,082	\$ 1,080	\$ 1,134	\$ 1,191	\$ 1,251	\$ 1,313	\$ 1,379
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 394	\$ 53	\$ 53	\$ 54	\$ 56	\$ 58	\$ 59	\$ 61
# Internal, Overheads	\$ 1,115	\$ 146	\$ 163	\$ 138	\$ 138	\$ 145	\$ 169	\$ 216
# Materials	\$ 5,486	\$ 636	\$ 635	\$ 699	\$ 769	\$ 846	\$ 930	\$ 972
# Overheads - External	\$ 1,142	\$ 142	\$ 170	\$ 143	\$ 143	\$ 150	\$ 173	\$ 221
Total	\$ 16,785	\$ 2,097	\$ 2,139	\$ 2,193	\$ 2,323	\$ 2,477	\$ 2,675	\$ 2,880

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Substation Modernization - Noyes Island D

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-002512	Charge Code: Electric Distribution	Project Sponsor: Carrier, Devin	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: H1 2026	In-Service Date: H2 2029

Project description:

Noyes Island is an existing 34.5/12.5/8.3kV distribution station built in 1950, located in Binghamton Division. The 34.5kV system has three buses separated by circuit breakers which connect L414 to Northside, L416 to Glenwood, L452 to Bevier, L410 to Oakdale, and L415 to Northside. The 34.5kV system is also connected to one 13.2MVar capacitor bank with bus 2 and four distribution transformers. Bank #1 (34.5-8.3kV) is connected to bus 9 and Bank #5 (34.5-8.3kV) is connected to Bus 7. The 8.3kV bus 7 is also connected to a 2.7MVar capacitor bank. Bank # 2 (34.5-12.5kV) is connected to Bus 6 and Bank #6 (34.5-12.5kV) is connected to Bus 4. There is on 3.6MVar capacitor bank connected to the 12.5kV Bus 5. Noyes Island acts as a key junction point of the Binghamton 34.5kV sub transmission network and is at a critical location to deliver reliable power supply to customers of downtown Binghamton.

The intent of this project is to fully rebuild the Station with 34.5kV and 12.5kV Gas Insulated Substation to the 500 year flood level. Install two 37MVA 34.5/12.5kV Transformer banks with LTC. This will include installing transformer foundation with oil containment and power cable duct. Install eleven Circuit Breakers in 34.5kV GIS and twenty-four Circuit Breakers in 12.5kV GIS with associated standard numerical relays (IED'S) for protection and control equipment. To add four 12.5kV/8.3kV step down Transformer banks and keep the distribution circuit at 8.3kV. The project shall also consider installation of new 13.2MVar and 2.7MVar Capacitor bank with foundation and associated cable connection and a completely new GIS building. Refer to Electrical One Line for overall site details.

Project Scope:

The scope of work associated with this project considers:

- Install two new 34.5 DELTA/12.5 GRDY kV, 37 MVA with LTC Transformers to replace existing bank #1, #2, #5 and #6. Surge Arresters will also be added on the high side and low side of the New Transformers. The new Transformer Bank #1 and #2 will be connected to the 34.5kV and 12.5kV system via overhead conductors or rigid bus. Overhead conductors shall be insulated as necessary to meet minimum safety and clearance requirement.
- Install a new 34.5kV GIS Switchgear with 2000A/1200A circuit breakers to serve as a high side interrupting device and a new 12.5kV GIS Switchgear with 2000A, circuit breakers as a low side interrupting device.
- Install new 34.5kV, 1200A, motor-operated group-operated disconnect switch and 12.5kV, 2000A group-operated manual disconnect switches on new transformer Banks (#1 and #2) high side and low side respectively.
- Install a new 3-phase 13.2 MVar Capacitor Bank with its associated manual disconnect switches connected to 34.5kV Bus.
- Install a new 3-phase 2.7 MVar Capacitor Bank with its associated manual disconnect switches connected to 12.5 kV Bus.
- Install new control and protection relays and cabinet in GIS Control House.
- Install Cable Trench and Ducts for Power Cable connection to Distribution Transformers and Capacitor Banks.
- Upgrade existing ground grid to account for new equipment being installed in substation. Soil resistivity testing will be completed to determine the extent of additions to the existing system.
- Install new control cabling per TM2.71.14.
- Re-evaluating existing AC/DC services for new installations and future loads.

Project Benefits:

The rebuild and enhancement of the substation provides increased reliability to the customer base. Gas Insulated Switchgear (GIS) offers several benefits including: compact size, reduced maintenance needs, high reliability, enhanced safety due to its enclosed design, suitability for harsh environments, and the ability to minimize space requirements compared to traditional air-insulated switchgear.

Project Risks and Mitigation Plan:

The Noyes Island property is at an elevation 7.5 feet below the 500-year floodplain. Studies will be conducted to determine the methods by which to raise the substation and its access above this elevation. Oil containment will also be considered.

The subsurface geotechnical conditions are substandard and will not hold the loads of the substation. Studies will be conducted to determine the extent of any required mitigation practices.

When transitioning lines and remote ends to a new substation from an old, there exists significant risk if sequencing and switching is not properly planned. This project will require a detailed outage sequence plan to be developed by the Engineer and confirmed by ECC well in advance the transition.

In the current economic climate supply chains and material lead times are of concern. This poses a risk to the project schedule and cost. Our processes endeavor to mitigate this by purchasing equipment in phases. Certain materials are specified in the initiation and planning phases and the project is designed to match the equipment specified given the overall intent of the scope and electrical requirements. Early procurement is the best strategy.

Specification and procurement of other materials require a more advanced design and present a procurement risk. Standardization of materials and Master Material agreements are in place to streamline the process and use materials as readily available as possible.

Risk of No Action:

The decision to take no action would result in the continued operation of the existing aged substation and reliance on old protection and control equipment. Failure of the station including catastrophic loss of one or more critical elements would leave the City of Binghamton vulnerable to prolonged outages and great economic loss. The Company would likely be subjected to regulatory penalties and the loss of reputation.

Project Alternatives:

Two other alternative configurations were considered for this project, both a variance of the configuration on the same property to limit the amount of overhead and underground lines.

The first alternative was to configure the station elements (GIS, transformers and control house) in a linear fashion along State St, at the corner of Eldridge St. This would require the acquisition of new property and the demolition of existing commercial buildings and structures.

A second alternative assessed was to configure the substation on the Company owned property along State St and adjacent to an operating business. This concept would require open excavations along and very near to the property line of the business. This could require shoring and disruption to the owner. Additionally, this would require demolition of functioning fuel pumps, a storage building and disrupt service center operations.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 133	\$ -	\$ 4	\$ 27	\$ 48	\$ 54		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 359	\$ -	\$ 102	\$ 224	\$ 33	\$ 0		
# Internal - Non-AC	\$ 21	\$ -	\$ 21	\$ 0	\$ -	\$ -		
# Internal, Labor	\$ 173	\$ -	\$ 70	\$ 98	\$ 5	\$ -		
# Internal, Overheads	\$ 71	\$ -	\$ 27	\$ 40	\$ 4	\$ 0		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ 143	\$ -	\$ 50	\$ 82	\$ 10	\$ 0		
Total	\$ 900	\$ -	\$ 275	\$ 471	\$ 100	\$ 54		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 2,782	\$ -	\$ 325	\$ 227	\$ 325	\$ 1,897	\$ 9	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 18,489	\$ -	\$ -	\$ -	\$ 9,000	\$ 9,229	\$ 260	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 6,511	\$ -	\$ 1,476	\$ 1,033	\$ 1,476	\$ 2,521	\$ 4	\$ -
# Internal, Overheads	\$ 2,572	\$ -	\$ 269	\$ 342	\$ 850	\$ 1,095	\$ 17	\$ -
# Materials	\$ 10,600	\$ -	\$ 1,000	\$ 3,000	\$ 2,240	\$ 4,360	\$ -	\$ -
# Overheads - External	\$ 3,686	\$ -	\$ 589	\$ 495	\$ 1,096	\$ 1,488	\$ 19	\$ -
Total	\$ 44,640	\$ -	\$ 3,659	\$ 5,097	\$ 14,986	\$ 20,589	\$ 309	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Line 890 Rebuild

PROJECT INFORMATION

OpCo: NYSEG	Project ID: UH-N0000416-NYSEG-ET	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

Line 890 has been identified as being in "Poor" condition with a health score of 42% by Asset Management. This line is a 46kV line, that goes from the Blue Mountain Lake Substation to the Raquette Lake Substation, and provides services for 3,086 Customers in the respective area. The existing insulators are noted to be deteriorating on the lines, and there is presently no static wire existing for this line.

Project Scope:

The project will rebuild of 13.1 miles of 46kV lines from the Raquette Lake Substation to the Blue Mountain Lake Substation. This project will include erecting new wood poles, self-supporting laminated wood and steel poles on angles and dead-ends. The Transmission Lines will be completely reconducted with approx. 12 miles of Spacer Cable and approx. 1 mile of open wire. Underbuild replacement and/or transfers will be required along select areas of the line.

The project scope is divided in two separate WBSs to support a NYS DOT Bridge Relocation on NY Route 28 first and the full Rebuild of the Line will follow. Separate permitting (NYSDEC, USACE and APA) is required due to the timing of the Bridge Relocation. The original UH-N000416 WBS consists of 12.5 Miles in length with 250 structures and the other UH-N000456 WBS consists of 0.6 miles in length with 10 structures being completed before the NYS DOT bridge rebuild work. These segments are mostly roadside. The .6 miles phase UH-N0000456 has been completed and put in service. To date, we have added \$4.72 million to rate base and the final phase will add an additional \$30.12 million to Rate Base.

Project Benefits:

As Part of improving resiliency to the Long Lake Station, Raquette Lake and Indian Lake areas, Avangrid NYSEG has installed a Generator at the Blue Mountain Lake Substation. This Project has completed Phase 1 of installing the generators for manual operation, and is entering Phase 2 for setting up controls for remote operation along fiber being installed on T-lines. This project is independent of the Line 890 Rebuild Project and there currently are no concerns of coordination between the projects. The L890 Rebuild Project will provide updated infrastructure and resiliency by replacing deteriorated insulators and conductor. Currently there is no static wire which will be addressed as well. The pole replacements along the 13 mile stretch will update the structures to current standards and replace those installed around 1955.

Project Risks and Mitigation Plan:

Line 890 is located along NY State Route 28 within the Adirondack Park, and will require coordination of permitting and approvals by the APA, NYDOT, and NYDEC. Line 890 also includes underbuild (secondary lines) owned by National Grid from the Raquette Lake substation to NYSEG Pole existing pole #74. Line 890 is a 46kV Radial feed from the Raquette lake Substation to the Blue Mountain Lake Substation and this will need to be taken into account for the Construction outage and Sequence Plan (COSP).

Risk of No Action:

Without a static wire, this line is presently at higher risk for lighting related outages and does not meet Avangrid's standards for lightning protection. The Line's poles are an average age of 60 years old, with the majority of the poles being installed in 1955.

Project Alternatives:

N/A

Basis for Project Estimates

Estimate accuracy: +/- 25% accuracy

Design accuracy: IFC

Design: The project will rebuild of 13.1 miles of 46kV lines from the Raquette Lake Substation to the Blue Mountain Lake Substation. This project will include erecting new wood poles, self-supporting laminated wood and steel poles will be placed on angles and dead-ends. The transmission line will be completely reconducted with approximately 12 miles of Spacer Cable and approximately 1 mile of open wire. Underbuild replacement and transfers will be required along select areas of the line.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 493	\$ 53	\$ 94	\$ 112	\$ 205	\$ 29		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 3,498	\$ 217	\$ 226	\$ 202	\$ 2,853	\$ -		
# Internal - Non-AC	\$ 258	\$ 107	\$ 108	\$ 42	\$ 1	\$ 0		
# Internal, Labor	\$ 410	\$ 6	\$ 32	\$ 102	\$ 269	\$ 0		
# Internal, Overheads	\$ 559	\$ 37	\$ 54	\$ 43	\$ 425	\$ 0		
# Materials	\$ 401	\$ 0	\$ 0	\$ 0	\$ 401	\$ -		
# Overheads - External	\$ 1,143	\$ 60	\$ 81	\$ 88	\$ 914	\$ 0		
Total	\$ 6,763	\$ 481	\$ 595	\$ 589	\$ 5,068	\$ 30		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 2,282	\$ 192	\$ -	\$ 546	\$ 1,544	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 16,042	\$ -	\$ -	\$ 6,412	\$ 9,607	\$ 23	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 1,426	\$ -	\$ -	\$ 834	\$ 591	\$ 1	\$ -	\$ -
# Materials	\$ 4,923	\$ -	\$ -	\$ 4,923	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 1,414	\$ -	\$ -	\$ 799	\$ 613	\$ 1	\$ -	\$ -
Total	\$ 26,087	\$ 192	\$ -	\$ 13,514	\$ 12,355	\$ 26	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG URD Replacement Program

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-003651	Charge Code: Electric Distribution	Project Sponsor: Potter, George	Project Type: Project
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The purpose of this program is to replace underground facilities with aged or failing equipment and access difficulties.

Many of the NYSEG URDs were built in the 1970s and 1980s and are 40-50+ years old. The underground infrastructure in these developments are aging and experience an increasing number of failures as the infrastructure begins to break down. The electric cable utilized in these installations were traditionally a concentric neutral style design with the neutral located on the outside of the cable. This design leads to severe corrosion along the cable. In addition to an increase in full cable failures, the breakdown of the neutral also tends to lead to an increase in stray voltage conditions in the developments. All manufacturers of this style cable have highly recommended any current cable under this design be replaced as soon as possible. Many of the developments also utilized vaults with underground, submersible transformers as opposed to the current standard of above ground, pad-mounted transformers. The former design creates difficulties in accessing the equipment and can lead to extended outage times during maintenance and repairs.

Project Scope:

This program will be upgrading underground facilities by installing new underground cables in new ductwork and replacing submersible equipment with new above ground pad mounted devices.

The following units and average unit costs will be addressed between 2025-2031:

2025 - 9,438 (units) / \$85 (unit cost)
2026 - 8,865 (units) / \$88 (unit cost)
2027 - 9,443 (units) / \$90 (unit cost)
2028 - 9,679 (units) / \$93 (unit cost)
2029 - 10,087 (units) / \$96 (unit cost)
2030 - 10,474 (units) / \$99 (unit cost)
2031 - 10,834 (units) / \$101 (unit cost)

Unit is defined as feet of cable

Project Benefits:

Due to the aging condition of the direct buried cable equipment and the access difficulties, a full replacement of these underground facilities is necessary. Replacement of the aging infrastructure will help to improve the overall reliability for the customers within the subdivision and reduce future maintenance costs.

Project Risks and Mitigation Plan:

The Company must align with State and Federal reliability standards which is evidence of the Company's commitment to these standards through a well executed program. The program identifies tasks within same reach to help reduce operational costs and improve the timeliness of the execution plan. As this program matures, the expectation is that all identified direct buried cable will be replaced.

Risk of No Action:

The URD replacement program proactively identifies high-risk direct buried cable to prevent potential increases in outage frequency. Without this proactive work, the system may experience more frequent outages. Additionally, there are risks of negatively impacting SAIFI goals, environmental factors, supply chain stability, public perception, and facing regulatory penalties.

Project Alternatives:

The URD replacement program aims to replace one-for-one assets that are in poor condition. Alternatives are considered on a case-by-case basis to ensure the most effective solutions are implemented.

Basis for Project Estimates

The financial plan is based on an average cost per foot of direct buried cable replacement. The average cost is determined by the cost of construction crews, internal labor costs, material costs, and overheads applicable to replacing direct buried cable.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 84	\$ 11	\$ 10	\$ 11	\$ 12	\$ 12	\$ 13	\$ 14
# CIAC	\$ -227	\$ -32	\$ -31	\$ -32	\$ -32	\$ -33	\$ -33	\$ -34
# External Services	\$ 4,340	\$ 560	\$ 538	\$ 587	\$ 611	\$ 647	\$ 682	\$ 716
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 501	\$ 65	\$ 63	\$ 68	\$ 70	\$ 75	\$ 79	\$ 83
# Internal, Overheads	\$ 546	\$ 74	\$ 78	\$ 68	\$ 67	\$ 71	\$ 82	\$ 106
# Materials	\$ 1,728	\$ 199	\$ 196	\$ 218	\$ 238	\$ 264	\$ 291	\$ 321
# Overheads - External	\$ 632	\$ 81	\$ 92	\$ 79	\$ 78	\$ 82	\$ 95	\$ 123
Total	\$ 7,604	\$ 958	\$ 947	\$ 999	\$ 1,044	\$ 1,118	\$ 1,209	\$ 1,329

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 31	\$ 4	\$ 4	\$ 4	\$ 4	\$ 4	\$ 5	\$ 5
Materials	\$ 8	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 38	\$ 5	\$ 5	\$ 5	\$ 5	\$ 6	\$ 6	\$ 6

NYSEG - Battery Program

PROJECT INFORMATION

OpCo: NYSEG	Project ID: UI-N0060-NYSEG-ED	Charge Code: Electric Distribution	Project Sponsor: Malone, Chris	Project Type: Annual Program
Business Area: Digital Grid	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The battery replacement program is responsible for the cycle replacement of substation batteries. Batteries are a critical component of the auxiliary DC System that powers the protection and control system. A failure in this system will negatively affect the reliability of the installations.

The battery replacement program in substations is prioritized based on the condition of the batteries, as assessed through periodic tests. These tests help identify the state of the batteries and determine which ones require urgent replacement to ensure the reliability and safety of the electrical supply. This approach ensures that resources are allocated efficiently and that substations operate optimally.

Batteries planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources.

Project Scope:

The batteries scheduled for replacement over the next three years are listed below:

2025

- Colliers
- Coopers Corners (115 kV)
- Coopers Corners A (System 345 kV)
- Erie St.
- Fraser (System A)
- Fraser (System B)
- Kintigh (System A)
- Kintigh(System B)
- Lake Ave
- North Broadway
- State St.
- Stolle Rd 115kv
- Stolle Rd 345kv (System A)
- Stoney Ridge (System A)
- Stoney Ridge (System B)
- Sullivan Park
- Watercure Road (System A)
- Watercure Road (System B)

2026

- Alden
- Dayton
- Dike
- Interlaken
- Locke
- Montour Falls
- Oriskany Falls
- Rein Rd.
- Robinson Road (System B)
- Roll Rd.
- Tuttle Place
- West Davenport
- Wherele Dr

2027

- Frog Valley
- Grand Gorge
- Hazel
- Holland
- Jordan Rd.
- Mt. Upton
- New Berlin
- Sand St.
- State School
- Windham

Project Benefits:

Proactive battery replacement offers substantial benefits across multiple dimensions. Primarily, it enhances the reliability and continuous availability of backup power, significantly reducing the likelihood of unexpected battery failures during critical power outages. By anticipating battery issues before they manifest, proactive replacement improves operational safety, minimizing risks associated with battery degradation or potential malfunctions, thus ensuring safer working conditions for personnel.

Additionally, proactive battery management contributes to more predictable and lower maintenance costs by reducing the need for emergency repairs, allowing maintenance activities to be scheduled efficiently without disrupting normal operations. This strategic approach also extends the lifespan of other substation equipment, as it safeguards sensitive components such as protection and control systems from damage that can result from inadequate or unstable power supplies.

Furthermore, proactive replacement ensures compliance with regulatory standards, mitigating the risk of potential penalties or fines due to system failures. It enhances overall system performance by consistently maintaining optimal voltage levels and ensuring energy availability during grid disturbances, consequently reducing downtime and supporting critical service continuity.

From a financial perspective, proactive battery replacement enables more accurate budget planning and forecasting, effectively avoiding unexpected capital expenses linked to sudden battery failures. Finally, this practice provides notable environmental benefits, as scheduled replacements facilitate proper battery disposal and recycling, reducing the risks of contamination or environmental damage caused by battery leakage or deterioration.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could impact its progress. In scenarios where a suitable spare part is unavailable, the program may need to be utilized to address the emergency battery failure. Depending on the delivery time of the utility batteries and the nature of the failure, it may be necessary to make adjustments to the plan, potentially postponing scheduled work to the following year. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

Risk of No Action:

Not proactively replacing the batteries in a substation can have serious consequences for the reliability and safety of the electrical supply. Batteries are crucial for the operation of the substation's protection and control systems, which activate in the event of failures in the main grid. If the batteries are deteriorated or fail, these systems may not function correctly, potentially resulting in prolonged power outages. This not only affects end users but also jeopardizes the operation of critical and essential services, such as hospitals and emergency systems.

Furthermore, the lack of proactive battery replacement can lead to additional costs and increased operational risks. Older batteries are more prone to unexpected failures, which may require emergency interventions and costly repairs. These situations not only escalate maintenance expenses but can also cause damage to other substation equipment due to inadequate protection. Ultimately, the absence of a proactive replacement program can compromise the operational efficiency and safety of the electrical infrastructure, negatively impacting service quality and customer satisfaction.

Project Alternatives:**1. Direct Battery Replacement (Recommended Option)**

Replacing the batteries directly is the most advantageous technical and economic choice because:

- Provides immediate, continuous, and reliable backup power during outages.
- Requires minimal maintenance with a long lifespan (typically 10-20 years, depending on technology).
- Offers instantaneous response to grid failures, protecting sensitive equipment.
- Easily integrates with existing systems.
- Has minimal environmental impact compared to fossil fuel alternatives.

2. Installation of a Standby Generator (Diesel/Gasoline)

Key considerations:

- Advantages:
 - Provides extended autonomy for prolonged power outages.
 - Capable of handling higher electrical loads.
- Disadvantages:
 - Delay in startup (several seconds), leaving sensitive equipment momentarily unprotected.
 - Higher maintenance requirements, operational expenses (fuel, oil changes, filters), and lifecycle costs.
 - Increased noise, emissions, and regulatory constraints.

3. Installation of a Hybrid System (Battery + Generator)

Key considerations:

- Advantages:
 - Enhanced reliability and redundancy during prolonged outages.
 - Batteries cover immediate load demands, bridging the gap until the generator initiates.
- Disadvantages:
 - Higher complexity, both technically and administratively.
 - Significant increase in initial investment and ongoing operational expenses.

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

General Equipment - OPS-SO

PROJECT INFORMATION

OpCo: NYSEG	Project ID: UI-50005-NYSEG-ED	Charge Code: Electric Distribution	Project Sponsor: Kuhn, Dennis	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This capital program is used to replace tools and equipment for Substation Operations. This includes major testing equipment purchases such as power factor test sets, protective relay test sets, SF6 gas test sets, current transformer test sets, cable test sets as well as general hand tools such as hammers, wrenches, pliers, gloves, climbing rope, harnesses, equipment bags, ammeters, voltmeters, hot stick testers, drills, label makers, stepladders, etc.

Project Scope:

This program is designed to provide essential electrical equipment, tools, and safety gear for new employees, ensuring compliance with safety and Occupational Safety and Health Administration (OSHA) requirements. This program focuses on the replacement of tools and equipment at the end of their useful lives to maintain high safety standards. The tools and equipment covered include, but are not limited to, hammers, wrenches, pliers, gloves, climbing ropes, harnesses, equipment bags, and rubber goods. The tools and equipment include employee tool kits and replacement of tools/equipment for 165 craft employees as well as test kit items.

Below are the 2025-2031 estimated annual units and average unit rates excluding overheads based on a 3-year historical average (2022 - 2024):

Hand Tools (estimated units/purchase orders = 78) \$7,483/unit*

Spare Parts (estimated units/purchase orders = 10) \$9,642/unit**

Health & Safety (estimated units/purchase orders = 33) \$4,411/unit*

In addition to the above units and average costs, the budget includes \$143K for miscellaneous items.

*Unit rates are calculated with a 3% annual escalation for 2025- 2031

Refer to the 'The RC_Historical Analysis' tab for year-by-year breakdown of estimated units and average unit rates.

Project Benefits:

Provides tools and testing equipment that allows field technicians to perform maintenance and testing activities safely, and in accordance with NERC regulatory requirements including PRC-005 and NPCC Directory 8 testing as well as meeting NY PSC reliability targets for SAIFI and CAIDI. Proper tools and specialized test equipment streamlines workflows and saves time in testing. Properly updated test sets that meet the newest standards increases reliability and accuracy of testing results. Equipment is also used in work to replace failed transformers, regulators, capacitor banks, switches, etc.

Project Risks and Mitigation Plan:

Inadequate funding, on an annual basis, has been the primary risk associated with this program. Program tracking and monitoring of available budget is continually balanced with remaining/anticipated workload, and in many cases, financial offsets are required from other planned work to fund this mandatory work throughout the year. These offsets create downstream consequences since prioritized work can no longer be executed as planned which can affect any number of factors, mainly system reliability.

Risk of No Action:

The consequences of not undertaking this program will lead to system abnormal conditions and unsafe conditions for the public and workforce. Without the proper tools and equipment, delays in addressing emergent failures will have a negative impact on reliability (CAIDI) and lead to legal and regulatory scrutiny. Connecting customers and ensuring reliable service is our fundamental goal. Delayed or non-execution of customer restoration could result in fines, penalties and reputational damage.

Project Alternatives:

This program aims to replace outage equipment using an "in-kind" replacement strategy and therefore project alternatives are not applicable within this program.

Basis for Project Estimates

Historical pricing and costs

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 923	\$ 137	\$ 82	\$ 181	\$ 249	\$ 274		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ 2,728	\$ 237	\$ 454	\$ 639	\$ 793	\$ 605		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ 3,651	\$ 373	\$ 536	\$ 820	\$ 1,042	\$ 880		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,907	\$ 249	\$ 256	\$ 264	\$ 272	\$ 280	\$ 289	\$ 297
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 5,525	\$ 721	\$ 743	\$ 765	\$ 788	\$ 811	\$ 836	\$ 861
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 7,432	\$ 970	\$ 999	\$ 1,029	\$ 1,060	\$ 1,092	\$ 1,124	\$ 1,158

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG 46 kV Line 805 Upgrades - Brewster

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-003607	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP2 Partial Approval	Start Date: Ongoing	In-Service Date: H2 2031

Project description:

Line 805 is a 22-mile 46 kV transmission line in NYSEG's Brewster Division. The line has distribution under-build for approximately 14.9 miles. Line 805 is roadside for about 4 miles. The oldest parts of the transmission line were built in the 1930s. This transmission line currently provides a peak load of about 21 MW of power to approximately 6,250 customers. The Line 805 Upgrade project will mitigate the reliability needs, asset condition needs, and operational constraints outlined below.

Asset Condition Needs

Critical Needs from 2021 Aerial Inspection:

A review of the Monroe aerial inspection data suggests that the descriptions provided are overly critical. The structures on Line 805 are an average of 56 years old.

- 11 out of 466 structures (2%) are considered danger poles and should be replaced as soon as possible.
- 74 out of 466 structures (16%) failed visual inspection and are considered reject poles.

Additional Needs (TLDs):

46 out of 466 structures (10%) have TLDs that necessitate structure replacements. On top of the 131 structures that require replacement (28%), there are 181 additional structures with TLDs (39%). These TLDs include items like arm or insulator replacements and pole, arm, hardware, conductor, shield wire or guy repairs I.E. repairs that are not severe enough to warrant a pole replacement.

IEEE Reference Study: Aged ACSR Conductors Part II – Prediction of Remaining Life

For planning purposes, a mean useful life of 70 years is considered valid for existing conductors. Existing conductors with single layer steel cores last about 12 years less (58 years) than those with two layers. According to this criteria, 37% of conductor is past its useful life today on this line.

Reliability Needs

The Transmission Planning "LTP" Study identified a 11.1 MW loss of load criteria violation for an outage on Line 805 between Dover Plains and Wassauc. The preferred solution is to close or automate the N.O. switch at Amenia Substation (Automatic Throwover). This Amenia reconfiguration would reduce the loss of load to 5.7 MW or 2,055 customers.

The 2021 TPL identified that any contingency event which results in the loss of 115/46 kV transformation at Pawling can result in voltage collapse in the surrounding area. Pawling 115/46 kV substation is the strongest source into the northern region of the 46 kV network in Brewster. The preferred solution is to add a series tie breaker and one line breaker at Pawling Substation.

There are two proposed interconnection projects that may affect the loading on Line 805:

Load interconnection of 27.8 MW at Ten Mile River Substation.

Generator interconnection of 100 MW in North Brewster.

Outages:

There have been 10 outages on Line 805 since January 2019.

Lightning Protection:

7.8 miles of Line 805 does not have shield wire and is more susceptible to lightning strike related outages and damages.

Operational Concerns

Working Clearances:

- Can't complete climbing inspections for tangent structures with horizontal post insulators. Limited by 2'10" Minimum Approach Distance (Avangrid Networks Safety Handbook 2.13.1.e & Table 2, OSHA 1910.269)

Distribution Under-build:

- Significant difficulty to avoid distribution when needing to work on transmission above
- Can't get bucket mounted conductor lift tool in between to work on pole or change insulators or arms
- Insufficient vertical clearances in many cases to use hot stick methods without also moving distribution conductors

Right of Way Needs:

- Developing a right of way corridor instead of 'pole rights only' easements
- Ability to better execute the vegetation management program
- Better access for maintenance
- Improved outage response time

Project Scope:

Full Rebuild (\$96.1 M, ISD 2031): Rebuild Line 805 on the existing centerline with 477 Pelican ACSR and OPGW. The line would be rebuilt with light duty steel poles in a davit arm delta configuration. Angle and dead-end structures would employ the use of guy wires.

Project Benefits:

SAIFI Avoidance: 0.005-0.006 per year after project is in service.

Addresses all aging infrastructure and the line will be built in accordance with Avangrid standards.

OPGW provides an enhanced future communication path for protection and control system upgrades.

Converts 'pole rights only' easements to ROW where transmission line isn't road-side or ROW does not exist (12 miles).

The selected alternative yields the longest lasting solution since steel poles have a longer lifespan than wood poles.

The newly rebuilt line will reduce outages due to increased structural resiliency and vegetation clearing during construction.

Project Risks and Mitigation Plan:

Top risks associated with the project would be worker injury during construction. This risk can be mitigated by instituting a Health and Safety Plan (HASP).

This project is in the pre-conceptual stage, a risk register has not been created for this project.

Risk of No Action:

Continued outages and customer interruptions due to failed equipment or lightning strikes.

Operational constraints will continue:

- Working Clearances - Cannot complete climbing inspections for tangent structures with horizontal post insulators. Limited by 2'10" Minimum Approach Distance (Avangrid Networks Safety Handbook 2.13.1.e & Table 2, OSHA 1910.269))

Distribution Under-build concerns will remain:

- Significant difficulty to avoid distribution when needing to work on transmission above
- Cannot get bucket mounted conductor lift tool in between to work on pole or change insulators or arms
- Insufficient vertical clearances in many cases to use hot stick methods without also moving distribution conductors.

Project Alternatives:

Reconductor & Selected Structure Replacements (\$84.8 M, ISD 2031): Reconductor Line 805 with a similarly sized ACSR or ACCR. Perform structure replacements as required to mitigate visual, structural or clearance failures. The line would be rebuilt with wood poles in the existing structure configuration. Angle and dead-end structures would employ the use of guy wires. SAIFI Avoidance: 0.003 per year after project is in service.

This alternative was not selected for the following reasons:

- The five- or 10-year inspection cycles would likely indicate that some of the remaining untouched structures need replacement (No deferred maintenance costs like a full rebuild).
- ROW would not be obtained for this option.
- The 7.8 miles of transmission line without lightning protection would remain without lightning protection.
- Assumes no additional structural overloads as a result of the reconductor.

Basis for Project Estimates

These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, Avangrid Master Service Agreement rates from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Escalation rates are based upon current U.S. inflation rates. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 6	\$ -	\$ 1	\$ 4	\$ 1	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 315	\$ -	\$ 63	\$ 189	\$ 63	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 39	\$ -	\$ 9	\$ 22	\$ 7	\$ -	\$ -	\$ -
# Materials	\$ 196	\$ -	\$ 39	\$ 118	\$ 39	\$ -	\$ -	\$ -
# Overheads - External	\$ 37	\$ -	\$ 9	\$ 22	\$ 7	\$ -	\$ -	\$ -
Total	\$ 593	\$ -	\$ 122	\$ 354	\$ 117	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Cobble Hill Transformer Replacement

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-004275	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: H1 2025	In-Service Date: H2 2025

Project description:

Cobble Hill substation is an existing 115-34.5kV substation located in Lancaster Division constructed in 1974 and serves approximately 3,688 customers. The 115kV portion of the station is configured as straight bus that connects to transmission lines L733 (Tapped off National Grid's Line 151) and L906 (Tapped off National Grid's Line 152). The substation is equipped with a 115-34.5kV mobile transformer bank to replace the one that had failed. The 34.5kV bus is configured as a straight bus that connects to sub-transmission lines L530 and L548 to Holland, L520 to South Colder, and L531 to Colroad Tap. The project has been initiated to replace the failed transformer and discontinue the use of the mobile transformer. The transformer failure occurred on December 25, 2022.

Project Scope:

The general scope of this project is to replace Bank #1 with a new 3PH 115-34.5kV 50 MVA transformer with LTC. This will include installing a new transformer foundation with oil containment and oil minder pump system, and 3 high side 115 KV Closed Coupling Voltage Transformers (CCVT), upgrading of existing circuit protection.

1. Install a new 115 DELTA/34.5 GRDY KV, 30/40/50 MVA w/LTC Transformer to replace Bank #1. The new Transformer Bank #1 will be connected to the existing 34.5kV bus via overhead conductors and rigid bus. Overhead conductors shall be insulated as necessary to meet minimum safety and clearance requirement.
2. Upgrade existing 115kV Circuit Switcher to enhance safety and line protection.
3. Three (3) high side 115kV PT to be added to enhance safety and line protection.
4. Install new control cabling.
5. One 34.5 KV PT to be added in low side to enhance safety and line protection.
6. Existing substation ground grid will be evaluated on the impact of the additional equipment are to be connected to the station ground grid.

Project Benefits:

The execution of this project will result in the continued reliable power to the 3,700 customers that the substation serves. The mobile transformer will be returned to its customary standby state and will be available for use in planned outages and emergency restoration at this or other substations. The transformer will include an On Load Tap Changer (OLTC) having the following benefits:

1. Voltage regulation - OLTCs can automatically adjust voltage levels to maintain stability, even when the load changes. This helps prevent blackouts and brownouts.
2. Energy efficiency - OLTCs keep voltage levels at an optimal level, which helps the power system run more efficiently and reduces wasted energy.
3. Equipment longevity - OLTCs help ensure stable voltage levels, which reduces stress on equipment and helps it last longer.
4. Cost savings - OLTCs can make tap changes without interrupting power, which can save money in the long run.
5. Grid stability - OLTCs can help increase grid voltage when demand is high and decrease it when demand is low. This helps ensure grid stability.
6. Load flexibility - OLTCs can adapt to changing loads without interruption.

The installation will include upgraded digital relaying for increased line and transformer protection from overload and fault conditions.

The foundation for the transformer is being constructed with an oil containment system consisting of a surrounding reservoir and oil minder pump designed to prevent oil contamination of the surrounding soil in the event of a failure of the transformer and oil discharge.

Soils, having been contaminated by the failure of the original transformer are to be reclaimed and sent to a landfill for remediation.

Project Risks and Mitigation Plan:

While the substation is operating on a mobile transformer there is a risk of failure to the mobile. Failure of the mobile would result in the interruption of service to the area customers. The continued use of the mobile transformer limits its availability for use in the event of a failure of another transformer in the system.

The project is being expedited by using a transformer that was allocated for another project thereby shortening the duration of procurement and fabrication of the new transformer.

Risk of No Action:

The Cobble Hill Substation is currently operating on a mobile transformer since the failure of T1. While the mobile transformer is occupied at Cobble Hill it is not available for use if another failure at another substation were to occur. The decision to take no action will necessitate the permanent use of the mobile transformer and limit the options to respond to the failure of other transformers in the system. This might have consequences to the duration and restoration of unplanned outages yielding a regulatory violation.

Additionally, if the mobile were to fail there would be limited options for the restoration of local power served by the Substation.

Project Alternatives:

Two additional alternatives were considered. Replace with an older spare of a smaller rating, or purchase a new transformer which was not selected due to lead time and criticality to replace now.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 32	\$ -	\$ -	\$ -	\$ 3	\$ 28		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 571	\$ -	\$ -	\$ -	\$ 102	\$ 469		
# Internal - Non-AC	\$ 0	\$ -	\$ -	\$ -	\$ 0	\$ -		
# Internal, Labor	\$ 74	\$ -	\$ -	\$ -	\$ 40	\$ 34		
# Internal, Overheads	\$ 263	\$ -	\$ -	\$ -	\$ 17	\$ 246		
# Materials	\$ 1,015	\$ -	\$ -	\$ -	\$ -	\$ 1,015		
# Overheads - External	\$ 342	\$ -	\$ -	\$ -	\$ 44	\$ 297		
Total	\$ 2,297	\$ -	\$ -	\$ -	\$ 207	\$ 2,090		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 316	\$ 316	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 5,261	\$ 3,207	\$ 2,055	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 225	\$ 225	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 546	\$ 375	\$ 171	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,213	\$ 1,213	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 565	\$ 387	\$ 177	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 8,126	\$ 5,723	\$ 2,403	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Homer City 345kV Transmission Line Upgrade

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-001310	Charge Code: Electric Transmission	Project Sponsor: Craven, Mike	Project Type: Project
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: H1 2027	In-Service Date: H2 2028

Project description:

This project is to rebuild two very old 345 kV lines which are in poor asset condition

The 345 kV Line 47 runs from Mainesburg Substation (First Energy) to Homer City Substation (PJM). The Line was constructed in 1969. The 345 kV Line 48 runs from Pierce Brook Substation (First Energy) to Homer City Substation (PJM). The Line was constructed in 1977.

System Impacts - The Homer City 345kV Transmission Line is considered part of the Bulk Transmission Electric System and the economic risk due to a failure in the line is high given its potential impacts to the grid or electric system from the ISO's (Independent System Operators) perspective (NYISO and PJM) and adjacent utility operators, i.e. First Energy and National Grid. NYSEG utilizes the Homer City line for financial transactions between the NYISO and PJM to benefit both the company and NY rate payers. A forced outage of the line would negatively impact that opportunity.

Health of the Infrastructure – The Homer City 345kV Transmission Line 47 was constructed and placed in service over 50 years ago in 1969. Over 95% of the wood pole structures are greater than 50 years old and are near or over their life expectancy. Even though Line 48 is slightly newer (constructed circa 1977), the significant amount of Transmission Line Deficiencies (TLDs) confirms a similar state of asset condition in comparison to Line 47.

While there are many differing studies and opinions regarding the life expectancy of wood transmission poles, the one common factor considered is the environment in which the poles are exposed to such as wetlands or streams and woodpecker prone areas. The Homer City 345kV Transmission Lines are exposed to these types of environments.

There are currently 534 TLDs on Line 47. 180 of these TLDs necessitate structure replacement.

There are currently 495 TLDs on Line 48. 128 of these TLDs necessitate structure replacement.

In March 2019, a failure occurred on Structure B194 in Morris Township PA on the 47 Line. The knee brace failed first followed by failure of the crossarm. The ground underneath the structure was scorched where the conductor contacted the earth.

Project Scope:

The full rebuild of 345 kV Line 47 ISD 2041 and full rebuild of 345 kV Line 48 ISD 2038:

Rebuild Line 47 and 48 on an offset with bundled 1590 ACSS and OPGW. The lines will be rebuilt with light duty steel H-Frame tangents, self-supported running angle, and dead-end structures.

Project Benefits:

Addresses all aging infrastructure and TLDs. The lines will be built in accordance with Avangrid standards (which they are currently not).

Increased Reliability and Safety of Critical BES Transmission Line – By eliminating the severe deficiencies associated with the structures and major components that have a high risk of failure, this project will result in an increase in reliability and safe operation of the lines.

Decreased Economic Risks – Intervening on these lines now will reduce the risk of failure and decrease the financial impact to the company and NY rate payers. NYSEG utilizes the Homer City line for financial transactions between the NYISO and PJM which benefits both the company and NY rate payers. A forced short- or long-term outage of the line would negatively impact that opportunity.

Decreased Operations and Maintenance (O&M) Costs – Implementing a planned capital rebuild project will result in decreased O&M costs compared to a reactive approach.

OPGW provides an enhanced future communication path for protection and control system upgrades, which further improves system reliability.

Project Risks and Mitigation Plan:

The top risk associated with the project would be worker injury during construction. This risk can be mitigated by instituting a Health and Safety Plan (HASP).

Do nothing and intervene each time a failure occurs. As previously noted, over 95% of the wood pole structures, crossarms and insulators on Line 47 are greater than 50 years old and are near or over life expectancy and have deteriorated faster due to the environment they are exposed to. The risks of failure are high, and with each failure public and environmental safety are compromised. Over time, aggregate costs to rate payers will end up being higher than a proactive approach. This is not a viable option.

Selected Structure Replacements and Reconductor:

Eliminate the most severe deficiencies associated with the structures and major components that have the highest risk of failure. Reconductor the transmission line. This would be a high cost project which would end up leaving behind assets that are still 50+ years old. If the most severe deficiencies were all located together, this approach may be appropriate due to the lower cost. However, with the TLDs being as dispersed as they are, this would be high cost with relatively low benefit.

These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, Avangrid Master Service Agreement rates from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Escalation rates are based upon current U.S. inflation rates. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 594	\$ -	\$ 49	\$ 197	\$ 235	\$ 113		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 2,283	\$ -	\$ 2,316	\$ -32	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ 411	\$ -	\$ 398	\$ 13	\$ -	\$ -		
# Materials	\$ 394	\$ -	\$ 303	\$ 91	\$ -	\$ -		
# Overheads - External	\$ 553	\$ -	\$ 541	\$ 12	\$ -	\$ -		
Total	\$ 4,235	\$ -	\$ 3,607	\$ 280	\$ 235	\$ 113		

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ 49	\$ -	\$ 49	\$ -0	\$ -	\$ -		
Materials	\$ 1	\$ -	\$ 1	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ 49	\$ -	\$ 50	\$ -0	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 62,152	\$ -	\$ -	\$ 8,977	\$ 8,930	\$ 8,672	\$ 19,680	\$ 15,895
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 434,691	\$ -	\$ -	\$ 40,402	\$ 40,189	\$ 39,028	\$ 88,572	\$ 226,500
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 14,460	\$ -	\$ -	\$ 2,088	\$ 2,077	\$ 2,017	\$ 4,578	\$ 3,698
# Internal, Overheads	\$ 44,580	\$ -	\$ -	\$ 6,224	\$ 5,805	\$ 5,532	\$ 13,624	\$ 13,395
# Materials	\$ 279,861	\$ -	\$ -	\$ 40,422	\$ 40,208	\$ 39,046	\$ 88,614	\$ 71,570
# Overheads - External	\$ 44,998	\$ -	\$ -	\$ 6,283	\$ 5,860	\$ 5,584	\$ 13,751	\$ 13,521
Total	\$ 880,742	\$ -	\$ -	\$ 104,396	\$ 103,069	\$ 99,879	\$ 228,820	\$ 344,579

[illegible]

Homer City Capital Breakers & Upgrades

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-003105	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP3 Partial Approval	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

Overview: This project was created to fund co-owned projects proposed by First Energy or NYSEG at Homer City substation, which NYSEG has a 50/50 ownership of. First Energy has proposed approximately \$21.6 M in planned upgrades at Homer City substation which have not yet been agreed to by both parties. Both First Energy and NYSEG must scope and pay for services related to these upgrades.

Current State Needs Assessment: The Homer City substation has infrastructure over 57 years old. Most equipment, including the two 345/230/23 kV transformers, are in poor condition. Spare parts are either obsolete or prohibitively expensive. To improve reliability, meet forecasted PJM generation deliverability needs, and ensure regulatory compliance, First Energy has proposed projects to address immediate and future needs at the substation.

Project Scope:

Proposed Upgrades:

- 1) Homer City Replace 345-230 TNN-BK 345/230kV Serial D59026: Replace the existing 345/230/23 kV transformer with a new 345/230 kV transformer, and install a separate 230/23 kV transformer with its associated 230 kV circuit breaker to replace the tertiary.
- 2) PN Program - Group 1 - Install Traveling Wave Fault Locator System: Part of a larger program to install traveling wave fault locating at EHV substations, allowing for quicker identification of faults and improved response time.
- 3) Install Counter UAS - Tier 2 Substations: Install Counter UAS (Unmanned Aerial Systems) anti-drone technology at Homer City Substation to protect against aerial attack vectors. This includes installing indications and alarms to comply with CIP standards.
- 4) Homer City Online Battery Monitor: Part of a larger program to install online battery monitoring on select station battery banks for remote monitoring, expected to eliminate annual inspections and satisfy PRC-005.
- 5) Homer City Replace 345-230 TS, Circuit Switcher, Relay Protection: Replace the existing 345/230/23 kV transformer with a new 345/230 kV transformer, and install a separate 230/23 kV transformer with its associated 230 kV circuit breaker to replace the tertiary.
- 6) Homer City 345 kV Isolate-Generation: Remove revenue metering, circuit breaker indication and control that could impact the substation when plant is demolished. Install new primary and backup station power transformers to feed substation load. Install circuit breaker controls (remote and local) for 6 generator breakers. Install primary and backup relay protection for the three generator buses. Generate agreements for unimpeded access to substation property. Isolate and remove transmission lines to generators.
- 7) 345 kV North Bus Protection and Standoff Insulators Upgrade: Upgrade the 345kV bus insulators and the relays.
- 8) 230 kV North Bus Protection and Standoff Insulators Upgrade: Upgrade the 230kV bus insulators and the relays.
- 9) 345 kV Replace #2 GEN A and GEN B -Disconnect SW(2) and Ground SW(2) (S&E): Upgrade the 345kV switches and insulators.
- 10) 230kV Hooversville Line exit: Upgrade the 230kV line switches, insulators, CCVTs, & wave trap.
- 11) 230 kV Johnstown Line exit upgrade (S&E): Upgrade the 230kV line switches, insulators, CCVTs, & wave trap.
- 12) 345 kV South Bus Protection and 345kV South Bus support Insulators: Upgrade the 345kV bus insulators and the relays.
- 13) 230 kV South Bus Protection and 230 kV South Bus Support Insulators: Upgrade the 230kV bus insulators and the relays.
- 14) ARHC (Armstrong-Homer City) 345kV Line-Rebuild-34.5 miles: Replace existing wood poles with steel, rehab foundations, replace existing steel components. The line is not owned by NYSEG. Some funding is needed when relay settings are changed (50% NYSEG).
- 15) Homer City -Replace-Control House: Replace existing building with new EMP-hardened enclosure.

Project Benefits:

The upgrades proposed by First Energy address several asset condition needs, Bulk Power System (BPS) reliability needs, and regulatory compliance requirements. As a 50/50 owner of the Homer City substation, NYSEG must agree to and pay for a portion of these upgrades.

Project Risks and Mitigation Plan:

These projects will require working in an energized substation yard during construction. To mitigate risks, it is essential to develop and discuss detailed construction sequence plans, outage plans, and risk mitigation plans with the Energy Control Center and the execution team before any construction activities begin.

Risk of No Action:

Failing to take action will lead to a continuous decline in reliability, increasing the risk of equipment failures and higher O&M costs at the Homer City substation. Additionally, NERC CIP-006 Requirements 1.5, 1.6, and 1.7 may not be met.

Proposed Upgrades Alternatives:

- Upgrade 1: Refurbish existing 345/230/23kV transformer.
- Upgrade 2: Do nothing
- Upgrade 3: Multiple alternative systems were tested at EPRI.
- Upgrade 4: Perform quarterly and annual O&M battery inspections.
- Upgrade 5: Refurbish existing 345/230/23kV transformer.
- Upgrade 6: Do nothing
- Upgrade 7: Do nothing
- Upgrade 8: Do nothing
- Upgrade 9: Do nothing
- Upgrade 10: Do nothing
- Upgrade 11: Do nothing
- Upgrade 12: Do nothing
- Upgrade 13: Do nothing
- Upgrade 14: Do nothing
- Upgrade 15: Design EMP hardened building around existing building.

The project cost estimates are provided by First Energy and include engineering costs, materials costs, construction/commissioning costs, and anticipated contingency costs for each project. As a 50/50 owner of the Homer City substation, NYSEG must review and agree to these estimates before project execution.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 141	\$ -	\$ 4	\$ 0	\$ 136	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 4,049	\$ -	\$ -	\$ -	\$ 4,049	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ 4,190	\$ -	\$ 4	\$ 0	\$ 4,185	\$ -		

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,764	\$ -	\$ -	\$ 832	\$ 505	\$ 427	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 7,939	\$ -	\$ -	\$ 3,746	\$ 2,273	\$ 1,920	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 410	\$ -	\$ -	\$ 194	\$ 118	\$ 99	\$ -	\$ -
# Internal, Overheads	\$ 1,178	\$ -	\$ -	\$ 577	\$ 328	\$ 272	\$ -	\$ -
# Materials	\$ 7,942	\$ -	\$ -	\$ 3,748	\$ 2,274	\$ 1,921	\$ -	\$ -
# Overheads - External	\$ 1,189	\$ -	\$ -	\$ 583	\$ 331	\$ 275	\$ -	\$ -
Total	\$ 20,422	\$ -	\$ -	\$ 9,680	\$ 5,829	\$ 4,913	\$ -	\$ -

[illegible]

NYSEG Substation Modernization - South Owego

PROJECT INFORMATION

OpCo: NYSEG	Project ID: UH-N0000256-NYSEG-ET	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP2 Technical	Start Date: H1 2028	In-Service Date: Ongoing

Project description:

Overview: Initiated in 2011, this project aims to address asset condition needs and reduce outage risks for South Owego customers. The area relies on two 115/34.5kV transformers, serving about 10,142 customers (40 MW load), and a 115 kV line feeding 5,131 customers (12 MW load). Initially, the project focused on replacing aged 115kV and 34.5kV equipment. However, due to severe asset conditions and other reliability risks, a comprehensive assessment was conducted.

Current State Needs Assessment: South Owego's infrastructure, over 68 years old, is in poor condition and would require vintage or expensive replacement parts. Structural analysis revealed significant deficiencies in the 115kV yard under NESC loading conditions. The 2021 transmission studies identified several issues:

The project aims to: 1) Resolve asset health issues. 2) Mitigate voltage and thermal needs. 3) Add capacity for future load growth.

Project Scope:

This project includes the followign scope:

1. Construct a 115kV/34.5kV GIS substation with two 50 MVA transformers (LTC-equipped) to operate in parallel.
2. Install two 12.4 MVAR 115 kV capacitor banks.
3. Construct a new control house for relay upgrades, HMI, and a fully automated control system.
4. Decommission the existing substation and transfer all loads to the new yard.

The cost is estimated at \$148.3 M.

Project Benefits:

Reliability: The new 115 kV BAAH configuration enhances system reliability with N-1 and N-1-1 contingency headroom, ensuring continuous service during after faults or during maintenance. Additionally the new 50 MVA 115/34.5 kV transformers will avoid thermal violations under N-1 conditions. Asset Condition: Resolves all electrical equipment issues identified in the AVANGRID 2021 assessments as well as the structural deficiencies which were identified.

Capacity Headroom: Relieves voltage and thermal constraints, allowing for up to 20 MW of future load growth in the South Owego area.

Project Risks and Mitigation Plan:

Due to real estate constraints on the existing property, a new parcel or right-of-way (ROW) will be required. To minimize project delays and re-engineering prior to construction, early engagement with the environmental and permitting team is necessary. Additionally, future load interconnection projections of up to 10 MW on the 34.5 kV sub-transmission system have been studied for this area. The project schedule will need to be coordinated with any future development or load requests to ensure readiness for load growth.

Risk of No Action:

Without full project funding, the identified reliability and asset condition issues could cause severe low voltage and thermal violations for up to 10,142 customers (40 MW load), eventually leading to unplanned interruptions and further degrading NYSEG's reliability statistics. Due to lack of capacity, the existing substation would be unable to support future load interconnection requests in this growing area. Additionally, this project began several years ago and has accumulated a small amount of construction work in progress (CWIP) from engineering and overheads.

An alternative solution involves:

- Advantages: Accommodates all queued loads and future interconnection requests up to 20 MW on the 34.5kV system.
Disadvantages: Limited to 8 MW load growth on the 115kV system and potential overload with N-1 loss of a 50 MVA transformer.

This alternative was not selected because of the lower capacity gains and continued potential N-1 overload that could occur.

The cost is estimated at \$146 M for this alternative

Components: Internal labor, external resources, materials, engineering (internal and external), and applicable overheads costs.
Sources: Historical man-hour data, construction costs for similar activities, budgetary quotes from suppliers, and analogous cost estimates from similar NYSEG projects.
Review Process: Estimates are regularly reviewed and updated as the project progresses and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG 001 Spare Tx Pgm 120-36.2kV 50MVA

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-005918	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: H2 2026

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the NYSEGE #1 120-36.2kV 50MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

Long lead times from the transformer manufacturer would present a reliability risk.

The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

Mitigation Plan: Account for this risk by following our robust procurment process. Additionally, start the procurment process as soon as possible, and ensure constant communication is maintained with the transformer manufacturer.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers. Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence. Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 185	\$ 43	\$ 142	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 22	\$ 10	\$ 12	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ 1	\$ 1	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 23	\$ 11	\$ 12	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 226	\$ 178	\$ 48	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 2,000	\$ 1,600	\$ 400	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 260	\$ 214	\$ 46	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,717	\$ 2,057	\$ 660	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG 002 Spare Tx Pgm 120-36.2kV 50MVA

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-005917	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: H2 2026

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the NYSEG #2 120-36.2kV 50MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

Long lead times from the transformer manufacturer would present a reliability risk.

The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

Mitigation Plan: Account for this risk by following our robust procurement process. Additionally, start the procurement process as soon as possible, and ensure constant communication is maintained with the transformer manufacturer.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers. Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence. Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 185	\$ 43	\$ 142	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 22	\$ 10	\$ 12	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ 1	\$ 1	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 23	\$ 11	\$ 12	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 226	\$ 178	\$ 48	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 2,000	\$ 1,600	\$ 400	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 260	\$ 214	\$ 46	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,717	\$ 2,057	\$ 660	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG 003 Spare Tx Pgm 36-13.2kV 37.3MVA

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-005915	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: H2 2026

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the NYSEG #3 36-13.2kV 37.3MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

Long lead times from the transformer manufacturer would present a reliability risk.

The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

Mitigation Plan: Account for this risk by following our robust procurement process. Additionally, start the procurement process as soon as possible, and ensure constant communication is maintained with the transformer manufacturer.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers. Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence. Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 140	\$ 33	\$ 107	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 22	\$ 10	\$ 12	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ 1	\$ 1	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 23	\$ 11	\$ 12	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 171	\$ 134	\$ 37	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,500	\$ 1,200	\$ 300	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 197	\$ 162	\$ 36	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,054	\$ 1,550	\$ 504	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG 004 Spare Tx Pgm 46-13.2kV 14MV

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-005916	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: H2 2026

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the NYSEG #4 46-13.24kV 14MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

Long lead times from the transformer manufacturer would present a reliability risk.

The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

Mitigation Plan: Account for this risk by following our robust procurement process. Additionally, start the procurement process as soon as possible, and ensure constant communication is maintained with the transformer manufacturer.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers. Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence. Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 140	\$ 33	\$ 107	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 22	\$ 10	\$ 12	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ 1	\$ 1	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 23	\$ 11	\$ 12	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 171	\$ 134	\$ 37	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,500	\$ 1,200	\$ 300	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 197	\$ 162	\$ 36	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,054	\$ 1,550	\$ 504	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG 005 SprTxPgm 34.5-12.5/4.8kV 20MVA

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006506	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the NYSEG #5 34.5-12.5/4.8kV 20MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

The risks associated with the program are intricately tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, the companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we would be compelled to rely on old, unreliable transformers that have been previously used in past projects. These transformers would need to undergo a costly refurbishment process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to widespread disruptions and increased maintenance costs.

Moreover, the delay in purchasing new spares would exponentially increase the reliability risk. The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

In summary, the lack of adequate funding for new spares not only forces us to depend on less reliable, refurbished components but also significantly heightens the risk of system failures due to the extended lead times required for procurement. Ensuring timely and sufficient funding is therefore critical to maintaining the integrity and reliability of our electric system, preventing potential failures, and avoiding the high costs associated with emergency repairs and system downtime.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers.

Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 315	\$ -	\$ 36	\$ 78	\$ 201	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 520	\$ 496	\$ 5	\$ 14	\$ 5	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 24	\$ -	\$ 8	\$ 8	\$ 8	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 141	\$ -	\$ 28	\$ 84	\$ 28	\$ -	\$ -	\$ -
# Materials	\$ 2,253	\$ -	\$ 451	\$ 1,352	\$ 451	\$ -	\$ -	\$ -
# Overheads - External	\$ 275	\$ -	\$ 56	\$ 163	\$ 56	\$ -	\$ -	\$ -
Total	\$ 3,529	\$ 496	\$ 584	\$ 1,700	\$ 749	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG 006 SprTxPgm 34.5-12.5/4.8kV 12MVA

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006507	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the NYSEG #6 34.5-12.5/4.8kV 12MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

The risks associated with the program are intricately tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, the companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we would be compelled to rely on old, unreliable transformers that have been previously used in past projects. These transformers would need to undergo a costly refurbishment process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to widespread disruptions and increased maintenance costs.

Moreover, the delay in purchasing new spares would exponentially increase the reliability risk. The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

In summary, the lack of adequate funding for new spares not only forces us to depend on less reliable, refurbished components but also significantly heightens the risk of system failures due to the extended lead times required for procurement. Ensuring timely and sufficient funding is therefore critical to maintaining the integrity and reliability of our electric system, preventing potential failures, and avoiding the high costs associated with emergency repairs and system downtime.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers.

Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 295	\$ -	\$ 36	\$ 74	\$ 185	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 520	\$ 496	\$ 5	\$ 14	\$ 5	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 24	\$ -	\$ 8	\$ 8	\$ 8	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 127	\$ -	\$ 26	\$ 76	\$ 26	\$ -	\$ -	\$ -
# Materials	\$ 2,028	\$ -	\$ 406	\$ 1,217	\$ 406	\$ -	\$ -	\$ -
# Overheads - External	\$ 249	\$ -	\$ 51	\$ 147	\$ 51	\$ -	\$ -	\$ -
Total	\$ 3,244	\$ 496	\$ 531	\$ 1,537	\$ 680	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG 007 SprTxPgm 34.5-12.5/4.8kV 10MVA

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006508	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the NYSEG#7 34.5-12.5/4.8kV 10MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

The risks associated with the program are intricately tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, the companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we would be compelled to rely on old, unreliable transformers that have been previously used in past projects. These transformers would need to undergo a costly refurbishment process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to widespread disruptions and increased maintenance costs.

Moreover, the delay in purchasing new spares would exponentially increase the reliability risk. The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

In summary, the lack of adequate funding for new spares not only forces us to depend on less reliable, refurbished components but also significantly heightens the risk of system failures due to the extended lead times required for procurement. Ensuring timely and sufficient funding is therefore critical to maintaining the integrity and reliability of our electric system, preventing potential failures, and avoiding the high costs associated with emergency repairs and system downtime.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers.

Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 154	\$ -	\$ -	\$ 31	\$ 123	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 24	\$ -	\$ 5	\$ 14	\$ 5	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 24	\$ -	\$ 8	\$ 8	\$ 8	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 109	\$ -	\$ 22	\$ 65	\$ 22	\$ -	\$ -	\$ -
# Materials	\$ 1,728	\$ -	\$ 346	\$ 1,037	\$ 346	\$ -	\$ -	\$ -
# Overheads - External	\$ 213	\$ -	\$ 44	\$ 126	\$ 44	\$ -	\$ -	\$ -
Total	\$ 2,252	\$ -	\$ 424	\$ 1,281	\$ 547	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG 008 SprTxPgm 115-34.5/12.5kV 30MVA

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006510	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the NYSEG #8 115-34.5/12.5kV 30MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

The risks associated with the program are intricately tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, the companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we would be compelled to rely on old, unreliable transformers that have been previously used in past projects. These transformers would need to undergo a costly refurbishment process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to widespread disruptions and increased maintenance costs.

Moreover, the delay in purchasing new spares would exponentially increase the reliability risk. The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

In summary, the lack of adequate funding for new spares not only forces us to depend on less reliable, refurbished components but also significantly heightens the risk of system failures due to the extended lead times required for procurement. Ensuring timely and sufficient funding is therefore critical to maintaining the integrity and reliability of our electric system, preventing potential failures, and avoiding the high costs associated with emergency repairs and system downtime.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers.

Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 307	\$ -	\$ -	\$ 61	\$ 246	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 24	\$ -	\$ 5	\$ 14	\$ 5	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 24	\$ -	\$ 8	\$ 8	\$ 8	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 218	\$ -	\$ 44	\$ 131	\$ 44	\$ -	\$ -	\$ -
# Materials	\$ 3,496	\$ -	\$ 699	\$ 2,098	\$ 699	\$ -	\$ -	\$ -
# Overheads - External	\$ 421	\$ -	\$ 85	\$ 251	\$ 85	\$ -	\$ -	\$ -
Total	\$ 4,490	\$ -	\$ 841	\$ 2,562	\$ 1,087	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG 013 SprTxPgm 34.5-12.5/4.8kV 20MVA

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006516	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the NYSEG #13 34.5-12.5/4.8kV 20MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

The risks associated with the program are intricately tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, the companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we would be compelled to rely on old, unreliable transformers that have been previously used in past projects. These transformers would need to undergo a costly refurbishment process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to widespread disruptions and increased maintenance costs.

Moreover, the delay in purchasing new spares would exponentially increase the reliability risk. The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

In summary, the lack of adequate funding for new spares not only forces us to depend on less reliable, refurbished components but also significantly heightens the risk of system failures due to the extended lead times required for procurement. Ensuring timely and sufficient funding is therefore critical to maintaining the integrity and reliability of our electric system, preventing potential failures, and avoiding the high costs associated with emergency repairs and system downtime.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers.

Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 199	\$ -	\$ -	\$ -	\$ 40	\$ 160	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 24	\$ -	\$ -	\$ 5	\$ 14	\$ 5	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 24	\$ -	\$ -	\$ 8	\$ 8	\$ 8	\$ -	\$ -
# Internal, Overheads	\$ 141	\$ -	\$ -	\$ 28	\$ 84	\$ 28	\$ -	\$ -
# Materials	\$ 2,253	\$ -	\$ -	\$ 451	\$ 1,352	\$ 451	\$ -	\$ -
# Overheads - External	\$ 275	\$ -	\$ -	\$ 56	\$ 163	\$ 56	\$ -	\$ -
Total	\$ 2,917	\$ -	\$ -	\$ 548	\$ 1,661	\$ 707	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG 014 SprTxPgm 34.5-12.5/4.8kV 12MVA

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006517	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the NYSEG #14 34.5-12.5/4.8kV 12MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

The risks associated with the program are intricately tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, the companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we would be compelled to rely on old, unreliable transformers that have been previously used in past projects. These transformers would need to undergo a costly refurbishment process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to widespread disruptions and increased maintenance costs.

Moreover, the delay in purchasing new spares would exponentially increase the reliability risk. The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

In summary, the lack of adequate funding for new spares not only forces us to depend on less reliable, refurbished components but also significantly heightens the risk of system failures due to the extended lead times required for procurement. Ensuring timely and sufficient funding is therefore critical to maintaining the integrity and reliability of our electric system, preventing potential failures, and avoiding the high costs associated with emergency repairs and system downtime.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers.

Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards.

Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

[illegible]

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 188	\$ -	\$ -	\$ -	\$ 40	\$ 148	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 24	\$ -	\$ -	\$ 5	\$ 14	\$ 5	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 24	\$ -	\$ -	\$ 8	\$ 8	\$ 8	\$ -	\$ -
# Internal, Overheads	\$ 130	\$ -	\$ -	\$ 28	\$ 76	\$ 26	\$ -	\$ -
# Materials	\$ 2,073	\$ -	\$ -	\$ 451	\$ 1,217	\$ 406	\$ -	\$ -
# Overheads - External	\$ 254	\$ -	\$ -	\$ 56	\$ 147	\$ 51	\$ -	\$ -
Total	\$ 2,693	\$ -	\$ -	\$ 548	\$ 1,502	\$ 643	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG 015 SprTxPgm 115-34.5/12.5kV 30MVA

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006518	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the NYSEG #15 115-34.5/12.5kV 30MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

The risks associated with the program are intricately tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, the companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we would be compelled to rely on old, unreliable transformers that have been previously used in past projects. These transformers would need to undergo a costly refurbishment process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to widespread disruptions and increased maintenance costs.

Moreover, the delay in purchasing new spares would exponentially increase the reliability risk. The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

In summary, the lack of adequate funding for new spares not only forces us to depend on less reliable, refurbished components but also significantly heightens the risk of system failures due to the extended lead times required for procurement. Ensuring timely and sufficient funding is therefore critical to maintaining the integrity and reliability of our electric system, preventing potential failures, and avoiding the high costs associated with emergency repairs and system downtime.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers.

Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 307	\$ -	\$ -	\$ -	\$ 61	\$ 246	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 24	\$ -	\$ -	\$ 5	\$ 14	\$ 5	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 24	\$ -	\$ -	\$ 8	\$ 8	\$ 8	\$ -	\$ -
# Internal, Overheads	\$ 218	\$ -	\$ -	\$ 44	\$ 131	\$ 44	\$ -	\$ -
# Materials	\$ 3,496	\$ -	\$ -	\$ 699	\$ 2,098	\$ 699	\$ -	\$ -
# Overheads - External	\$ 421	\$ -	\$ -	\$ 85	\$ 251	\$ 85	\$ -	\$ -
Total	\$ 4,490	\$ -	\$ -	\$ 841	\$ 2,562	\$ 1,087	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Spare Power Transformer Program				
PROJECT INFORMATION				
OpCo:	Project ID:	Charge Code:	Project Sponsor:	Project Type:
NYSEG	PRJ-005170	Electric Transmission	Malone, Chris	Annual Program
Business Area:	Rate Case Category	Project Stage:	Start Date:	In-Service Date:
Planning & Coordination	Asset Condition	IP2 Technical	Ongoing	Ongoing
Project description: The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers. Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity. The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.				
Project Scope: Projected purchase of NYSEG 6 spares in 2028, 7 spares in 2029 and 7 spares in 2030.				
Project Benefits: The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges. One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs. Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.				
Project Risks and Mitigation Plan: The risks associated with the program are tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, the companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we would be compelled to rely on old, unreliable transformers that have been used in past projects. These transformers would need to undergo a costly refurbishment process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to most customer outages and increased maintenance costs. Moreover, the delay in purchasing new spares would drastically increase the reliability risk. The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a high-risk situation, where the electric system's overall reliability and performance are degraded.				

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers.

Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Project Alternatives:

One alternative is increasing the inventory of mobile transformers. The existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs.

Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 2,681	\$ -	\$ -	\$ -	\$ -	\$ 581	\$ 1,050	\$ 1,050
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 383	\$ -	\$ -	\$ -	\$ -	\$ 83	\$ 150	\$ 150
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 383	\$ -	\$ -	\$ -	\$ -	\$ 83	\$ 150	\$ 150
# Internal, Overheads	\$ 1,915	\$ -	\$ -	\$ -	\$ -	\$ 415	\$ 750	\$ 750
# Materials	\$ 29,496	\$ -	\$ -	\$ -	\$ -	\$ 6,396	\$ 11,550	\$ 11,550
# Overheads - External	\$ 3,448	\$ -	\$ -	\$ -	\$ -	\$ 748	\$ 1,350	\$ 1,350
Total	\$ 38,306	\$ -	\$ -	\$ -	\$ -	\$ 8,306	\$ 15,000	\$ 15,000

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Spare Circuit Breaker Program

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006548	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Annual Program
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

Ensuring the reliability and resilience of electrical infrastructure is critical for maintaining continuous power delivery and protecting the grid from unplanned outages and failures. Circuit breakers play a vital role in this process by isolating faulty sections of the grid, preventing widespread outages, and safeguarding power equipment. The Spare Circuit Breaker Program is crucial for New York's power infrastructure and is designed to address key challenges and opportunities in maintaining a robust inventory of substation circuit breaker spares. The absence of such inventory currently poses a significant threat to system reliability, as evidenced by past failures in our service areas. By maintaining a dedicated, reliable stock of spare breakers, operators can rapidly replace faulty units, minimizing downtime and enhancing overall reliability.

The program optimizes the selection of spare breakers, balancing the costs of maintaining inventory with the need for grid reliability. Having spare breakers readily available also enables us to respond promptly to emergencies, mitigating risks and ensuring the safety of both our infrastructure and the public. This rapid response capability is crucial in maintaining trust and confidence in our electrical system. As our grid continues to expand and evolve, the Spare Breaker Program prepares us for future challenges, ensuring that our infrastructure can meet the growing and changing demands of our society.

A total of 58 spare circuit breakers, encompassing 21 different types, have been identified and recommended for purchase from 2026 to 2028. The estimated capital investment for this program for the first three years is approximately \$8.6 million for the NYSEG operating company, reflecting the significant investment required to maintain and enhance our service capabilities. This comprehensive investment plan underscores our commitment to providing reliable service to our customers while also preparing for potential future contingencies. By increasing and diversifying our circuit breaker inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges. We estimate to purchase \$3 million worth of spares from 2029 to 2031 types and exact quantity to be determined depending on system needs.

Project Scope:

- 1.This project involves the purchase of one (1) 38 kV 2000A 40 kA 125 VDC GOP spare breaker with a total estimated cost of \$0.09 M. The estimated ISD is 12/31/2026.
- 2.This project involves the purchase of eight (8) 38 kV 1200A 40 kA 125 VDC GOP spare breaker with a total estimated cost of \$0.7 M. The estimated ISD is 12/31/2026.
- 3.This project involves the purchase of one (1) 38 kV 1200A 40 kA 48 VDC GOP spare breaker with a total estimated cost of \$0.09 M. The estimated ISD is 12/31/2026.
- 4.This project involves the purchase of one (1) 15.5 kV 2000A 25 kA 125 VDC GOP spare breaker with a total estimated cost of \$0.09 M. The estimated ISD is 12/31/2026.
- 5.This project involves the purchase of eight (8) 15.5 kV 1200A 25 kA 125 VDC GOP spare breaker with a total estimated cost of \$0.7 M. The estimated ISD is 12/31/2026.
- 6.This project involves the purchase of one (1) 15.5 kV 2000A 25 kA 48 VDC GOP spare breaker with a total estimated cost of \$0.09 M. The estimated ISD is 12/31/2026.
- 7.This project involves the purchase of six (6) 15.5 kV 1200A 25 kA 48 VDC GOP spare breaker with a total estimated cost of \$0.5 M. The estimated ISD is 12/31/2026.
- 8.This project involves the purchase of one (1) 15.5 kV 2000A 25 kA 24 VDC GOP spare breaker with a total estimated cost of \$0.09 M. The estimated ISD is 12/31/2026.
- 9.This project involves the purchase of four (4) 15.5 kV 1200A 25 kA 24 VDC GOP spare breaker with a total estimated cost of \$0.35 M. The estimated ISD is 12/31/2026.
- 10.This project involves the purchase of one (1) 145 kV 3000A 40kA 125 VDC IPO spare breaker with a total estimated cost of \$0.35 M. The estimated ISD is 12/31/2027.
- 11.This project involves the purchase of six (6) 145 kV 1200A 40kA 125 VDC GOP spare breaker with a total estimated cost of \$1 M. The estimated ISD is 12/31/2027.
- 12.This project involves the purchase of one (1) 145 kV 2000A 63kA 125 VDC GOP spare breaker with a total estimated cost of \$0.16 M. The estimated ISD is 12/31/2027.
- 13.This project involves the purchase of three (3) 145 kV 3000A 40kA 125 VDC GOP spare breaker with a total estimated cost of \$0.5 M. The estimated ISD is 12/31/2027.
- 14.This project involves the purchase of six (6) 72 kV 1200A 31.5/40kA 125 VDC GOP spare breaker with a total estimated cost of \$0.7 M. The estimated ISD is 12/31/2027.
- 15.This project involves the purchase of one (1) 72 kV 2000A 31.5/40kA 125 VDC GOP spare breaker with a total estimated cost of \$0.12 M. The estimated ISD is 12/31/2027.

16. This project involves the purchase of one (1) 72 kV 2000A 31.5/40kA 48 VDC GOP spare breaker with a total estimated cost of \$0.12 M. The estimated ISD is 12/31/2027.

17. This project involves the purchase of one (1) 72 kV 2000A 31.5/40kA 24 VDC GOP spare breaker with a total estimated cost of \$0.12 M. The estimated ISD is 12/31/2027.

18. This project involves the purchase of one (1) 145 kV 3000A 40kA 48 VDC GOP spare breaker with a total estimated cost of \$0.16 M. The estimated ISD is 12/31/2027.

19. This project involves the purchase of one (1) 345 kV 4000A 63kA 125 VDC IPO spare breaker with a total estimated cost of \$0.7 M. The estimated ISD is 12/31/2028.

20. This project involves the purchase of two (2) 345 kV 3000A 63kA 125 VDC IPO spare breaker with a total estimated cost of \$1.4 M. The estimated ISD is 12/31/2028.

21. This project involves the purchase of three (3) 245 kV 3000A 63kA 125 VDC IPO spare breaker with a total estimated cost of \$0.8 M. The estimated ISD is 12/31/2028.

Project Benefits:

Maintaining a stock of spare breakers is crucial for minimizing downtime and enhancing overall reliability. By having these spares readily available, we can swiftly replace faulty units, ensuring that operations continue smoothly without significant interruptions.

This program also streamlines the replacement process, reducing the time and resources required to restore normal operations. Instead of needing to urgently procure parts to address an emergent situation, we can instead efficiently manage replacements, allowing for expedited customer restoration using new equipment.

Moreover, the program offers significant cost savings. By procuring spares in advance and taking advantage of bulk discounts, we avoid the premium costs associated with urgent procurement. This proactive approach not only saves money but also ensures that we are always prepared.

Having spare breakers on hand enables us to respond promptly to emergencies, mitigating risks and ensuring safety. In critical situations, the ability to quickly replace faulty units can make a significant difference in maintaining the integrity of our operations.

As our grid expands and customer's reliance on their electricity supply increases through electrification of heating and transportation, this program prepares us for future challenges; bolstering our infrastructure's ability to meet evolving needs.

Project Risks and Mitigation Plan:

The risks associated with the Spare Circuit Breaker Program are intricately tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we may need to rely on retired, unreliable, or repaired equipment that has been a previously in-service piece of equipment. These used circuit breakers would need to undergo a costly reconditioning process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to widespread disruptions and increased maintenance costs.

Moreover, the delay in purchasing new spares would increase the reliability risk caused by the failure of poor health equipment. The procurement process for equipment can involve long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to periods of supply chain instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

In summary, the lack of adequate funding for new spares not only forces us to depend on less reliable, refurbished components but also significantly heightens the risk of system failures due to the extended lead times required for procurement. Ensuring timely and sufficient funding is therefore critical to maintaining the integrity and reliability of our electric system, preventing potential failures, and avoiding the high costs associated with emergency repairs and system downtime.

Risk of No Action:

The absence of a comprehensive inventory of spare circuit breakers poses a significant threat to the reliability of our power system.

Without a dedicated stock of reliable spare circuit breakers, the risk of prolonged substation outages increases significantly. In the event of a failure that necessitating immediate replacement, the absence of readily available spares could result in extended interruptions to our customers. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare equipment. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare circuit breakers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Alternatives to establishing a spare circuit breaker program and purchasing spares present several significant challenges. With the limited/non-existent inventory of spares, unplanned emergency replacements require using circuit breakers purchased for planned projects. This results in additional capital expenditure on replenishing the breaker for these ongoing projects and delays the project progression. Another alternative is to use old/retired breakers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished breakers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the circuit breaker spares program is crucial to ensure the stability and efficiency of our infrastructure.

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Mobile Substation Evaluation - NYSEG

PROJECT INFORMATION

OpCo: New York State Electric & Gas Corporation	Project ID: PRJ-005950	Charge Code: Electric Transmission	Project Sponsor: Camargo, Rogerio	Project Type: Project
Business Area: Digital Grid	Rate Case Category Asset Condition	Project Stage: IP2 Technical	Start Date: 12/31/2024	In-Service Date: 12/31/2024

Project description:

Mobile substations are a requirement for Electric Operations, as they support the electric load during emergencies, project execution, and maintenance. The existing fleet of mobiles is unable to support the required load, and more units have been requested. We conducted a study to evaluate the purchase of these units.

Project Scope:

The study was broken down into three parts. 1) Understand the required future load and compare that to the existing mobile availability. 2) Understand the health condition of each of the units to determine if they can perform the required actions. 3) Develop a business case analysis to compare the cost of new mobiles to constantly refurbishing old ones. The results of these phases are described below. The demand was split into five categories, these are cases in which mobile substations are used: substation maintenance, mobile maintenance, resolving emergencies, project completion, and on standby in case of overloads. NYSEG has 21 mobile units, 6 of these are in such poor condition they cannot be used, the oldest was purchased in 1970. Maintenance is very costly and is usually performed one step at a time. For example, if a breaker is fixed in 2024, it is possible for the frame to break in 2025.

Project Benefits:

1) Keep up with transformer standards as the required sizes increase. 2) Purchasing new mobiles allows managers to request the specific sizes they need to fit their substation restrictions. 3) This will be a long-term investment that will save money on refurbishments. Mobiles have a lifespan of 20-25 years without any major ones. 4) Keep up to date with projects & substation maintenance. 5) Having a mobile available reduces the duration of outages that occur due to a transformer failure, because the unit can support the load. This is only possible if there are units not tied up to other activities and are in decent condition.

Project Risks and Mitigation Plan:

Risk 1: Lengthy procurement process for mobile devices

Description:

The procurement process for mobile devices is lengthy, which may delay the delivery of materials and impact the project schedule.

Mitigation:

Secure all required funding approvals within the current year to enable Purchasing to initiate the procurement process as early as possible. Without funding approval, Purchasing cannot start any procurement activities.

Risk 2: Increased supplier costs after RFP release

Description:

Supplier pricing may increase after the Request for Proposal (RFP) is released, potentially exceeding the project budget.

Mitigation:

Release the RFP as soon as possible to lock in pricing and minimize exposure to market cost increases.

Risk of No Action: NYSEG currently owns a limited number of mobile substations; however, past studies indicate that additional units are required. If this project does not move forward, NYSEG's operational flexibility will be at risk.
Project Alternatives: No alternatives.
Basis for Project Estimates Budgetary quotes from suppliers.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2021	2022	2023	2024	2025		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2021	2022	2023	2024	2025		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$'000's)

Capital Details:	Total	2026	2027	2028	2029	2030		
# AFUDC	\$ 107	\$ 36	\$ 36	\$ 36	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 5,684	\$ 1,895	\$ 1,895	\$ 1,895	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ 773	\$ 306	\$ 241	\$ 226	\$ -	\$ -		
# Materials	\$ 3,539	\$ 1,180	\$ 1,180	\$ 1,180	\$ -	\$ -		
# Overheads - External	\$ 755	\$ 299	\$ 235	\$ 221	\$ -	\$ -		
Total	\$ 10,858	\$ 3,715	\$ 3,587	\$ 3,557	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2026	2027	2028	2029	2030
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

NYSEG C-Truss				
PROJECT INFORMATION				
OpCo: NYSEG	Project ID: PRJ-007444	Charge Code: Electric Distribution	Project Sponsor: Paul Iannuzzelli	Project Type: Asset Betterments
Business Area: Process & Technology	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: H1 2026	In-Service Date: H2 2030
Project description: Wood poles with a remaining strength below 67% are "reject" poles per the National Electrical Safety Code (NESC) . The code requires these poles to be restored or replaced. Pole restoration with the C-Truss system has provided utility companies with a fast and cost-effective alternative to pole replacements. According to industry studies, trussing (a means of reinforcement) increases a wood poles lifespan by 25%-50%. The process involves reinforcing the poles with the steel truss positioned against the pole and driven into the ground to a depth well below the groundline decay zone per technical specification. This program will reduce the need for wood pole replacements, assisting a constrained supply chain and reduce overall cost to the customer and the company.				
Project Scope: The objective of this program is to add trussing to Distribution and Transmission wood poles to extend their service life. The program plans to "c-truss" approximately 2,268 distribution poles and 86 transmission poles annually. The selection criteria for trussing includes rejected poles due for replacement, found by WPIT to have more than 2 inches of remaining shell at groundline, and an assumption that 80% of these poles have good pole tops based on historical estimates. This yearly program cost increases by 5% annually for inflation.				
Project Benefits: Trussing is a cost-effective method to extend the life of utility poles. This approach is significantly less expensive than full pole replacement. For distribution poles, the cost of trussing is approximately \$800 per pole, compared to over \$8,600 for a full replacement. For transmission poles, the cost is about \$1,500 per structure, which is much less than the \$45,500 required for a new transmission pole. The flexibility of the installation method makes it possible to restore poles that are installed in rear-lots and in concrete along with poles having various attachments and difficult access. This will decrease the annual amount of pole replacements in the wood pole inspect and treat program, alleviating the existing backlog of reject and danger poles scheduled for replacement (11,665 NYSEG poles as of 06/26/25). Due to the industry studies validating significant life extension, the cost of "c-truss" system can be capitalized and used to reduce O&M costs. There are four positive Reliability impacts: 1. Reinforced poles will reduce the number of outages due to fewer wood pole failures. 2. Pole failures require longer restoration times compared to other T&D equipment and replacing/reinforcing them should be a priority. 3. Pole reinforcement doesn't require outages and is done while wood pole is in service. 4. The flexibility of the installation method makes it possible to restore poles that are installed in rear-lots and in concrete along with poles having various attachments and difficult to access areas.				
Project Risks and Mitigation Plan: 1. Project will reduce the likelihood of an injury to an employee or the member of the public and property damage by timely reinforcing rejected poles with a C-Truss prior to its failure. There is backlog of over 11,000 rejected wood poles going back to 2012 that are waiting replacement. There are several examples of rejected poles failing resulting in property damage and injury. In 2021, a rejected pole failed when two apprentices were climbing it in Elmira division. In 2019, in Zisko v NYSEG case, customer alleges a deteriorated pole caused a property fire in Binghamton division. 2. Reinforced poles will reduce the number of outages resulting in a fewer electric service interruptions. 3. Pole failures require longer restoration times compared to other T&D equipment and replacing/reinforcing them should be a priority. 4. Pole reinforcement doesn't require outages and is done while wood pole is in service. 5. The flexibility of the installation method makes it possible to restore poles that are installed in rear-lots and in concrete along with poles having various attachments and difficult to access areas.				

Risk of No Action:

1. "Run to failure" strategy will result in more wood pole failures. It will have a negative impact on CAIDI/SAIDI resulting in negative revenue adjustments.
2. Wood pole replacements take longer compared to other TD equipment. Accessibility is a significant issue, especially for transmission poles, due to remoteness and sensitivity of the environment that these structures are in. DEC and other permitting along with ROW corridor matting may be necessary for the larger and heavier vehicles to replace structures. Reinforcement requires a side by side to haul equipment and labor.

Project Alternatives:

There are no program alternatives except for a replacement of wood poles. The wood poles reinforcement will increase their lifespan by more than 20%-50% by reducing the effective strength loss of the pole saving money for our customers.. This approach is significantly less expensive than pole replacement. For distribution poles, the cost of c-trussing is approximately \$800 per pole, compared to \$8,600 for a replacement. For transmission poles, the cost is about \$1,500 per structure, which is much less than the \$45,500 required for a new transmission wood pole.

Basis for Project Estimates

Actual historic costs with + inflation.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 10,731	\$ -	\$ 2,057	\$ 2,102	\$ 2,146	\$ 2,191	\$ 2,237	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 26	\$ -	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ -
# Internal, Overheads	\$ 1,291	\$ -	\$ 247	\$ 253	\$ 258	\$ 264	\$ 269	\$ -
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 3,227	\$ -	\$ 618	\$ 632	\$ 645	\$ 659	\$ 673	\$ -
Total	\$ 15,276	\$ -	\$ 2,927	\$ 2,992	\$ 3,054	\$ 3,118	\$ 3,184	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-NYSEG-L879

PROJECT INFORMATION

OpCo: New York State Electric & Gas Corporation	Project ID: PRJ-007466	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP2 Technical	Start Date: 1/0/1900	In-Service Date: 1/0/1900

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The List of TLD notifications will be reviewed on a particular circuit during the engineering process. The focus will be on Level 2 and Level 3 notifications that require capital work, generally structure replacements. The Planned Maintenance Report (PMR) of all notifications will be reviewed annually and rely on Operational Excellence's Power BI tool for prioritization of which lines to address. Line 879 Plattsburgh = 9 Notifications

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2021	2022	2023	2024	2025		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2021	2022	2023	2024	2025		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$'000's)

Capital Details:	Total	2026	2027	2028	2029	2030		
# AFUDC	\$ 52	\$ -	\$ 5	\$ 10	\$ 37	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 414	\$ -	\$ 40	\$ 80	\$ 294	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 52	\$ -	\$ 5	\$ 10	\$ 37	\$ -		
# Internal, Overheads	\$ 61	\$ -	\$ 6	\$ 12	\$ 43	\$ -		
# Materials	\$ 352	\$ -	\$ 34	\$ 68	\$ 250	\$ -		
# Overheads - External	\$ 68	\$ -	\$ 7	\$ 13	\$ 48	\$ -		
Total	\$ 999	\$ -	\$ 97	\$ 193	\$ 708	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2026	2027	2028	2029	2030
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

TLD Replacements-NYSEG-L977

PROJECT INFORMATION

OpCo: New York State Electric & Gas Corporation	Project ID: PRJ-007362	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: 1/0/1900	In-Service Date: 1/0/1900

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The List of TLD notifications will be reviewed on a particular circuit during the engineering process. The focus will be on Level 2 and Level 3 notifications that require capital work, generally structure replacements. The Planned Maintenance Report (PMR) of all notifications will be reviewed annually and rely on Operational Excellence's Power BI tool for prioritization of which lines to address. Line 977 Geneva = 8 Notifications

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, NYSEG is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2021	2022	2023	2024	2025		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2021	2022	2023	2024	2025		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2026	2027	2028	2029	2030		
# AFUDC	\$ 40	\$ 15	\$ 25	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 320	\$ 120	\$ 200	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 40	\$ 15	\$ 25	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ 56	\$ 24	\$ 32	\$ -	\$ -	\$ -		
# Materials	\$ 272	\$ 102	\$ 170	\$ -	\$ -	\$ -		
# Overheads - External	\$ 62	\$ 27	\$ 35	\$ -	\$ -	\$ -		
Total	\$ 790	\$ 303	\$ 487	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2026	2027	2028	2029	2030
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -



RG&E Electric Asset Condition

RGE T&S Asset Condition Replacement Program

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-003020	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The T&S Asset Condition Replacement Program aims to enhance the health of RG&E systems through comprehensive facility surveys and a long-term mitigation strategy. The 5-year plan focuses on assessing underground cable facilities, prioritizing needs based on failure risk and customer impact, and developing projects to replace cables beyond their useful life. Additionally, the plan includes rejuvenating cables that show signs of aging but are still within their useful life.

The investment plan allocates small expenditures in 2026 and larger investments from 2027 onwards for specific underground replacement and rejuvenation projects. Approximately 36.67% of RG&E customers rely on aging underground cable systems, spanning 3,061 cable miles with average ages ranging from 25 to over 100 years. Increased underground cable failures over the past four years highlight the urgent need for detailed assessments to identify asset conditions, maintenance, and operational needs.

The project's primary objective is to conduct a comprehensive needs assessment of RG&E's underground cable systems, evaluating asset conditions and identifying maintenance and operational needs. This assessment aims to develop a prioritized plan for cable replacement, rejuvenation, and maintenance, mitigating risks associated with aging infrastructure and ensuring reliable electric service.

Improving data accuracy in the SAP database is also a key goal. Accurate data is essential for effective asset management and decision-making. The assessment will verify and correct existing data, gather new information through field inspections and testing, and support the development of a robust prioritization algorithm for resource allocation.

Following the assessments, the project will implement cable replacements and rejuvenation based on the prioritized plan. These interventions will optimize capital expenditures for reliability improvements, enhancing the performance and sustainability of the underground infrastructure. This project is a critical step towards modernizing RG&E's underground cable systems, addressing aging infrastructure, and improving data accuracy. The successful completion of this project will benefit both the utility company and its customers, providing a more resilient and dependable electric service across RG&E.

Project Scope:

The scope of the project involves engaging a contractor to perform a detailed assessment of the underground transmission and distribution cable systems. This includes using cable system assessment technologies such as TDR, Tan-Delta, and Partial Discharge. Where needed, the contractor will correct or update erroneous mapping of the underground cable system, verify cable age, type, length, and in-service dates, assess cable loading and termination conditions, evaluate gas usage for nitrogen-filled cables, conduct oil testing for high-pressure oil-filled cables, and assess cathodic protection, among other tasks. Based on the assessment results, a prioritization algorithm will be developed to guide resource allocation for cable replacement, rejuvenation, and maintenance efforts.

In addition to the assessment and prioritization, the scope of work will include the actual replacement or rejuvenation of the identified cables as part of the project. This means that the contractor will not only identify the cables that need attention but, together with internal resources, they will also carry out the necessary interventions to ensure the reliability and safety of the underground cable systems. This comprehensive approach ensures that the project addresses both the diagnostic and corrective aspects of cable management.

The project deliverables include a comprehensive assessment report detailing the condition of the underground cable systems, a prioritized list of recommended interventions, updated and accurate data in the SAP database, and recommendations for improving system reliability and safety. The inclusion of actual replacement or rejuvenation activities as part of the deliverables ensures that the project outcomes are actionable and lead to tangible improvements in the cable infrastructure.

The project is expected to commence in 2026, with the assessment and prioritization phase taking approximately 24 months. The remaining work, including the actual replacement or rejuvenation of cables, will span a period of 20+ years, contingent on funding approval. Currently, the estimated per mile cost of underground (UG) cable replacements is \$3.6 million per mile for transmission cables and \$2 million per mile for distribution cables.

For RGE, we plan to replace 1 transmission line mile every year and 5 distribution miles from 2027 to 2028. We will then increase our distribution miles to 10 miles per year.

Project Benefits:

The project to assess and upgrade RG&E's underground cable systems offers numerous benefits that will significantly enhance the electric service provided to customers throughout New York state.

Firstly, the project will improve system reliability. By conducting a comprehensive needs assessment and identifying the condition of the underground cables, the project will help mitigate the risks associated with aging infrastructure. This proactive approach will reduce the frequency of outages and failures, ensuring a more consistent and dependable electric service for customers.

Secondly, the project will optimize capital expenditures. By developing a prioritized plan for cable replacement, rejuvenation, and maintenance, the project will ensure that resources are allocated efficiently. This targeted approach will maximize the impact of investments, leading to cost-effective improvements in the underground systems' performance and longevity.

Thirdly, the project will enhance data accuracy. By verifying and correcting existing data in the SAP database and gathering new information through field inspections and testing, the project will improve the quality of data used for asset management and decision-making. Accurate data is crucial for developing effective maintenance strategies and ensuring the long-term sustainability of the underground infrastructure.

Fourthly, the project will increase safety. By addressing the aging underground cables and implementing necessary interventions, the project will reduce the risk of cable failures that could pose safety hazards. This will create a safer environment for both utility workers and the general public.

Lastly, the project will support future growth and demand. By modernizing the underground cable systems and ensuring they can meet current and future demands, the project will provide a robust foundation for the continued development of the electric grid. This will support economic growth and development in the region, benefiting both the utility company and its customers.

Overall, this project represents a critical investment in the future of RG&E's underground cable systems, delivering significant benefits in terms of reliability, cost-efficiency, data accuracy, safety, and capacity to meet future demands.

Project Risks and Mitigation Plan:

The project to assess and upgrade RG&E's underground cable systems carries several risks that need to be addressed to ensure its success. Here are the key risks and their corresponding mitigation plans:

Risk of Incomplete or Inaccurate Data Collection: The project relies heavily on accurate data to assess the condition of the underground cables. Inaccurate or incomplete data can lead to incorrect assessments and suboptimal decision-making.

Mitigation Plan: Implement a robust data verification process that includes cross-referencing existing data with field inspections and testing. Utilize advanced data collection technologies and methodologies to ensure comprehensive and accurate data gathering. Regular audits and quality checks should be conducted throughout the project to maintain data integrity.

Risk of Unanticipated Cable Failures During Assessment: Given the aging infrastructure, there is a risk that cables may fail unexpectedly during the assessment phase, causing service disruptions.

Mitigation Plan: Develop a contingency plan that includes rapid response teams and backup systems to address any unexpected failures promptly. Ensure that all assessment activities are closely monitored and that any signs of potential failure are addressed immediately. Additionally, communicate with customers about the potential for temporary disruptions and the measures being taken to minimize them.

Risk of Insufficient Funding or Resource Allocation: The project requires significant investment in terms of capital and resources. Insufficient funding or misallocation of resources can hinder the project's progress and effectiveness.

Mitigation Plan: Secure funding commitments from stakeholders and ensure a detailed budget plan is in place. Prioritize project activities based on criticality and potential impact on system reliability. Regularly review and adjust the budget and resource allocation to align with project needs and progress.

Risk of Delays in Project Implementation: Delays in the assessment and subsequent implementation phases can extend the period during which the aging infrastructure remains vulnerable, increasing the risk of failures.

Mitigation Plan: Develop a detailed project timeline with clear milestones and deadlines. Implement project management best practices, including regular progress reviews, risk assessments, and contingency planning. Engage experienced project managers and ensure effective communication and coordination among all project teams.

Risk of Stakeholder Resistance or Lack of Support: Resistance from stakeholders, including utility employees, regulatory bodies, and customers, can impede project progress and acceptance.

Mitigation Plan: Engage stakeholders early in the project to build support and address concerns. Provide transparent and regular updates on project progress and benefits. Conduct training and awareness programs for utility employees to ensure they understand the project's importance and their role in its success. Foster a collaborative environment where stakeholder feedback is valued and incorporated into project planning and execution.

By addressing these risks with comprehensive mitigation plans, the project can proceed smoothly and achieve its objectives of improving the reliability, safety, and sustainability of RG&E's underground cable systems.

Risk of No Action:

If no action is taken to address the aging underground systems, the risks to the reliability and performance of electric service will continue to escalate. With 36.67% of RG&E's customers relying on these aging systems, the potential for widespread service disruptions is significant. The underground systems, spanning 3,061 cable miles include cables that are over 100 years old. The increasing frequency of underground cable failures over the past four years underscores the urgent need for a detailed assessment to identify asset conditions, maintenance, and operational needs.

Without a comprehensive needs assessment, the condition of the underground cables will remain uncertain, leading to unanticipated failures and outages. The lack of a prioritized plan for cable replacement, rejuvenation, and maintenance will result in a reactive approach to infrastructure management, which is less efficient and more costly. The continued degradation of the underground systems will compromise the reliability of electric service, causing inconvenience and potential safety hazards for customers.

Inaccurate and outdated data in the SAP database will further exacerbate the challenges of managing the underground cable systems. Without verifying and correcting existing data, and gathering new information through field inspections and testing, the utility companies will struggle to make informed decisions about asset management. This lack of accurate data will hinder the development of effective maintenance strategies and resource allocation, leading to suboptimal use of capital expenditures and increased operational risks.

The absence of a proactive approach to addressing the aging infrastructure will also pose significant safety risks. Aging cables are more prone to failures, which can lead to hazardous situations for both utility workers and the public. Without timely interventions, the risk of accidents and injuries will increase, compromising the safety of the electric service environment.

Ultimately, failing to modernize RG&E's underground cable systems will jeopardize the long-term sustainability of the electric grid. The inability to meet current and future demands will hinder economic growth and development in the region. The continued reliance on outdated infrastructure will result in higher maintenance costs, reduced system reliability, and increased customer dissatisfaction. Taking no action will not only affect the utility companies' performance but also negatively impact the quality of life for their customers.

Project Alternatives:

When considering alternatives to the proposed project for assessing and upgrading RG&E's underground cable systems, several options emerge, each with its own set of benefits and drawbacks.

One alternative is to continue with the current reactive maintenance approach. This would involve addressing cable failures as they occur without a comprehensive needs assessment or proactive replacement plan. While this option may initially seem cost-effective, it carries significant risks. The increasing frequency of underground cable failures suggests that this approach will likely lead to higher long-term costs due to emergency repairs and service disruptions. Additionally, the reliability and performance of the electric service will continue to degrade, causing inconvenience and potential safety hazards for customers.

Another alternative is to implement a partial upgrade focused on the most critical areas. This would involve identifying and replacing only the most at-risk cables based on available data. While this targeted approach could improve reliability in the short term, it may not address the underlying issues of aging infrastructure comprehensively. The lack of accurate and up-to-date data in the SAP database could lead to suboptimal decisions about which cables to prioritize, potentially leaving significant vulnerabilities unaddressed.

A third alternative is to invest in advanced monitoring and diagnostic technologies to continuously assess the condition of the underground cables. This approach would involve installing sensors and other monitoring equipment to detect early signs of cable degradation and failures. While this could provide valuable real-time data and help prevent unexpected outages, it would still require significant investment and may not fully address the need for a comprehensive replacement and rejuvenation plan. Additionally, the effectiveness of this approach depends on the accuracy and reliability of the monitoring technologies.

A fourth alternative is to outsource the entire assessment and upgrade process to a specialized third-party contractor. This could leverage the expertise and resources of a company experienced in managing underground cable systems. While this option could potentially expedite the project and ensure high-quality results, it may also involve higher costs and require careful oversight to ensure alignment with NYSEG and RG&E's specific needs and standards.

Another option is to implement a phased replacement over an extended period. This approach involves spreading the replacement and rejuvenation of underground cables over a longer timeframe, such as 10-20 years. While this can help manage costs and resource allocation more effectively, it also means that many aging cables will remain in service for an extended period, increasing the risk of failures and outages. The prolonged timeline may also lead to higher cumulative costs due to inflation and the need for ongoing emergency repairs.

An enhanced preventive maintenance program is another alternative. Instead of a full-scale replacement, this approach focuses on significantly ramping up preventive maintenance activities, such as regular inspections, testing, and minor repairs. While this can help extend the lifespan of existing cables and reduce the frequency of failures, it may not be sufficient to address the fundamental issues of aging infrastructure. The effectiveness of preventive maintenance is limited, and it may only delay the inevitable need for major replacements.

Selective use of cable rejuvenation technologies is another option. Cable rejuvenation involves injecting a fluid into the insulation of aging cables to restore their dielectric properties and extend their lifespan. This can be a cost-effective alternative to full replacement. However, rejuvenation is not suitable for all types of cables or all conditions, and its effectiveness can vary. There is also a risk that rejuvenated cables may still fail prematurely, leading to unexpected outages and additional costs.

Each of these alternatives offers potential benefits but also comes with significant risks. The proposed comprehensive needs assessment and prioritized replacement plan remains the most balanced approach, addressing the aging infrastructure holistically while mitigating risks and optimizing resource allocation.

These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, Avangrid Master Service Agreement rates from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within RGE. Escalation rates are based upon current U.S. inflation rates. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

[illegible]

Station 29 Modernization Project

PROJECT INFORMATION

OpCo: RG&E	Project ID: UH-R0005226-RGE-ED	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP2 Partial Approval	Start Date: H1 2025	In-Service Date: H2 2031

Project description:

Overview: The Station 29 Project aims to address asset condition and reliability issues at Stations 29 and 34 both located in Rochester, NY. The project involves infrastructure upgrades and the expansion of Station 29 and the demolition of Station 34.

There is interplay between the Station 29 Project and the Station 34 project. The Station 29 Project encompasses the substation work at both Stations 29 and Station 34 to expand Station 29 and demolish Station 34. The Station 34 Project encompasses the line work between Stations 29, 34, and 137 to allow for Stations 29 and 137 to feed the distribution presently fed out of Station 34.

Current State Needs Assessment: Station 29, constructed in 1947, faces significant asset condition issues due to aged equipment. Ten of the 4 kV circuit breakers are in poor health and six of the 34 kV circuit breakers are in very poor health according to Asset Management's Health Index. Numerous foundations are in need of repair and the majority of its protective relays are of the obsolete electromechanical type, meaning spare and replacement parts are unavailable for purchase.

Station 34, constructed in 1924, faces significant asset condition and reliability issues. Five of the 4 kV circuit breakers are in poor health, two of the 11 kV circuit breakers are in poor health, and seven of the 11 kV circuit breakers are in very poor health. The control house building is also in poor condition and has large cracks running the length of the building along the cliff face that it overhangs. The majority of its protective relays are electromechanical as well. The reliability issues are due to the single distribution transformer, which cannot be taken out of service for maintenance without causing customer outages.

Both Stations 29 and 34 serve customers in Disadvantaged Communities and Potential Environmental Justice Areas.

Project Scope:

The selected project proposal involves replacing five 34 kV breakers in kind, replacing the three existing 34/4 kV transformers with two new 22.4 MVA transformers, and replacing the two existing 4 kV buses at Station 29. Lastly, the existing control building at Station 34 will be demolished.

Project Benefits:

The proposed project will mitigate the existing reliability and asset condition needs within Disadvantaged Communities and Potential Environmental Justice Areas, as well as increase the system capacity headroom allowing for additional load growth over time.

Reliability: The project will significantly enhance system reliability by providing N-1 contingency to Station 34's customers, which is currently missing due to the single transformer configuration. By upgrading the infrastructure and adding redundancy, the project will ensure continuous service even during faults or maintenance activities. Reliability will also be improved by automating Station 29 with microprocessor relaying to speed up fault clearing times and allow for faster outage response.

Asset Condition: Multiple circuit breakers at both stations are in poor or very poor health and multiple relays are of the obsolete electromechanical type in need of replacement. At Station 29 several foundations are in poor health and at Station 34 the control house building is in poor condition. Upgrading these components will improve the overall health and performance of the electrical assets, reducing the risk of failures and outages.

Capacity Headroom: Transferring Station 34's 4kV loads to Station 29 creates thermal constraints on the existing transformers. Replacement of these transformers with larger units affords for N-1 capacity as well as significant future load growth.

Project Risks and Mitigation Plan:

The project's key risks are demolishing Station 34 with minimal interference with the planned state park to be built nearby and the potential that the Station 34 Project would be cancelled resulting in the stations missing the crucial line work. Communication and coordination with the state park project stakeholders will help prevent any conflicts with the demolition of Station 34. Clear communication about the crucial link between these two projects will prevent the cancellation of the other piece.

Risk of No Action:

A decision to take no action would leave the assets in poor and very poor health to continue to degrade until they fail in service. Their failure could cause outages, further stressing the remaining assets by the fault current they would be exposed to during the event, and significantly loading or overloading other circuits and transformers when loads are switched to restore service. Additionally, these failures would warrant the replacement of the failed assets under an accelerated time frame at an inopportune moment rather than at a planned time.

One alternative that was considered is similar to the selected proposal with the addition of the installation of series reactors on lines 721 and 724 at Station 137. The full scope involves replacing five 34 kV breakers in kind, replacing the three existing 34/4 kV transformers with two new transformers, and replacing the two existing 4 kV buses at Station 29. This second alternative included constructing four 4kV line extensions between Station 29 and 34 to allow for the 4 kV distribution fed out of Station 34 to be fed from Station 29, as well as doubling the number of cables on line 640 between Stations 34 and 137. Splicing the lines at Station 34; 641 to 642, 640 to 664, and 544 to 643, and demolishing Station 34 were also included in this alternative. Lastly, series reactors at Station 137 on lines 721 and 724 would be installed. The selective alternative removed the reactor installation from its scope because it would reduce the capacity of the 34.5 kV network to transmit power.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects at NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses and more detailed information becomes available. These cost estimates do not include AFUDC.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE - Pole Replace (WPIT) Program

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-001581	Charge Code: Electric Distribution	Project Sponsor: Shail, Joshua	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

Wood Pole Inspect and Treat (WPIT) program was established in 2021 to address the growing number of asset condition needs identified among RGE's fleet of wooden type distribution and transmission poles as part of routine field inspections.

Field inspections are performed across all RGE divisions (4 total), on a yearly basis, to identify wood poles that are deemed in need of replacement or repairs. Inspections include ground line evaluations to identify instances of wood decay, excavation and boring techniques to identify decay at-or-below ground line, and "Sounding" the pole which includes striking the pole with a mallet and listening for signs of a hollow structure.

Inspections include the visual observation of the pole from top to bottom and looking for signs such as: woodpecker holes, split tops, excessive leaning, structural damage. The following determines which inspection technique is used:

Age of Pole (0-10 Years) - Visual

Age of Pole (11+) - Sound, Boring, and partial excavation

Inspections occur from March to December and are used to inform a larger set of system needs including those that were identified in prior years but have not yet been addressed.

In Q4 of each calendar year, Electric Operations reviews the system needs identified through field inspections and prioritize the subsequent year's deployment based on the severity of the need.

Once the overall prioritization has been established, the annual plan is communicated to the local division for execution in the following calendar year.

Project Scope:

The WPIT program consists of a field inspection that generates notifications for work execution on decayed poles. The execution happens following a workplan based on the notification priority and a reliability score that includes asset data, customer exposure and historical reliability variables. At RGE an average of 2,500 customers were interrupted annually by pole decay and insulator related causes over the past 3 years.

The following units and average unit costs will be addressed between 2025-2031:

2025 - 496 (units) / \$9,134 (unit cost)

2026 - 509 (units) / \$9,408 (unit cost)

2027 - 522 (units) / \$9,690 (unit cost)

2028 - 536 (units) / \$9,981 (unit cost)

2029 - 549 (units) / \$10,280 (unit cost)

2030 - 563 (units) / \$10,589 (unit cost)

2031 - 577 (units) / \$10,906 (unit cost)

Project Benefits:

Pole replacements and repairs serve to mitigate safety risks and have been shown to improve overall system reliability metrics (e.g., SAIFI).

Project Risks and Mitigation Plan:

The Company must align with State and Federal reliability standards which is evidence of the Company's commitment to these standards through a well executed program. The program identifies tasks within same reach to help reduce operational costs and improve the timeliness of the execution plan. As this program matures, the expectation is that all distribution poles are to be inspected on a 10-year cycle, which would equate to 10% of the Company's distribution poles being inspected annually.

RGE use internal designations and specify WPIT severity levels based on the following internal nomenclature.

WPIT Level 2A: Recommended replacement within 30 days.

WPIT Level 2: Recommended replacement within one year.

Level 2A poles are missing a substantial level of strength and are likely to come down in the next storm. The remaining notifications were ranked by reliability impact for RGE, by the number of customers downstream of the specific location, the historical customer impact, the device type, the notifications per specific FLOC and the historical incident count.

Risk of No Action:

The WPIT program proactively inspects and treats wood poles to prevent potential increases in outage frequency. Without this proactive work, the system may experience more frequent outages. Additionally, there are risks of negatively impacting SAIFI goals, environmental factors, supply chain stability, public perception, and facing regulatory penalties.

Project Alternatives:

The WPIT program aims to replace one-for-one assets that are in poor condition. Alternatives are considered on a case-by-case basis to ensure the most effective solutions are implemented.

Basis for Project Estimates

The financial plan is based on an average cost per pole replacement. The average cost is determined by the cost of construction crews, internal labor costs, material costs, and overheads applicable to replacing a pole.

FINANCIAL INFORMATION**Actual Capital Spent, all amounts shown below in thousands (\$000's)**

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 179	\$ -	\$ 11	\$ 56	\$ 40	\$ 72		
# CIAC	\$ -859	\$ -	\$ -	\$ -110	\$ -471	\$ -278		
# External Services	\$ 8,371	\$ -	\$ 1,069	\$ 2,950	\$ 2,555	\$ 1,797		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 384	\$ -	\$ 109	\$ 74	\$ 86	\$ 115		
# Internal, Overheads	\$ 813	\$ -	\$ 104	\$ 246	\$ 195	\$ 268		
# Materials	\$ 1,544	\$ -	\$ 236	\$ 379	\$ 370	\$ 558		
# Overheads - External	\$ 2,158	\$ -	\$ 225	\$ 654	\$ 631	\$ 647		
Total	\$ 12,589	\$ -	\$ 1,755	\$ 4,249	\$ 3,406	\$ 3,179		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ 550	\$ -	\$ 71	\$ 195	\$ 166	\$ 117		
Materials	\$ 9	\$ -	\$ -	\$ 3	\$ 3	\$ 3		
Other O&M	\$ 1	\$ -	\$ 1	\$ -	\$ -	\$ -		
Total	\$ 560	\$ -	\$ 72	\$ 198	\$ 169	\$ 121		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 547	\$ 65	\$ 70	\$ 74	\$ 78	\$ 82	\$ 87	\$ 92
# CIAC	\$ -5,867	\$ -782	\$ -826	\$ -835	\$ -843	\$ -851	\$ -860	\$ -869
# External Services	\$ 37,070	\$ 4,529	\$ 4,784	\$ 5,023	\$ 5,274	\$ 5,538	\$ 5,815	\$ 6,106
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 1,110	\$ 136	\$ 143	\$ 150	\$ 158	\$ 166	\$ 174	\$ 183
# Internal, Overheads	\$ 1,771	\$ 287	\$ 290	\$ 272	\$ 248	\$ 221	\$ 218	\$ 236
# Materials	\$ 4,775	\$ 583	\$ 616	\$ 647	\$ 679	\$ 713	\$ 749	\$ 786
# Overheads - External	\$ 3,645	\$ 554	\$ 604	\$ 565	\$ 517	\$ 460	\$ 454	\$ 491
Total	\$ 43,052	\$ 5,371	\$ 5,680	\$ 5,897	\$ 6,112	\$ 6,329	\$ 6,638	\$ 7,025

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 1,507	\$ 197	\$ 207	\$ 211	\$ 216	\$ 220	\$ 225	\$ 230
Materials	\$ 25	\$ 3	\$ 3	\$ 4	\$ 4	\$ 4	\$ 4	\$ 4

Other O&M	\$ 2	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Total	\$ 1,534	\$ 201	\$ 211	\$ 215	\$ 220	\$ 224	\$ 229	\$ 234

Station 82 Upgrades

PROJECT INFORMATION

OpCo: RG&E	Project ID: UH-R0000612-RGE-ET	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP2 Partial Approval	Start Date: H1 2025	In-Service Date: H2 2032

Project description:

The purpose of this project is to construct a replacement substation 82 incorporating breaker-and-a-half bus configuration, migrating the transmission lines and distribution circuits from old substation 82 to new substation 82, and disassembling and removing the old substation 82 components.

Substation 82 is a critical facility located in Brighton, NY providing tie points for 115KV transmission. Two 115KV/34KV transformers and two 115KV/12KV transformers step down the voltage and supply both 34KV and 12KV distribution circuits.

A site assessment was completed in February 2021 concluding that equipment condition varies between "fair" and "good". Numerous devices were identified which lack physical separation between redundant trains. A rigid bus assessment was completed in April 2021 which concluded that several bus segments exceed their allowable bus strength utilization ratios by 184% or larger. Significant upgrades would be required to extend the life of substation components to maintain the reliability and availability of the transmission lines connected to the substation. Additionally, RG&E has determined that several of the 115KV transmission lines need to be replaced due to the need for expanded capacity.

The existing substation has three 115KV bus segments, two 34KV bus segments and two 12KV bus segments. The buses are configured in a single bus configuration which prohibits expansion of the existing facility without a significant investment to eliminate single point vulnerabilities.

Project Scope:

A new substation will be built adjacent to the existing substation. Transmission lines will be relocated from the old substation to the new substation. Once new construction is completed the new substation will be placed into service as substation 82 and the existing substation will be demolished.

Scope of work includes:

- Replacement of all 115KV, 34KV and 12KV equipment with the exception of two 115KV capacitor banks which will be relocated to the new substation
- Installation of new 115KV buses and associated breakers into six bays of breaker-and-a-half (BAAH) configuration to ensure all equipment has redundant connections to the 115KV buses
- Installation of two (2) new 115/34.5KV transformers
- Installation of two (2) new 115/12.5KV transformers
- Installation of new protection and control systems
- Construction of a 115KV control building housing air insulated switchgear (AIS) controls
- Installation of four modular control buildings containing gas insulated switchgear (GIS) for 34KV and 12.5KV controls
- Installation of new protection and control devices powered from a dual AC distribution system
- Installation of two trains of DC distribution for control power
- Installation of new communications interfaces and required auxiliary systems

Transformer T1 failed in 2019 and a spare is currently in service. Transformers T2 and T3 are 45+ years old and physically degrading. 115KV, 34KV and 12KV circuit breakers have been rated "poor" and "very poor" and require replacement. Upgrading the Station 82-to-Mortimer bus tie to 3000 amps will increase the Summer Normal Rating to 598MVA.

Project Benefits:

Increased equipment reliability including improvements in 115 kV breaker fault duty and increased breaker thermal capacity.

Project implementation will also provide operational flexibility to ensure full utilization of the increased transformer capacity at Station 80.

Replacing aging transformers will increase the availability and reliability of the station. Transformer T1 failed in 2019 and is currently powered by a temporary transformer. Transformers T2 and T3 are 45+ years old and operating beyond their planned end of life.

New circuit breakers installed as part of the upgrade will have higher current carrying capabilities than the existing breakers eliminating the breakers as the operationally limiting devices. The new breakers will provide RG&E with the ability to increase the summer LTE rating of circuits connected to the station.

Project Risks and Mitigation Plan:**Risk #1:**

Long lead items impact the deadline for completing the Article VII project.

Mitigation Plan: The Article VII paperwork will be submitted before the completion of detailed engineering. This will provide the ability to initiate contracts for long lead items in parallel with the mandated 12 month PSC review of Article VII paperwork.

Risk #2:

Adverse customer impact due to extended circuit outages during construction.

Mitigation Plan: Vacant land adjacent to the substation will be acquired to provide the ability to construct the new substation while the existing substation remains in service. Energization of the new substation can be performed in phases, minimizing the duration of transmission and distribution circuit outages.

Risk #3:

Construction vehicle traffic is viewed negatively by property owners on the street which provides access to the facility.

Mitigation Plan: the property borders multiple roads which can be utilized for construction vehicles. In lieu of using the single entrance/exit, a second access road will be constructed to the site, thereby reducing construction traffic by 50% on the existing access road.

Risk of No Action:

A study was performed to determine the condition of installed equipment at Station 82. [REDACTED]

Maintaining the existing substation with overloaded equipment and no margin to compensate for unplanned distribution circuit outages reduces the potential availability and reliability of the station. These limitations could result in unplanned and long duration outages affecting multiple customers connected to the facility.

Project Alternatives:

1. Rebuild Station 82 on the existing property. This option was eliminated due to the need for an extended outage of multiple distribution circuits, which would require long term temporary backfeeds to circuits to maintain redundancy in the distribution system.
2. Do nothing. This option was eliminated due to the ageing and obsolete equipment at the substation which will have a negative effect on the future availability and reliability of the facility.
3. Perform a full rebuild of Station 82 utilizing adjacent vacant land to build the new substation while the old substation remains in service. Install 115KV AIS breaker and a half bus configuration and new GIS switchgear for the 12KV and 34KV distribution circuits. This option was selected as the best alternative to meet the long term availability and reliability requirements of the transmission and distribution system without requiring extended circuit outages to implement the solution.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects at RG&E. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 547	\$ 17	\$ 44	\$ 78	\$ 154	\$ 254		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 2,290	\$ 14	\$ 264	\$ 460	\$ 1,399	\$ 153		
# Internal - Non-AC	\$ 5	\$ 0	\$ 0	\$ -	\$ 5	\$ -		
# Internal, Labor	\$ 408	\$ 127	\$ 108	\$ 65	\$ 93	\$ 15		
# Internal, Overheads	\$ 172	\$ 8	\$ 20	\$ 35	\$ 94	\$ 15		
# Materials	\$ 40	\$ -	\$ -	\$ 40	\$ -	\$ -		
# Overheads - External	\$ 690	\$ 59	\$ 78	\$ 126	\$ 378	\$ 49		
Total	\$ 4,153	\$ 224	\$ 514	\$ 804	\$ 2,123	\$ 487		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 16,455	\$ 382	\$ 324	\$ -	\$ -	\$ -	\$ 6,385	\$ 9,363
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 29,602	\$ 121	\$ 100	\$ 509	\$ 378	\$ 8,780	\$ 7,216	\$ 12,498
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 3,900	\$ -	\$ 150	\$ -	\$ -	\$ 1,250	\$ 1,250	\$ 1,250
# Internal, Overheads	\$ 2,733	\$ 6	\$ 13	\$ 113	\$ 142	\$ 749	\$ 885	\$ 826
# Materials	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,000	\$ 5,000
# Overheads - External	\$ 6,275	\$ 13	\$ 51	\$ 77	\$ 278	\$ 1,744	\$ 2,127	\$ 1,984
Total	\$ 68,964	\$ 521	\$ 638	\$ 699	\$ 798	\$ 12,523	\$ 22,864	\$ 30,921

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Station 37 Modernization Project

PROJECT INFORMATION

OpCo: RG&E	Project ID: UH-R0005232-RGE-ED	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP2 Partial Approval	Start Date: H1 2025	In-Service Date: H2 2031

Project description:

Overview: The station 37 project aims to address asset condition at stations 37 located in Rochester, NY. The project involves upgrades of station 37.

Current State Needs Assessment: Station 37, constructed in 1923, faces significant asset condition issues due to aged equipment. Six 4 kV breakers are in poor health, three 11 kV breakers are in poor health, and seven 11kV breakers are in very poor health. One 34 kV breaker is in fair health but is a CG-38 model (which is known to be a poor performer), three 34 kV breakers are in poor health, and two 34 kV breakers are in very poor health, one of which is overdutied in system normal. One of the two 34/11 kV transformers is in poor health and the other is in fair health, but, as they operate in parallel, they should be replaced together. The majority of protective relays are of the obsolete electromechanical type for which spare and replacement parts can no longer be purchased. The series reactor on line 609 is in poor health. Station 37 serves customers in Disadvantaged Communities and Potential Environmental Justice Areas.

Project Scope:

The selected project proposal involves replacing five 34kV breakers in kind, replacing the two 34/11kV transformers with two new 37.3 MVA transformers, replacing the two existing 11kV buses, replacing five 4kV breakers in kind, and replacing the 609 line reactor.

Project Benefits:

The proposed project will mitigate the existing asset condition needs within Disadvantaged Communities and Potential Environmental Justice Areas.

Asset Condition: Multiple circuit breakers at Station 37 are in poor or very poor health (one is in fair health but is a known poor performer) and one transformer is in poor health. Multiple relays are of the obsolete electromechanical type in need of replacement and the 609 line reactor is in poor health. Upgrading these components will improve the overall health and performance of the electrical assets, reducing the risk of failures and outages.

Reliability: Reliability will be improved by automating Station 37 with microprocessor relaying to speed up fault clearing times and allow for faster outage response.

Project Risks and Mitigation Plan:

The project's key risks are securing the circuit outages necessary to move the lines to the new breaker positions or replace the circuit breaker in place. This can be mitigated by careful outage coordination and conducting the outages during off peak times to ensure overloads won't be caused on adjacent circuits.

Risk of No Action:

A decision to take no action would leave the assets in poor and very poor health to continue to degrade until they fail in service. Their failure could cause outages, further stressing the remaining assets by the fault current they would be exposed to during the event, and significantly loading or overloading other circuits and transformers when loads are switched to restore service. Additionally, these failures would warrant the replacement of the failed assets under an accelerated time frame at an inopportune moment rather than at a planned time.

Project Alternatives:

The proposed alternative solution includes replacing just one 4kV breaker in kind and completely replacing the bus with the other four breakers in poor health. The full scope involves replacing five 34kV breakers in kind, replacing the two 34/11kV transformers, replacing the two existing 11kV buses, replacing one 4kV breaker in kind, replacing one 4kV bus, and replacing the 609 line reactor. This option was not selected due to the higher cost of installing a new bus instead of solely replacing the breakers.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects at NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses and more detailed information becomes available. Please note that these cost estimates do not include AFUDC. The total estimated cost is \$68.57 million.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 810	\$ 149	\$ 153	\$ 150	\$ 169	\$ 189		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 104	\$ -	\$ 8	\$ 80	\$ 15	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 49	\$ -	\$ 7	\$ 40	\$ 2	\$ -		
# Internal, Overheads	\$ 10	\$ -	\$ 1	\$ 7	\$ 1	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ 43	\$ -	\$ 4	\$ 34	\$ 5	\$ -		
Total	\$ 1,015	\$ 149	\$ 174	\$ 311	\$ 193	\$ 189		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 5,211	\$ 221	\$ 236	\$ 253	\$ 253	\$ 1,844	\$ 2,404	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 44,022	\$ -	\$ -	\$ -	\$ 598	\$ 6,192	\$ 19,382	\$ 17,850
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 1,033	\$ -	\$ -	\$ -	\$ -	\$ 517	\$ 517	\$ -
# Internal, Overheads	\$ 938	\$ -	\$ -	\$ -	\$ 23	\$ 551	\$ 364	\$ -
# Materials	\$ 8,000	\$ -	\$ -	\$ -	\$ -	\$ 8,000	\$ -	\$ -
# Overheads - External	\$ 2,392	\$ -	\$ -	\$ -	\$ 126	\$ 1,348	\$ 918	\$ -
Total	\$ 61,597	\$ 221	\$ 236	\$ 253	\$ 999	\$ 18,453	\$ 23,585	\$ 17,850

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE Line 920 Replacement Prj Cap

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-005271	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP2 Partial Approval	Start Date: H1 2026	In-Service Date: H2 2029

Project description:

RGE Line 920 is an underground 115 kV pipe-type cable transmission link between Station 23 and 42 (both stations are located in Rochester). This transmission line serves as a critical link between the eastern 115 kV network and the western 115 kV network in Rochester. The circuit was constructed in 1975 (49 years old) and is approximately 4.0 miles circuit length. In 2023, the transmission line experienced four (4) leaks. All leaks were promptly addressed and handled in accordance with Avangrid's Spill Prevention Containment & Control (SPCC) plan. All work was performed under the authority of NY State Department Environmental Conservation.

Project Risks and Mitigation Plan section below.

Asset Condition Needs: Direct Current Voltage Gradient (DCVG) results: The DCVG survey found 95 indications along Circuit 920. These locations typically indicate defects in the pipe coating where the steel pipe is in contact with the soil and have a greater potential for corrosion. Close Internal Survey (CIS) results: The CIS measured 20,870 feet of OFF (IR Free) potentials to be more positive than -0.850 V/CSE, which does not satisfy the industry accepted criteria for effective cathodic protection. The line termination structure at Station 23 is located indoors. The termination is in good condition (no foundation issues, no steel corrosion or coating issues). The line termination structure at Station 42 is located outdoors. The galvanized coating is failing, and rust is visible. The foundation of the termination structure has been repaired before and shows signs of cracking. Concrete spalling and exposed rebar are present on the columns supporting Line 920 over the Genesee River.

Project Scope:

Reuse the existing steel pipe & replace existing cable with Prysmian XPLE Cable

Cost Estimate: \$36.4 M, 2028 (ISD)

The selected solution alternative consists of removing the existing cables and oil and pulling in a modern XLPE cable through the existing steel pipe (eliminates the need for a SPCC). This cable is sized (physically) such that it can be used in the existing steel pipe with a pipe liner thickness of up to 0.23 inches.

Prysmian believes residual Polybutene 015 oil would damage the conductor over time. The system must be thoroughly cleaned prior to installation.

Preliminary pulling calculations indicate 11 additional manholes will be required. The existing cathodic protection system must be maintained to minimize future corrosion to the pipe. Remove Line 920 riser at Station 42 (eliminates asset condition need). Remove redundant switch 92007. This frees up space in the substation yard.

Project Benefits:

Calculations indicate this cable meets existing rating of [REDACTED] Verified in CYMCAP. Under summer, winter and shoulder cases, this solution alternative eliminates the reliability needs. All known asset condition needs are addressed.

Project Risks and Mitigation Plan:

If Line 920 does not get placed back in service, the follow reliability contingencies can occur:

Risk of No Action:

Reliability scenarios as outlined above.

If the oil is not removed from the system, there is a potential for future leaks.

Project Alternatives:

Alternative 1: Replace Line 920 – Station 23 to Station 42. Cost Estimate: \$80.0 M, 2029 (ISD).

Alternative 1 consists of removing the existing oil-filled cable system and replacing it with a modern XLPE cable system.

Total Length: 4.0 miles

Utilize the existing ROW

2000 kcmil CU XLPE cable (eliminates the need for a SPCC)

Concrete duct bank with 6 conduits

Splice chambers at 1,500 feet spacing along circuit

I-490 crossing by suspension from existing overpass

CSX rail crossing by Jack & Bore

Preliminary calculation indicates this cable meets existing rating of [REDACTED] EII_ends Verified in CYMCAP.

Under summer, winter and shoulder cases, this solution alternative eliminates the reliability needs.

Alternative 2: Operate Line 920 at Reduced Oil Pressure to minimize future leaks. Dismissed – Not feasible.

The pressurized fluid acts as the insulator and does not conduct electricity. The pressurized dielectric fluid prevents electrical discharges in the conductor's insulation. Without the high pressure, a cable fault is immanent.

Extremely low oil pressure levels may allow voids (or bubbles) to form at the ends of the cable. These voids are electrically weak and they can cause cable terminations to fail.

Basis for Project Estimates

These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, Avangrid Master Service Agreement rates from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within RGE. Escalation rates are based upon current U.S. inflation rates. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

Estimating Notes for Selected Alternative:

Removals pricing is based on Line 901 cable & oil legacy removal costs (adjusted for inflation). This estimate includes the removals of line termination structures and the closing of a single oil tank. Added \$100K for the removal of oil tanks (St. 23 and 42) and building at S. 42.

Scope includes upgrading 863 feet of Circuit 2144 Paper & Lead Cable in order to achieve the necessary rating for Circuit 920. Remove cable in Section 78.22 and install new cable in Section 78.22 2/3.

Added \$25K to Removals pricing for the removal of Switch 92007 at Station 42. 1 additional manhole will be required due to the removal of the Line 920 riser and Switch 92007.

Increased construction rate to from default 2000 feet per month to 4000 feet per month in Timeframe of Projects. This increased speed should account for the lack of ductbank work.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 5	\$ -	\$ -	\$ -	\$ -	\$ 5		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 311	\$ -	\$ -	\$ -	\$ -	\$ 311		
# Internal - Non-AC	\$ 29	\$ -	\$ -	\$ -	\$ -	\$ 29		
# Internal, Labor	\$ 0	\$ -	\$ -	\$ -	\$ -	\$ 0		
# Internal, Overheads	\$ 31	\$ -	\$ -	\$ -	\$ -	\$ 31		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ 93	\$ -	\$ -	\$ -	\$ -	\$ 93		
Total	\$ 468	\$ -	\$ -	\$ -	\$ -	\$ 468		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 2,793	\$ -	\$ 162	\$ 378	\$ 1,177	\$ 1,075	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 24,121	\$ -	\$ 3,934	\$ 3,795	\$ 6,928	\$ 9,464	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 134	\$ -	\$ 43	\$ 20	\$ 38	\$ 32	\$ -	\$ -
# Internal, Overheads	\$ 1,989	\$ -	\$ 527	\$ 480	\$ 403	\$ 579	\$ -	\$ -
# Materials	\$ 2,562	\$ -	\$ 359	\$ 336	\$ 638	\$ 1,229	\$ -	\$ -
# Overheads - External	\$ 4,670	\$ -	\$ 1,248	\$ 1,130	\$ 948	\$ 1,344	\$ -	\$ -
Total	\$ 36,268	\$ -	\$ 6,274	\$ 6,139	\$ 10,132	\$ 13,723	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Station 43 Circuit Upgrades

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-003934	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

The project consists of upgrading six distribution circuits (C444,C462, C464, C470, C2104 , and C2105) from 4kV to 12kV to accommodate the new Station 43 modernization.

Project Scope:

Sta 43 currently has six (6) circuits that exit from the station at a voltage of 2400/4160V. These circuits are numbered as 444 (7.5 miles of circuitry), 462 (6.7 miles of circuitry), 464 (15.4 miles of circuitry), 470 (10.6 miles of circuitry), 2104 (10.2 miles of circuitry) and 2105 (10.1 miles of circuitry). New 22.4MVA 34kV/12kV LTC substation transformers and GIS switchgear are being installed as part of the Sta 43 Modernization Project. This project consists of the evaluation of the existing six (6) 4kV circuits to determine 12kV compatibility. Where the existing circuitry is evaluated to be non-compatible with a 12kV conversion (due to ratings of insulators, lightning arresters, cables or existing clearances among other things) a design to replace those facilities must be developed and provided. Existing infrastructure (poles, wires, conduit systems, manholes, cables) should be utilized as much as possible to minimize cost and disruption to the general public.

The following specific considerations should be made:

- Any cable that is rated at 5kV needs to be replaced with 15kV cable. The existing duct systems need to be evaluated to determine the presence of spare conduits or the requirement of new conduit. The size and condition of the manholes will also need to be evaluated to determine if the condition is adequate for new cable and/or equipment and that proper clearances can be achieved.
- Existing underground fusing and switches must be evaluated to determine sizing and proper compliance with current Avangrid safety standards (ie. visual open)
- Existing underground equipment must be evaluated for proper compliance with current Avangrid safety standards (ie. clearances for transformers in manholes).
- The installation of stepdown transformers will need to be implemented in locations where the installation of 12kV equipment or converting to 12kV is not possible.
- Existing tie-points need to be considered and every effort needs to be made to maintain tie-points for a reasonable amount of load.

Project Benefits:

Replacing the current circuit breakers to bring them up to Avangrid Standards. The asset condition is as follows:

1. Circuit breakers for 34.5kV are 70 years old and rated as follows: 5X4352 tie breaker is ""Poor"", and 72622 and 75012 are ""Very Poor"".
2. Circuit breakers for 4.16kV (210402 and 210502) are 62 years old and rated ""Very Poor"". There is one installed spare that is rated ""Poor"" at 5XSP43."

Project Risks and Mitigation Plan:

Failure to meet an Outage milestone - Risk of contractor missing an Outage milestone previously agreed with the System Operator, causing delays to the Project and extra cost due to the need of rescheduling. Ensure constant communication with the contractor. Make sure all risks are accounted for. Outage cancellation by System Operator - Risk of System Operator cancelling an Outage milestone previously agreed, causing the needs for rescheduling or rearranging the construction sequence. Cost and schedule impacts caused by needs of de-mobilizing contractors, relocating construction crews, storing equipment, etc. Proper communication with ECC

Additional scope added to the project - Risk that additional scope is added late in the project that results in major unforeseen costs and schedule adjustments impacting the overall project spend, completion date, etc. This could be due to additional engineering needs, additional resources such as a larger PMS, additional subcontractors, etc. Obtain all approvals from stakeholders for the project scope. Prevent scope creep - while allowing common sense compromises to allow for a smooth transition

Poor construction sequence plan - Risk of having a poor construction sequence plan and having the need of making adjustments during construction, resulting in schedule adjustments and potential delays, impact on the outage schedule and the project budget. Have a well defined scope of work. Detailed design driven construction sequence.

Risk of No Action:

Potential increase of load demands from the customers could cause reliability issues. The new station can not be operated as currently constructed because the new transformers are 34.5kV to 12.47kV

Project Alternatives:

Alternative 1: Replace the new transformers at the station with 34.5kV to 4.16kV.

Alternative 2: Install new stepdown transformers outside of the station. Currently, it is at 34.5kV to 12.47kV. Install new 12.47kV to 4.16kV stepdown transformers on each circuit outside the station.

Selected alternative: Limited upgrade of each circuit from 4.16kV to 12.7kV

Selected alternative: Limited upgrade of each circuit from 4.16kV to 12.7kV
Utilize estimating tools as well as historical data to choose the selected alternative approximately at \$26.4M

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Station 43 Modernization Project

PROJECT INFORMATION

OpCo: RG&E	Project ID: UH-R0005227-RGE-ED	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: H1 2027	In-Service Date: H2 2027

Project description:

The Station 43 Substation Project is aimed to enhance the station's capacity and alleviate the overload on the existing transformers. The project mainly involved replacing the two existing 6.25 MVA 34.5kV/4kV power transformers with two new 12/16/20(22.4) MVA 34.5kV/12kV power transformers.

Project Scope:

The work associated with this project involved:

The replacement of transformers 3T & 4T. New 34.5kV, 12/16/20(22.4)MVA Transformers, foundations were placed at the north end of the substation. Oil containment and firewalls were installed for the new Transformers. 1T is connected to new 34kV GIS Bus Section 1 and 2T is connected to new 34kV GIS Bus Section 2.

The work associated with the 12 and 34kV equipment involved:

- New 34kV GIS switchgear with 2 Bus sections (34kV Bus Section 1 and 34kV Bus Section 2).
- New 12kV GIS switchgear with 2 Bus sections (2kV Bus Section 1, and 12kV Bus Section 2).
- Bus Section 1 and Bus Section 2 are electrically connected using underground cable.
- Bus Section 1 and Bus Section 2 (34kV) are connected between Bus tie breaker 6X4352 and bus tie switch 6X4353.
- Bus Section 1 and Bus Section 2 (12kV) are connected between Bus tie breaker 2X4342 and bus tie switch 2X4343.
- New microprocessor relays were installed on the new 12 and 34kV switchgear bus sections, as well as new control cabinets.
- All local control for switchgear bus section is working through the new HMI.
- Fire rated wall was installed between the switchgear bus sections.

Project Benefits:

The load on the existing 6.25 MVA transformer banks #3 and #4 at Station 43 reached 113% and 95% of their PLBN rating, respectively, during the summer peak of 2011. Station 43 serves approximately 6,467 residential and commercial customers. Losing either transformer would place the remaining transformer in a situation where it is loaded well above its LTE rating, conflicting with Distribution Planning Criteria.

To address these issues, the project proposes replacing the existing transformers with larger 12/16/20(22.4) MVA 34.5kV/12kV power transformers. This upgrade facilitates increased switching capabilities with adjacent circuits and is necessary for the future 4-12kV conversion of area distribution.

Project Risks and Mitigation Plan:

Risk: Space constraints, existing and new substation temporary remain in the existing station property.

Risk Mitigation: Closely coordinated all vendors' schedules to ensure that, at all times, the substation maintained the most effective head-count for the work to be completed. Every time a new vendor was introduced to the project, the FCM would have them wait for confirmation for up to a week before work was scheduled to start.

Risk: Permits

Risk Mitigation: Held several conversations with the city of Rochester to understand architectural impact and to inform the town about the benefits these upgrades would bring to the community and customers.

Risk: Outages

Risk Mitigation: Planned outage sequences ahead of time and communicated them to the Electric Control Center. This strategy facilitated proper planning and scheduling, considering the needs of all stakeholders.

Risk of No Action:

Failure to execute this project would have significantly impacted the reliability and quality of our service due to the risk of voltage violations. The existing transformer was imminently incapable of handling the increasing demand from our customers. Moreover, operating the aging station required higher maintenance and operational costs, which would negatively affect our customers as well.

Project Alternatives:

In kind replacement: Upgrade existing transformers and maintain 4.16 kV circuits.

Engineering: Not applicable
Construction: Based off of estimated supplied by engineering firm that designed the project, and historical costs considering inflation
Material: Based off of historical cost, considering inflation
Labor: Rolling 6 months of actuals
Project Management: Rolling 6 months of actuals
AFUDCs & Overheads: Calculated automatically by Primavera/P6

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 3,107	\$ 376	\$ 613	\$ 963	\$ 1,155	\$ 0		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 8,185	\$ 891	\$ 824	\$ 5,456	\$ 1,032	\$ -19		
# Internal - Non-AC	\$ 2	\$ -	\$ 0	\$ 1	\$ 0	\$ -		
# Internal, Labor	\$ 1,436	\$ 159	\$ 161	\$ 355	\$ 734	\$ 28		
# Internal, Overheads	\$ 935	\$ 119	\$ 186	\$ 466	\$ 164	\$ -1		
# Materials	\$ 4,103	\$ 958	\$ 1,450	\$ 1,305	\$ 403	\$ -13		
# Overheads - External	\$ 2,872	\$ 295	\$ 392	\$ 1,454	\$ 726	\$ 5		
Total	\$ 20,639	\$ 2,799	\$ 3,626	\$ 10,000	\$ 4,214	\$ 1		

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 29	\$ -	\$ -	\$ 29	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 716	\$ -	\$ -	\$ 716	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 170	\$ -	\$ -	\$ 170	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 35	\$ -	\$ -	\$ 35	\$ -	\$ -	\$ -	\$ -
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 106	\$ -	\$ -	\$ 106	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,057	\$ -	\$ -	\$ 1,057	\$ -	\$ -	\$ -	\$ -

[illegible]

Station 156 Circuit Upgrades

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-004207	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Digital Grid	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: Ongoing	In-Service Date: H2 2026

Project description:

Conversion from 4.16kV to 12.47kV of the distribution lines 255 & 257. The circuit upgrade is required to fully capitalize the station 156 upgrade that has taken place and placed in service on Jan/2024 as part of Station 156 Transf./Facilities upgrade project. This is a legacy project being inherited from the substations group.- This project was initial budgeted in with the Substation Project portion UH-R0000720.

Project Scope:

- The 255 circuit has 483 customers and will be relabel to the 5324 Circuit has about 7.3 miles of Overhead lines and .9 miles of Underground lines
- The 257 circuit has 494 customers and will be relabel to the 5323 Circuit has about 6.4 miles of Overhead lines and 1.2 miles of Underground lines
- CIR 255 (NEW CIR 5324)• Install 5 Transmission Poles, 99 Distribution Poles. This is the summation of all distribution poles. Class 50'2 thru 35'3. Poles being replaced are based on condition, age of asset, and whether the pole structures can accommodate 15kV rated insulators • Install 31 Small Transformers (10-25 kVa) to accommodate 4kV to 12 kV conversion. This batch is an assortment of dual transformers (1PH applications) and conventional transformers (3PH Bank Applications)
- Install 14 Large Transformers (50-2500 kVa) Transformers to be replaced to accommodate 4kV to 12 kV conversion. Mostly for 3PH applications that will have to be installed at time of conversion and not during make ready work.
- Install 1-1000 kVa pad mount transformer for industrial location on circuit
- Install 1-2500 kVa pad mount transformer for industrial location on circuit
- Install 336 AB PRI –12,000'
- Install 1/0 AAAC PRI/NEU – 2000'
- Install 1/0 TRIPLEX – 1000'

Project Benefits:

Utility poles, transformers, conductor, and reclosers will be replaced and installed providing positive longterm company and customer value; creating smarter, stronger, and more resilient circuits as part of this modernization project. This modernization project will have a positive impact on SAIFI and CAIDI.

Project Risks and Mitigation Plan:

XXXXXXXXXXXXXXXXXXXXXXXXXXXX

Risk of No Action:
XXXXXXXXXXXXXXXXXXXXXXXXXXXX

XXXXXXXXXXXXXXXXXXXXXXXXXXXX

Project Alternatives:
XXXXXXXXXXXXXXXXXXXXXXXXXXXX

XXXXXXXXXXXXXXXXXXXXXXXXXXXX

Basis for Project Estimates

XXXXXXXXXXXXXXXXXXXXXXXXXXXXX

XXXXXXXXXXXXXXXXXXXXXXXXXXXX

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 83	\$ -	\$ -	\$ -	\$ 15	\$ 68		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 787	\$ -	\$ -	\$ -	\$ 184	\$ 603		
# Internal - Non-AC	\$ 2	\$ -	\$ -	\$ -	\$ -	\$ 2		
# Internal, Labor	\$ 595	\$ -	\$ -	\$ -	\$ 172	\$ 423		
# Internal, Overheads	\$ 206	\$ -	\$ -	\$ -	\$ 49	\$ 157		
# Materials	\$ 674	\$ -	\$ -	\$ -	\$ 236	\$ 438		
# Overheads - External	\$ 696	\$ -	\$ -	\$ -	\$ 191	\$ 505		
Total	\$ 3,042	\$ -	\$ -	\$ -	\$ 847	\$ 2,195		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 769	\$ 462	\$ 307	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 4,187	\$ 2,768	\$ 1,419	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 225	\$ 154	\$ 71	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 572	\$ 379	\$ 193	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 507	\$ 344	\$ 164	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 6,260	\$ 4,106	\$ 2,154	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Station 192 Circuit Upgrades

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-004208	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: H1 2025	In-Service Date: H2 2027

Project description:

Scope Description: Station 192 is currently a 4.16kv substation and being converted to 12.47kv. This project consists of design and construction for all Circuits 215, 216, 232 will need to be converted to 12.47kv, to include conductor upgrades, install SCADA devices, step bank, cap bank removal, sequential reclosing, and fuse coordination, along with possible tie to 192LS. This project is associated with UH-R0005251 / Station 192 Trans Facilities Upgrade.

Project Scope:

Station 192 is currently a 4.16kv substation and is being converted to 12.47kv to handle new customer loads. This project consists of design and construction for the entirety of Circuits 215, 216, 232 which will need to be converted to 12.47kv. This project scope also includes conductor upgrades, install SCADA devices, step bank, cap bank removal, sequential reclosing, and fuse coordination, along with possible tie to 192LS. This project is associated with UH-R0005251 / Station 192 Trans Facilities Upgrade. Work for Circuit 216 will not go beyond the associated step transformer.

Project Benefits:

Circuit upgrades with addition of sequential reclosing will improve reliability and circuit stability, through conversion of existing equipment to handling 12kV operation levels. The existing 34/4kV substation transformer is currently overtaxed from high customer loading during peak demand periods.

Project Risks and Mitigation Plan:

This project is associated with UH-R0005251 / Station 192 Trans Facilities Upgrade, and must be completed after UH_R0005251, which affects the resultant schedule and costs. Outage constraints by ECC may apply to this project, affecting schedule and cost.

Risk of No Action:

The existing 34/4kV Substation Transformer is loaded to 113% of rating (2013 loading). Not upgrading the substation can present a risk of unplanned outages that will directly affect customers. If this project is not completed, there is a higher probability of inability to consistently support anticipated customer load demands, especially during peak demand periods. With increased reliance on the availability of electricity over other conventional energy sources, it is even more important to move this project forward, in order to avoid equipment malfunction from over-use.

Project Alternatives:

Option A:

Replace Existing Transformer with a 34.5/12kV Transformer. This will facilitate upgrades of the Lines & Transformers associated with the exist 4kV Circuits (C232, C215 & C216).

OPTION "A" is the preferred solution and has been discussed with Maintenance Engineering, Asset Management and Distribution Engineering. With this option the 34.5/12kV Transformer can be installed for the facilitation of future line upgrades for the existing 4kV circuits.

Option B:

Replace Existing Transformer with a 34.5/4kV Transformer. This would allow additional time for the circuits conversion. However, another Transformer will be required at a later date when the Circuits (C232, C215 & C216) are upgraded.

Option C:

Replace Existing Transformer with a 34.5kv Dual Rated Transformer with 12.5Y/4.6/1.38kV on the low side. This will enable future upgrades of the "Line" Transformers associated with the existing 4kV Circuits (C232, C215 & C216).

Basis for Project Estimates

Utilize estimating tools as well as historical data and bid PayID to forecast a project cost approximately at \$15.6M

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 2	\$ -	\$ -	\$ -	\$ -	\$ 2		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 184	\$ -	\$ -	\$ -	\$ -	\$ 184		
# Internal - Non-AC	\$ 0	\$ -	\$ -	\$ -	\$ -	\$ 0		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ 17	\$ -	\$ -	\$ -	\$ -	\$ 17		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ 50	\$ -	\$ -	\$ -	\$ -	\$ 50		
Total	\$ 252	\$ -	\$ -	\$ -	\$ -	\$ 252		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 898	\$ 231	\$ 451	\$ 215	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 9,191	\$ 1,885	\$ 3,635	\$ 3,670	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 69	\$ 36	\$ 33	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 581	\$ 288	\$ 155	\$ 138	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 2,985	\$ 2,985	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 1,258	\$ 549	\$ 378	\$ 332	\$ -	\$ -	\$ -	\$ -
Total	\$ 14,982	\$ 5,974	\$ 4,653	\$ 4,356	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Station 192 Trans Facilities Upgrade

PROJECT INFORMATION

OpCo: RG&E	Project ID: UH-R0005251-RGE-ED	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

Distribution System Planning has requested a new project at Station 192 consisting in:

- Replace existing 1500KVA transformer with a new 10/12.5/14MVA, and upgrade station equipment to facilitate the upgrade of three (3) 4kV circuits to 12kV (C232, C215, C216)

The justification of this replacement is the following:

- The existing 34/4kV Substation Transformer is loaded to 113% of rating (2013 loading). This 1.5 MVA unit supports three distribution circuits.
- The enhance station capacity and conversion to 12kV will facilitate adjacent station, 12kV circuit tie over for increased N-1 contingency.
- The larger transformer will improve system reliability by providing N-1 capacity to adjacent circuits that currently are without adequate circuit ties during high demand periods.
- It will also facilitate the (possible) decommissioning of nearby station 181 and the eventual 4-12kV conversion of adjacent station circuits.

Project Scope:

Mobilize equipment, personnel, office, and sanitary facilities to project location.

Install new foundations for new Transformer 2T, Station Service Transformer, Lighting Pole and Power House Foundation (50'x32').

Install grounding system.

Install complete Oil Minder system including pump station, manhole, piping, pumps, level detectors, splash block, panel and interconnecting conduits and wiring at the minder station only.

Install stormwater drainage system.

Installation of Fence and final layers of grading (gravel base, stone topping and gravel surface) and revegetation

Install conduits, trench and duct banks.

Install Three (4) 36kV Surge Arresters

Install Three (3) 10kV Surge Arresters

Install One (1) Three Phase Station Service Transformer

Install One (1) new Transformer

Lightning protection

Install CT's for GIS Application

Install Dead breaks

Install GIS SwitchGear

Install facilities in Power House (lighting, AC/DC Power equipment, Security Systems). HVAC will be installed by the control building contractor.

Raceway and wiring will be installed by AG contractor.

Install control and protection relays and panels and batteries.

Install work lightings and perimeter lighting.

Install low voltage control cables and power cables and terminate.

De-mobilize from project site.

Project Benefits:

The existing 34/4kV Substation Transformer is loaded to 113% of rating (2013 loading). This 1.5 MVA unit supports three distribution circuits.

- The enhance station capacity and conversion to 12kV will facilitate adjacent station, 12kV circuit tie over for increased N-1 contingency.
- The larger transformer will improve system reliability by providing N-1 capacity to adjacent circuits that currently are without adequate circuit ties during high demand periods.
- It will also facilitate the (possible) decommissioning of nearby station 181 and the eventual 4-12kV conversion of adjacent station circuit

Project Risks and Mitigation Plan:**Risk #1:**

Adverse weather can pull construction crews away from the job site to assist with storm recovery.

Mitigation Plan: Account for this risk by putting time into the schedule.

Risk #2:

Long lead material items can cause delays in the project.

Mitigation Plan: Account for this risk by putting time into the schedule, and plan on procuring material as soon as possible.

Risk #3:

Risk of not being able to secure the permits required for ROW Clearing, Surveys, Construction or any other type of site works by the activity milestone defined in the schedule, causing the need of adjusting the project delivery sequence and impacting both cost and schedule.

Mitigation Plan: Obtain a permitting consultant early on in the design process and maintain their assistance throughout the Project. Maintain open communication with the all stakeholders throughout the Project.

Risk of No Action:

The existing 34/4kV Substation Transformer is loaded to 113% of rating (2013 loading). Not upgrading the substation can present a risk of unplanned outages that will directly affect customers. Additionally, upgrading the substation will provide much safer equipment for personnel to utilize.

Project Alternatives:**Option A:**

Replace Existing Transformer with a 34.5/12kV Transformer. This will facilitate upgrades of the Lines & Transformers associated with the exist 4kV Circuits (C232, C215 & C216).

OPTION "A" is the preferred solution and has been discussed with Maintenance Engineering, Asset Management and Distribution Engineering. With this option the 34.5/12kV Transformer can be installed for the facilitation of future line upgrades for the existing 4kV circuits.

Option B:

Replace Existing Transformer with a 34.5/4kV Transformer. This would allow additional time for the circuits conversion. However, another Transformer will be required at a later date when the Circuits (C232, C215 & C216) are upgraded.

Option C:

Replace Existing Transformer with a 34.5kv Dual Rated Transformer with 12.5Y/4.6/1.38kV on the low side. This will enable future upgrades of the "Line" Transformers associated with the existing 4kV Circuits (C232, C215 & C216).

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects at RG&E. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 1,324	\$ 122	\$ 175	\$ 224	\$ 314	\$ 490		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 2,807	\$ 217	\$ 586	\$ 294	\$ 1,181	\$ 529		
# Internal - Non-AC	\$ 12	\$ -	\$ -	\$ 1	\$ 5	\$ 6		
# Internal, Labor	\$ 374	\$ 64	\$ 83	\$ 68	\$ 88	\$ 70		
# Internal, Overheads	\$ 312	\$ 15	\$ 53	\$ 33	\$ 125	\$ 85		
# Materials	\$ 1,035	\$ 47	\$ 200	\$ 117	\$ 446	\$ 225		
# Overheads - External	\$ 986	\$ 59	\$ 143	\$ 111	\$ 430	\$ 243		
Total	\$ 6,849	\$ 525	\$ 1,240	\$ 848	\$ 2,589	\$ 1,647		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,886	\$ 870	\$ 1,016	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 5,316	\$ 1,688	\$ 2,577	\$ 1,051	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 169	\$ 169	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 479	\$ 281	\$ 155	\$ 43	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 3,773	\$ 2,902	\$ 814	\$ 57	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 999	\$ 553	\$ 346	\$ 100	\$ -	\$ -	\$ -	\$ -
Total	\$ 12,623	\$ 6,464	\$ 4,909	\$ 1,251	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Station 5 Substation Mod D

PROJECT INFORMATION

OpCo: RG&E	Project ID: UH-R0000105-RGE-ED	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: H1 2025	In-Service Date: H1 2026

Project description:

Station 5 is a hydro-electric generating station which includes a substation in the facility. The substation provides the ability to export power produced by the three hydro-electric generators to the 11.5KV distribution system in Rochester, NY. There are twelve 11.5KV distribution circuits connected to the facility.

The station was constructed in 1916. Upgrades have been performed during the course of its operating life, but the power distribution switchgear (constructed with 1950s and older technology) cannot handle the fault current capability at the station, resulting in a restriction in the amount of power which can be transported. The design of the switchgear also challenges Operations personnel to meet modern OSHA requirements for equipment and personnel protection.

The modernization project is intended to replace ageing, over-dutied and obsolete equipment in the station with modern equipment, eliminating the distribution switchgear as a limiting componet for exporting power, providing enhanced protection of personnel and equipment with modern digital protective relays and bringing the facility into compliance with modern OSHA standards.

Project Scope:

The project will upgrade the distribution switchgear in the station with modern Gas Insulated Switchgear (GIS) in a ring bus configuration.

Scope includes:

- Removal of existing 11.5KV breakers, switches, reactors and associated protective devices
- Installation of new 11.5KV GIS switchgear
- Installation of new microprocessor based digital protective relays
- Replacement of distribution circuit current limiting reactors
- Replacement of generator grounding breakers
- Replacement of 11.5KV power distribution cables
- Install of new T&D and Fossil-Hydro protection and control cabinets
- Installation of three new trains of stationary batteries
- Modification of floors 1, 2 and 3 as required based on the proposed plant configuration
- Upgrade HVAC and Fire Protection systems
- Upgrade station grounding and extend ground loop to exterior of facility

Project Benefits:

Replacing obsolete breakers, switchgear and controls with modern equipment will extend the useful life of the station.

New digital protection and control systems will provide enhanced protection and control over the existing systems for the generator and distribution equipment.

New GIS switchgear will eliminate the distribution equipment as a limiting factor to dispatch power.

Additionally, the facility will be brought into compliance with modern OSHA standards.

Project Risks and Mitigation Plan:**Risk #1:**

Scope expansion for unplanned structural upgrades which may be discovered during renovation due to building age/condition. The facility is over 100 years old and may not be capable of supporting new switchgear, reactors, cabling, etc.

Mitigation Plan: Structural analysis of floors and walls is included in the base scope for detailed engineering. Load bearing capabilities of the structure will be evaluated taking into consideration equipment being removed from the facility and new equipment being installed. A civil/structural engineer is assigned to the project to provide oversight for all structural issues.

Risk #2:

Adverse weather impacts critical path schedule. The facility is located adjacent to the lower falls in the Genesee river gorge creating the potential for heavy icing on the building and roadways during winter which could restrict outdoor work. The inability to use the station overhead crane to reach the second and third floors necessitated removal of portions of the exterior walls forcing the project to perform significant rigging activities from the exterior of the building utilizing a mobile crane.

Mitigation Plan: The project schedule was revised to perform near critical path rigging activities before entering the winter weather season. Rescheduled activities include use of a mobile crane to rig switchgear to the third floor of the facility through an opening in the exterior wall and installing the new station exterior ground loop. The baseline schedule had these activities being performed during winter (December/January).

Risk #3:

Challenges may be experienced when integrating existing control systems with new equipment.

Mitigation Plan: The potential for undocumented wiring was identified during project planning. Additional funds were allocated to have wiremen perform point to point wire verification on equipment being maintained and interfaced with new protection and control systems.

Risk of No Action:

Maintaining the overburdened equipment leaves personnel and equipment susceptible to the negative effects of a fault, including sustaining major equipment damage and potential serious injury or loss of life.

Continuing to operate ageing and obsolete equipment reduces the availability and reliability of the station as a power producing asset.

Project Alternatives:

1. Install a generator step-up transformer and export power at 34KV, in lieu of the existing 11.5KV distribution equipment. This option was eliminated due to engineering challenges associated with installation of a 34KV/11.5KV transformer in the Genesee river gorge and extending 34KV transmission circuits to the facility.
2. Do nothing. This option was eliminated due to the existing overdutied breakers which create potential hazards for personnel and equipment. Ageing and obsolete equipment will also have a negative effect on the future availability and reliability of the facility.
3. Upgrade the station with modern GIS switchgear in a ring bus configuration. This option was selected as the best alternative to improved personnel and equipment safety and to extend the operating lifespan of the facility.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects at RG&E. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 7,890	\$ 1,093	\$ 1,337	\$ 1,430	\$ 1,801	\$ 2,228		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 9,285	\$ 968	\$ 1,039	\$ 921	\$ 2,092	\$ 4,266		
# Internal - Non-AC	\$ 1	\$ 0	\$ -	\$ 0	\$ 0	\$ 0		
# Internal, Labor	\$ 1,330	\$ 271	\$ 235	\$ 269	\$ 378	\$ 177		
# Internal, Overheads	\$ 1,147	\$ 150	\$ 124	\$ 161	\$ 205	\$ 507		
# Materials	\$ 3,967	\$ 1,224	\$ 607	\$ 884	\$ 452	\$ 800		
# Overheads - External	\$ 3,461	\$ 388	\$ 325	\$ 473	\$ 798	\$ 1,476		
Total	\$ 27,080	\$ 4,094	\$ 3,666	\$ 4,139	\$ 5,726	\$ 9,455		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 2,135	\$ 1,548	\$ 588	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 6,482	\$ 5,734	\$ 748	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 72	\$ 36	\$ 36	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 351	\$ 317	\$ 34	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 729	\$ 729	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 801	\$ 715	\$ 86	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 10,569	\$ 9,078	\$ 1,491	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE - Electric Ops (Line Insp CAP)

PROJECT INFORMATION

OpCo: RG&E	Project ID: UI-R5071-RGE-ED	Charge Code: Electric Distribution	Project Sponsor: Shail, Joshua	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Distribution Line Inspection program at RGE is a New York State Public Service Commission (PSC) mandated visual inspection order. The entire distribution system is inspected on a five-year cycle. The program involves replacing poles, cross arms, cutouts, transformers, and any other units of property identified during the annual inspection. Additionally, the program includes other maintenance inspection initiatives such as infrared and helicopter inspections.

Program initiatives have created division-specific work plans focused on two phases of priority:

Phase 1: Includes all DLI Level II notifications that will be found during the 2024-2030 inspection cycles. These notifications are addressed based on their due dates.

Phase 2: Includes DLI Level III notifications and all other maintenance deficiency programs. These notifications are prioritized based on their impact on customer reliability and System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) scores.

All Level I notifications are immediately vetted and prioritized at the division level due to the immediate concerns identified during inspections.

Project Scope:

The program involves replacing poles, cross arms, cutouts, transformers, and any other units of property identified during the annual inspection.

The DLD program consists of a field inspection that generates notifications for execution of work on company equipment. The execution happens following a workplan based on the notification priority and a reliability score that includes asset data, customer exposure and historical reliability variables. At RGE an average of 66,000 customers were interrupted annually by company equipment failure causes over the past 3 years.

The following units and average unit costs will be addressed between 2025-2031:

2025 - 1,641 (units) / \$939 (unit cost)
2026 - 1,726 (units) / \$967 (unit cost)
2027 - 1,766 (units) / \$996 (unit cost)
2028 - 1,806 (units) / \$1,026 (unit cost)
2029 - 1,846 (units) / \$1,057 (unit cost)
2030 - 1,886 (units) / \$1,089 (unit cost)
2031 - 1,928 (units) / \$1,121 (unit cost)

Project Benefits:

Replacing deficient poles and equipment will rejuvenate an aging system, thereby increasing reliability and reducing customer outages. This proactive approach will also minimize the need for costly emergency repairs, lessening the potential for accidents and injuries to both customers and employees.

The program ensures compliance with safety standards and maintains safety for the public and utility workers. By replacing poles using current standards and as determined by pole loading analysis per the National Electrical Safety Code (NESC) Northeast wind and radial ice modeling parameters, the reliability and resiliency of the RGE distribution system are improved.

Project Risks and Mitigation Plan:

Potential increased power losses due to degraded conductors, risk of outages from weakened components, increased maintenance needs, potential for sagging or breaking wires, and a reduced capacity to transmit electricity efficiently could affect reliability and stability. Regular inspections and maintenance of the lines are essential to promptly identify and address these potential issues.

Risk of No Action:

If no action is taken and deteriorated poles and equipment are not replaced, this will result in non-compliance with NESC requirements and put the safety of the public and utility workers at risk.

Project Alternatives:

This program aims to replace outage equipment using an “in-kind” replacement strategy.

Basis for Project Estimates

Future annual spending targets are determined through an annual analysis that considers historical itemized component upgrades (such as poles, transformers, and conductors) and overall spending from prior years. Projections for P25 spending are based on prior actuals by component upgrade type, with a current and justified escalation factor used to inform each subsequent out-year.

FINANCIAL INFORMATION**Actual Capital Spent, all amounts shown below in thousands (\$000's)**

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 1,030	\$ 51	\$ 182	\$ 263	\$ 256	\$ 277		
# CIAC	\$ -608	\$ -1	\$ -2	\$ -458	\$ -89	\$ -58		
# External Services	\$ 2,557	\$ 429	\$ 300	\$ 370	\$ 810	\$ 648		
# Internal - Non-AC	\$ 1	\$ 0	\$ 0	\$ -	\$ 1	\$ -		
# Internal, Labor	\$ 1,235	\$ 405	\$ 827	\$ -36	\$ 22	\$ 17		
# Internal, Overheads	\$ 498	\$ 135	\$ 204	\$ 45	\$ 39	\$ 75		
# Materials	\$ 1,843	\$ 564	\$ 1,052	\$ 212	\$ -74	\$ 89		
# Overheads - External	\$ 1,306	\$ 337	\$ 540	\$ 93	\$ 143	\$ 193		
Total	\$ 7,862	\$ 1,921	\$ 3,103	\$ 489	\$ 1,107	\$ 1,241		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ 2,288	\$ 506	\$ 807	\$ 253	\$ 336	\$ 385		
Materials	\$ 394	\$ 14	\$ 99	\$ 11	\$ 180	\$ 90		
Other O&M	\$ 1	\$ 0	\$ 1	\$ 0	\$ -	\$ 0		
Total	\$ 2,683	\$ 520	\$ 908	\$ 264	\$ 516	\$ 475		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 193	\$ 26	\$ 24	\$ 26	\$ 27	\$ 28	\$ 30	\$ 31
# CIAC	\$ -908	\$ -119	\$ -129	\$ -129	\$ -131	\$ -132	\$ -133	\$ -135
# External Services	\$ 6,685	\$ 797	\$ 866	\$ 909	\$ 954	\$ 1,002	\$ 1,052	\$ 1,105
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 228	\$ 27	\$ 29	\$ 31	\$ 33	\$ 34	\$ 36	\$ 38
# Internal, Overheads	\$ 637	\$ 110	\$ 103	\$ 96	\$ 88	\$ 78	\$ 77	\$ 84
# Materials	\$ 6,792	\$ 810	\$ 880	\$ 924	\$ 970	\$ 1,018	\$ 1,069	\$ 1,123
# Overheads - External	\$ 1,173	\$ 190	\$ 192	\$ 180	\$ 164	\$ 146	\$ 145	\$ 156
Total	\$ 14,800	\$ 1,841	\$ 1,965	\$ 2,036	\$ 2,105	\$ 2,176	\$ 2,276	\$ 2,402

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 3,100	\$ 405	\$ 426	\$ 435	\$ 444	\$ 454	\$ 463	\$ 473
Materials	\$ 534	\$ 70	\$ 73	\$ 75	\$ 76	\$ 78	\$ 80	\$ 81
Other O&M	\$ 2	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Total	\$ 3,636	\$ 475	\$ 499	\$ 510	\$ 521	\$ 532	\$ 543	\$ 555

RGE PCB Transformer Replacements

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-003652	Charge Code: Electric Distribution	Project Sponsor: Shail, Joshua	Project Type: Project
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The RGE PCB Transformer Replacement Program is a focused initiative to identify and replace distribution transformers containing Polychlorinated Biphenyls (PCBs) as part of RGE's commitment to environmental compliance and public safety. By addressing these aging assets, the program not only ensures compliance with environmental regulations but also reduces risks associated with transformer failures, ultimately supporting the reliability and safety of the electric distribution system.

Project Scope:

The program is designed to target transformers identified as containing PCBs. Field reviews and site assessments will guide the design and planning for replacements, ensuring a systematic and effective approach. Decommissioned transformers will be removed and disposed of in accordance with RGE standards.

The following units and average unit costs will be addressed between 2025-2031:

2025 - 177 (units) / \$8,161 (unit cost)
2026 - 163 (units) / \$8,405 (unit cost)
2027 - 178 (units) / \$8,658 (unit cost)
2028 - 184 (units) / \$8,917 (unit cost)
2029 - 194 (units) / \$9,185 (unit cost)
2030 - 203 (units) / \$9,460 (unit cost)
2031 - 212 (units) / \$9,744 (unit cost)

Project Benefits:

The primary benefit of the RGE PCB Transformer Replacement Program is the removal and proper disposal of PCB-containing transformers and reducing environmental risks. The program also underscores RGE's commitment to sustainability, regulatory compliance, and the responsible modernization of its electric distribution infrastructure.

Project Risks and Mitigation Plan:

The Company must align with State and Federal reliability standards which is evidence of the Company's commitment to these standards through a well executed program. The program identifies tasks within same reach to help reduce operational costs and improve the timeliness of the execution plan. As this program matures, the expectation is that all PCB Transformers are to be replaced in a timely manner.

Risk of No Action:

The PCB Transformer replacement program proactively replaces PCB transformers to prevent potential increases in environmental risks. Without this proactive work, the system may experience more environmental exposure. Additionally, there are risks of negatively impacting SAIFI goals, environmental factors, supply chain stability, public perception, and facing regulatory penalties.

Project Alternatives:

The PCB transformer replacement program aims to replace one-for-one assets that identified as containing PCB's. Alternatives are considered on a case-by-case basis to ensure the most effective solutions are implemented.

Basis for Project Estimates

The financial plan is based on an average cost per transformer replacement. The average cost is determined by the cost of construction crews, internal labor costs, material costs, disposal, and overheads applicable to replacing a transformer.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 176	\$ 24	\$ 23	\$ 22	\$ 24	\$ 26	\$ 28	\$ 30
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 5,442	\$ 700	\$ 672	\$ 736	\$ 767	\$ 812	\$ 856	\$ 898
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 604	\$ 77	\$ 73	\$ 82	\$ 86	\$ 91	\$ 95	\$ 100
# Internal, Overheads	\$ 537	\$ 96	\$ 78	\$ 79	\$ 73	\$ 67	\$ 68	\$ 76
# Materials	\$ 5,539	\$ 643	\$ 598	\$ 704	\$ 768	\$ 851	\$ 940	\$ 1,034
# Overheads - External	\$ 1,039	\$ 173	\$ 154	\$ 156	\$ 144	\$ 132	\$ 134	\$ 147
Total	\$ 13,336	\$ 1,713	\$ 1,597	\$ 1,779	\$ 1,861	\$ 1,978	\$ 2,121	\$ 2,286

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE URD Replacement Program

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-003653	Charge Code: Electric Distribution	Project Sponsor: Matyjas, Walter	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: H1 2025	In-Service Date: H2 2025

Project description:

The purpose of this program is to replace underground facilities with aged or failing equipment and access difficulties.

Many of the RGE URDs were built in the 1970s and 1980s and are 40-50+ years old. The underground infrastructure in these developments are aging and experience an increasing number of failures as the infrastructure begins to break down. The electric cable utilized in these installations were traditionally a concentric neutral style design with the neutral located on the outside of the cable. This design leads to severe corrosion along the cable. In addition to an increase in full cable failures, the breakdown of the neutral also tends to lead to an increase in stray voltage conditions in the developments. All manufacturers of this style cable have highly recommended any current cable under this design be replaced as soon as possible. Many of the developments also utilized vaults with underground, submersible transformers as opposed to the current standard of above ground, pad-mounted transformers. The former design creates difficulties in accessing the equipment and can lead to extended outage times during maintenance and repairs.

Project Scope:

This program will be upgrading underground facilities by installing new underground cables in new ductwork and replacing submersible equipment with new above ground pad mounted devices.

The following units and average unit costs will be addressed between 2025-2031:

2025 - 22,946 (units) / \$85(unit cost)
2026 - 22,176 (units) / \$88 (unit cost)
2027 - 23,129 (units) / \$90 (unit cost)
2028 - 24,099 (units) / \$93 (unit cost)
2029 - 25,124 (units) / \$96 (unit cost)
2030 - 26,206 (units) / \$99 (unit cost)
2031 - 26,209 (units) / \$101 (unit cost)

Unit is defined as feet of cable

Project Benefits:

Due to the aging condition of the direct buried cable equipment and the access difficulties, a full replacement of these underground facilities is necessary. Replacement of the aging infrastructure will help to improve the overall reliability for the customers within the subdivision and reduce future maintenance costs.

Project Risks and Mitigation Plan:

The Company must align with State and Federal reliability standards which is evidence of the Company's commitment to these standards through a well executed program. The program identifies tasks within same reach to help reduce operational costs and improve the timeliness of the execution plan. As this program matures, the expectation is that all identified direct buried cable will be replaced.

Risk of No Action:

The URD replacement program proactively identifies high-risk direct buried cable to prevent potential increases in outage frequency. Without this proactive work, the system may experience more frequent outages. Additionally, there are risks of negatively impacting SAIFI goals, environmental factors, supply chain stability, public perception, and facing regulatory penalties.

Project Alternatives:

The URD replacement program aims to replace one-for-one assets that are in poor condition. Alternatives are considered on a case-by-case basis to ensure the most effective solutions are implemented.

Basis for Project Estimates

The financial plan is based on an average cost per foot of direct buried cable replacement. The average cost is determined by the cost of construction crews, internal labor costs, material costs, and overheads applicable to replacing direct buried cable.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 21	\$ -	\$ -	\$ -	\$ 0	\$ 21		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 1,624	\$ -	\$ -	\$ -	\$ 25	\$ 1,598		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 28	\$ -	\$ -	\$ -	\$ 2	\$ 26		
# Internal, Overheads	\$ 201	\$ -	\$ -	\$ -	\$ 2	\$ 200		
# Materials	\$ 152	\$ -	\$ -	\$ -	\$ 1	\$ 150		
# Overheads - External	\$ 510	\$ -	\$ -	\$ -	\$ 7	\$ 502		
Total	\$ 2,535	\$ -	\$ -	\$ -	\$ 38	\$ 2,498		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ 5	\$ -	\$ -	\$ -	\$ -	\$ 5		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ 5	\$ -	\$ -	\$ -	\$ -	\$ 5		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 235	\$ 37	\$ 25	\$ 30	\$ 32	\$ 35	\$ 37	\$ 39
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 7,380	\$ 953	\$ 945	\$ 992	\$ 1,042	\$ 1,094	\$ 1,149	\$ 1,206
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 795	\$ 86	\$ 104	\$ 109	\$ 115	\$ 121	\$ 127	\$ 133
# Internal, Overheads	\$ 726	\$ 129	\$ 111	\$ 106	\$ 100	\$ 91	\$ 92	\$ 97
# Materials	\$ 7,452	\$ 874	\$ 867	\$ 954	\$ 1,049	\$ 1,154	\$ 1,270	\$ 1,283
# Overheads - External	\$ 1,403	\$ 230	\$ 220	\$ 210	\$ 196	\$ 178	\$ 180	\$ 190
Total	\$ 17,991	\$ 2,309	\$ 2,272	\$ 2,402	\$ 2,534	\$ 2,672	\$ 2,854	\$ 2,948

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 78	\$ 10	\$ 11	\$ 11	\$ 11	\$ 11	\$ 12	\$ 12
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 78	\$ 10	\$ 11	\$ 11	\$ 11	\$ 11	\$ 12	\$ 12

RGE - Subst Major Capital

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-001582	Charge Code: Electric Distribution	Project Sponsor: Kuhn, Dennis	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

Substation Majors is a blanket program for substation capital improvements & upgrades that addresses emergent failures of major equipment and packages. Including but not limited to relay upgrades, breaker replacements, transformer replacements, battery replacements. All upgrades are meant to maintain and improve system reliability and area load growth across all RGE substation areas.

Substation Majors includes improvements of major equipment and packages, planned & unplanned to all substation equipment due to age or condition at transmission voltages.

Project Scope:

This program encompasses all needed substation capital upgrades or replacements mostly generated by failure or imminent failure but can include work related to reliability, customer load growth, age and condition of substation equipment.

Project Benefits:

Substation majors investment is needed to complete critical capital improvements to all RGE substations and their equipment to improve customer reliability, system stability and to identify, replace or improve equipment due to age or condition. The risk of not having this program available for needed upgrades is failing substation equipment which would directly impact system stability, customer reliability, regulatory relations and reputational risks along with exposure to larger NRA's.

Project Risks and Mitigation Plan:

Inadequate funding, on an annual basis, has been the primary risk associated with this program. Program tracking and monitoring of available budget is continually balanced with remaining/anticipated workload, and in many cases, financial offsets are required from other planned work to fund this mandatory work throughout the year. These offsets create downstream consequences since prioritized work can no longer be executed as planned which can affect any number of factors, mainly system reliability.

Risk of No Action:

The consequences of not undertaking this project will lead to system abnormal conditions and unsafe conditions for the public and workforce. Not addressing emergent failures will have a negative impact on reliability (CAIDI) and lead to legal and regulatory scrutiny. Connecting customers and ensuring reliable service is our fundamental goal; taking no action to restore customers after equipment failure is not an option. Delayed or non-execution of customer restoration could result in fines, penalties and reputational damage.

Project Alternatives:

This program aims to replace outaged equipment using an "in-kind" replacement strategy and therefore project alternatives are not applicable within this program.

Basis for Project Estimates

If project estimates are known at the time of the annual budget planning process, those costs will be used as the basis for planned funding. Typically, however, the cost of this program is based on the historical average expenditure by the Company per year, or a combination of both historical and estimated known project costs.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 267	\$ -	\$ 3	\$ 61	\$ 93	\$ 110		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 2,381	\$ -	\$ 100	\$ 716	\$ 786	\$ 778		
# Internal - Non-AC	\$ 0	\$ -	\$ -	\$ -	\$ 0	\$ -		
# Internal, Labor	\$ 228	\$ -	\$ 18	\$ 77	\$ 81	\$ 52		
# Internal, Overheads	\$ 205	\$ -	\$ 8	\$ 49	\$ 63	\$ 85		
# Materials	\$ 198	\$ -	\$ 25	\$ 23	\$ 76	\$ 73		
# Overheads - External	\$ 705	\$ -	\$ 24	\$ 176	\$ 245	\$ 259		
Total	\$ 3,984	\$ -	\$ 178	\$ 1,103	\$ 1,345	\$ 1,358		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 178	\$ 22	\$ 22	\$ 24	\$ 25	\$ 27	\$ 28	\$ 29
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 10,522	\$ 660	\$ 1,450	\$ 1,522	\$ 1,599	\$ 1,679	\$ 1,762	\$ 1,851
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 893	\$ 120	\$ 119	\$ 123	\$ 127	\$ 131	\$ 134	\$ 138
# Internal, Overheads	\$ 430	\$ 77	\$ 69	\$ 65	\$ 59	\$ 52	\$ 52	\$ 56
# Materials	\$ 168	\$ 20	\$ 19	\$ 21	\$ 24	\$ 26	\$ 28	\$ 30
# Overheads - External	\$ 1,117	\$ 193	\$ 182	\$ 170	\$ 155	\$ 137	\$ 135	\$ 146
Total	\$ 13,307	\$ 1,091	\$ 1,861	\$ 1,925	\$ 1,988	\$ 2,051	\$ 2,140	\$ 2,249

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE - Subst Minor Capital

PROJECT INFORMATION

OpCo: RG&E	Project ID: UI-R0018-RGE-ED	Charge Code: Electric Distribution	Project Sponsor: Kuhn, Dennis	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Substation Capital Minors program is the primary capital budget is a hybrid reactive and proactive program supporting 168 substations. The program is used to replace minor failed equipment in substations in order to provide continual reliable service to our customers and to support minor betterment projects that target increased system reliability, security, as well as equipment restorations/replacements required to meet NERC regulatory requirements including PRC-005 such as relay replacements and protective communication system upgrades.

Project Scope:

The Substation Minors Betterments program covers work at substations <\$500K threshold for a major project and covers not only the planned activities but also it addresses unplanned events as a result of inspections or failures.

Below are the 2025-2031 estimated annual work type components and average unit rates excluding overheads based on a work type cost basis historical average.

Animal Prevention 1 @ \$20,870/each.

--Supports new installations where there are no animal fences currently and replacements of old and/or failed animal fences. Also supports installation of animal guards on bushings, bus, line exits.

Grounds/Driveway/Control House Improvements; 2 @ \$19,700/each.

--Supports physical grounds and control house upkeep and betterments at substations. Includes driveway paving/new driveways, control house door, roof, lighting replacements, spill prevention measures.

HVAC - 1 @ \$14,000/each.

--Supports new HVAC installations at control houses that do not have them as well as failure of HVAC units at existing locations.

Instrument Transformer Replacement 2 @ \$9,900/each.

--Supports replacement of failed instrument transformers (CT's, PT's, CCVT's) in substations

Insulator Replacement - 1 @ \$42,700/each.

--Supports brown glass replacements at substations as well as failures of insulators.

Lightning Replacement - 8 @ \$3,300/each.

--Supports lightning arrester replacements due to failures.

Regulator Replacement - 2 @ \$60,700/each.

--Supports regulator replacements due to load increases due to customer requests that are non-customer funded. Also supports regulator replacements due to failures

Relay/Meter/RTU/DME/Control Upgrades - 8 @ \$18,100/each.

--Supports relay replacements, meter replacements, transformer LTC control upgrades, RTU replacements, DME replacements; mostly due to failure conditions or when required to meet a compliance activity or upgrade due to obsolete parts availability or support.

Security Fence - 1 @ \$14,800/each.

-- Supports substation gate replacements. These deteriorate due to wear and tear, new gates establish efficient entry/exit and improve security.

Switch Replacement 6 @ \$35,300/each.

--Supports replacement of switches upon failure.

Misc Costs not Detailed in Work Type \$15K.

--Examples: capacitor can replacements, mobile substation cables, ltc transformer filter system replacements as required.

The average costs were escalated by P25 - 3%; P26-P30 - 6% and P31 - 4.5%.

Refer to the 'The RC_Historical Analysis' tab for year-by-year breakdown of estimated units and average unit rate of components.

Project Benefits:

This program provides the ability to maintain and improve substation equipment and facilities that allow for the continual safe and reliable operation of the electric system as required by regulatory requirements and targets identified by the NY PSC. This program provides the company with the agility path to correct what is negatively impacting reliability in a proactive way. It additionally allows for the timely replacement of failed equipment and thus increases system reliability by limiting the duration primary equipment is out of service. Security of substations and substation equipment is heavily reliant on the substations minors budget to replace fencing, add lighting and cameras across 4 RGE divisions and 168 substations.

Project Risks and Mitigation Plan:

Inadequate funding, on an annual basis, has been the primary risk associated with this program. Program tracking and monitoring of available budget is continually balanced with remaining/anticipated workload, and in many cases, financial offsets are required from other planned work to fund this mandatory work throughout the year. These offsets create downstream consequences since prioritized work can no longer be executed as planned which can affect any number of factors, mainly system reliability.

Risk of No Action:

The consequences of not undertaking this project will lead to system abnormal conditions and unsafe conditions for the public and workforce. Not addressing emergent failures will have a negative impact on reliability (CAIDI) and lead to legal and regulatory scrutiny. Connecting customers and ensuring reliable service is our fundamental goal; taking no action to restore customers after equipment failure is not an option. Delayed or non-execution of customer restoration could result in fines, penalties and reputational damage. The scheduled replacement contributes to the reduction of outages because of substation equipment failures, which has been identified as the main root cause of substation outages.

Substation Minors Betterments contributes to the reduction of System Average Interruption Frequency Index (SAIFI).

Project Alternatives:

This program aims to replace outage equipment using an "in-kind" replacement strategy and therefore project alternatives are not applicable within this program.

Basis for Project Estimates

Future annual spending targets are informed by an annual analysis which considers historical itemized components and overall spending from prior years. Using prior actuals, by work type component, is the basis for future spending projections and a current and justified escalation factor is used to inform each subsequent out-year.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 316	\$ 171	\$ 105	\$ 15	\$ 6	\$ 19		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 970	\$ 339	\$ 430	\$ 61	\$ 97	\$ 42		
# Internal - Non-AC	\$ 0	\$ 0	\$ -	\$ 0	\$ -	\$ 0		
# Internal, Labor	\$ 809	\$ 333	\$ 148	\$ 88	\$ 94	\$ 146		
# Internal, Overheads	\$ 200	\$ 52	\$ 55	\$ 31	\$ 22	\$ 39		
# Materials	\$ 933	\$ 235	\$ 249	\$ 210	\$ 88	\$ 151		
# Overheads - External	\$ 690	\$ 218	\$ 154	\$ 94	\$ 94	\$ 129		
Total	\$ 3,918	\$ 1,347	\$ 1,141	\$ 500	\$ 402	\$ 527		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 89	\$ 9	\$ 15	\$ 12	\$ 12	\$ 13	\$ 14	\$ 15
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,244	\$ 266	\$ 291	\$ 305	\$ 321	\$ 337	\$ 353	\$ 371
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 1,206	\$ 150	\$ 163	\$ 168	\$ 173	\$ 178	\$ 184	\$ 189
# Internal, Overheads	\$ 234	\$ 38	\$ 37	\$ 35	\$ 33	\$ 30	\$ 30	\$ 32
# Materials	\$ 2,311	\$ 247	\$ 270	\$ 297	\$ 327	\$ 360	\$ 396	\$ 413
# Overheads - External	\$ 625	\$ 96	\$ 102	\$ 96	\$ 88	\$ 79	\$ 79	\$ 84
Total	\$ 6,708	\$ 806	\$ 878	\$ 913	\$ 954	\$ 996	\$ 1,055	\$ 1,105

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE - UG Cable Replacements

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-003003	Charge Code: Electric Distribution	Project Sponsor: Shail, Joshua	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP4 Change	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The RGE Cable Replacement Program is a systematic initiative designed to proactively and preventatively replace aged underground cables, primarily in the Rochester Region (City of Rochester). Approximately 510 sections of aged and obsolete cable have been identified, with the oldest installation being 101 years old as of 2021. This program aims to enhance the reliability and safety of the electric infrastructure by addressing the most critical sections of the underground cable network.

Project Scope:

1. Priority One: Address the '4-core' cable as identified in our records. These cable sections will be prioritized first by the total number of downstream customers connected.
2. In addition to the obsolete cable, any 'pump-log' duct (i.e., wooden ducts) encountered will be replaced in conjunction with any cable replacements.
3. Likewise, any collapsed ducts will be replaced as encountered. External vendors will be utilized for camera inspections to help predetermine the scope, i.e., cable replacement or total rebuild of the ducted system.
4. While the mainlines with the highest customer counts will be addressed first, any 'side taps' (i.e., smaller laterals off the mainline) will also be replaced at that time. This approach ensures synergistic efficiencies and avoids negative impacts from stakeholders such as customers, public officials, or the media, by preventing the need to revisit and disturb an area twice.
5. One caveat to the priority noted in #1 above: If a given street is on the City of Rochester's Moratorium List, it will be deferred until the City allows any utility work to commence.
6. Similarly, if there are repeat and/or frequent outages in a section of cable already identified in this program, that section will be moved up the priority list accordingly.
7. Lastly, pending cable replacements will be reviewed in relation to any planned Highway Reconstruction or Relocations. The timing can be advanced or delayed to align our schedules.

Approximately 510 sections of aged and obsolete cable have been identified, with the oldest installation being 101 years old as of 2021. Priority One is to address the 4-core cable as identified in our records.

Distribution underground cable failures at RGE contributed 0.026 (3%) to overall SAIFI on average over the last 5 years (2020-2024) and 0.10 (6.6%) to SAIDI. The average duration over the past 5 years for UG cable failure outages is 3.9 hours, with 25% lasting more than 5.4 hours, and 10% more than 8.2 hours. In addition, there is a tendency for locations of cable failures to have an increased frequency of future cable failures, adversely affecting the same customers and the CEMI/CELID metrics. To prioritize the replacement of the underground circuits constituting Underground Residential Distributions (URDs), we first developed an algorithm to identify and group portions of underground circuits based on the riser poles and proximity of the cables. Then, the outage history, length of the UG cable, number of transformers/vault pads, and age of the cable was used to train a predictive machine learning model to give a probability of repeat outages in the future. This model, along with the other features, most heavily the age and outage history, were used to determine a prioritization of replacement for URDs at RGE.

These cable sections will be prioritized first by the total number of downstream customers connected.

The following units and average unit costs will be addressed between 2025-2031:

2025 - 6,726 (units) / \$415 (unit cost)
2026 - 6,516 (units) / \$427 (unit cost)
2027 - 6,526 (units) / \$440 (unit cost)
2028 - 6,526 (units) / \$453 (unit cost)
2029 - 6,526 (units) / \$467 (unit cost)
2030 - 6,526 (units) / \$481 (unit cost)
2031 - 6,526 (units) / \$495 (unit cost)

*Unit defined as foot of cable

Project Benefits:

This program will help prevent customer outages by enhancing the capacity of the RG&E underground system and ensuring redundancies within the network.

Project Risks and Mitigation Plan:

Without a dedicated and funded replacement program, the 'run to failure' model results in prolonged unplanned outages. In many cases, cables cannot be spliced due to obsolescence, or new cables cannot be pulled through old conduits that are blocked or collapsed. Consequently, unplanned outages can extend up to 30 hours, leading to negative press and significant impacts on reliability.

Risk of No Action:

The cable replacement program proactively identifies high-risk cables to prevent potential increases in outage frequency. Without this proactive work, the system may experience more frequent outages. Additionally, there are risks of negatively impacting SAIFI goals, environmental factors, supply chain stability, public perception, and facing regulatory penalties.

Project Alternatives:

This program aims to replace one-for-one assets that are in poor condition. Alternatives are evaluated on a case-by-case basis to ensure the most effective solutions are implemented.

Basis for Project Estimates

The financial plan is based on the average cost per foot of cable replacement. This average cost is determined by the expenses for construction crews, internal labor, materials, and applicable overheads.

FINANCIAL INFORMATION**Actual Capital Spent, all amounts shown below in thousands (\$000's)**

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 357	\$ -	\$ -	\$ 37	\$ 120	\$ 200		
# CIAC	\$ -1	\$ -	\$ -	\$ -	\$ -1	\$ -		
# External Services	\$ 6,445	\$ -	\$ -	\$ 2,740	\$ 907	\$ 2,798		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 171	\$ -	\$ -	\$ 36	\$ 60	\$ 75		
# Internal, Overheads	\$ 756	\$ -	\$ -	\$ 213	\$ 101	\$ 442		
# Materials	\$ 1,530	\$ -	\$ -	\$ 342	\$ 291	\$ 896		
# Overheads - External	\$ 2,003	\$ -	\$ -	\$ 609	\$ 346	\$ 1,048		
Total	\$ 11,259	\$ -	\$ -	\$ 3,977	\$ 1,824	\$ 5,458		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ 188	\$ -	\$ -	\$ 147	\$ -21	\$ 62		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ 188	\$ -	\$ -	\$ 147	\$ -21	\$ 62		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 302	\$ 49	\$ 35	\$ 41	\$ 42	\$ 43	\$ 45	\$ 46
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 18,204	\$ 2,432	\$ 2,438	\$ 2,512	\$ 2,587	\$ 2,664	\$ 2,744	\$ 2,827
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 222	\$ 30	\$ 30	\$ 31	\$ 32	\$ 32	\$ 33	\$ 34
# Internal, Overheads	\$ 863	\$ 164	\$ 143	\$ 131	\$ 118	\$ 103	\$ 100	\$ 105
# Materials	\$ 2,098	\$ 280	\$ 281	\$ 289	\$ 298	\$ 307	\$ 316	\$ 326
# Overheads - External	\$ 1,743	\$ 312	\$ 292	\$ 268	\$ 241	\$ 210	\$ 204	\$ 216
Total	\$ 23,431	\$ 3,266	\$ 3,219	\$ 3,272	\$ 3,317	\$ 3,360	\$ 3,442	\$ 3,554

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 474	\$ 62	\$ 65	\$ 66	\$ 68	\$ 69	\$ 71	\$ 72
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 474	\$ 62	\$ 65	\$ 66	\$ 68	\$ 69	\$ 71	\$ 72

TLD Replacements RGE				
PROJECT INFORMATION				
OpCo: RG&E	Project ID: PRJ-002965	Charge Code: Electric Distribution	Project Sponsor: Malone, Chris	Project Type: Annual Program
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: H1 2025	In-Service Date: H2 2025
Project description: The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.				
Project Scope: The 11, 35, 115, 345 kV Lines are located in the Canandaigua, Fillmore, Sodus and Rochester Division. This TLD Project involves addressing 3490 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include 30% of pole replacements and 70% of crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations. Since 2020, outages on these transmission lines have affected 275,739 customers . This project will focus on addressing the notifications classified in the higher rankings.				
Project Benefits: The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.				
Project Risks and Mitigation Plan: •Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance. •Limited funding to address the backlog of TLD's as defined in the rate case. •Ability to get materials in a timely manner-- Order long lead materials during engineering phase. •Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.				
Risk of No Action: If the TLD Replacement Program is not expanded in scope, RGE is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.				
Project Alternatives: Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.				
Basis for Project Estimates Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.				

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 128	\$ -	\$ -	\$ 8	\$ 32	\$ 88		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 999	\$ -	\$ -	\$ 229	\$ 428	\$ 342		
# Internal - Non-AC	\$ 30	\$ -	\$ -	\$ 3	\$ 20	\$ 6		
# Internal, Labor	\$ 37	\$ -	\$ -	\$ -	\$ 37	\$ -		
# Internal, Overheads	\$ 75	\$ -	\$ -	\$ 13	\$ 31	\$ 31		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ 263	\$ -	\$ -	\$ 44	\$ 124	\$ 95		
Total	\$ 1,532	\$ -	\$ -	\$ 297	\$ 672	\$ 563		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 3,021	\$ 196	\$ -	\$ 50	\$ 150	\$ 625	\$ 1,000	\$ 1,000
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 29,278	\$ 678	\$ 3,000	\$ 3,400	\$ 1,200	\$ 5,000	\$ 8,000	\$ 8,000
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 2,815	\$ -10	\$ -	\$ 50	\$ 150	\$ 625	\$ 1,000	\$ 1,000
# Internal, Overheads	\$ 1,441	\$ 9	\$ -	\$ 35	\$ 91	\$ 322	\$ 485	\$ 499
# Materials	\$ 19,347	\$ 137	\$ -	\$ 340	\$ 1,020	\$ 4,250	\$ 6,800	\$ 6,800
# Overheads - External	\$ 3,377	\$ 104	\$ -	\$ 80	\$ 208	\$ 736	\$ 1,108	\$ 1,140
Total	\$ 59,279	\$ 1,114	\$ 3,000	\$ 3,955	\$ 2,820	\$ 11,559	\$ 18,393	\$ 18,439

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-RGE-L701

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-007371	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2025

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L701 is located in Canandaigua and Rochester Division. This TLD Project involves addressing 36 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings.

All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include 53% of pole replacements and 47% of crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 8,090 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, RGE is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 220	\$ 50	\$ 100	\$ 70	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,760	\$ 400	\$ 800	\$ 560	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 220	\$ 50	\$ 100	\$ 70	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 218	\$ 70	\$ 91	\$ 57	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,496	\$ 340	\$ 680	\$ 476	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 388	\$ 90	\$ 183	\$ 114	\$ -	\$ -	\$ -	\$ -
Total	\$ 4,302	\$ 1,000	\$ 1,954	\$ 1,347	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

TLD Replacements-RGE-L795

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-007372	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

The Transmission Line Deficiencies Replacement program (TLD Replacement Program) prioritizes the line segments needing intervention based on deficiencies identified on the transmission system by the various inspection programs (Crossarm Inspections, Aerial Inspections, Infrared Inspections, Transmission Line Inspection program and Wood Pole Inspect and Treat Program) Interventions are determined for each line segment and these interventions are engineered and scheduled for construction.

Project Scope:

The 34.5kV L795 is located in Sodus Division. This TLD Project involves addressing 159 notifications identified as Level 2 and Level 3. These notifications require capital processing and are classified within the highest Operational Prioritization Rankings. All notifications will undergo an engineering review before construction begins, with a focus on capital notifications (primarily structure replacements and reframes) to align with the agreement on the division of TLD work between Projects and Operations. The notifications include 16% of pole replacements and 84% of crossarm replacements. Poles and crossarms will be replaced using wood poles and/or light-duty steel poles based on engineering recommendations.

Since 2020, outages on this transmission line have affected 17,845 customers . This project will focus on addressing the notifications classified in the higher rankings.

Project Benefits:

The TLD Program will address the 20,000+ backlog of notifications generated by Maintenance Engineering inspection programs. Remedying these deficiencies will harden the transmission system, increase resiliency and reliability of lines by mitigating the most decayed transmission structures, which will therefore improve reliability to customers by reducing the risk of outages due to asset condition issues. Additionally, mitigating the most deficient transmission structures over time will decrease the need for full line rebuilds due to asset condition. Eliminating the TLD program would allow continued decay of an aging transmission system and increase the risk of outages due to asset condition.

Project Risks and Mitigation Plan:

- Outage availability to carry out work-- Most work is planned to be accomplished without an outage, but will require a non-reclose assurance.
- Limited funding to address the backlog of TLD's as defined in the rate case.
- Ability to get materials in a timely manner-- Order long lead materials during engineering phase.
- Real estate and environmental risks to access transmission lines for construction work-- Begin easement research, outreach to land owners and environmental studies early in the engineering phase.

Risk of No Action:

If the TLD Replacement Program is not expanded in scope, RGE is subject to an increasing risk of transmission line outage exposure, which will have a direct impact on customers and affect the companies' overall reliability metrics. It is expected that overdue TLD needs will continue to grow as new inspection methods are allowing more structures to be assessed (e.g., CVI) and the overall transmission line infrastructure continues to age. The longer these deficient assets remain in the field, the greater the risk of failures and potential customer outages. It is not possible, with historical funding trends, to reduce this backlog substantially as the current pace of new needs notifications outpaces the company's ability to address them.

Project Alternatives:

Each project has alternatives that are considered during the design review stage to meet the technical and constructability needs related to the project plan. Location of facilities, backup, and capacity are all considerations that go into each project design.

Basis for Project Estimates

Budget level estimates are based on the number of notifications and the average actual cost per notification from similar projects. The estimate can be refined when engineering is completed and contractor pricing is solicited.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 900	\$ 20	\$ 25	\$ 130	\$ 350	\$ 375	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 7,200	\$ 160	\$ 200	\$ 1,040	\$ 2,800	\$ 3,000	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 900	\$ 20	\$ 25	\$ 130	\$ 350	\$ 375	\$ -	\$ -
# Internal, Overheads	\$ 629	\$ 28	\$ 23	\$ 106	\$ 247	\$ 225	\$ -	\$ -
# Materials	\$ 6,120	\$ 136	\$ 170	\$ 884	\$ 2,380	\$ 2,550	\$ -	\$ -
# Overheads - External	\$ 1,246	\$ 36	\$ 46	\$ 213	\$ 498	\$ 453	\$ -	\$ -
Total	\$ 16,994	\$ 400	\$ 489	\$ 2,502	\$ 6,626	\$ 6,978	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

General Equipment - OPS-T&D

PROJECT INFORMATION

OpCo: RG&E	Project ID: UI-50004-RGE-ED	Charge Code: Electric Distribution	Project Sponsor: Shail, Joshua	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The RGE General Equipment Program is dedicated to the replacement of tools and equipment, specifically for Transmission and Distribution (T&D) Operations. This program ensures that employees have access to the necessary tools and equipment to perform their duties efficiently and safely. Additionally, it includes the outfitting of trucks with the required equipment to support field operations.

Project Scope:

The RGE General Equipment Program is designed to provide essential electrical equipment, tools, and safety gear for new employees, ensuring compliance with safety and Occupational Safety and Health Administration (OSHA) requirements. This program focuses on the replacement of tools and equipment at the end of their useful lives to maintain high safety standards. The tools and equipment covered include, but are not limited to, hammers, wrenches, pliers, gloves, climbing ropes, harnesses, equipment bags, and rubber goods.

In addition to standard tools, the program also includes the purchase of specialty tools and multi-functional testing devices to outfit vehicles for craft workers. These specialty tools include high-speed pumps, hydraulic-operated cutters and drills, Arc Flash Blankets, fault locating equipment, climbing gear, and saws.

Below are the 2025-2031 estimated annual units and average unit rates excluding overheads based on a 3-year historical average (2022 - 2024):

Hand Tools (estimated units/purchase orders = 112) \$5,907/unit*

Work Clothes (estimated units/purchase orders = 4) \$46,640/unit*

Health & Safety (estimated units/purchase orders = 53) \$3,333/unit**

Grounding Kits (estimated units/purchase orders = 8) \$10,000/unit*- Begins in 2026

Wire Stripping Tool (estimated units = 50) \$3,040/unit - One-time purchase in 2026

Truck Mount Hipo (estimated units = 3) \$20,000/unit - One-time purchase in 2026

Sniffers (estimated units = 3) \$10,000/unit - One-time purchase in 2026

In addition to the above units and average costs, the budget includes \$115K for miscellaneous items.

*Unit rates are calculated with a 3% annual escalation for 2025- 2031

Refer to the 'The RC_Historical Analysis' tab for year-by-year breakdown of estimated units and average unit rates.

Project Benefits:

Tools and equipment periodically break down and therefore it is necessary to replace them. Safety has also improved over the years due to more ergonomic tools that are lighter and have safety measures integrated to protect employees during use when performing heavy construction work.

Project Risks and Mitigation Plan:

The most common risks associated with this work are: workers may lack the necessary tools to perform construction and maintenance tasks; frequent use of manual equipment can lead to increased muscle fatigue and injuries; and insufficient personal protective equipment (PPE) for arc flash, electrical testing tools, hazardous gas sensors, blast blankets, and confined space entry equipment can result in injuries or fatalities.

Mitigation Plan: Continue to invest in safety gear, mechanized tools, and updated technology to stay current with industry advancements.

Risk of No Action:

High-risk tasks such as confined space entry, working at heights, working on live parts, using critical mechanical tools and lifts, performing hot work, line breaking or hot tapping, and working near unguarded moving parts all pose significant risks to workers. Without the proper safety gear, tools, and testing equipment, these activities can lead to serious injuries or fatalities.

Project Alternatives:

The Company sources gear and equipment through framework agreements and trusted suppliers to ensure both quality and cost-effectiveness.

There are no viable alternatives to working safely without the proper safety gear and tools. Ensuring the availability of high-quality safety equipment is essential for protecting workers and maintaining a safe working environment.

The budget for this program is typically determined based on the average actual costs over the past three years.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE Station 5 - Transmission Line Upgrades

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-003696	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: H1 2025	In-Service Date: H2 2027

Project description:

RGE Station 5 is an 11.5 kV substation located on the Genesee River in Rochester. Station 5 is fed from a hydro-electric dam with three turbines that have a combined output of 54 MW.

- The station was originally constructed circa 1917. Most of the circuits out of Station 5 are about the same age; approximately 100 years old.
- The Station 5 Rebuild Project has undergone multiple design iterations and has been around since 2012. Construction started in Q3 2023.
- The Station 5 Substation Project was originally IP2 approved with the concession that the 11 kV transmission upgrades were to be completed separately and at a later date. Transmission line upgrades were not included in the original Station 5 IP2 approval.
- If Station 5 is replaced without upgrading the existing 11 kV circuits, RGE will not be able to deliver the full hydro-electric output provided by the station.

Project Scope:

Replace concrete incline that carries circuits from the powerhouse up to street level near Driving Park Avenue and Carthage Drive. Based upon a specialized engineering feasibility study, it is technically feasible and practical to construct a new concrete Incline in the same location as the existing incline structure. The new Incline will not negatively affect the Driving Park Avenue Bridge's east abutment. The expected service life for the Incline exceeds 100 years based on the service life of the present incline and the use of improved materials for the new Incline. The proposed Incline is narrower than the existing incline. Therefore, the existing easements and property limits are large enough for the permanent work.

- Restore circuits 523 K&N, 524 K&N, 566, 581 K&N, 596, 605, 606, 613, 642, 643 back to service.
- Remove MH 90.01 7/64 to avoid failure and potential damage to Station 5 assets.

Project Benefits:

Restores circuits 523 K&N, 524 K&N, 566, 581 K&N, 596, 605, 606, 613, 642, 643 back to service. These circuits allow for 38.9 MVA of generating capacity. This will allow Fossil Hydro to utilize two hydro electric turbines.

The Incline Structure will be replaced with a new concrete structure expected to last approximately 100 years.

Project Risks and Mitigation Plan:

Project scope of work not well defined - Risk that the scope of work (SOW) is not well defined and updated, either through narratives, discussions, confirmations, minutes or meetings, illustrations, figures, verification lists, digital photos, responsibility matrices and other means that may subsequently be used as a basis for control of the price and program settings. Hold regular status meetings with engineering and construction personnel. Include Fossil Hydro personnel in project team meetings.

Failure to meet an Outage milestone - Risk of contractor missing an Outage milestone previously agreed with the System Operator, causing delays to the Project and extra cost due to the need of rescheduling. Ensure constant communication with the contractor. Make sure all risks are accounted for. Contractor missing project key milestones and deliverables compared to baseline - Risk of Vendors and Contractors not meeting the project key milestones and key deliverables compared to baseline. Properly defined schedule and scope.

Risk of No Action:

Substation team finishes the substation but they only have existing transmission lines to connect to. They cannot achieve the full capacity of the hydro electric dam. With the existing lines that will need to be upgraded, they can only run one turbine. With the Phase I plan, hydro can run 2 turbines.

Project Alternatives:

Alternative 1 (Selected) – 11.5 kV Solution, Incline Structure Route, Phase 1.

Cost: \$19 M (+50%/-25%). ISD 2027.

Based upon a specialized engineering feasibility study, it is technically feasible and practical to construct a new concrete Incline in the same location as the existing incline structure. The new Incline will not negatively affect the Driving Park Avenue Bridge's east abutment. The expected service life for the Incline exceeds 100 years based on the service life of the present incline and the use of improved materials for the new Incline. The proposed Incline is narrower than the existing incline. Therefore, the existing easements and property limits are large enough for the permanent work. Restore circuits 523 K&N, 524 K&N, 566, 581 K&N, 596, 605, 606, 613, 642, 643 back to service. These circuits allow for 38.9 MVA of generating capacity. Fossil Hydro requires 27.6 MVA to run two turbines.

Remove MH 90.01 7/64

Alternative 2 – 11.5 kV Solution, Substation Road Access Route. Cost: \$48.1 M (+50%/-25%). ISD 2029.

All Station 5 circuits are restored to original electrical configuration (except Circuits 669 and 596). All construction is concrete-encased duct bank. Normal maintenance and operation practices can be employed. Lowest construction risk – no construction near any existing infrastructure.

Alternative 3 – 11.5 kV Solution, Incline Structure Route, Phase 2. Cost: \$10.7 M (+50%/-25%). ISD 2030.

This alternative completely rebuilds Circuit 523 K&N and 524 K&N to Station 95. All Station 5 circuits are restored to original electrical configuration (except Circuit 669). Reroute circuits 610 K&N and 613 to avoid the collapsed retaining wall. Increases the project cost by \$1M to \$2M (fully loaded).

Alternative 4 – 34.5 kV Solution, Incline Structure Route, Phase 2. Cost: \$22.1 M (+50%/-25%). ISD 2030.

Install a GIS substation at the top of the Incline Structure, to the east of Carthage Drive within the vacant parking lot. Install a 11/34.5 kV step-up transformer to convert 11 kV generation to 34.5 kV transmission. Utilize the 11.5 kV cables installed in Phase 1 to feed the 11/34.5 kV step-up transformer. In-and-out nearby Line 713 into RGE Station 5. Reroute all 11 kV lines currently connecting to RGE Station 5 to maintain system stability. Solution is currently being verified for electrical feasibility by Transmission Planning.

Basis for Project Estimates

Utilize estimating tools to choose the selected alternative approximately at \$19M

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 57	\$ -	\$ -	\$ 1	\$ 22	\$ 33		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 309	\$ -	\$ -	\$ 132	\$ 177	\$ -		
# Internal - Non-AC	\$ 40	\$ -	\$ -	\$ -	\$ 38	\$ 2		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ 21	\$ -	\$ -	\$ 8	\$ 13	\$ 0		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ 76	\$ -	\$ -	\$ 25	\$ 50	\$ 1		
Total	\$ 504	\$ -	\$ -	\$ 167	\$ 301	\$ 36		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 939	\$ 183	\$ 232	\$ 524	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 12,862	\$ 2,841	\$ 3,072	\$ 6,949	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 90	\$ 30	\$ 30	\$ 30	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 647	\$ 165	\$ 161	\$ 322	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 2,121	\$ 467	\$ 509	\$ 1,146	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 1,484	\$ 369	\$ 372	\$ 742	\$ -	\$ -	\$ -	\$ -
Total	\$ 18,143	\$ 4,055	\$ 4,376	\$ 9,713	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE Spare Power Transformer Program				
PROJECT INFORMATION				
OpCo:	Project ID:	Charge Code:	Project Sponsor:	Project Type:
RG&E	PRJ-005168	Electric Transmission	Malone, Chris	Project
Business Area:	Rate Case Category	Project Stage:	Start Date:	In-Service Date:
Planning & Coordination	Asset Condition	IP2 Technical	Ongoing	Ongoing
Project description: The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers. Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity. The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.				
Project Scope: Projected purchase of RGE 4 spares in 2028, 3 spares in 2029 and 3 spares in 2030.				
Project Benefits: The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges. One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs. Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.				
Project Risks and Mitigation Plan: The risks associated with the program are intricately tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, the companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we would be compelled to rely on old, unreliable transformers that have been previously used in past projects. These transformers would need to undergo a costly refurbishment process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to widespread disruptions and increased maintenance costs. Moreover, the delay in purchasing new spares would exponentially increase the reliability risk. The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised. In summary, the lack of adequate funding for new spares not only forces us to depend on less reliable, refurbished components but also significantly heightens the risk of system failures due to the extended lead times required for procurement. Ensuring timely and sufficient funding is therefore critical to maintaining the integrity and reliability of our electric system, preventing potential failures, and avoiding the high costs associated with emergency repairs and system downtime.				

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers.

Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 961	\$ -	\$ -	\$ -	\$ -	\$ 261	\$ 350	\$ 350
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 137	\$ -	\$ -	\$ -	\$ -	\$ 37	\$ 50	\$ 50
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 137	\$ -	\$ -	\$ -	\$ -	\$ 37	\$ 50	\$ 50
# Internal, Overheads	\$ 686	\$ -	\$ -	\$ -	\$ -	\$ 186	\$ 250	\$ 250
# Materials	\$ 10,569	\$ -	\$ -	\$ -	\$ -	\$ 2,869	\$ 3,850	\$ 3,850
# Overheads - External	\$ 1,235	\$ -	\$ -	\$ -	\$ -	\$ 335	\$ 450	\$ 450
Total	\$ 13,726	\$ -	\$ -	\$ -	\$ -	\$ 3,726	\$ 5,000	\$ 5,000

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 137	\$ -	\$ -	\$ -	\$ -	\$ 37	\$ 50	\$ 50
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 7,275	\$ -	\$ -	\$ -	\$ -	\$ 1,975	\$ 2,650	\$ 2,650
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 421	\$ -	\$ -	\$ -	\$ -	\$ 118	\$ 149	\$ 154
# Materials	\$ 4,530	\$ -	\$ -	\$ -	\$ -	\$ 1,230	\$ 1,650	\$ 1,650
# Overheads - External	\$ 790	\$ -	\$ -	\$ -	\$ -	\$ 222	\$ 280	\$ 288
Total	\$ 13,152	\$ -	\$ -	\$ -	\$ -	\$ 3,582	\$ 4,779	\$ 4,791

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE 001 Spare Tx Pgm 120-13.2kV 22.4MVA

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-005919	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: H2 2026

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the RGE #1 120-13.2kV 22.4MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

Long lead times from the transformer manufacturer would present a reliability risk.

The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

Mitigation Plan: Account for this risk by following our robust procurment process. Additionally, start the procurment process as soon as possible, and ensure constant communication is maintained with the transformer manufacturer.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers. Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence. Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 203	\$ 45	\$ 158	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 22	\$ 10	\$ 12	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 24	\$ 12	\$ 12	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 127	\$ 100	\$ 27	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 2,000	\$ 1,600	\$ 400	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 240	\$ 193	\$ 47	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,616	\$ 1,960	\$ 656	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

RGE 002 Spare Tx Pgm 120-13.2kV 22.4MVA

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-005920	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: H2 2026

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the RGE #2 120-13.24kV 22.4MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

Long lead times from the transformer manufacturer would present a reliability risk.

The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

Mitigation Plan: Account for this risk by following our robust procurment process. Additionally, start the procurment process as soon as possible, and ensure constant communication is maintained with the transformer manufacturer.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers. Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence. Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 203	\$ 45	\$ 158	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 22	\$ 10	\$ 12	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 24	\$ 12	\$ 12	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 127	\$ 100	\$ 27	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 2,000	\$ 1,600	\$ 400	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 240	\$ 193	\$ 47	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,616	\$ 1,960	\$ 656	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE 003 SprTxPgm 34.5-12.5/4kV 22.4MVA

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006509	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the RGE #3 34.5-12.5/4kV 22.4MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

The risks associated with the program are intricately tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, the companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we would be compelled to rely on old, unreliable transformers that have been previously used in past projects. These transformers would need to undergo a costly refurbishment process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to widespread disruptions and increased maintenance costs.

Moreover, the delay in purchasing new spares would exponentially increase the reliability risk. The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

In summary, the lack of adequate funding for new spares not only forces us to depend on less reliable, refurbished components but also significantly heightens the risk of system failures due to the extended lead times required for procurement. Ensuring timely and sufficient funding is therefore critical to maintaining the integrity and reliability of our electric system, preventing potential failures, and avoiding the high costs associated with emergency repairs and system downtime.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers.

Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost based on the most recent transformer prices. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 325	\$ -	\$ 68	\$ 198	\$ 59	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 44	\$ 4	\$ 5	\$ 30	\$ 5	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 40	\$ 8	\$ 6	\$ 10	\$ 16	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 112	\$ -	\$ 25	\$ 67	\$ 20	\$ -	\$ -	\$ -
# Materials	\$ 3,003	\$ 753	\$ 450	\$ 1,350	\$ 450	\$ -	\$ -	\$ -
# Overheads - External	\$ 238	\$ -	\$ 54	\$ 143	\$ 42	\$ -	\$ -	\$ -
Total	\$ 3,762	\$ 765	\$ 608	\$ 1,798	\$ 590	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE 004 SprTxPgm 115-34.5/12.5kV 20MVA

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006511	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the RGE #4 115-34.5/12.5kV 20MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

The risks associated with the program are intricately tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, the companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we would be compelled to rely on old, unreliable transformers that have been previously used in past projects. These transformers would need to undergo a costly refurbishment process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to widespread disruptions and increased maintenance costs.

Moreover, the delay in purchasing new spares would exponentially increase the reliability risk. The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

In summary, the lack of adequate funding for new spares not only forces us to depend on less reliable, refurbished components but also significantly heightens the risk of system failures due to the extended lead times required for procurement. Ensuring timely and sufficient funding is therefore critical to maintaining the integrity and reliability of our electric system, preventing potential failures, and avoiding the high costs associated with emergency repairs and system downtime.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers.

Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 378	\$ -	\$ 81	\$ 226	\$ 71	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -				\$ -	\$ -	\$ -
# External Services	\$ 44	\$ 4	\$ 5	\$ 30	\$ 5	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 50	\$ 8	\$ 6	\$ 20	\$ 16	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 133	\$ -	\$ 30	\$ 80	\$ 23	\$ -	\$ -	\$ -
# Materials	\$ 3,453	\$ 753	\$ 540	\$ 1,620	\$ 540	\$ -	\$ -	\$ -
# Overheads - External	\$ 284	\$ -	\$ 64	\$ 171	\$ 50	\$ -	\$ -	\$ -
Total	\$ 4,342	\$ 765	\$ 726	\$ 2,147	\$ 705	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE 005 SprTxPgm 115-34.5/12.5kV 20MVA

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006519	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the RGE #5 115-34.5/12.5kV 20MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

The risks associated with the program are intricately tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, the companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we would be compelled to rely on old, unreliable transformers that have been previously used in past projects. These transformers would need to undergo a costly refurbishment process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to widespread disruptions and increased maintenance costs.

Moreover, the delay in purchasing new spares would exponentially increase the reliability risk. The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

In summary, the lack of adequate funding for new spares not only forces us to depend on less reliable, refurbished components but also significantly heightens the risk of system failures due to the extended lead times required for procurement. Ensuring timely and sufficient funding is therefore critical to maintaining the integrity and reliability of our electric system, preventing potential failures, and avoiding the high costs associated with emergency repairs and system downtime.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers.

Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

[illegible]

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 378	\$ -	\$ -	\$ 81	\$ 226	\$ 71	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 44	\$ 4	\$ -	\$ 5	\$ 30	\$ 5	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 50	\$ 8	\$ -	\$ 6	\$ 20	\$ 16	\$ -	\$ -
# Internal, Overheads	\$ 116	\$ -	\$ -	\$ 27	\$ 70	\$ 20	\$ -	\$ -
# Materials	\$ 3,453	\$ 753	\$ -	\$ 540	\$ 1,620	\$ 540	\$ -	\$ -
# Overheads - External	\$ 248	\$ -	\$ -	\$ 57	\$ 149	\$ 42	\$ -	\$ -
Total	\$ 4,289	\$ 765	\$ -	\$ 716	\$ 2,114	\$ 694	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE 006 SprTxPgm 34.5-4kV 14MVA

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006524	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The Spare Power Transformer Program was established in 2024 to ensure that NYSEG and RG&E had a reliable and dependable method for assessing and determining the necessary spare power transformer purchases in the event of transformer failures. This program is crucial for New York's power infrastructure, addressing the urgent need for a dedicated substation power transformer spares inventory. The current lack of such inventory poses a significant risk to system reliability, as evidenced by recent transformer failures in our service territories. While portable mobile substation transformers have provided temporary relief, these incidents underscore the critical importance of establishing a robust spares program to ensure a continuous and reliable supply of power to our customers.

Without dedicated, reliable spare power transformers, there is a heightened risk of prolonged substation outages in the event of transformer failures requiring immediate replacement. A total of 86 spare power transformers, encompassing 51 different types, have been identified and recommended for purchase. This strategic decision is aimed at bolstering our infrastructure's resilience and ensuring operational continuity.

The estimated capital investment for this program as a part of this proposed rate case is approximately \$67 million (35 Transformers) for the NYSEG component, reflecting the significant investment required to maintain and enhance our service capabilities. Similarly, the RG&E component is projected to incur a capital investment of about \$28 million (15 Transformers). This comprehensive investment plan underscores our commitment to providing reliable service to our customers, while also preparing for potential future contingencies. By increasing and diversifying our transformer inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges.

Project Scope:

This Project Scope is the purchase of the RGE #6 34.5-4kV 14MVA transformer.

Project Benefits:

The Spare Power Transformer Program is a strategic initiative designed to ensure a continuous and reliable power supply for our customers by establishing a robust spares program. This program significantly bolsters our infrastructure's resilience and guarantees operational continuity. At its core, the spares algorithm employs a repeatable and justified methodology, leveraging established transformer risk scores and prioritizing purchases based on system needs rather than historical purchasing patterns. This approach ensures that our inventory is diversified, thereby mitigating risks associated with equipment failures and enhancing our ability to respond swiftly to unforeseen challenges.

One of the key benefits of this program is the formation of the transformer spares working group. This group is instrumental in establishing a clear process for handling power transformer emergencies, purchasing spare power transformers, and maintaining accountability among key players. It ensures that NYSEG and RG&E are ready and equipped with a healthy inventory of spare power transformers, and clear visibility and established maintenance protocols. Accurate spare power transformer equipment data in SAP is critical for establishing precise transformer assessment scores. Additionally, the group facilitates both short- and long-term planning for adjustments in spare purchase strategies as the system evolves, ensuring that our approach remains dynamic and responsive to changing needs.

Furthermore, the program enhances the visibility of capital investment plans for spares and supports robust budget forecasting. This comprehensive approach not only strengthens our operational capabilities but also provides a clear framework for future growth and adaptation, ensuring that we can continue to deliver reliable power to our customers under any circumstances.

Project Risks and Mitigation Plan:

The risks associated with the program are intricately tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, the companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we would be compelled to rely on old, unreliable transformers that have been previously used in past projects. These transformers would need to undergo a costly refurbishment process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to widespread disruptions and increased maintenance costs.

Moreover, the delay in purchasing new spares would exponentially increase the reliability risk. The procurement process for these spares involves long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to prolonged periods of instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

In summary, the lack of adequate funding for new spares not only forces us to depend on less reliable, refurbished components but also significantly heightens the risk of system failures due to the extended lead times required for procurement. Ensuring timely and sufficient funding is therefore critical to maintaining the integrity and reliability of our electric system, preventing potential failures, and avoiding the high costs associated with emergency repairs and system downtime.

Risk of No Action:

The absence of a comprehensive inventory of spare power transformers poses a significant threat to the reliability of our power system. Recent transformer failures within the state have already highlighted this critical vulnerability. While portable mobile substation transformers have provided temporary relief, they are not a sustainable solution for ensuring a continuous and reliable power supply, particularly during major events such as hurricanes or unexpected widespread faults and multiple outages across the system.

It is essential to recognize that power must be transmitted from the substations, where the power transformers are located, before it can be distributed. Ensuring the reliability of equipment within the substation is imperative. Even if the distribution system is robust and reliable, it will be ineffective if power cannot be supplied from the substations due to extended transformer outages caused by a lack of spare power transformers.

Without a dedicated stock of reliable spare power transformers, the risk of prolonged substation outages increases significantly. In the event of transformer failures that necessitate immediate replacement, the absence of readily available spares could result in extended power interruptions. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare power transformers. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare power transformers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Project Alternatives:

Alternatives to establishing a spare power transformer program and purchasing spares present several significant challenges. Our existing inventory of mobile transformers is insufficient to meet the growing demand, as these units are not only deployed during emergencies but are also essential for routine maintenance activities and substation construction projects. This limited inventory means we cannot always ensure their availability when needed, leading to potential service disruptions. In addition, mobile transformers are not intended to be used as permanent fixes and relying on this strategy would have negative impacts when considering emergency and planned outage needs. Another alternative is to use old transformers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished transformers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable and investing in the transformer spares program is crucial to ensure the stability and efficiency of our infrastructure.

Basis for Project Estimates

The spare transformer cost estimates encompass the cost of equipment, required internal labor, external resources, internal and external engineering, and appropriate miscellaneous project support costs. These estimates are derived from the estimated cost of equipment provided by Standards. Appropriate project support costs and applicable overheads and allocations are likewise estimates. The cost of equipment is routinely reviewed and updated as more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 250	\$ -	\$ -	\$ 35	\$ 108	\$ 107	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 40	\$ -	\$ -	\$ 5	\$ 30	\$ 5	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 42	\$ -	\$ -	\$ 6	\$ 20	\$ 16	\$ -	\$ -
# Internal, Overheads	\$ 88	\$ -	\$ -	\$ 20	\$ 53	\$ 15	\$ -	\$ -
# Materials	\$ 2,051	\$ -	\$ -	\$ 431	\$ 1,271	\$ 349	\$ -	\$ -
# Overheads - External	\$ 187	\$ -	\$ -	\$ 43	\$ 112	\$ 32	\$ -	\$ -
Total	\$ 2,657	\$ -	\$ -	\$ 540	\$ 1,594	\$ 523	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE Spare Circuit Breaker Program

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006545	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Annual Program
Business Area: Planning & Coordination	Rate Case Category Asset Condition	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

Ensuring the reliability and resilience of electrical infrastructure is critical for maintaining continuous power delivery and protecting the grid from unplanned outages and failures. Circuit breakers play a vital role in this process by isolating faulty sections of the grid, preventing widespread outages, and safeguarding power equipment. The Spare Circuit Breaker Program is crucial for New York's power infrastructure and is designed to address key challenges and opportunities in maintaining a robust inventory of substation circuit breaker spares. The absence of such inventory currently poses a significant threat to system reliability, as evidenced by past failures in our service areas. By maintaining a dedicated, reliable stock of spare breakers, operators can rapidly replace faulty units, minimizing downtime and enhancing overall reliability.

The program optimizes the selection of spare breakers, balancing the costs of maintaining inventory with the need for grid reliability. Having spare breakers readily available also enables us to respond promptly to emergencies, mitigating risks and ensuring the safety of both our infrastructure and the public. This rapid response capability is crucial in maintaining trust and confidence in our electrical system. As our grid continues to expand and evolve, the Spare Breaker Program prepares us for future challenges, ensuring that our infrastructure can meet the growing and changing demands of our society.

A total of 16 spare circuit breakers, encompassing 15 different types, have been identified and recommended for purchase from 2026 to 2028. The estimated capital investment for this program for the first three years is approximately \$2.9 million for the RGE operating company. This comprehensive investment plan underscores our commitment to providing reliable service to our customers while also preparing for potential future contingencies. By increasing and diversifying our circuit breaker inventory, we aim to mitigate risks associated with equipment failures and enhance our ability to respond swiftly to any unforeseen challenges. We estimate to purchase \$3 million of spares from 2029 to 2031. Breaker types and quantity to be determined depending on future system needs.

Project Scope:

- 1.This project involves the purchase of one (1) 38 kV 2000A 40 kA 125 VDC GOP spare breaker with a total estimated cost of \$0.09 M. The estimated ISD is 12/31/2026.
- 2.This project involves the purchase of one (1) 38 kV 1200A 40 kA 125 VDC GOP spare breaker with a total estimated cost of \$0.09 M. The estimated ISD is 12/31/2026.
- 3.This project involves the purchase of one (1) 38 kV 3000A 40 kA 125 VDC GOP spare breaker with a total estimated cost of \$0.09 M. The estimated ISD is 12/31/2026.
- 4.This project involves the purchase of one (1) 38 kV 1200A 40 kA 250 VDC GOP spare breaker with a total estimated cost of \$0.09 M. The estimated ISD is 12/31/2026.
- 5.This project involves the purchase of two (2) 15.5 kV 1200A 25 kA 125 VDC GOP spare breaker with a total estimated cost of \$0.2 M. The estimated ISD is 12/31/2026.
- 6.This project involves the purchase of one (1) 15.5 kV 1200A 25 kA 48 VDC GOP spare breaker with a total estimated cost of \$0.09 M. The estimated ISD is 12/31/2026.
- 7.This project involves the purchase of one (1) 15.5 kV 1200A 25 kA 24 VDC GOP spare breaker with a total estimated cost of \$0.09 M. The estimated ISD is 12/31/2026.
- 8.This project involves the purchase of one (1) 15.5 kV 1200A 25 kA 250 VDC GOP spare breaker with a total estimated cost of \$0.09 M. The estimated ISD is 12/31/2026.
- 9.This project involves the purchase of one (1) 15.5 kV 3000A 40 kA 125 VDC GOP spare breaker with a total estimated cost of \$0.09 M. The estimated ISD is 12/31/2026.
- 10.This project involves the purchase of one (1) 145 kV 1200A 40 kA 125 VDC GOP spare breaker with a total estimated cost of \$0.2 M. The estimated ISD is 12/31/2027.
- 11.This project involves the purchase of one (1) 145 kV 2000A 40 kA 125 VDC GOP spare breaker with a total estimated cost of \$0.2 M. The estimated ISD is 12/31/2027.
- 12.This project involves the purchase of one (1) 145 kV 3000A 40 kA 125 VDC GOP spare breaker with a total estimated cost of \$0.2 M. The estimated ISD is 12/31/2027.
- 13.This project involves the purchase of one (1) 72 kV 1200A 31.5/40 kA 125 VDC IPO spare breaker with a total estimated cost of \$0.3 M. The estimated ISD is 12/31/2027.
- 14.This project involves the purchase of one (1) 72 kV 2000A 31.5/40 kA 125 VDC IPO spare breaker with a total estimated cost of \$0.3 M. The estimated ISD is 12/31/2027.
- 15.This project involves the purchase of one (1) 345 kV 3000A 63kA 125 VDC IPO spare breaker with a total estimated cost of \$0.7 M. The estimated ISD is 12/31/2028.

Project Benefits:

Maintaining a stock of spare breakers is crucial for minimizing downtime and enhancing overall reliability. By having these spares readily available, we can swiftly replace faulty units, ensuring that operations continue smoothly without significant interruptions.

This program also streamlines the replacement process, reducing the time and resources required to restore normal operations. Instead of needing to urgently procure parts to address an emergent situation, we can instead efficiently manage replacements, allowing for expedited customer restoration using new equipment.

Moreover, the program offers significant cost savings. By procuring spares in advance and taking advantage of bulk discounts, we avoid the premium costs associated with urgent procurement. This proactive approach not only saves money but also ensures that we are always prepared.

Having spare breakers on hand enables us to respond promptly to emergencies, mitigating risks and ensuring safety. In critical situations, the ability to quickly replace faulty units can make a significant difference in maintaining the integrity of our operations.

As our grid expands and customer's reliance on their electricity supply increases through electrification of heating and transportation, this program prepares us for future challenges; bolstering our infrastructure's ability to meet evolving needs.

Project Risks and Mitigation Plan:

The risks associated with the Spare Circuit Breaker Program are intricately tied to the availability of adequate funding for purchasing essential spares. Without sufficient financial resources, companies will likely face significant challenges in acquiring new spares, which are crucial for maintaining the reliability and efficiency of our electric system. Instead, we may need to rely on retired, unreliable, or repaired equipment that has been a previously in-service piece of equipment. These used circuit breakers would need to undergo a costly reconditioning process, which not only incurs high expenses but also results in components with questionable reliability. This situation would inevitably expose our electric system to a higher likelihood of failures, potentially leading to widespread disruptions and increased maintenance costs.

Moreover, the delay in purchasing new spares would increase the reliability risk caused by the failure of poor health equipment. The procurement process for equipment can involve long lead times, during which we are entirely dependent on the manufacturers' ability to produce and deliver the necessary components. Any delays or issues on the manufacturers' end would further exacerbate the risk, leaving our system vulnerable to periods of supply chain instability. The compounded effect of these delays and the reliance on refurbished, unreliable components would create a precarious situation, where the electric system's overall reliability and performance are severely compromised.

In summary, the lack of adequate funding for new spares not only forces us to depend on less reliable, refurbished components but also significantly heightens the risk of system failures due to the extended lead times required for procurement. Ensuring timely and sufficient funding is therefore critical to maintaining the integrity and reliability of our electric system, preventing potential failures, and avoiding the high costs associated with emergency repairs and system downtime.

Risk of No Action:

The absence of a comprehensive inventory of spare circuit breakers poses a significant threat to the reliability of our power system.

Without a dedicated stock of reliable spare circuit breakers, the risk of prolonged substation outages increases significantly. In the event of a failure that necessitating immediate replacement, the absence of readily available spares could result in extended interruptions to our customers. This would not only inconvenience our customers but could also have far-reaching consequences for critical infrastructure, businesses, and emergency services that depend on a stable power supply.

Furthermore, the financial implications of prolonged outages can be substantial. The costs associated with emergency repairs, temporary solutions, and the economic impact on businesses and residents can far exceed the investment required to maintain a robust inventory of spare equipment. Additionally, the reputational damage to the utility company could be significant, eroding customer trust and confidence.

Proactive measures to ensure system resilience and reliability are essential. This includes investing in a dedicated inventory of spare circuit breakers to mitigate the risk of catastrophic failures and ensure an uninterrupted power supply even during major disruptions. By doing so, we can safeguard our customers, support the community, and maintain the integrity of our power system.

Alternatives to establishing a spare circuit breaker program and purchasing spares present several significant challenges. With the limited or non-existent inventory of spares, unplanned emergency replacements require using circuit breakers purchased for planned projects. This results in additional capital expenditure on replenishing the breakers for these ongoing projects and delays the project progression. Another alternative is to use old or retired breakers that have been replaced during projects. However, these units require extensive refurbishment, which is both costly and time-consuming. Moreover, refurbished breakers are unreliable, posing a significant risk to our operations. From both a financial and reliability standpoint, these alternatives are not viable. Investing in the circuit breaker spares program is crucial to ensure the stability and efficiency of our infrastructure.

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within RGE. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 58	\$ -	\$ 9	\$ 11	\$ 9	\$ 10	\$ 9	\$ 10
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 272	\$ -	\$ 48	\$ 48	\$ 24	\$ 51	\$ 51	\$ 51
# Internal, Overheads	\$ 631	\$ -	\$ 90	\$ 106	\$ 148	\$ 96	\$ 95	\$ 95
# Materials	\$ 3,982	\$ -	\$ 650	\$ 756	\$ 515	\$ 689	\$ 685	\$ 687
# Overheads - External	\$ 766	\$ -	\$ 110	\$ 129	\$ 180	\$ 116	\$ 116	\$ 116
Total	\$ 5,708	\$ -	\$ 907	\$ 1,050	\$ 876	\$ 961	\$ 956	\$ 958

[illegible]

Mobile Substation Evaluation - RGE

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-005952	Charge Code: Electric Transmission	Project Sponsor: Camargo, Rogerio	Project Type: Project
Business Area: Electric Operations	Rate Case Category Asset Condition	Project Stage: IP2 Technical	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This initiative assesses the need for Avangrid Networks to purchase more mobile substations. A mobile substation is a self-contained trailer equipped with the necessary high and medium voltage components of a substation and are used for five main reasons: substation maintenance, project completion, emergency situations, unit maintenance, and to avoid transformer overloads. The emergency situations occur when there is a failure at the substation and a mobile must be installed so the entire circuit is not out of power. The units are aging, and repairs are very costly. For this reason, meeting demand is becoming difficult across the Avangrid facilities. Some units are reaching a condition level where they can no longer be used or transported safely. Although Avangrid owns 37 mobile substations, ~40% of those are unable to be used due to long term transformer failures or unit deterioration.

Project Scope:

Purchase units for each OPCO to be shared within its divisions. Purchasing more units would allow Avangrid to better serve their customers and avoid the fees associated with outages and not meeting SAIFI requirements. The mobiles are significant to performing regular tasks to reduce the frequency of customers out of power. For example, if a transformer goes and there are no mobiles to accommodate the load, all circuits connected to the device will be out of power. This study is requesting that RGE will purchase one 34.5kV unit. RGE currently has 3 mobiles, however 2 of them are in a good and usable condition. RGE would benefit from adding one more unit to their fleet. In times of need RGE will also share units with NYSEG's western divisions, such as Lancaster and Auburn. Additionally, a preventative maintenance schedule is proposed so these new units are inspected once every two years and kept in good condition.

Project Benefits:

Keep up with transformer standards as the required sizes increase. 2) Purchasing new mobiles allows managers to request the specific sizes they need to fit their substation restrictions. 3) This will be a long-term investment that will save money on refurbishments. Mobiles have a lifespan of 20-25 years without any major ones. 4) Keep up to date with projects & substation maintenance. 5) Having a mobile available reduces the duration of outages that occur due to a transformer failure, because the unit can support the load. This is only possible if there are units not tied up to other activities and are in decent condition

Project Risks and Mitigation Plan:

The top risks of not having new mobile substations and relying on aged ones include increased likelihood of equipment failure, higher maintenance costs, and reduced reliability. Aged mobile substations are more prone to technical failures due to wear and tear, which can lead to frequent outages and extended downtime. This not only disrupts power supply but also increases operational costs as more resources are needed for repairs and maintenance. Additionally, older equipment may not meet current regulatory standards, posing compliance risks and potential fines. The reliability of the power grid is compromised when aged substations fail, affecting service continuity and customer satisfaction. Safety hazards are also a concern, as older equipment may not have the latest safety features, increasing the risk of accidents. To mitigate these risks, investing in new mobile substations ensures a more reliable, efficient, and safe power supply, ultimately benefiting both the utility company and its customers

Risk of No Action:

If the project to acquire new mobile substations is not undertaken, several significant consequences could arise. Firstly, relying on aged mobile substations increases the likelihood of equipment failures due to wear and tear, leading to frequent outages and extended downtime. This not only disrupts power supply but also results in higher operational costs as more resources are needed for repairs and maintenance. Secondly, older equipment may not meet current regulatory standards, posing compliance risks and potential fines. The reliability of the power grid is compromised when aged substations fail, affecting service continuity and customer satisfaction. Additionally, safety hazards are a concern, as older equipment may lack the latest safety features, increasing the risk of accidents. Without new mobile substations, the ability to respond quickly to emergencies or planned maintenance is diminished, leading to longer restoration times and greater inconvenience for customers. Overall, not undertaking the project could result in increased costs, reduced reliability, and compromised safety, ultimately impacting both the utility company and its customers.

Refurbishment of Existing Mobile Substations: This approach focuses on upgrading and modernizing the current fleet of mobile substations. Refurbishment can include replacing outdated components, enhancing protection systems, and improving overall performance.

Do Nothing: Maintaining the status quo and continuing to use aged mobile substations without significant upgrades. This option carries high risks, including increased likelihood of equipment failure, higher maintenance costs, and reduced reliability

Mobile Substation manufacturers quotes

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 36	\$ -	\$ 12	\$ 12	\$ 12	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,895	\$ -	\$ 632	\$ 632	\$ 632	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 153	\$ -	\$ 57	\$ 51	\$ 45	\$ -	\$ -	\$ -
# Materials	\$ 1,180	\$ -	\$ 393	\$ 393	\$ 393	\$ -	\$ -	\$ -
# Overheads - External	\$ 287	\$ -	\$ 108	\$ 96	\$ 84	\$ -	\$ -	\$ -
Total	\$ 3,551	\$ -	\$ 1,202	\$ 1,184	\$ 1,165	\$ -	\$ -	\$ -

[illegible]



NYSEG Electric Reliability

NYSEG - Breaker Replacement Program				
PROJECT INFORMATION				
OpCo: NYSEG	Project ID: UI-N0061-NYSEG-ED	Charge Code: Electric Distribution	Project Sponsor: Malone, Chris	Project Type: Annual Program
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing
Project description: The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers. The program primarily follows an annual prioritization process, focusing on an “in-kind” replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime. In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs. The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 33.5% (1,317 units) of circuit breakers in New York Operating Companies (NY Opcos) are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2031 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas. The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system. Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency. Program projections indicate that 60% to 70% of the planned replacement units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency. By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.				
Project Scope: 1) We are forecasting to install approximately 86 breakers in 2028, around 72 breakers in 2029, and approximately 74 breakers in 2030. The actual in-service completion dates will vary depending on the voltage class of each breaker. 2) Individual breaker replacement projects costing more than \$500,000 will have a unique project ID created under this Breaker Replacement Program funding. Any breaker replacement estimated to cost less than \$500,000 will be purchased directly under this program ID number.				

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk R14 and R15 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as R14 or R15. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of R14 and R15 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 7,783	\$ 925	\$ 1,272	\$ 1,265	\$ 1,972	\$ 2,348		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 35,854	\$ 5,133	\$ 6,123	\$ 8,970	\$ 5,580	\$ 10,047		
# Internal - Non-AC	\$ 2,114	\$ 328	\$ 341	\$ 472	\$ 400	\$ 572		
# Internal, Labor	\$ 5,414	\$ 2,042	\$ 1,031	\$ 706	\$ 934	\$ 701		
# Internal, Overheads	\$ 8,649	\$ 1,715	\$ 1,614	\$ 1,823	\$ 1,317	\$ 2,180		
# Materials	\$ 16,693	\$ 4,334	\$ 2,260	\$ 3,713	\$ 3,055	\$ 3,332		
# Overheads - External	\$ 13,658	\$ 2,699	\$ 2,266	\$ 2,777	\$ 2,640	\$ 3,276		
Total	\$ 90,165	\$ 17,176	\$ 14,909	\$ 19,726	\$ 15,899	\$ 22,455		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ 3	\$ -	\$ -	\$ -	\$ 3	\$ -		
Materials	\$ 6	\$ 2	\$ -	\$ -	\$ 3	\$ -0		
Other O&M	\$ 14	\$ 2	\$ 0	\$ 2	\$ 1	\$ 9		
Total	\$ 22	\$ 5	\$ 0	\$ 2	\$ 7	\$ 9		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 12,037	\$ 2,722	\$ 1,090	\$ 131	\$ 482	\$ 1,893	\$ 2,863	\$ 2,856
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 55,516	\$ 9,531	\$ 5,379	\$ 646	\$ 2,380	\$ 9,347	\$ 14,134	\$ 14,099
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 9,404	\$ 1,150	\$ 966	\$ 116	\$ 427	\$ 1,678	\$ 2,537	\$ 2,531
# Internal, Overheads	\$ 6,416	\$ -1,336	\$ 1,067	\$ 101	\$ 349	\$ 1,344	\$ 2,210	\$ 2,681
# Materials	\$ 30,382	\$ 4,206	\$ 3,062	\$ 368	\$ 1,355	\$ 5,321	\$ 8,045	\$ 8,026
# Overheads - External	\$ 13,697	\$ 99	\$ 1,872	\$ 177	\$ 612	\$ 2,357	\$ 3,877	\$ 4,702
Total	\$ 127,452	\$ 16,373	\$ 13,436	\$ 1,539	\$ 5,605	\$ 21,940	\$ 33,666	\$ 34,894

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 7	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1
Materials	\$ 16	\$ 2	\$ 2	\$ 2	\$ 2	\$ 2	\$ 2	\$ 2
Other O&M	\$ 42	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6	\$ 6
Total	\$ 66	\$ 9	\$ 9	\$ 9	\$ 9	\$ 10	\$ 10	\$ 10

Circuit Breaker Replacement - Northside 115 kV

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007292	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace two (2) 115kV (93652 and 94452) breakers at Northside Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing two (2) 115kV (93652 and 94452) breakers.
The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement.

Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 115	\$ 1	\$ 36	\$ 78	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 588	\$ 25	\$ 178	\$ 385	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 106	\$ 5	\$ 32	\$ 69	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 76	\$ 25	\$ 19	\$ 32	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 325	\$ 5	\$ 101	\$ 219	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 86	\$ 15	\$ 26	\$ 45	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,297	\$ 76	\$ 392	\$ 829	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Locus St

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007291	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace one (1) 34 kV (B1-2) breaker and five (5) 12.5 kV (15022, 15122, 15222, 15322 and 15422) breakers at Locus Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing one (1) 34 kV (B1-2) breaker and five (5) 12.5 kV (15022, 15122, 15222, 15322 and 15422) breakers. The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 193	\$ 0	\$ 66	\$ 127	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 961	\$ 11	\$ 325	\$ 626	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 173	\$ 2	\$ 58	\$ 112	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 98	\$ 11	\$ 35	\$ 53	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 543	\$ 2	\$ 185	\$ 356	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 127	\$ 6	\$ 48	\$ 73	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,095	\$ 32	\$ 716	\$ 1,347	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Milliken

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007290	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

This project is to replace two (2) 34 kV (52162 and 5B-62) breakers and five (5) 115 kV breaker (97462, 97562, B5-62, B6-62 and T1-62) at Milliken Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing two (2) 34 kV (52162 and 5B-62) breakers and five (5) 115 kV breaker (97462, 97562, B5-62, B6-62 and T1-62). The estimated ISD is 12/31/2026.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 271	\$ 20	\$ 251	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,896	\$ 658	\$ 1,237	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 362	\$ 140	\$ 222	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 812	\$ 658	\$ 154	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 824	\$ 120	\$ 704	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 612	\$ 399	\$ 213	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 4,777	\$ 1,995	\$ 2,782	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Morgan Road

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007289	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace two (2) 115kV (93642 and 93742) breakers and four (4) 34 kV (43142, 43342, 1B-42 and GB-42) breakers at Morgan Road Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing two (2) 115kV (93642 and 93742) breakers and four (4) 34 kV (43142, 43342, 1B-42 and GB-42) breakers. The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 295	\$ 1	\$ 99	\$ 195	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,477	\$ 25	\$ 489	\$ 963	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 266	\$ 5	\$ 88	\$ 173	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 158	\$ 25	\$ 52	\$ 81	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 831	\$ 5	\$ 278	\$ 548	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 200	\$ 15	\$ 72	\$ 112	\$ -	\$ -	\$ -	\$ -
Total	\$ 3,227	\$ 76	\$ 1,079	\$ 2,073	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - New Berlin

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007288	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace three (3) 4.8 kV (11152, 11252 and C1-52) breakers at New Berlin Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an “in-kind” replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing three (3) 4.8 kV (11152, 11252 and C1-52) breakers. The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 90	\$ -	\$ 32	\$ 59	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 445	\$ -	\$ 156	\$ 289	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 80	\$ -	\$ 28	\$ 52	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 41	\$ -	\$ 17	\$ 24	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 253	\$ -	\$ 89	\$ 165	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 57	\$ -	\$ 23	\$ 34	\$ -	\$ -	\$ -	\$ -
Total	\$ 965	\$ -	\$ 343	\$ 622	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - North Endicott 115 kV

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007287	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace three (3) 115kV (92082, 93882 and 93882) breakers at North Endicott Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing three (3) 115kV (92082, 93882 and 93882) breakers.
The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 174	\$ 1	\$ 56	\$ 117	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 884	\$ 30	\$ 276	\$ 578	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 160	\$ 6	\$ 49	\$ 104	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 108	\$ 30	\$ 29	\$ 49	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 491	\$ 5	\$ 157	\$ 329	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 126	\$ 18	\$ 41	\$ 67	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,943	\$ 91	\$ 608	\$ 1,244	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Orchard Park

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007286	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

This project is to replace four (4) 4.8 kV (28522, 28622 and 28722 and C1-22) breakers at Orchard Park Substation

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing four (4) 4.8 kV (28522, 28622 and 28722 and C1-22) breakers.
The estimated ISD is 12/31/2026.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 89	\$ 5	\$ 84	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 565	\$ 150	\$ 415	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 106	\$ 32	\$ 74	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 195	\$ 150	\$ 44	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 264	\$ 27	\$ 236	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 152	\$ 91	\$ 61	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,371	\$ 456	\$ 915	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - River Road

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007284	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace one (1) 46 kV (C1-72) breaker and five (5) 4.8 kV (10272, 10272, 10472, 10572 and C2-72) breakers at River Road Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing one (1) 46 kV (C1-72) breaker and five (5) 4.8 kV (10272, 10272, 10472, 10572 and C2-72) breakers. The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 193	\$ 0	\$ 66	\$ 127	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 961	\$ 11	\$ 325	\$ 626	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 173	\$ 2	\$ 58	\$ 112	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 98	\$ 11	\$ 35	\$ 53	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 543	\$ 2	\$ 185	\$ 356	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 127	\$ 6	\$ 48	\$ 73	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,095	\$ 32	\$ 716	\$ 1,347	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Sand Street

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007283	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

This project is to replace three (3) 4.8 kV (12, 22 and 62) breakers at Sand Street Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an “in-kind” replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing three (3) 4.8 kV (12, 22 and 62) breakers.
The estimated ISD is 12/31/2026.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement.

Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 63	\$ 4	\$ 59	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 421	\$ 132	\$ 289	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 80	\$ 28	\$ 52	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 162	\$ 132	\$ 31	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 188	\$ 24	\$ 165	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 122	\$ 80	\$ 43	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,036	\$ 399	\$ 637	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Sleight Road

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007282	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

This project is to replace eight (8) 34 kV (54112, 54212, 54312, 54412, 54512, 54612, T1-12 and 2B-12) breakers and one (1) 115 kV breaker (T2-12) at Sleight Road Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing eight (8) 34 kV (54112, 54212, 54312, 54412, 54512, 54612, T1-12 and 2B-12) breakers and one (1) 115 kV breaker (T2-12).

The estimated ISD is 12/31/2026.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 268	\$ 18	\$ 250	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,836	\$ 602	\$ 1,235	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 349	\$ 128	\$ 222	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 733	\$ 602	\$ 131	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 812	\$ 109	\$ 703	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 547	\$ 365	\$ 182	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 4,547	\$ 1,824	\$ 2,723	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Stilesville

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007280	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace one (1) 115kV (B2-22) breaker and three (3) 46 kV (1B-22, 2B-22 and 83122) breakers at Stilesville Substation..

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing one (1) 115kV (B2-22) breaker and three (3) 46 kV (1B-22, 2B-22 and 83122) breakers. The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 137	\$ 7	\$ 127	\$ 3	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 881	\$ 241	\$ 626	\$ 14	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 166	\$ 51	\$ 112	\$ 2	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 309	\$ 241	\$ 67	\$ 1	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 408	\$ 44	\$ 356	\$ 8	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 240	\$ 146	\$ 92	\$ 2	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,141	\$ 731	\$ 1,381	\$ 29	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Transit

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007279	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

This project is to replace two (2) 34 kV (50572 and 50672) breakers and three (3) 12.5 kV (41472, 41672 and 41772) breakers at Transit Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing two (2) 34 kV (50572 and 50672) breakers and three (3) 12.5 kV (41472, 41672 and 41772) breakers. The estimated ISD is 12/31/2026.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Legion Drive

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007276	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace two (2) 34 kV (50012 and 51012) breakers and four (4) 4.8 kV (15212, 15312, 15412 and C1-12) breakers at Legion Drive Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing two (2) 34 kV (50012 and 51012) breakers and four (4) 4.8 kV (15212, 15312, 15412 and C1-12) breakers. The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement.

Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 210	\$ -	\$ 74	\$ 137	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,037	\$ -	\$ 363	\$ 674	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 186	\$ -	\$ 65	\$ 121	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 95	\$ -	\$ 39	\$ 57	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 591	\$ -	\$ 207	\$ 384	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 132	\$ -	\$ 54	\$ 79	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,252	\$ -	\$ 801	\$ 1,451	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Lake Ave

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007275	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

This project is to replace four (4) 12.5 kV (48262, 48362, 48462 and C1-62) breakers at Lake Ave Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing four (4) 12.5 kV (48262, 48362, 48462 and C1-62) breakers.
The estimated ISD is 12/31/2026.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 89	\$ 5	\$ 84	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 565	\$ 150	\$ 415	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 106	\$ 32	\$ 74	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 195	\$ 150	\$ 44	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 264	\$ 27	\$ 236	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 152	\$ 91	\$ 61	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,371	\$ 456	\$ 915	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Ferndale

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007273	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace two (2) 115kV (95042 and 95942) breakers at Ferndale Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing two (2) 115kV (95042 and 95942) breakers.
The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 115	\$ 1	\$ 48	\$ 66	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 588	\$ 25	\$ 237	\$ 326	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 106	\$ 5	\$ 43	\$ 59	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 97	\$ 25	\$ 27	\$ 44	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 325	\$ 5	\$ 135	\$ 186	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 115	\$ 15	\$ 38	\$ 62	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,346	\$ 76	\$ 528	\$ 742	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Dick Rd

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007272	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace three (3) 34 kV (53312, 53412 and 53712) breakers and six (6) 4.8 kV (39012, 39112, 39212, 39412, 39612 and C1-12) breakers at Dick Rd Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing three (3) 34 kV (53312, 53412 and 53712) breakers and six (6) 4.8 kV (39012, 39112, 39212, 39412, 39612 and C1-12) breakers.
The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 315	\$ -	\$ 110	\$ 205	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,556	\$ -	\$ 545	\$ 1,011	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 279	\$ -	\$ 98	\$ 182	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 143	\$ -	\$ 58	\$ 85	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 886	\$ -	\$ 310	\$ 576	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 198	\$ -	\$ 80	\$ 118	\$ -	\$ -	\$ -	\$ -
Total	\$ 3,377	\$ -	\$ 1,201	\$ 2,176	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Caton Avenue

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007271	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace three (3) 34 kV (57352, 57452 & 1B-52) breakers and two (2) 115 kV breaker (95852 & 96052) at Caton Ave Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing three (3) 34 kV (57352, 57452 & 1B-52) breakers and two (2) 115 kV breaker (95852 & 96052). The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 182	\$ 11	\$ 166	\$ 6	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,196	\$ 348	\$ 819	\$ 30	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 226	\$ 74	\$ 147	\$ 5	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 438	\$ 348	\$ 87	\$ 2	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 546	\$ 63	\$ 466	\$ 17	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 335	\$ 211	\$ 121	\$ 3	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,924	\$ 1,055	\$ 1,806	\$ 64	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - 14th Street

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006552	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace three (3) 4.8 kV, three (3) 7.2 kV and three (3) 34.5 kV breakers at 14th Street Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of existing circuit breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of NYSEG and RG&E circuit breakers in are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs or projects are excluded from this program to avoid duplication of effort and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery bank voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. In some cases breakers may be added to a substation if a bay is available and its addition will enhance the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection, reliability, and operability of the electrical system.

Engineering and project development for circuit breaker replacement includes evaluating the condition of switches, insulators, and foundations. Station topology is reviewed to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements (potentially including automation upgrades) are made to enhance control and reliability. The scope of work is determined through outreach to Substation Operations, Transmission and Distribution Planning, Digital Grid, and the Protection & Control groups. These types of upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, reducing disruptions to our customers, and optimizing operations.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing the following breakers at 14th Street Substation:

Three (3) 4.8 kV breakers (11772, 11872, 29372),

Three (3) 7.2 kV breakers (2B-72, 2C-72),

Three (3) 34.5 kV breakers (51572, 52672, 52972).

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk R14 and R15 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences that can include entire substation outages due to the failure of a circuit breaker. If this failure results in damage to adjacent equipment, the repair costs, outage duration, and outage scope can be significant.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as R14 or R15. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of R14 and R15 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining legacy equipment (e.g., brown glass insulators and electromechanical relays) in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, compromising the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to the long-term sustainability of the system.

A more comprehensive and holistic solution is achieved by replacing the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers. This approach mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, in the long run this strategy is cost-effective. While the initial investment may be higher due to the expanded scope of ancillary equipment replacement, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to customers.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical labor data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 334	\$ -	\$ -	\$ 94	\$ 167	\$ 73	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,650	\$ -	\$ -	\$ 463	\$ 826	\$ 360	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 296	\$ -	\$ -	\$ 83	\$ 148	\$ 65	\$ -	\$ -
# Internal, Overheads	\$ 237	\$ -	\$ -	\$ 65	\$ 113	\$ 59	\$ -	\$ -
# Materials	\$ 939	\$ -	\$ -	\$ 264	\$ 470	\$ 205	\$ -	\$ -
# Overheads - External	\$ 229	\$ -	\$ -	\$ 63	\$ 109	\$ 57	\$ -	\$ -
Total	\$ 3,685	\$ -	\$ -	\$ 1,032	\$ 1,834	\$ 820	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Bulkhead

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006555	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace three (3) 4.8 kV and two (2) 12.5 kV breakers at Bulkhead Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of existing circuit breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of NYSEG and RG&E circuit breakers are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs or projects are excluded from this program to avoid duplication of effort and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery bank voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. In some cases breakers may be added to a substation if a bay is available and its addition will enhance the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection, reliability, and operability of the electrical system.

Engineering and project development for circuit breaker replacement includes evaluating the condition of switches, insulators, and foundations. Station topology is reviewed to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements (potentially including automation upgrades) are made to enhance control and reliability. The scope of work is determined through outreach to Substation Operations, Transmission and Distribution Planning, Digital Grid, and the Protection & Control groups. These types of upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, reducing disruptions to our customers, and optimizing operations.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing the following breakers at Bulkhead Substation:

Three (3) 4.8 kV breakers (12842, 7942, C-42),
Two (2) 12.5 kV breakers (32242, 32342).

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences that can include entire substation outages due to the failure of a circuit breaker. If this failure results in damage to adjacent equipment, the repair costs, outage duration, and outage scope can be significant.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining legacy equipment (e.g., brown glass insulators and electromechanical relays) in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, compromising the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to the long-term sustainability of the system.

A more comprehensive and holistic solution is achieved by replacing the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers. This approach mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, in the long run this strategy is cost-effective. While the initial investment may be higher due to the expanded scope of ancillary equipment replacement, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to customers.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 168	\$ -	\$ -	\$ 67	\$ 101	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 829	\$ -	\$ -	\$ 332	\$ 497	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 149	\$ -	\$ -	\$ 60	\$ 89	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 128	\$ -	\$ -	\$ 53	\$ 75	\$ -	\$ -	\$ -
# Materials	\$ 472	\$ -	\$ -	\$ 189	\$ 283	\$ -	\$ -	\$ -
# Overheads - External	\$ 124	\$ -	\$ -	\$ 51	\$ 72	\$ -	\$ -	\$ -
Total	\$ 1,868	\$ -	\$ -	\$ 751	\$ 1,117	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Cadyville

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006556	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace one (1) 6.6 kV and four (4) 11.5 kV breakers at Cadyville Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of existing circuit breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of NYSEG and RG&E circuit breakers in are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs or projects are excluded from this program to avoid duplication of effort and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery bank voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. In some cases breakers may be added to a substation if a bay is available and its addition will enhance the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection, reliability, and operability of the electrical system.

Engineering and project development for circuit breaker replacement includes evaluating the condition of switches, insulators, and foundations. Station topology is reviewed to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements (potentially including automation upgrades) are made to enhance control and reliability. The scope of work is determined through outreach to Substation Operations, Transmission and Distribution Planning, Digital Grid, and the Protection & Control groups. These types of upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, reducing disruptions to our customers, and optimizing operations.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing the following breakers at Cadyville Substation:

One (1) 6.6 kV breaker (03-11),
Four (4) 11.5 kV breakers (01-11, 02-11, 1B-11, S1-11).

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement.

Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences that can include entire substation outages due to the failure of a circuit breaker. If this failure results in damage to adjacent equipment, the repair costs, outage duration, and outage scope can be significant.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining legacy equipment (e.g., brown glass insulators and electromechanical relays) in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, compromising the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to the long-term sustainability of the system.

A more comprehensive and holistic solution is achieved by replacing the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers. This approach mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, in the long run this strategy is cost-effective. While the initial investment may be higher due to the expanded scope of ancillary equipment replacement, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to customers.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 168	\$ -	\$ -	\$ 67	\$ 101	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 829	\$ -	\$ -	\$ 332	\$ 497	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 149	\$ -	\$ -	\$ 60	\$ 89	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 128	\$ -	\$ -	\$ 53	\$ 75	\$ -	\$ -	\$ -
# Materials	\$ 472	\$ -	\$ -	\$ 189	\$ 283	\$ -	\$ -	\$ -
# Overheads - External	\$ 124	\$ -	\$ -	\$ 51	\$ 72	\$ -	\$ -	\$ -
Total	\$ 1,868	\$ -	\$ -	\$ 751	\$ 1,117	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Cooperstown

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006560	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace four (4) 4.8 kV breakers at Cooperstown Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of existing circuit breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of NYSEG and RG&E circuit breakers in are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs or projects are excluded from this program to avoid duplication of effort and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery bank voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. In some cases breakers may be added to a substation if a bay is available and its addition will enhance the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection, reliability, and operability of the electrical system.

Engineering and project development for circuit breaker replacement includes evaluating the condition of switches, insulators, and foundations. Station topology is reviewed to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements (potentially including automation upgrades) are made to enhance control and reliability. The scope of work is determined through outreach to Substation Operations, Transmission and Distribution Planning, Digital Grid, and the Protection & Control groups. These types of upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, reducing disruptions to our customers, and optimizing operations.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing the following breakers at Cooperstown Substation:

Four (4) 4.8 kV breakers (12132, 12232, 12332, 12432).

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences that can include entire substation outages due to the failure of a circuit breaker. If this failure results in damage to adjacent equipment, the repair costs, outage duration, and outage scope can be significant.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining legacy equipment (e.g., brown glass insulators and electromechanical relays) in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, compromising the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to the long-term sustainability of the system.

A more comprehensive and holistic solution is achieved by replacing the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers. This approach mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, in the long run this strategy is cost-effective. While the initial investment may be higher due to the expanded scope of ancillary equipment replacement, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to customers.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 134	\$ -	\$ -	\$ 54	\$ 81	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 663	\$ -	\$ -	\$ 265	\$ 398	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 119	\$ -	\$ -	\$ 48	\$ 71	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 102	\$ -	\$ -	\$ 42	\$ 60	\$ -	\$ -	\$ -
# Materials	\$ 377	\$ -	\$ -	\$ 151	\$ 226	\$ -	\$ -	\$ -
# Overheads - External	\$ 99	\$ -	\$ -	\$ 41	\$ 58	\$ -	\$ -	\$ -
Total	\$ 1,495	\$ -	\$ -	\$ 601	\$ 894	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Macedon

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006574	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace four (4) 12.5 kV and seven (7) 34.5 kV breakers at Macedon Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of existing circuit breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of NYSEG and RG&E circuit breakers are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs or projects are excluded from this program to avoid duplication of effort and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery bank voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. In some cases breakers may be added to a substation if a bay is available and its addition will enhance the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection, reliability, and operability of the electrical system.

Engineering and project development for circuit breaker replacement includes evaluating the condition of switches, insulators, and foundations. Station topology is reviewed to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements (potentially including automation upgrades) are made to enhance control and reliability. The scope of work is determined through outreach to Substation Operations, Transmission and Distribution Planning, Digital Grid, and the Protection & Control groups. These types of upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, reducing disruptions to our customers, and optimizing operations.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing the following breakers at Macedon:

Four (4) 12.5 kV (2B-32, 60132, 60232 & 60332),
Seven (7) 34.5 kV breakers (3B-32, 53932, 54032, 54132, 58332, T1-32 & C2-32).

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement.

Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences that can include entire substation outages due to the failure of a circuit breaker. If this failure results in damage to adjacent equipment, the repair costs, outage duration, and outage scope can be significant.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining legacy equipment (e.g., brown glass insulators and electromechanical relays) in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, compromising the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to the long-term sustainability of the system.

A more comprehensive and holistic solution is achieved by replacing the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers. This approach mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, in the long run this strategy is cost-effective. While the initial investment may be higher due to the expanded scope of ancillary equipment replacement, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to customers.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 444	\$ -	\$ -	\$ 85	\$ 189	\$ 170	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,192	\$ -	\$ -	\$ 418	\$ 933	\$ 841	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 393	\$ -	\$ -	\$ 75	\$ 167	\$ 151	\$ -	\$ -
# Internal, Overheads	\$ 357	\$ -	\$ -	\$ 70	\$ 149	\$ 138	\$ -	\$ -
# Materials	\$ 1,248	\$ -	\$ -	\$ 238	\$ 531	\$ 479	\$ -	\$ -
# Overheads - External	\$ 346	\$ -	\$ -	\$ 67	\$ 144	\$ 134	\$ -	\$ -
Total	\$ 4,980	\$ -	\$ -	\$ 953	\$ 2,114	\$ 1,912	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Mohansic

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006577	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace nine (9) 13.2 kV breakers at Mohansic Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of existing circuit breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of NYSEG and RG&E circuit breakers are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs or projects are excluded from this program to avoid duplication of effort and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery bank voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. In some cases breakers may be added to a substation if a bay is available and its addition will enhance the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection, reliability, and operability of the electrical system.

Engineering and project development for circuit breaker replacement includes evaluating the condition of switches, insulators, and foundations. Station topology is reviewed to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements (potentially including automation upgrades) are made to enhance control and reliability. The scope of work is determined through outreach to Substation Operations, Transmission and Distribution Planning, Digital Grid, and the Protection & Control groups. These types of upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, reducing disruptions to our customers, and optimizing operations.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing the following breakers at Mohansic Substation:

Nine (9) 13.2 kV breakers (2B-12, 4B-12, T2-12, 40212, 40312, 40412, 40512, 40612 & 40712).

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences that can include entire substation outages due to the failure of a circuit breaker. If this failure results in damage to adjacent equipment, the repair costs, outage duration, and outage scope can be significant.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining legacy equipment (e.g., brown glass insulators and electromechanical relays) in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, compromising the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to the long-term sustainability of the system.

A more comprehensive and holistic solution is achieved by replacing the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers. This approach mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, in the long run this strategy is cost-effective. While the initial investment may be higher due to the expanded scope of ancillary equipment replacement, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to customers.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 302	\$ -	\$ -	\$ 121	\$ 181	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,492	\$ -	\$ -	\$ 597	\$ 895	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 268	\$ -	\$ -	\$ 107	\$ 161	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 230	\$ -	\$ -	\$ 96	\$ 134	\$ -	\$ -	\$ -
# Materials	\$ 849	\$ -	\$ -	\$ 340	\$ 509	\$ -	\$ -	\$ -
# Overheads - External	\$ 222	\$ -	\$ -	\$ 92	\$ 130	\$ -	\$ -	\$ -
Total	\$ 3,363	\$ -	\$ -	\$ 1,352	\$ 2,011	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Mulberry

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006578	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace five (5) 34.5 kV breakers at Mulberry Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of existing circuit breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of NYSEG and RG&E circuit breakers are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs or projects are excluded from this program to avoid duplication of effort and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery bank voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. In some cases breakers may be added to a substation if a bay is available and its addition will enhance the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection, reliability, and operability of the electrical system.

Engineering and project development for circuit breaker replacement includes evaluating the condition of switches, insulators, and foundations. Station topology is reviewed to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements (potentially including automation upgrades) are made to enhance control and reliability. The scope of work is determined through outreach to Substation Operations, Transmission and Distribution Planning, Digital Grid, and the Protection & Control groups. These types of upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, reducing disruptions to our customers, and optimizing operations.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing the following breakers at Mulberry Substation:

Five (5) 34.5 kV breakers (1B-22, 60022, 60122, 60322 & 60422).

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement.

Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences that can include entire substation outages due to the failure of a circuit breaker. If this failure results in damage to adjacent equipment, the repair costs, outage duration, and outage scope can be significant.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining legacy equipment (e.g., brown glass insulators and electromechanical relays) in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, compromising the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to the long-term sustainability of the system.

A more comprehensive and holistic solution is achieved by replacing the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers. This approach mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, in the long run this strategy is cost-effective. While the initial investment may be higher due to the expanded scope of ancillary equipment replacement, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to customers.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 221	\$ -	\$ -	\$ 22	\$ 77	\$ 122	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,092	\$ -	\$ -	\$ 109	\$ 382	\$ 601	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 196	\$ -	\$ -	\$ 20	\$ 69	\$ 108	\$ -	\$ -
# Internal, Overheads	\$ 182	\$ -	\$ -	\$ 20	\$ 64	\$ 99	\$ -	\$ -
# Materials	\$ 622	\$ -	\$ -	\$ 62	\$ 218	\$ 342	\$ -	\$ -
# Overheads - External	\$ 176	\$ -	\$ -	\$ 19	\$ 62	\$ 95	\$ -	\$ -
Total	\$ 2,489	\$ -	\$ -	\$ 251	\$ 872	\$ 1,366	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Pound Ridge

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006581	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace seven (7) 13.2 kV breakers at Pound Ridge Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of existing circuit breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of NYSEG and RG&E circuit breakers are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs or projects are excluded from this program to avoid duplication of effort and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery bank voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. In some cases breakers may be added to a substation if a bay is available and its addition will enhance the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection, reliability, and operability of the electrical system.

Engineering and project development for circuit breaker replacement includes evaluating the condition of switches, insulators, and foundations. Station topology is reviewed to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements (potentially including automation upgrades) are made to enhance control and reliability. The scope of work is determined through outreach to Substation Operations, Transmission and Distribution Planning, Digital Grid, and the Protection & Control groups. These types of upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, reducing disruptions to our customers, and optimizing operations.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing the following breakers at Pound Ridge:

Seven (7) 13.2 kV breakers (1B-12, 2B-12, 45512, 45612, 45712, 45812, T2-12).

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences that can include entire substation outages due to the failure of a circuit breaker. If this failure results in damage to adjacent equipment, the repair costs, outage duration, and outage scope can be significant.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining legacy equipment (e.g., brown glass insulators and electromechanical relays) in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, compromising the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to the long-term sustainability of the system.

A more comprehensive and holistic solution is achieved by replacing the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers. This approach mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, in the long run this strategy is cost-effective. While the initial investment may be higher due to the expanded scope of ancillary equipment replacement, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to customers.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 235	\$ -	\$ -	\$ 94	\$ 141	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,160	\$ -	\$ -	\$ 464	\$ 696	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 208	\$ -	\$ -	\$ 83	\$ 125	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 179	\$ -	\$ -	\$ 74	\$ 105	\$ -	\$ -	\$ -
# Materials	\$ 660	\$ -	\$ -	\$ 264	\$ 396	\$ -	\$ -	\$ -
# Overheads - External	\$ 173	\$ -	\$ -	\$ 72	\$ 101	\$ -	\$ -	\$ -
Total	\$ 2,616	\$ -	\$ -	\$ 1,052	\$ 1,564	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Roll Rd

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006584	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace five (5) 34.5 kV breakers at Roll Rd Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of existing circuit breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of NYSEG and RG&E circuit breakers are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs or projects are excluded from this program to avoid duplication of effort and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery bank voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. In some cases breakers may be added to a substation if a bay is available and its addition will enhance the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection, reliability, and operability of the electrical system.

Engineering and project development for circuit breaker replacement includes evaluating the condition of switches, insulators, and foundations. Station topology is reviewed to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements (potentially including automation upgrades) are made to enhance control and reliability. The scope of work is determined through outreach to Substation Operations, Transmission and Distribution Planning, Digital Grid, and the Protection & Control groups. These types of upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, reducing disruptions to our customers, and optimizing operations.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing the following breakers at Roll Rd Substation:

Five (5) 34.5 kV breakers (2B-52, 51252, 51452, 51652, 54552).

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences that can include entire substation outages due to the failure of a circuit breaker. If this failure results in damage to adjacent equipment, the repair costs, outage duration, and outage scope can be significant.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining legacy equipment (e.g., brown glass insulators and electromechanical relays) in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, compromising the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to the long-term sustainability of the system.

A more comprehensive and holistic solution is achieved by replacing the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers. This approach mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, in the long run this strategy is cost-effective. While the initial investment may be higher due to the expanded scope of ancillary equipment replacement, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to customers.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 221	\$ -	\$ -	\$ 22	\$ 77	\$ 122	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,092	\$ -	\$ -	\$ 109	\$ 382	\$ 601	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 196	\$ -	\$ -	\$ 20	\$ 69	\$ 108	\$ -	\$ -
# Internal, Overheads	\$ 182	\$ -	\$ -	\$ 20	\$ 64	\$ 99	\$ -	\$ -
# Materials	\$ 622	\$ -	\$ -	\$ 62	\$ 218	\$ 342	\$ -	\$ -
# Overheads - External	\$ 176	\$ -	\$ -	\$ 19	\$ 62	\$ 95	\$ -	\$ -
Total	\$ 2,489	\$ -	\$ -	\$ 251	\$ 872	\$ 1,366	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

W. Winfield 12.5KV Load Relief

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-004745	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: H1 2025	In-Service Date: H2 2027

Project description:

The West Winfield substation is a 46/12.47kV substation located within NYSEG's Oneonta division. The 46 kV is configured as a straight bus (currently with line sectionalizing capabilities) with a tapped off 3 1.667/2.147 MVA transformer bank, which supports two (2) distribution feeders (#260 and #261) serving 2,855 customers. The voltages (46kV and 12.5kV) share one (1) box structure. There are two (2) 12.5 kV circuit line regulators in the substation. Additionally, there is also a 1.2 MVAR capacitor bank on the 12.5 kV bus.

The West Winfield substation transformer bank is one of twenty (20) transformers identified under the Distribution Load Relief (DLR) program. The DLR program is designed to focus on conducting system wide facility surveys on substation transformers that are overloaded and/or start to exceed 90% capacity. This program devises a mitigation strategy to address these overload conditions.

West Winfield was IP1 approved in February 2023, under the DLR program and IP2 prioritized under the DLR program prioritization metrics which include, but are not limited to, N-0 overload percentage, top oil temperature readings, fan rating availability, substation inspections and operational concerns.

Project Scope:

The scope of work approved by the System Review Group on May 8, 2024 is to replace the existing transformer and install a new 12kV GIS inside a building enclosure including the batteries and protection and control equipment. The project will also include the installation of the new distribution line circuit exits from the substation and the demolition of and old storage building in the entrance to the site.

Replace existing T2 (6.44 MVA) with a new 46/12.5 kV (14 MVA) LTC transformer w/ one (1) new 46 kV breaker.
Remove two (2) 12.5kV voltage regulators.
Install new 12.5kV GIS enclosure.
Replace two (2) 12.5 kV "very poor" oil circuit breakers.
Install one (1) 46kV 4MVAR capacitor (2-2MVAR switched step) with one (1) 46 kV dedicated breaker.
Remove 12.5kV 1.2MVAR capacitor bank.
Install new Distribution circuit exits.

Project Benefits:

The existing transformer bank 2T (6.44MVA) at West Winfield substation is overloaded (100%) and the purpose of this project is to eliminate the existing overload condition and plan for future growth in the Oneonta division. The approved alternative resolves all the identified existing and future system needs. The existing transformer and breakers need to be replaced and a new transformer and GIS will be installed extending the life of the substation, increasing the reliability and ability to grow.

Project Risks and Mitigation Plan:

The main project risks are:

- Awarding of Transformer and GIS equipment.
GIS supply has already been awarded and Transformer will be awarded in the following months.
- Long lead times for materials.
Anticipate Detailed Engineering and work with standard materials and suppliers frameworks.
- Avoiding extending the yard and/or changing any existing easement or property limit.
Anticipate Detailed Engineering and make a proper analysis of the layout involving the GIS supplier to reduce the yard print.
Work with Operations to make sure the proposed lines design is acceptable.
- Avoid disconnecting the substation and having long outages.
Coordinate the works with Operations and anticipate Detailed Engineering to perform a proper construction phasing.

Risk of No Action:

The existing 46/12.5 kV transformer bank T2 (with 6.44 MVA normal rating) at West Winfield is overloaded (100%).

There are no identified transmission reliability needs at West Winfield in the 2021 Transmission Local Area Study. However, the future 5 year peak estimate increases the number of buses that are exposed to low voltage for a Line 951 fault (around +2%).

There are severe voltage collapse violations in the area, and additional load makes this condition marginally worse (more hours of exposure). Additionally, the Richfield Spring s 115/46 kV transformer may become overloaded (106% LTE) if the Brothertown Rd transformer is taken out of service.

Alternative 1:
Load Transfer to Bridgewater
Alternative was dismissed due to cost and significant substation and distribution upgrades.

Alternative 2:
14MVA Transformer Replacement w/ AIS
Alternative was dismissed due to yard expansion was required, it doesn't follow current Avangrid substation GIS standards and it has less expandability in the future than the chosen alternative.

Estimate based on historical projects:

1. Milo Substation (Similar GIS layout).
2. Existing GIS and Transformers proposals.
3. Current framework agreements for different materials and engineering costs.

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 3	\$ -	\$ -	\$ -	\$ -	\$ 3		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 154	\$ -	\$ -	\$ -	\$ -	\$ 154		
# Internal - Non-AC	\$ 1	\$ -	\$ -	\$ -	\$ -	\$ 1		
# Internal, Labor	\$ 23	\$ -	\$ -	\$ -	\$ -	\$ 23		
# Internal, Overheads	\$ 146	\$ -	\$ -	\$ -	\$ -	\$ 146		
# Materials	\$ 637	\$ -	\$ -	\$ -	\$ -	\$ 637		
# Overheads - External	\$ 183	\$ -	\$ -	\$ -	\$ -	\$ 183		
Total	\$ 1,146	\$ -	\$ -	\$ -	\$ -	\$ 1,146		

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,101	\$ 157	\$ 439	\$ 504	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 4,768	\$ 857	\$ 1,069	\$ 2,842	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 220	\$ 70	\$ 78	\$ 71	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 792	\$ 293	\$ 307	\$ 193	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 4,296	\$ 2,334	\$ 1,962	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 778	\$ 263	\$ 302	\$ 212	\$ -	\$ -	\$ -	\$ -
Total	\$ 11,955	\$ 3,974	\$ 4,158	\$ 3,823	\$ -	\$ -	\$ -	\$ -

[illegible]

New Centerport Substation (Port Byron - Load relief)

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-004088	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: H1 2025	In-Service Date: H2 2027

Project description:

The Port Byron and Weedsport substation transformers were identified under the Distribution Load Relief (DLR) program, which is designed to focus on conducting system wide facility surveys on substation transformers that are overloaded and/or beginning to exceed 90% capacity. This program devises a mitigation strategy to address these overload conditions.

Project Reliability Needs:

Distribution:

Port Byron 5 MVA 34.5/4.8 kV transformer bank #1 overloaded to 107% of CNR under 5-year historic average peak loading

Weedsport 5 MVA 34.5/4.8 kV transformer bank #1 overloaded to 97.5% of CNR under 5-year historic average peak loading

Transmission:

Low voltage reliability criteria violations identified under current-year peak load.

N-0 Needs – 34.5 kV system low voltage violations (<0.95 pu)

N-1 Needs – Widespread low voltage violations as low as 0.82 pu

Violations exacerbated by any future load growth at Port Byron and Weedsport.

Project Asset Needs:

Port Byron:

Transformer 1T: The 3-1ph transformers have good health index scores. However, the 65-year-old transformers show noticeable rust/ corrosion on tanks and radiators. Also, there is no visible primary oil containment for these transformers. Breakers: One (1) distribution breaker is assessed as fair (HI 3) in Health condition. This is a Westinghouse oil circuit breaker that was installed in 1995 for 4.8 kV distribution circuit 633. Structures and Foundations: The 34.5 kV & 4.8 kV box structures are in fair condition with depleted galvanized coatings on most members/bracing. Many foundations are in poor condition with heavy signs of deterioration from spalling, cracks, & scaling especially on the 34.5 kV level. Switches & Insulators: All 34.5kV and 13.2 kV switches have gray porcelain insulators and have no visual concerns. Protection: Utilizes outdoor cabinets and self-containment breakers (No control House). Mixture of microprocessors and obsolete electromechanical relays.

Weedsport:

Transformer 1T: The 3-1ph transformers have fair Health Index (HI-3) scores. However, the 74-year-old transformers shows noticeable rust/corrosion on tanks, radiators and bushing. Also, there is no visible primary oil containment for these transformers. Breakers: The two (2) distribution breakers are assessed as very poor (HI 5) in Health condition. These are General Electric oil circuit breakers, installed in 1955 & 1960 for 4.8kV distribution circuit 628 and 629, respectively. Structures and Foundations: The 34.5kV & 4.8kV box structures are in fair condition with depleted galvanized coatings on most members/bracing. Many foundations are in poor condition with heavy signs of deterioration from spalling, cracks, & scaling. Switches & Insulators: All 34.5kV and 13.2 kV switches have gray porcelain insulators and have no visual concerns. Protection: Utilizes outdoor cabinets and self containment breakers (No control House). Mostly obsolete electromechanical relays.

The Port Byron circuits 611 & 633 serve approx. 1,739 customers, with 5-year average peak loading of 5.35 MVA, while the Weedsport circuits 628 & 629 serve approx. 1,545 customers, with 5-year average peak loading of 4.88 MVA.

Project Scope:

New Centerport Substation with partial load transfers from Port Byron & Weedsport to the new Centerport Substation.

- Construct a new MV GIS substation with 34.5/12-4.8kV 22.4MVA LTC transformer at/near existing Centerport tap.
- Install a new 8 MVar 34.5 kV Capacitor bank at Centerport
- Transfer approx. 3 MVA of existing 4.8 kV load from Port Byron to new Centerport
- Transfer approx. 1.6 MVA of existing 4.8kV load from Weedsport to new Centerport.
- Replace 4.8kV circuit breaker 62812 at Weedsport with a new 15kV 1200A rated vacuum breaker

Project Benefits:

- Mitigate thermal overload (N-0) on T1 at Port Byron & Weedsport
- Capacitors mitigate low voltage concerns on the 34.5kV system
- Allows for future load growth/hosting capacity including DER integration at both Port Byron & Weedsport area
- Provides better 34.5 kV sectionalizing capabilities and speeds up restoration efforts in an event of a fault on the 34.5 kV system, thereby reducing loss of load exposure for a transmission line fault.
- Provides N-1 contingency support capabilities to/from adjacent substations or nearby circuits.
- Allows for future expendability to provide full N-1 capability
- Supports the long term plan to upgrade the 4.8kV system to 12.5kV, retire of existing Port Byron & Weedsport substation facilities and fully absorb their loads/customers.
- Limited/No mobile required utilizes the 4.8kV winding to allow for time and help facilitate a smooth transition of the 4.8kV conversion to 12.5kV in the future.
- Shortest delivery timeline (no circuit conversion is involved)
- Allow for future consolidation of Port Byron and Weedsport substations into a single substation, which would result in additional O&M cost savings

Project Risks and Mitigation Plan:

Unforeseen subsurface conditions:

The property we are currently pursuing to purchase appeared to be located over a principal aquifer according to the EAF mapper. The EAF mapper is a screening tool intended to assist project sponsors and reviewing agencies in preparing an environmental assessment form. Although the EAF mapper provides the most up-to-date digital data available to DEC, it should be verified for accuracy. We also reviewed the Web soil survey to determine the depth to water table. According to the Web soil survey, the depth to water table ranges from 21.29 inches to 53.94 inches. Prior to any land negotiations, they landowner has allowed us to perform a ground water study to determine actual water depths. Groundwater was encountered in each of the test borings during drilling at depths ranging from approximately 9.0 feet bgs to 10.0 bgs. If groundwater is encountered during construction, the use of local sumps and pumps should be adequate to control groundwater fluctuations. If continuous pumping of infiltrating water is required, the pump shall be placed within crushed stone in a sump area that is dug outside of the planned foundation footprint. Perched or trapped water may be encountered within soil layers of differing gradation, particularly within fill layers. Groundwater levels will fluctuate due to seasonal affects and/or construction related activities. The project team will continue to monitor these conditions and follow the recommendations provided by LaBella's Geotechnical Engineers. We will also ensure that the construction RFP includes dewatering as part of the construction contractors' scope of work.

Risk of No Action:

The decision to take 'no action' regarding the build of a new substation near the Centerport tap will result in the following:

- Port Byron transformers are currently overloaded and Weedsport transformers are projected to be overload in the near future.
- Voltage and thermal constraints on the network.
- No contingency support to the nearby substations and circuits to reduce outages and speed up restoration time for customers.
- Future load growth/ hosting capacity including DER integration at both Port Byron and Weedsport areas will be minimal.
- Will not allow for consolidation of Port Byron and Weedsport substations into a single substation, which could result in Capital and future O&M cost savings.
- No support for the long-term plan to upgrade the 4.8kV system to 12.5kV, retire of existing Port Byron & Weedsport substation facilities and fully absorb their loads/customers.

Project Alternatives:

Alt 1: Port Byron substation rebuild with partial load transfer from Weedsport to Port Byron:

- Rebuild Port Byron to a new MV GIS substation with 34.5/12 4.8kV 22.4MVA LTC transformer
- Install a new 8MVar 34.5kV Capacitor bank at Port Byron
- Fully convert approx. 13 miles of the two Port Byron 4.8kV circuits to 12kV.
- Partially convert approx. 0.65 miles of Weedsport 4.8kV #629 circuit to 12kV and transfer approx. 1 MVA of Load from Weedsport to Port Byron.
- Replace 4.8kV circuit breaker 62812 at Weedsport with a new 15kV 1200A rated vacuum breaker

Alt 2: Weedsport substation rebuild with full load transfer from Port Byron to Weedsport:

- Rebuild Weedsport to a new MV GIS substation with 34.5/12 4.8kV 22.4MVA LTC transformer
- Install 2 x 6 MVar 34.5kV capacitor banks at Weedsport
- Fully convert approx. 10 miles of the two Weedsport 4.8kV circuits to 12kV.
- Fully convert approx. 13 miles of the two Port Byron 4.8kV circuits to 12kV and transfer approx. 7 MVA of Load to Weedsport.

Alt 3 (Selected): \$34M- New Centerport substation with partial load transfers from Port Byron & Weedsport to New Centerport substation:

- Construct a new MV GIS substation with 34.5/12 4.8kV 22.4MVA LTC transformer at/near existing Centerport tap.
- Install a new 8MVar 34.5kV Capacitor bank at Centerport
- Transfer approx. 3 MVA of existing 4.8kV load from Port Byron to New Centerport
- Transfer approx. 1.6 MVA of existing 4.8kV load from Weedsport to New Centerport.
- Replace 4.8kV circuit breaker 62812 at Weedsport with a new 15kV 1200A rated vacuum breaker.

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates within the estimating workbook are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

O&M Details:		Total	2020	2021	2022	2023	2024
Total	\$	-	\$ -	\$ -	\$ -	\$ -	\$ -

[illegible][illegible]

NYSEG Distribution Load Relief - Erie Street

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006529	Charge Code: Electric Distribution	Project Sponsor: Balch, Bruce	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2031

Project description:

The NYSEG Distribution Load Relief (DLR) Program was established to identify substation transformer and distribution feeder thermal needs (overloads) and propose cost-effective solutions that would mitigate these existing system needs. This program is focused on ensuring full N-0 "all-lines-in" operability across the NYSEG distribution system. The DLR Program will reduce the risk of utility equipment damage and/or failure which would negatively impact our customers. DLR projects are prioritized based on the consideration of weighted factors including, but not limited to, historic/forecasted thermal loading with respect to equipment ratings, asset health, and potential customer impacts.

Background: The Erie Street Substation is a 34.5/4.8 kV substation located in the City of Lancaster. It is supplied by 115 kV transmission Lines 921, 922, and 926 from Depew Tap, North Broadway, and Pavement Road Substations, respectively. The 4.8 kV distribution bus is fed by one 11.03 MVA transformer and one 9.38 MVA transformer operating in parallel for a total combined rating of 20.41 MVA. There are six 4.8 kV distribution feeders serving about 6,303 customers and 17.29 MVA of load.

Needs:

- 4.8 kV feeder #205: Heavily loaded during peak load conditions over the last three years (3-year average peak loading at 91%). Circuit #205 is limited by the 477 kcmil aluminum overhead exit conductor (5.03 MVA rating).
- 4.8 kV feeder #208: Loaded during peak load conditions over the last three years (3-year average peak loading at 88%). Circuit #208 is limited by the 4/0 copper overhead exit conductor (3.28 MVA rating).
- Substation transformer (T3) is heavily loaded and is approaching its thermal limits during peak load conditions over the last three years (3-year average peak loading at 91%). Transformer T3 is limited by its normal rating (9.38 MVA).
- Erie Street Transformer T3 has been assessed with a "Fair" (HI-3) Health Score and is approaching the need for replacement.
- Erie Street Transformer T4 has been assessed with a "Fair" (HI-3) Health Score and is approaching the need for replacement.

Project Scope:

The selected proposal involves distribution and substation upgrades necessary to address immediate system needs. The expected project in-service date is Q4 2031.

Substation Upgrades:

1. Replace the 9.38 MVA substation transformer T3 with a 22.4 MVA 34.5/12.47 kV transformer and LTC.
2. Install new dedicated 34.5 kV high-side and 12.47 kV low-side breakers for the new transformer T3.
3. Transfer all Erie Street circuits to be fed from the new transformer T3.

Distribution Upgrades:

1. Erie Street circuit #202: Perform a voltage conversion from 4.8 kV to 12.47 kV over approximately 2.8 miles. Install 2 step transformers for the single-phase spur lines.
2. Erie Street circuit #203: Perform a voltage conversion from 4.8 kV to 12.47 kV over approximately 1.9 miles. Install 27 step transformers for the single-phase spur lines.
3. Erie Street circuit #205: Perform a voltage conversion from 4.8 kV to 12.47 kV over approximately 3.3 miles. Install 22 step transformers for the single-phase spur lines.
4. Erie Street circuit #207: Perform a voltage conversion from 4.8 kV to 12.47 kV over approximately 0.7 miles. Install 4 step transformers for the single-phase spur lines.
5. Erie Street circuit #208: Perform a voltage conversion from 4.8 kV to 12.47 kV over approximately 1.7 miles. Install 10 step transformers for the single-phase spur lines.
6. Erie Street circuit #209: Perform a voltage conversion from 4.8 kV to 12.47 kV over approximately 1.55 miles. Install 12 step transformers for the single-phase spur lines.
7. Erie Street circuit #208: Install a normally open SCADA recloser to tie into Cemetery Road #490.

Project Benefits:

The primary driver of the project is to address current capacity-driven needs. In addition to mitigating these needs, the proposed project will also enhance reliability and resiliency, and create capacity to support future load growth on the Erie Street substation transformer T3 and distribution circuits #205, and #208.

Capacity: The project will relieve emergent thermal needs on distribution circuits #205, #208 and transformer T3, which have been overloaded within the last three years. Resolving these thermal loading needs will provide immediate benefits to customers by limiting risks associated with equipment-related outages. Additional benefits include providing interim capacity headroom on circuits #205, #208 and transformer T3 to support customer load growth and electrification while a longer term solution for the area is developed. The maximum N-0 capacity gained on the distribution system is 13 MVA.

Reliability: The project will enhance system reliability by providing partial N-1 backup capabilities between Erie Street #208 and Cemetery Road #490. By installing a SCADA-operable tie recloser and upgrading the capacity of circuit #208, the project will improve system performance under outage conditions and will also provide additional operational flexibility, including for maintenance activities.

Asset Conditions: There are no electrical equipment asset condition needs at Erie Street. Transformer T3 and T4 has a "Fair" (HI-3) Health Score, which is approaching the end of useful life designated by (HI-4) or (HI-5).

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to worsening thermal overloads that could lead to utility equipment damage and/or equipment-related outages. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include, mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) There can be risks associated with taking a shorter-term approach to system upgrades instead of implementing longer-term comprehensive solutions. The intent of the Distribution Load Relief (DLR) Program is to develop projects that can be deployed quickly to mitigate emergent loading issues. Accordingly, the scope of projects in the DLR Program is generally restricted exclusively to resolving near-term loading constraints, with some exceptions (e.g., relevant severe asset condition needs). By not holistically considering longer-term needs when developing solutions, there is a risk that the solutions implemented to address near-term needs may not be optimal and/or cost-efficient when a comprehensive area solution is eventually deployed. For the Erie Street DLR Project, this risk is mitigated because the proposed upgrades will immediately provide benefits by eliminating overload risk on transformer T3, circuits #205, and #208 by enhancing reliability and resiliency for customers in the area. Additionally, to ensure cost-efficiency over the life of the new facilities, all proposed new construction is being cost-effectively "right-sized" to a NYSEG-standard 12.5 kV voltage class construction to accommodate a future comprehensive area solution, and the proposed distribution voltage conversion from 4.8 kV to 12.5 kV .

Risk of No Action:

Erie Street transformer T3, circuits #205 and #208 are currently facing thermal constraints. Opting to take no action on the proposed short-term solution would mean that emergency operational solutions for current system constraints would need to be developed as an interim measure to ensure that the electric system can be operated within acceptable reliability and safety limits. Pursuing short-term solutions instead of a comprehensive solution may result in a less cost-efficient buildout of infrastructure, especially if comprehensive action is significantly delayed.

There is also a risk that unmitigated load growth in the Area could drive system constraints to a point where the electric system is, in effect, inoperable due to excessive demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth, leading to significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's goals because there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

An alternative project was evaluated that installed 2 parallel 22.4 MVA substation transformers and performed a voltage conversion on all Erie Street distribution circuits to 12.47 kV.

Additionally, the proposed solution performed better than the alternative because it will improve reliability by forming a SCADA-operable circuit tie between circuits #208 and #490 while also more evenly distributing customers between the feeders.

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

[illegible]

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 319	\$ -	\$ -	\$ 11	\$ 37	\$ 57	\$ 157	\$ 57
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 16,893	\$ -	\$ -	\$ 604	\$ 1,950	\$ 3,024	\$ 8,308	\$ 3,007
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 2,023	\$ -	\$ -	\$ 71	\$ 216	\$ 328	\$ 977	\$ 431
# Materials	\$ 10,518	\$ -	\$ -	\$ 376	\$ 1,214	\$ 1,883	\$ 5,173	\$ 1,872
# Overheads - External	\$ 1,956	\$ -	\$ -	\$ 69	\$ 208	\$ 317	\$ 945	\$ 416
Total	\$ 31,709	\$ -	\$ -	\$ 1,132	\$ 3,626	\$ 5,609	\$ 15,560	\$ 5,783

[illegible]

NYSEG Distribution Load Relief - State Street

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006539	Charge Code: Electric Distribution	Project Sponsor: Balch, Bruce	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2029

Project description:

The NYSEG Distribution Load Relief (DLR) Program was established to identify substation transformer and distribution feeder thermal needs (overloads) and propose cost-effective solutions that would mitigate these existing system needs. This program is focused on ensuring full N-0 "all-lines-in" operability across the NYSEG distribution system. The DLR Program will reduce the risk of utility equipment damage and/or failure which would negatively impact our customers. DLR projects are prioritized based on the consideration of weighted factors including, but not limited to, historic/forecasted thermal loading with respect to equipment ratings, asset health, and potential customer impacts.

Background: The State Street Substation is a 115/34.5/12.47 kV substation located in the City of Auburn. State Street is supplied by the 115 kV transmission Lines 931, 972, 971, 976, and 710 which are from Austeel, Elbridge, Clinton Corn, Wright Ave, and Elbridge Substations, respectively. The 12.47 kV bus is fed by one 22.4 MVA transformer (T5). There are three distribution feeders serving about 5,268 customers and 21.66 MVA of load.

Needs:

- State Street Transformer T5 (23.52 MVA rating) is heavily loaded and has been approaching its thermal limit during peak load conditions within the last three years (3-year average peak loading at 92%).
- State Street Transformer T5 has been assessed with a "Fair" (HI-3) Health Score and is approaching the need for replacement.
- The feeder circuit breakers for the #709 and #712 feeders have all been assessed with a "Poor" (HI-4) Health Score and are in need of replacement.

Project Scope:

The selected proposal involves substation and distribution upgrades necessary to address immediate system needs. This includes addressing relevant asset condition needs for facilities with a "Poor" (HI-4) Health Score. The expected project in-service date is Q4 2030.

Substation Upgrades:

1. Replace the existing State Street 22.4 MVA 34.5/12.47 kV transformer T5 with a new 37.3 MVA 115/12.47 kV LTC transformer.
2. Install a new 115 kV high-side bus connection for the new transformer.
3. Install a new 115 kV breaker on the high side of the transformer.
4. Install a new 15 kV breaker on the low side of the transformer.
5. Install a new feeder with a 15 kV breaker as feeder protection at State Street.
6. Replace two 15.5 kV circuit breakers (#709 and #712) that have a "Poor" (HI-4) Health Score with new 15 kV breakers.

Distribution Upgrades:

1. New State Street Circuit Scope:
 - a. Double circuit out of State Street Substation following State Street #712 approximately 0.13 miles with 3-phase 477 kcmil Al to support the new State Street circuit and load transfer.
 - b. Disconnect the existing line heading northeast on State Street #712 and connect it to the end of the new circuit.
 - c. Transfer 1.477 MVA (39 customers) from State Street #712 to the new State Street circuit.
2. State Street #712 Load Transfer: Transfer 1.234 MVA (239 customers) from Grant Ave #720 to the new State Street circuit:
 - a. Install a normally open SCADA recloser on Grant Ave #720.A16.
 - b. Close the existing normally open switch between Grant Ave #720 and the previous State Street #712.
 - c. Install three 1-phase 4.8 kV 100A regulators to correct voltage violations and support load transfer.
3. State Street #712 Load Transfer: Transfer 2.77 MVA (421 customers) from State Street #709 to State Street #711:
 - a. State Street circuit #711: Open the existing normally closed SCADA recloser.
 - b. State Street circuit #709: Install a new normally closed SCADA recloser to create a new tie between #709 and #711.
 - c. State Street circuit #709: Open the existing fuse cutout to create a normally open point.
4. State Street circuit #712: Install three 7.2 kV 200 KVAR switched capacitors. Install three 30K fuses to act as capacitor protection.

Project Benefits:

The primary driver of the project is to address current capacity-driven needs. In addition to mitigating these needs, the proposed project will also replace equipment identified to be in Very Poor condition, enhance reliability and resiliency, and create capacity to support future load growth on the State Street T5 transformer.

Capacity: The project will relieve emergent thermal needs on the State Street transformer T5, which has been heavily loaded within the last three years. Resolving this thermal loading need will provide immediate benefits to customers by limiting risks associated with equipment-related outages. Additional benefits include providing interim capacity headroom on T5 to support customer load growth and electrification while a longer-term solution for the area is developed. The maximum N-0 capacity gained on the distribution system is 14.4 MVA.

Reliability: The project will enhance system reliability by providing N-1 backup capabilities between the following circuits: a. State Street New and Grant Ave #720 b. State Street #709 and Grant Ave #718 c. State Street #709 and Grant Ave #719 d. State Street #711 and State Street #709 e. State Street #711 and State Street #712 f. State Street #712 and Wright Ave #704. By upgrading the capacity of T5, the project will improve system performance under outage conditions and provide additional operational flexibility, including for maintenance activities.

Asset Condition: Preliminary electrical equipment asset condition needs in State Street were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. Two circuit breakers for feeders #709 and #712 have a "Poor" (HI-4) Health Score in State Street Substation. Equipment that is in poor or very poor condition has exceeded its useful life and should be replaced to limit the risk of equipment-related outages. Such equipment is included for replacement or retirement in the conceptual solution. Site inspections will be performed to identify any additional asset condition needs. Transformer T5 has a "Fair" (HI-3) Health Score, which is approaching the end of useful life designated by (HI-4) or (HI-5).

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to worsening thermal overloads that could lead to utility equipment damage and/or equipment-related outages. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include, mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) There can be risks associated with taking a shorter-term approach to system upgrades instead of implementing longer-term comprehensive solutions. The intent of the Distribution Load Relief (DLR) Program is to develop projects that can be deployed quickly to mitigate emergent loading issues. Accordingly, the scope of projects in the DLR Program is generally restricted exclusively to resolving near-term loading constraints, with some exceptions (e.g., relevant severe asset condition needs). By not holistically considering longer-term needs when developing solutions, there is a risk that the solutions implemented to address near-term needs may not be optimal and/or cost-efficient when a comprehensive area solution is eventually deployed. For the State Street DLR Project, this risk is mitigated because the proposed upgrades will immediately provide benefits by eliminating overload risk on State Street T5, replacing critical distribution assets that are in Very Poor condition, and enhancing reliability and resiliency for customers in the area.

Risk of No Action:

State Street T5 is currently facing thermal constraints. Opting to take no action on the proposed short-term solution would mean that emergency operational solutions for current system constraints would need to be developed as an interim measure to ensure that the electric system can be operated within acceptable reliability and safety limits. Pursuing short-term solutions instead of a more comprehensive solution may result in a less cost-efficient buildout of infrastructure, especially if comprehensive action is significantly delayed.

There is also a risk that unmitigated load growth in the Area could drive system constraints to a point where the electric system is, in effect, inoperable due to excessive demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth, leading to significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's goals because there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

An alternative project was evaluated to offload the constrained Grant Ave transformer (T1), State Street transformer (T5), and Stryker Ave transformer (T1). Within this scope, Grant Ave T1 will have an “in-kind” replacement along with load transfers. The plan includes multiple load transfers: a. Transferring 2.62 MVA (793 customers) off Grant Ave circuit #720 to a new circuit at Grant Ave, b. Transferring 2.05 MVA (1,051 customers) off State Street circuit #709 to Grant Ave circuit #718, c. Transferring 3.18 MVA (793 customers) off Stryker Ave circuit #721 to Grant Ave circuit #719, and d. Transferring 1.55 MVA (28 customers) off State Street circuit #712 to Grant Ave circuit #720. This also includes the replacement of three 14.4 kV breakers at Grant Ave Substation and two 14.4 kV breakers at State Street Substation, which were assessed to be in very poor condition.

Basis for Project Estimates

FINANCIAL INFORMATION

[illegible]

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 104	\$ -	\$ -	\$ 23	\$ 69	\$ 10	\$ 3	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 5,517	\$ -	\$ -	\$ 1,214	\$ 3,631	\$ 541	\$ 133	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 618	\$ -	\$ -	\$ 143	\$ 401	\$ 59	\$ 16	\$ -
# Materials	\$ 3,435	\$ -	\$ -	\$ 756	\$ 2,261	\$ 337	\$ 83	\$ -
# Overheads - External	\$ 598	\$ -	\$ -	\$ 138	\$ 388	\$ 57	\$ 15	\$ -
Total	\$ 10,273	\$ -	\$ -	\$ 2,274	\$ 6,749	\$ 1,003	\$ 248	\$ -

[illegible]

NYSEG Distribution Load Relief - Grant Ave

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006530	Charge Code: Electric Distribution	Project Sponsor: Balch, Bruce	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The NYSEG Distribution Load Relief (DLR) Program was established to identify substation transformer and distribution feeder thermal needs (overloads) and propose cost-effective solutions that would mitigate these existing system needs. This program is focused on ensuring full N-0 "all-lines-in" operability across the NYSEG distribution system. The DLR Program will reduce the risk of utility equipment damage and/or failure which would negatively impact our customers. DLR projects are prioritized based on the consideration of weighted factors including, but not limited to, historic/forecasted thermal loading with respect to equipment ratings, asset health, and potential customer impacts.

Background: The Grant Ave Substation is a 34.5/12.47 kV substation located in the City of Auburn. Grant Ave is supplied by the 34.5 kV sub-transmission Line 507 from the State Street Substation. Grant Ave has the option to be fed from Line 509, which is normally open and fed from State Street. The 12.47 kV bus is fed by one 14 MVA transformer (T1). There are three distribution feeders serving about 5,456 customers and 13.09 MVA of load.

Needs:

- Grant Ave Transformer T1 (14.7 MVA rating) is loaded and has been approaching its thermal limit during peak load conditions within the last three years (3-year average peak loading at 89%).
- Grant Ave Transformer T1 has been assessed with a "Fair" (HI-3) Health Score and is approaching the need for replacement.
- The circuit breakers for feeders #718, #719, and #720 have all been assessed with a "Very Poor" (HI-5) Health Score and need replacement.

Project Scope:

The selected proposal involves substation upgrades only, which are necessary to address the immediate system needs. This includes addressing relevant asset condition needs for facilities with a "Poor" (HI-4) and "Very Poor" (HI-5) Health Score. The expected project in-service date is Q4 2029.

Substation Upgrades:

1. Replace the existing Grant Ave 14 MVA 34.5/12.47 kV transformer with a new 22.4 MVA 34.5/12.47 kV LTC transformer.
2. Remove the existing high-side fuse and install a new 34.5 kV breaker on the high side of the new Grant Ave transformer T1.
3. Install a new 15 kV breaker on the low side of the new Grant Ave transformer T1.
4. Replace three 14.4 kV feeder breakers that have a "Very Poor" (HI-5) Health Score with new 15 kV breakers.

Project Benefits:

The primary driver of the project is to address current capacity-driven needs. In addition to mitigating these needs, the proposed project will also replace equipment identified to be in Very Poor condition, enhance reliability and resiliency, and create capacity to support future load growth on the Grant Ave T1 transformer.

Capacity: The project will relieve emergent thermal needs on the Grant Ave transformer T1, which has been heavily loaded within the last three years. Resolving this thermal loading need will provide immediate benefits to customers by limiting risks associated with equipment-related outages. Additional benefits include providing interim capacity headroom on T1 to support customer load growth and electrification while a longer-term solution for the area is developed. The maximum N-0 capacity gained on the distribution system is 10.1 MVA.

Reliability: The project will enhance system reliability by providing N-1 backup capabilities between the following circuits:

- State Street circuit #709 and Grant Ave circuit #718
- State Street circuit #712 and Grant Ave circuit #720
- Stryker Ave circuit #721 and Grant Ave circuit #719.

By upgrading the capacity of T1, the project will improve system performance under outage conditions and provide additional operational flexibility, including for maintenance activities.

Asset Condition: Preliminary electrical equipment asset condition needs in Grant Ave Substation were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. There are three circuit breakers with a Very Poor (HI-5) Health Score in Grant Ave Substation: #718, #719, and #720. Equipment that is in poor or very poor condition has exceeded its useful life and should be replaced to limit the risk of equipment-related outages. Such equipment is included for replacement or retirement in the conceptual solution. Site inspections will be performed to identify any additional asset condition needs.

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to worsening thermal overloads that could lead to utility equipment damage and/or equipment-related outages. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include, mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) There can be risks associated with taking a shorter-term approach to system upgrades instead of implementing longer-term comprehensive solutions. The intent of the Distribution Load Relief (DLR) Program is to develop projects that can be deployed quickly to mitigate emergent loading issues. Accordingly, the scope of projects in the DLR Program is generally restricted exclusively to resolving near-term loading constraints, with some exceptions (e.g., relevant severe asset condition needs). By not holistically considering longer-term needs when developing solutions, there is a risk that the solutions implemented to address near-term needs may not be optimal and/or cost-efficient when a comprehensive area solution is eventually deployed. For the Grant Ave DLR Project, this risk is mitigated because the proposed upgrades will immediately provide benefits by eliminating overload risk on Grant Ave T1, replacing critical distribution assets that are in Very Poor condition, and enhancing reliability and resiliency for customers in the area.

Risk of No Action:

Grant Ave T1 is currently facing thermal constraints. Opting to take no action on the proposed short-term solution would mean that emergency operational solutions for current system constraints would need to be developed as an interim measure to ensure that the electric system can be operated within acceptable reliability and safety limits. Pursuing short-term solutions instead of a comprehensive solution may result in a less cost-efficient buildout of infrastructure, especially if comprehensive action is significantly delayed.

There is also a risk that unmitigated load growth in the Area could drive system constraints to a point where the electric system is, in effect, inoperable due to excessive demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth, leading to significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's goals because there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

Project Alternatives:

An alternative project was evaluated to offload the constrained Grant Ave transformer T1, State Street transformer T5, and Stryker Ave transformer T1. Within this scope, Grant Ave T1 will have an "in-kind" replacement along with load transfers. The plan includes multiple load transfers: a. Transferring 2.62 MVA (793 customers) off Grant Ave circuit #720 to a new circuit at Grant Ave, b. Transferring 2.05 MVA (1,051 customers) off State Street circuit #709 to Grant Ave circuit #718, c. Transferring 3.18 MVA (793 customers) off Stryker Ave circuit #721 to Grant Ave circuit #719, and d. Transferring 1.55 MVA (28 customers) off State Street circuit #712 to Grant Ave circuit #720. This also includes the replacement of three 14.4 kV breakers at Grant Ave Substation and two 14.4 kV breakers at State Street Substation, which were assessed to be in very poor condition.

This alternative was dismissed because, while the total cost estimate was somewhat lower than the combined solutions for Grant Ave, State Street, and Stryker Ave (\$14.7 million or 144% less), it provides significantly less benefits. The alternative solution only adds an additional 30 MVA total, while the preferred solutions at Grant Ave, State Street, and Stryker Ave add 33.3 MVA in total (11% more capacity gained). This solution also requires a 37.3 MVA transformer to be installed at Grant Ave Substation, fed from 34.5 kV sub-transmission.

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 75	\$ -	\$ -	\$ 16	\$ 58	\$ 2	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,996	\$ -	\$ -	\$ 827	\$ 3,048	\$ 122	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 447	\$ -	\$ -	\$ 97	\$ 337	\$ 13	\$ -	\$ -
# Materials	\$ 2,488	\$ -	\$ -	\$ 515	\$ 1,898	\$ 76	\$ -	\$ -
# Overheads - External	\$ 433	\$ -	\$ -	\$ 94	\$ 326	\$ 13	\$ -	\$ -
Total	\$ 7,440	\$ -	\$ -	\$ 1,549	\$ 5,665	\$ 226	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Distribution Load Relief - Cantitoe

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006526	Charge Code: Electric Distribution	Project Sponsor: Balch, Bruce	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2029

Project description:

The NYSEG Distribution Load Relief (DLR) Program was established to identify substation transformer and distribution feeder thermal needs (overloads) and propose cost-effective solutions that would mitigate these existing system needs. This program is focused on ensuring full N-0 "all-lines-in" operability across the NYSEG distribution system. The DLR Program will reduce the risk of utility equipment damage and/or failure which would negatively impact our customers. DLR projects are prioritized based on the consideration of weighted factors including, but not limited to, historic/forecasted thermal loading with respect to equipment ratings, asset health, and potential customer impacts.

Background: The Cantitoe Substation is a 46/13.2 kV and 46/4.8 kV substation located in the Town of Bedford. It is supplied by 46 kV transmission Line 814 from the Bedford Hills and Pound Ridge Substations. The 4.8 and 13.2 kV distribution buses are fed by two 7.5 MVA transformers. There are two 4.8 kV and two 13.2 kV distribution feeders serving about 1004 customers with 6.86 MVA of load and 1460 customers with 9.47 MVA of load, respectively.

Needs:

- The 4.8 kV circuit #283 is heavily loaded and has exceeded its thermal limits during peak load conditions within the last three years (3-year average peak loading at 96%). Circuit #283 is limited by the 750 kcmil aluminum underground exit conductor (3.95 MVA rating).
- Substation transformer T2 is heavily loaded and has exceeded its thermal limits during peak load conditions within the last three years (3-year average peak loading at 90%). Transformer T2 is limited by its normal rating (10.5 MVA).
- Cantitoe Transformer T2 has been assessed with a "Fair" (HI-3) Health Score and is in need of replacement.

Project Scope:

The selected proposal involves substation and distribution upgrades only which are necessary to address the immediate system needs. This project will replace "in-kind" the 10.5 MVA substation transformer T2 with a new 22.4 MVA substation transformer and transfer 1.0 MVA of load off Cantitoe circuit #283 to Cross River circuit #468. The expected project in-service date is Q4 2031.

Substation Upgrades: Replace the in-kind 10.5 MVA substation transformer T2 with a new 22.4 MVA substation transformer by performing the following:

1. Replace the 10.5 MVA substation transformer T2 with a 22.4 MVA 46/4.8/13.2 kV LTC transformer.
2. Install new dedicated 46 kV high-side and 13.2 kV low-side breakers for the new transformer T2.

Distribution Upgrades: Transfer 1.0 MVA of load from Cantitoe circuit #283 to Cross River circuit #468 by performing the following:

1. Cantitoe circuit #283: Construct a new 3-phase section of approximately 0.28 miles with 477 kcmil AL to connect to Cross River #468.
2. Cantitoe circuit #283: Add a normally-open SCADA recloser between circuit #468 and the newly extended circuit #283.
3. Cantitoe circuit #283: Install three 1-phase 500 kVA 13.2/4.8 kV step banks to pick up the transferred load to Cross River #468.

Project Benefits:

The primary driver of the project is to address current capacity-driven needs.

Capacity: The project will relieve emergent thermal needs on substation transformer T2 and distribution feeder circuit #283, which have been heavily loaded within the last three years. Resolving these thermal loading needs will provide immediate benefits to customers by limiting risks associated with equipment-related outages. Additional benefits include providing interim capacity headroom on circuit #283 to support customer load growth and electrification while a longer-term solution for the area is developed. The maximum N-0 capacity gained on the distribution system is 11.9 MVA.

Reliability: The project will enhance system reliability by providing partial N-1 backup capabilities between Cantitoe #283 and Cross River #468. By installing a SCADA-operable tie recloser, the project will improve system performance under outage conditions and provide additional operational flexibility, including for maintenance activities.

Project Risks and Mitigation Plan:

1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to worsening thermal overloads that could lead to utility equipment damage and/or equipment-related outages. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include, mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) There can be risks associated with taking a shorter-term approach to system upgrades instead of implementing longer-term comprehensive solutions. The intent of the Distribution Load Relief (DLR) Program is to develop projects that can be deployed quickly to mitigate emergent loading issues. Accordingly, the scope of projects in the DLR Program is generally restricted exclusively to resolving near-term loading constraints, with some exceptions (e.g., relevant severe asset condition needs). By not holistically considering longer-term needs when developing solutions, there is a risk that the solutions implemented to address near-term needs may not be optimal and/or cost-efficient when a comprehensive area solution is eventually deployed. For the Cantitoe DLR Project, this risk is mitigated because the proposed upgrades will immediately provide benefits by eliminating overload risk on substation transformer T2 and circuit #283, as well as enhancing reliability and resiliency for customers in the area. Additionally, to ensure cost-efficiency over the life of the new facilities, all proposed new construction is being cost-effectively "right-sized" to a NYSEG-standard 12.5 kV voltage class construction to accommodate a future Comprehensive Area Solution, which will convert the 4.8 kV distribution system to 12.5 kV.

Risk of No Action:

Cantitoe transformer T2 and circuit #283 are currently facing thermal constraints. Opting to take no action on the proposed short-term solution would mean that emergency operational solutions for current system constraints would need to be developed as an interim measure to ensure that the electric system can be operated within acceptable reliability and safety limits. Pursuing short-term solutions instead of a comprehensive solution may result in a less cost-efficient buildout of infrastructure, especially if comprehensive action is significantly delayed.

There is also a risk that unmitigated load growth in the Area could drive system constraints to a point where the electric system is, in effect, inoperable due to excessive demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth, leading to significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's electrification goals because there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

Project Alternatives:

Alternative 2 replaces the 10.5 MVA substation transformer T2 "in-kind" with a 22.4 MVA 46/13.2 kV LTC power transformer, installing a new dedicated 46 kV high-side and 13.2 kV low-side breakers for the new transformer T2. This alternative also includes a voltage conversion on circuit #283 (~7.18 miles), installing a new circuit bay, and moving circuit #283 over to transformer T2. This alternative is three times the cost for the same amount of distribution capacity gained (11.9 MVA) compared to the preferred solution.

This alternative was dismissed because the total cost estimate was higher (\$17.94 million, 275% more), though the alternative provides significantly more benefits. The alternative solution adds an additional 10 MVA of capacity to circuit #283, while the preferred solution adds 1 MVA (90% less capacity gained), though overall 11.9 MVA of transformer capacity is equivalent for both solutions. The additional cost of the preferred solution will create future efficiencies since the project will support a future voltage class conversion in the area from 4.8 kV to the modern standard 12.5 kV, as the new distribution facilities will be built to a 12.5 kV construction standard.

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 65	\$ -	\$ 13	\$ 40	\$ 5	\$ 6	\$ 2	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,450	\$ -	\$ 663	\$ 2,141	\$ 243	\$ 305	\$ 98	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 423	\$ -	\$ 99	\$ 252	\$ 27	\$ 33	\$ 12	\$ -
# Materials	\$ 2,148	\$ -	\$ 413	\$ 1,333	\$ 151	\$ 190	\$ 61	\$ -
# Overheads - External	\$ 409	\$ -	\$ 96	\$ 244	\$ 26	\$ 32	\$ 11	\$ -
Total	\$ 6,495	\$ -	\$ 1,282	\$ 4,011	\$ 452	\$ 566	\$ 184	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Distribution Load Relief - Stryker Ave

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006541	Charge Code: Electric Distribution	Project Sponsor: Balch, Bruce	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2027

Project description:

The NYSEG Distribution Load Relief (DLR) Program was established to identify substation transformer and distribution feeder thermal needs (overloads) and propose cost-effective solutions that would mitigate these existing system needs. This program is focused on ensuring full N-0 "all-lines-in" operability across the NYSEG distribution system. The DLR Program will reduce the risk of utility equipment damage and/or failure which would negatively impact our customers. DLR projects are prioritized based on the consideration of weighted factors including, but not limited to, historic/forecasted thermal loading with respect to equipment ratings, asset health, and potential customer impacts.

Background: The Stryker Ave Substation is a 34.5/12.47 kV substation located in the City of Auburn. Stryker Ave is supplied by the 34.5 kV sub-transmission Line 510 from the Swift Street Substation. Stryker Ave can be supplied from the Franklin Street Rd. Substation, which is also connected to Line 510. The Franklin Street Rd. Substation source has a normally open switch in that direction. The 12.47 kV bus is fed by one 14.7 MVA transformer (T1). There are three distribution feeders serving about 4,800 customers and 14.4 MVA of load.

Needs:

- Stryker Ave Transformer T1 (14.7 MVA rating) is heavily loaded and has been approaching its thermal limit during peak load conditions within the last three years (3-year average peak loading at 98%).
- Stryker Ave Transformer T1 has been assessed with a "Fair" (HI-3) Health Score and is approaching the need for replacement.

Project Scope:

The selected proposal involves substation upgrades only, which are necessary to address the immediate system needs. This includes addressing relevant asset condition needs for facilities with "Very Poor" (HI-5) and "Poor" (HI-4) Health Scores. The expected project in-service date is Q4 2029.

Substation Upgrades:

1. Replace the existing Stryker Ave 14 MVA 34.5/12.47 kV transformer ("Fair" HI-3) with a new 22.4 MVA 34.5/12.47 kV LTC transformer.
2. Remove the existing high-side fuse and install a new 34.5 kV breaker on the high side of the new Stryker Ave transformer T1.
3. Install a new 15 kV breaker on the low side of the new Stryker Ave transformer T1.

Project Benefits:

The primary driver of the project is to address current capacity-driven needs. In addition to mitigating these needs, the proposed project will also replace equipment identified to be in fair condition, enhance reliability and resiliency, and create capacity to support future load growth on the Stryker Ave T1 transformer.

Capacity: The project will relieve emergent thermal needs on the Stryker Ave transformer T1, which has been approaching overload within the last three years. Resolving this thermal loading need will provide immediate benefits to customers by limiting risks associated with equipment-related outages. Additional benefits include providing interim capacity headroom on T1 to support customer load growth and electrification while a longer-term solution for the area is developed. The maximum N-0 capacity gained for the distribution system is 8.8 MVA.

Reliability: The project will enhance system reliability by providing N-1 backup capabilities between the following circuits: a. Grant Ave circuit #719 and Stryker Ave circuit #721 b. Wright Ave circuit #705 and Stryker Ave circuit #702. By upgrading the capacity of T1, the project will improve system performance under outage conditions and provide additional operational flexibility, including for maintenance activities.

Asset Condition: Preliminary electrical equipment asset condition needs in Stryker Ave were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. No equipment that is in poor or very poor condition and exceeded its useful life was identified. Site inspections will be performed to identify any additional asset condition needs.

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to worsening thermal overloads that could lead to utility equipment damage and/or equipment-related outages. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include, mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) There can be risks associated with taking a shorter-term approach to system upgrades instead of implementing longer-term comprehensive solutions. The intent of the Distribution Load Relief (DLR) Program is to develop projects that can be deployed quickly to mitigate emergent loading issues. Accordingly, the scope of projects in the DLR Program is generally restricted exclusively to resolving near-term loading constraints, with some exceptions (e.g., relevant severe asset condition needs). By not holistically considering longer-term needs when developing solutions, there is a risk that the solutions implemented to address near-term needs may not be optimal and/or cost-efficient when a comprehensive area solution is eventually deployed.

For the Stryker Ave DLR Project, this risk is mitigated because the proposed upgrades will immediately provide benefits by eliminating overload risk on Stryker Ave T1, replacing critical distribution assets that are in Very Poor condition, and enhancing reliability and resiliency for customers in the area.

Risk of No Action:

Stryker Ave T1 is currently facing thermal constraints. Opting to take no action on the proposed short-term solution would mean that emergency operational solutions for current system constraints would need to be developed as an interim measure to ensure that the electric system can be operated within acceptable reliability and safety limits. Pursuing short-term solutions instead of a comprehensive solution may result in a less cost-efficient buildout of infrastructure, especially if comprehensive action is significantly delayed.

There is also a risk that unmitigated load growth in the Area could drive system constraints to a point where the electric system is, in effect, inoperable due to excessive demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth, leading to significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's goals because there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

Project Alternatives:

An alternative area project was evaluated to offload the constrained Grant Ave transformer (T1), State Street transformer (T5), and Stryker Ave transformer (T1). Within this scope, Grant Ave (T1) will have an "in-kind" replacement along with load transfers. The plan includes multiple load transfers: a. Transferring 2.62 MVA (793 customers) off Grant Ave circuit #720 to a new circuit at Grant Ave, b. Transferring 2.05 MVA (1,051 customers) off State Street circuit #709 to Grant Ave circuit #718, c. Transferring 3.18 MVA (793 customers) off Stryker Ave circuit #721 to Grant Ave circuit #719, and d. Transferring 1.55 MVA (28 customers) off State Street circuit #712 to Grant Ave circuit #720. This also includes the replacement of three 14.4 kV breakers at Grant Ave Substation and two 14.4 kV breakers at State Street Substation, which were assessed to be in very poor condition.

This area alternative was dismissed because the preferred solutions at Grant Ave, State Street, and Stryker Ave combined add 33.3 MVA in total (11% more capacity in the preferred alternative.) In addition this alternative solution would also require a 37.3 MVA transformer to be installed at Grant Ave Substation, fed from 34.5 kV sub-transmission.

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 62	\$ -	\$ 14	\$ 44	\$ 4	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,297	\$ -	\$ 737	\$ 2,327	\$ 233	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 410	\$ -	\$ 110	\$ 274	\$ 26	\$ -	\$ -	\$ -
# Materials	\$ 2,053	\$ -	\$ 459	\$ 1,449	\$ 145	\$ -	\$ -	\$ -
# Overheads - External	\$ 397	\$ -	\$ 106	\$ 265	\$ 25	\$ -	\$ -	\$ -
Total	\$ 6,218	\$ -	\$ 1,426	\$ 4,359	\$ 433	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Distribution Load Relief - Orchard Park

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006535	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The NYSEG Distribution Load Relief (DLR) Program was established to identify substation transformer and distribution feeder thermal needs (overloads) and propose cost-effective solutions that would mitigate these existing system needs. This program is focused on ensuring full N-0 "all-lines-in" operability across the NYSEG distribution system. The DLR Program will reduce the risk of utility equipment damage and/or failure which would negatively impact our customers. DLR projects are prioritized based on the consideration of weighted factors including, but not limited to, historic/forecasted thermal loading with respect to equipment ratings, asset health, and potential customer impacts.

Background: The Orchard Park Substation is a 34.5/4.8 kV substation located in the Town of Orchard Park. Orchard Park Substation is supplied by 34.5 kV sub-transmission Lines 528 and 526 from the Big Tree Substation. The 4.8 kV distribution bus is fed by one 9.38 MVA transformer. There are three 4.8 kV distribution feeders serving about 2472 customers and 8.65 MVA of load.

Needs:

- 4.8 kV feeder #286 is heavily loaded and is approaching its thermal limits during peak load conditions within the last three years (3-year average peak loading at 94%). Circuit #286 is limited by the 438A feeder regulator (3.87 MVA Rating).
- Transformer T1 (9.38 MVA Rating) is heavily loaded and is approaching its thermal limits during peak load conditions within the last three years (3-year peak loading at 92%).
- The feeder circuit breakers for the #285 and #287 feeders have all been assessed with a "Very Poor" (HI-5) Health Score and are in need of replacement.
- The feeder circuit breaker for the #286 feeder has been assessed with a "Fair" (HI-3) Health Score and is approaching the need for replacement.
- Orchard Park transformer T1 has 1 phase (Trans-Z) that has been assessed with a "Poor" (HI-4) Health Score and is in need of replacement.

Project Scope:

The selected proposal involves substation upgrades only which are necessary to address the immediate system needs. This includes addressing relevant asset condition needs for facilities with a "Fair" (HI-3) through "Very Poor" (HI-5) Health Scores. The expected project in-service date is Q4 2029.

Substation Upgrades:

1. Replace three 14.4 kV circuit breakers (#285, #286, and #287) that have a "Fair" (HI-3) and "Very Poor" (HI-5) Health Score with new 15 kV breakers.
2. Remove existing three 1-phase 34.5/4.8 kV (9.375 MVA normal rating) and replace with one 3-phase 34.5/4.8 - 12.47 kV 22.4 MVA dual winding transformer with LTC.
3. Replace existing fuse on high side of transformer with one 34.5 kV breaker.
4. Install one new 15 kV breaker on low-side of transformer.
5. Remove all feeder regulators.

Project Benefits:

The primary driver of the project is to address current capacity-driven needs. In addition to mitigating these needs, the proposed project will also replace equipment identified to be in Very Poor condition, enhance reliability and resiliency, and create capacity to support future load growth on the Orchard Park T1 and #286 feeder.

Capacity: The project will relieve emergent thermal needs on distribution feeder circuit #692, which has been approaching overload within the last three years. Resolving this thermal loading need will provide immediate benefits to customers by limiting risks associated with equipment-related outages. Additional benefits include providing interim capacity headroom on Orchard Park T1 and #286 to support customer load growth and electrification while a longer term solution for the area is developed. The maximum N-0 capacity gained on the distribution system is 5.5 MVA.

Reliability: The project will enhance system reliability by providing N-1 backup capabilities by upgrading the capacity of Orchard Park T1 and #286, the project will improve system performance under outage conditions and will also provide additional operational flexibility, including for maintenance activities.

Asset Condition: Preliminary electrical equipment asset condition needs in Orchard Park were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. There are two(2) circuit breakers with a Very Poor (HI-5) Health Score #285 and #287 in Orchard Park Substation. Additionally, transformer T1 has a Poor (HI-4) Health score. Equipment that is in poor, or very poor condition have exceeded their useful life and should be replaced to limit the risk of equipment-related outages. Such equipment are included for replacement or retirement in the conceptual solution. Site inspections will be performed to identify any additional asset condition needs. Circuit breaker with Fair (HI-3) Health Score #286, which is approaching the end of useful life designated by (HI-4) or (HI-5).

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to worsening thermal overloads that could lead to utility equipment damage and/or equipment-related outages. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include, mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) There can be risks associated with taking a shorter-term approach to system upgrades instead of implementing longer-term comprehensive solutions. The intent of the Distribution Load Relief (DLR) Program is to develop projects that can be deployed quickly to mitigate emergent loading issues. Accordingly, the scope of projects in the DLR Program is generally restricted exclusively to resolving near-term loading constraints, with some exceptions (e.g., relevant severe asset condition needs). By not holistically considering longer-term needs when developing solutions, there is a risk that the solutions implemented to address near-term needs may not be optimal and/or cost-efficient when a comprehensive area solution is eventually deployed. For the Orchard Park DLR Project, this risk is mitigated because the proposed upgrades will immediately provide benefits by eliminating overload risk on T1 and circuit #286, replacing critical distribution assets that are in very poor condition, as well as enhancing reliability and resiliency for customers in the area. Additionally, to ensure cost-efficiency over the life of the new facilities, all proposed new construction is being cost-effectively "right-sized" to a NYSEG-standard 12.5 kV voltage class construction to accommodate a future comprehensive area solution, which will convert the 4.8 kV distribution system to 12.5 kV.

Risk of No Action:

Orchard Park T1 and #286 are currently facing thermal constraints. Opting to take no action on the proposed short-term solution would mean that emergency operational solutions for current system constraints would need to be developed as an interim measure to ensure that the electric system can be operated within acceptable reliability and safety limits. Pursuing short-term solutions instead of a comprehensive solution may result in a less cost-efficient buildout of infrastructure, especially if comprehensive action is significantly delayed.

There is also a risk that unmitigated load growth in the Area could drive system constraints to a point where the electric system is, in effect, inoperable due to excessive demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth, leading to significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's goals because there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

Project Alternatives:

An alternative project was evaluated that, offloaded the constrained Orchard Park T1 and #286 by upgrading the transformer T1 to 34.5/12.47 kV 22.4 MVA transformer. In addition to the transformer upgrade performing a voltage conversion from 4.8 kV to 12.47 kV. The alternative also included the replacement of the five 14.4 kV circuit breakers assessed to be in Very Poor condition.

This alternative was dismissed because, while the total cost estimate was significantly higher (\$44.15 M (712%) more). The preferred solution will create future efficiencies since the project will support a future voltage class conversion in the area from 4.8 kV to the modern standard 12.47 kV since the new distribution facilities will be built to a 12.5 kV construction standard.

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 62	\$ -	\$ -	\$ 15	\$ 45	\$ 2	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,285	\$ -	\$ -	\$ 774	\$ 2,392	\$ 119	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 368	\$ -	\$ -	\$ 91	\$ 264	\$ 13	\$ -	\$ -
# Materials	\$ 2,045	\$ -	\$ -	\$ 482	\$ 1,489	\$ 74	\$ -	\$ -
# Overheads - External	\$ 356	\$ -	\$ -	\$ 88	\$ 256	\$ 13	\$ -	\$ -
Total	\$ 6,117	\$ -	\$ -	\$ 1,450	\$ 4,446	\$ 221	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Distribution Load Relief - Maplewood

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006534	Charge Code: Electric Distribution	Project Sponsor: Balch, Bruce	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The NYSEG Distribution Load Relief (DLR) Program was established to identify substation transformer and distribution feeder thermal needs (overloads) and propose cost-effective solutions that would mitigate these existing system needs. This program is focused on ensuring full N-0 "all-lines-in" operability across the NYSEG distribution system. The DLR Program will reduce the risk of utility equipment damage and/or failure which would negatively impact our customers. DLR projects are prioritized based on the consideration of weighted factors including, but not limited to, historic/forecasted thermal loading with respect to equipment ratings, asset health, and potential customer impacts.

Background: The Maplewood Substation is a 34.5/12.47/4.8 kV substation located in the Town of Thompson. Maplewood Substation is supplied by 34.5 kV sub-transmission Line 347 from Kiamesha and Coopers Corners Substations. The 4.8 kV distribution bus is fed by one 5 MVA transformer (T1). There are two 4.8 kV distribution feeders serving about 649 customers and 2.92 MVA of load. The 12.47 kV distribution bus is fed by one 10.5 MVA transformer (T2). There is one 12.47 kV distribution feeder serving about 2403 customers and 9.12 MVA of load.

Needs:

- 12.47 kV feeder #229 is heavily loaded and is approaching its thermal limits during peak load conditions within the last three years (3-year average peak loading at 91%). Circuit #229 is limited by the 438A feeder regulator (10.06 MVA rating).
- Transformer T2 (10.5 MVA rating) is loaded and is approaching its thermal limits during peak load conditions within the last three years (3-year peak loading at 87%).
- The feeder circuit breakers for the #127, #128, and #229 feeders have all been assessed with a "Very Poor" (HI-5) Health Score and are in need of replacement.
- Transformer T2 is comprised of three single phase transformers; one phase (Trans-L) that has been assessed with a "Fair" (HI-3) Health Score and is approaching the need for replacement.

Project Scope:

The selected proposal involves substation upgrades which are necessary to address the immediate system needs. This includes addressing relevant asset condition needs for facilities with a "Poor" (HI-4) and "Very Poor" (HI-5) Health Score. The expected project in-service date is Q4 2029.

Substation Upgrades:

1. Replace three 14.4 kV circuit breakers (#127, #128, and #229) that have a "Very Poor" (HI-5) Health Score with new 15 kV breakers.
2. Remove existing three 1-phase 34.5/12.47 kV (10.5 MVA normal rating) transformers and replace with one 3-phase 34.5/12.47 kV 22.4 MVA transformer with a load tapchanger (LTC). This larger transformer capacity helps accommodate future voltage conversion and allows for tying circuits in the area. Installation of a smaller replacement unit would likely be quickly overloaded by adding more area load.
3. Replace existing fuse on high side of transformer with one 34.5 kV breaker.
4. Install one new 15 kV breaker on low-side of transformer.
5. Remove 438A feeder regulator for circuit #229.

Project Benefits:

The primary driver of the project is to address current capacity-driven needs. In addition to mitigating these needs, the proposed project will also replace equipment identified to be in Very Poor condition, enhance reliability and resiliency, and create capacity to support future load growth on the Maplewood T2 and circuit #229.

Capacity: The project will relieve emergent thermal needs on transformer T2 and distribution feeder circuit #229, which has been approaching overload within the last three years. Resolving this thermal loading need will provide immediate benefits to customers by limiting risks associated with equipment-related outages. Additional benefits include providing interim capacity headroom on Maplewood T2 and #229 to support customer load growth and electrification while a longer term solution for the area is developed. The maximum N-0 capacity gained on the distribution system is 3.0 MVA.

Reliability: The project will enhance system reliability by providing N-1 backup capabilities by upgrading the capacity of Maplewood T2 and circuit #229, the project will improve system performance under outage conditions and will also provide additional operational flexibility, including for maintenance activities.

Asset Condition: Preliminary electrical equipment asset condition needs in Maplewood were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. There are three(3) circuit breakers with a Very Poor (HI-5) Health Score #127, #128, and #229 in Maplewood Substation. Equipment that is in poor, or very poor condition have exceeded their useful life and should be replaced to limit the risk of equipment-related outages. Such equipment are included for replacement or retirement in the conceptual solution. Site inspections will be performed to identify any additional asset condition needs. Transformer T2 has one phase with a Fair (HI-3) Health score, which is approaching the end of useful life designated by (HI-4) or (HI-5).

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to worsening thermal overloads that could lead to utility equipment damage and/or equipment-related outages. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include, mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) There can be risks associated with taking a shorter-term approach to system upgrades instead of implementing longer-term comprehensive solutions. The intent of the Distribution Load Relief (DLR) Program is to develop projects that can be deployed quickly to mitigate emergent loading issues. Accordingly, the scope of projects in the DLR Program is generally restricted exclusively to resolving near-term loading constraints, with some exceptions (e.g., relevant severe asset condition needs). By not holistically considering longer-term needs when developing solutions, there is a risk that the solutions implemented to address near-term needs may not be optimal and/or cost-efficient when a comprehensive area solution is eventually deployed. For the Maplewood DLR Project, this risk is mitigated because the proposed upgrades will immediately provide benefits by eliminating overload risk on Maplewood T2 and #229, replacing critical distribution assets that are in very poor condition, as well as enhancing reliability and resiliency for customers in the area.

Risk of No Action:

Maplewood T2 and circuit #229 are currently facing thermal constraints. Opting to take no action on the proposed short-term solution would necessitate the development of emergency operational solutions for current system constraints as an interim measure to ensure the electric system can be operated within acceptable reliability and safety limits. Pursuing short-term solutions instead of a comprehensive solution may result in a less cost-efficient buildout of infrastructure, especially if comprehensive action is significantly delayed.

There is also a risk that load growth in the area could drive system constraints to a point where the electric system becomes inoperable during periods of high demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in load growth leading to significant overload and potential undervoltage conditions with limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's goals because there is likely insufficient capacity to support the electrification of large loads such as school buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

Project Alternatives:

An alternative project was evaluated that, offloaded the constrained Maplewood #229 by upgrading the 438A feeder regulator to a 656A regulator.

This alternative was dismissed because, while the total cost estimate was significantly lower (\$6.01 M (4,006%) less), the alternative provides significantly less benefits. The alternative solution only adds an additional 0.4 MVA of capacity to circuit #229, while the preferred solution adds 3 MVA (650% less capacity gained).

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:		Total	2020	2021	2022	2023	2024
	Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 62	\$ -	\$ -	\$ 15	\$ 45	\$ 2	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,265	\$ -	\$ -	\$ 774	\$ 2,369	\$ 122	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 366	\$ -	\$ -	\$ 91	\$ 262	\$ 13	\$ -	\$ -
# Materials	\$ 2,033	\$ -	\$ -	\$ 482	\$ 1,475	\$ 76	\$ -	\$ -
# Overheads - External	\$ 354	\$ -	\$ -	\$ 88	\$ 253	\$ 13	\$ -	\$ -
Total	\$ 6,079	\$ -	\$ -	\$ 1,450	\$ 4,404	\$ 226	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Distribution Load Relief - Jarvis Street

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006532	Charge Code: Electric Distribution	Project Sponsor: Balch, Bruce	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2029

Project description:

The NYSEG Distribution Load Relief (DLR) Program was established to identify substation transformer and distribution feeder thermal needs (overloads) and propose cost-effective solutions that would mitigate these existing system needs. This program is focused on ensuring full N-0 "all-lines-in" operability across the NYSEG distribution system. The DLR Program will reduce the risk of utility equipment damage and/or failure which would negatively impact our customers. DLR projects are prioritized based on the consideration of weighted factors including, but not limited to, historic/forecasted thermal loading with respect to equipment ratings, asset health, and potential customer impacts.

Background: The Jarvis Street Substation is a 34.5/4.8 kV substation located in the City of Binghamton. Jarvis Street Substation is supplied by 34.5 kV underground sub-transmission Lines 413 and 443 from the Glenwood and Goudy Substations, respectively. The 4.8 kV distribution bus is fed by two 9.38 MVA transformers operating in parallel for a total combined rating of 18.75 MVA. There are five 4.8 kV distribution feeders serving about 5452 customers and 9.75 MVA of load.

Needs:

- 4.8 kV feeder #692 is heavily loaded and has exceeded its thermal limits during peak load conditions within the last three years (102% loading observed in 2022. 3-year average peak loading at 88%). Circuit #692 is limited by the 500 kcmil copper underground exit conductor (4.02 MVA rating).
- The feeder circuit breakers for the #687, #689, #690, #691, and #692 feeders have all been assessed with a "Very Poor" (HI-5) Health Score and are in need of replacement.

Project Scope:

The selected proposal involves distribution and substation upgrades only which are necessary to address the immediate system needs. This includes addressing relevant asset condition needs for facilities with a "Very Poor" (HI-5) Health Score. The expected project in-service date is Q4 2031.

Substation Upgrades:

1. Replace five 14.4 kV circuit breakers (#687, #689, #690, #691, and #692) that have a "Very Poor" (HI-5) Health Score with new 15 kV breakers.

Distribution Upgrades: Transfer 1.5 MVA of load from Jarvis Street circuit #692 to Jarvis Street circuit #690 by performing the following:

1. Jarvis St circuit #690: Reconductor approximately 400 feet of 1/0 Al conductor to 477 kcmil Al to support load transfer.
2. Jarvis St circuit #690: Perform a 3-phase extension of approximately 200 feet with 477 kcmil Al to support load transfer.
3. Jarvis St circuit #690: Construct new 3-phase section of approximately 300 feet with 477 kcmil Al to connect with portion Jarvis St. circuit #692 that will be converted to circuit #690.
4. Jarvis St circuit #692: Perform a 3-phase extension of approximately 900 feet with 477 kcmil Al and transfer to circuit #690.
5. Jarvis St. circuit #692: Perform an additional 3-phase extension of approximately 500 feet with 477Al kcmil Al and transfer to circuit #690.
6. Jarvis St. circuit #692: Add normally-open SCADA-operable tie recloser to form new tie point between circuit #692 and newly extended circuit #690.

Project Benefits:

The primary driver of the project is to address current capacity-driven needs. In addition to mitigating these needs, the proposed project will also replace equipment identified to be in Very Poor condition, enhance reliability and resiliency, and create capacity to support future load growth on the Jarvis St #692 feeder.

Capacity: This project creates an incremental 1.5 MVA of capacity on Jarvis Street circuit #692. The project will relieve emergent thermal needs on distribution feeder circuit #692, which has been overloaded within the last three years. Resolving this thermal loading need will provide immediate benefits to customers by limiting risks associated with equipment-related outages. Additional benefits include providing interim capacity headroom on circuit #692 to support customer load growth and electrification while a longer term solution for the area is developed. The maximum N-0 capacity gained on the distribution system is 0 MVA since the load transfers redistributes the loading to existing Jarvis Street circuits.

Reliability: The project will enhance system reliability by providing partial N-1 backup capabilities between Jarvis Street #690 and Jarvis Street #692. By installing a SCADA-operable tie recloser and upgrading the capacity of circuit #692, the project will improve system performance under outage conditions and will also provide additional operational flexibility, including for maintenance activities.

Asset Condition: Preliminary electrical equipment asset condition needs in Jarvis Street were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. There are five(5) circuit breakers with a Very Poor (HI-5) Health Score in Jarvis Street Substation, #687, #689, #690, #691, and #692. Equipment that is in poor, or very poor condition have exceeded their useful life and should be replaced to limit the risk of equipment-related outages. Such equipment are included for replacement or retirement in the conceptual solution. Site inspections will be performed to identify any additional asset condition needs.

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to worsening thermal overloads that could lead to utility equipment damage and/or equipment-related outages. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include, mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) There can be risks associated with taking a shorter-term approach to system upgrades instead of implementing longer-term comprehensive solutions. The intent of the Distribution Load Relief (DLR) Program is to develop projects that can be deployed quickly to mitigate emergent loading issues. Accordingly, the scope of projects in the DLR Program is generally restricted exclusively to resolving near-term loading constraints, with some exceptions (e.g., relevant severe asset condition needs). By not holistically considering longer-term needs when developing solutions, there is a risk that the solutions implemented to address near-term needs may not be optimal and/or cost-efficient when a comprehensive area solution is eventually deployed. For the Jarvis Street DLR Project, this risk is mitigated because the proposed upgrades will immediately provide benefits by eliminating overload risk on circuit #692, replacing critical distribution assets that are in very poor condition, as well as enhancing reliability and resiliency for customers in the area. Additionally, to ensure cost-efficiency over the life of the new facilities, all proposed new construction is being cost-effectively "right-sized" to a NYSEG-standard 12.5 kV voltage class construction to accommodate a future comprehensive area solution, which will convert the 4.8 kV distribution system to 12.5 kV.

Risk of No Action:

Jarvis Street circuit #692 is currently facing thermal constraints. Opting to take no action on the proposed short-term solution would mean that emergency operational solutions for current system constraints would need to be developed as an interim measure to ensure that the electric system can be operated within acceptable reliability and safety limits. Pursuing short-term solutions instead of a comprehensive solution may result in a less cost-efficient buildout of infrastructure, especially if comprehensive action is significantly delayed.

There is also a risk that unmitigated load growth in the Area could drive system constraints to a point where the electric system is, in effect, inoperable due to excessive demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth, leading to significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's goals because there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

Project Alternatives:

An alternative project was evaluated that, offloaded the constrained circuit #692 by upgrading the limiting underground substation exit conductor from 500 kcmil Cu underground to 750 kcmil Cu underground cable. The alternative also included the replacement of the five 14.4 kV circuit breakers assessed to be in Very Poor condition.

This alternative was dismissed because, while the total cost estimate was somewhat lower (\$680,000 (17%) less), the alternative provides significantly less benefits. The alternative solution only adds an additional 1 MVA of capacity to circuit #692, while the preferred solution adds 1.5 MVA (33% less capacity gained). The additional cost of the preferred solution will create future efficiencies since the project will support a future voltage class conversion in the area from 4.8 kV to the modern standard 12.5 kV since the new distribution facilities will be built to a 12.5 kV construction standard.

Additionally, the proposed solution performed better than the alternative because it will improve reliability by forming a SCADA-operable circuit tie between circuits #690 and #692 while also more evenly distributing customers between the feeders.

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 38	\$ -	\$ 5	\$ 22	\$ 4	\$ 2	\$ 5	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,014	\$ -	\$ 239	\$ 1,187	\$ 207	\$ 106	\$ 276	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 242	\$ -	\$ 36	\$ 140	\$ 23	\$ 11	\$ 32	\$ -
# Materials	\$ 1,254	\$ -	\$ 149	\$ 739	\$ 129	\$ 66	\$ 172	\$ -
# Overheads - External	\$ 234	\$ -	\$ 34	\$ 135	\$ 22	\$ 11	\$ 31	\$ -
Total	\$ 3,783	\$ -	\$ 462	\$ 2,224	\$ 384	\$ 197	\$ 516	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Distribution Load Relief - Clyde

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006527	Charge Code: Electric Distribution	Project Sponsor: Balch, Bruce	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The NYSEG Distribution Load Relief (DLR) Program was established to identify substation transformer and distribution feeder thermal needs (overloads) and propose cost-effective solutions to mitigate these existing system needs. This program focuses on ensuring full N-0 "all-lines-in" operability across the NYSEG distribution system. The DLR Program aims to reduce the risk of utility equipment damage and/or failure, which would negatively impact our customers. DLR projects are prioritized based on weighted factors, including but not limited to, historic/forecasted thermal loading with respect to equipment ratings, asset health, and potential customer impacts.

Background: The Clyde Substation is a 34.5/4.8 kV substation located in the Town of Clyde. It is supplied by 34.5 kV sub-transmission Lines 807 (RGE) and 574 from the Station 199 and Lyons Substations, respectively. The 4.8 kV distribution bus is fed by one 10.5 MVA transformer. There are three 4.8 kV distribution feeders serving about 1,736 customers and 9.03 MVA of load.

Needs:

- The 4.8 kV circuit #201 is moderately loaded and is starting to approach its thermal limits during peak load conditions over the last three years (3-year average peak loading at 82%). Circuit #201 is limited by the 219A feeder regulator (1.94 MVA rating).
- The 4.8 kV circuit #202 is heavily loaded and is approaching its thermal limits during peak load conditions over the last three years (3-year average peak loading at 93%). Circuit #202 is limited by the 477 kcmil aluminum overhead exit conductor (5.03 MVA rating).
- The 4.8 kV circuit #203 is heavily loaded and is approaching its thermal limits during peak load conditions over the last three years (3-year average peak loading at 94%). Circuit #203 is limited by the 328A feeder regulator (2.90 MVA rating).
- The feeder circuit breakers for the #201, #202, and #203 feeders have all been assessed with a "Very Poor" (HI-5) Health Score and are in need of replacement.

Project Scope:

The selected proposal involves distribution and substation upgrades necessary to address immediate system needs. This includes addressing relevant asset condition needs for facilities with a "Very Poor" (HI-5) Health Score. The expected project in-service date is Q4 2029.

Substation Upgrades:

1. Replace three 14.4 kV circuit breakers (#201, #202, and #203) that have a "Very Poor" (HI-5) Health Score with new 15 kV breakers.
2. Clyde #201: Replace the 219A feeder regulator with a 656A feeder regulator to support load transfer.
3. Clyde #203: Replace the 328A feeder regulator with a 656A feeder regulator to reduce overloading.

Distribution Upgrades: Transfer 1 MVA of load from Clyde circuit #202 to Clyde circuit #201 by performing the following

1. Clyde #202: Complete a new short 3-phase line extension with 477 kcmil AI that will be converted to circuit #201.
2. Clyde #202: Open the normally closed switch on circuit #202 L-606 P-110 to complete the load transfer and creating a normally open tie point between the circuits.

Project Benefits:

The primary driver of the project is to address current capacity-driven needs. In addition to mitigating these needs, the proposed project will also replace equipment identified to be in Very Poor condition, enhance reliability and resiliency, and create capacity to support future load growth on the Clyde #201, #202, and #203 feeders.

Capacity: The project will relieve emergent thermal needs on distribution feeder circuits #201, #202, and #203, which have been heavily loaded over the last three years. Resolving these thermal loading needs will provide immediate benefits to customers by limiting risks associated with equipment-related outages. Additional benefits include providing interim capacity headroom on all three circuits to support customer load growth and electrification while a longer-term solution for the area is developed. The maximum N-0 capacity gained on the distribution circuit is 5.22 MVA.

Reliability: The project will enhance system reliability by providing partial N-1 backup capabilities between Clyde #201 and Clyde #202. By creating a tie point between circuits #201 and #202, the project will improve system performance under outage conditions and balance customer counts.

Asset Condition: Preliminary electrical equipment asset condition needs in Clyde were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. There are three circuit breakers with a Very Poor (HI-5) Health Score in Clyde Substation: #201, #202, and #203. Equipment in poor or very poor condition has exceeded its useful life and should be replaced to limit the risk of equipment-related outages. Such equipment is included for replacement or retirement in the conceptual solution. Site inspections will be performed to identify any additional asset condition needs.

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to worsening thermal overloads that could lead to utility equipment damage and/or equipment-related outages. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include, mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) There can be risks associated with taking a shorter-term approach to system upgrades instead of implementing longer-term comprehensive solutions. The intent of the Distribution Load Relief (DLR) Program is to develop projects that can be deployed quickly to mitigate emergent loading issues. Accordingly, the scope of projects in the DLR Program is generally restricted exclusively to resolving near-term loading constraints, with some exceptions (e.g., relevant severe asset condition needs). By not holistically considering longer-term needs when developing solutions, there is a risk that the solutions implemented to address near-term needs may not be optimal and/or cost-efficient when a comprehensive area solution is eventually deployed. For the Clyde DLR Project, this risk is mitigated because the proposed upgrades will immediately provide benefits by eliminating overload risk on circuits #201, #202 and #203 replacing critical distribution assets that are in very poor condition, as well as enhancing reliability and resiliency for customers in the area. Additionally, to ensure cost-efficiency over the life of the new facilities, all proposed new construction is being cost-effectively "right-sized" to a NYSEG-standard 12.5 kV voltage class construction to accommodate a future comprehensive area solution, which will convert the 4.16 kV distribution system to 12.5 kV.

Risk of No Action:

Clyde circuits #201, #202, and #203 are currently facing thermal constraints. Opting to take no action on the proposed short-term solution would necessitate the development of emergency operational solutions for current system constraints as an interim measure to ensure the electric system can be operated within acceptable reliability and safety limits. Pursuing short-term solutions instead of a comprehensive solution may result in a less cost-efficient buildout of infrastructure, especially if comprehensive action is significantly delayed.

There is also a risk that load growth in the area could drive system constraints to a point where the electric system becomes inoperable during periods of high demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in load growth leading to significant overload and potential undervoltage conditions with limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's goals because there is likely insufficient capacity to support the electrification of large loads such as school buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

Project Alternatives:

An alternative project was evaluated that offloaded the constrained circuits #201, #202, and #203 by upgrading the "in-kind" 10.5 MVA transformer with a new 22.4 MVA transformer, installing 7.2 MVAR of substation capacitors, and converting the voltage to 12.47 kV for all three circuits. The alternative also included the replacement of the three 14.4 kV circuit breakers assessed to be in Very Poor condition.

This alternative was not selected due to cost and implementation timeline. The total cost estimate of the alternative was higher (\$23.28M, 1,200% more), however, it did provide significantly more benefits capacity benefits. The alternative solution adds an additional 11.8 MVA (380% more) of capacity to circuits #201, #202, and #203, while the preferred solution adds 3.1 MVA.

The preferred solution will evenly distribute customers counts across the circuits and provide a sooner in-service date, all at the lowest cost.

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 18	\$ -	\$ -	\$ 5	\$ 11	\$ 2	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 943	\$ -	\$ -	\$ 260	\$ 599	\$ 85	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 106	\$ -	\$ -	\$ 31	\$ 66	\$ 9	\$ -	\$ -
# Materials	\$ 587	\$ -	\$ -	\$ 162	\$ 373	\$ 53	\$ -	\$ -
# Overheads - External	\$ 102	\$ -	\$ -	\$ 30	\$ 64	\$ 9	\$ -	\$ -
Total	\$ 1,757	\$ -	\$ -	\$ 486	\$ 1,113	\$ 157	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Holland Substation DLR

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-005785	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The NYSEG Distribution Load Relief (DLR) Program was established to identify substation transformer and distribution feeder thermal needs (overloads) and propose cost-effective solutions that would mitigate these existing system needs. This program is focused on ensuring full N-0 "all-lines-in" operability across the NYSEG distribution system. The DLR Program will reduce the risk of utility equipment damage and/or failure which would negatively impact our customers. DLR projects are prioritized based on the consideration of weighted factors including, but not limited to, historic/forecasted thermal loading with respect to equipment ratings, asset health, and potential customer impacts.

Background:

The Holland substation is an existing 34.5/4.8 kV substation in the Lancaster division of NYSEG. The 34.5 kV is configured as a straight bus (currently no line sectionalizing capabilities) with a tapped 6.25 MVA (normal rating) transformer, which supports two (2) distribution feeders, #320 and #321, serving a total of ~2,200 customers.

Needs:

- The existing transformer (T1) is near overload (98%) under N-0 conditions. There is insufficient capacity on adjacent distribution circuits to effectively transfer load off of Holland.
- Two (2) 4.8 kV oil breaker have a Poor Health Index Score (HI-4)
- T1 (34.5/4.8kV) has a Good Health Index Score and no LTC. It has no visual signs of leaks and utilizes a steel beam and concrete foundation that has visual signs of deterioration (cracking)

Project Scope:

The selected traditional solution for the Holland Distribution Load Relief project is a full substation rebuild, including:

- Acquisition of adjacent land to the existing Holland Substation
- Construction of a new GIS 34.5 -4.8 kV substation with a 22.4 MVA LTC Transformer LTC
- Addition of a 3.6 MVar transmission capacitor
- Demolition of the existing station

This project is suitable for an Non-Wires Alternative (NWA) consideration and is being vetted through the NWA solicitation process.

Project Benefits:

By shifting load on a heavily loaded substation to more lightly loaded sources, NYSEG can enhance reliability, extend equipment lifespan, improve efficiency, and maintain better power quality. It leads to cost savings through avoiding the need for frequent repairs, replacements, costly upgrades, and helps in complying with regulatory standards. Overall, effective load management ensures a more resilient, efficient, and cost-effective power distribution system.

This solution will mitigate the existing Holland Transformer Bank 1 overload. This alternative will also increase reliability by upgrading an aging substation and several "poor" health circuit breakers.

Project Risks and Mitigation Plan:

Risks exist in project execution, particularly regarding engineering and material procurement. To ensure materials are received on time, long lead materials will be ordered proactively.

Weather delays pose a risk in distribution construction as resources frequently support storm restoration efforts. These weather-related delays can be mitigated by incorporating contingency into our construction schedules.

The health and safety are primary concerns. Risks associated with traffic control, working with energized equipment, slips, and trips are common on most projects. These risks are mitigated with project-specific health and safety plans.

Many projects involve de-energizing existing substation equipment to facilitate replacements or upgrades. This process inherently carries risk, such as potential power outages and the safety of personnel working on de-energized equipment. To mitigate these risks, mobile substations are used in applicable scenarios. Mobile substations allow for the temporary transfer of load, ensuring continuous power supply and minimizing disruptions to customers.

Additionally, detailed planning and coordination are essential to ensure the safe and efficient use of mobile substations. This includes thorough risk assessments, clear communication with all stakeholders, and adherence to strict safety protocols. By implementing these measures, the risks associated with de-energizing substation equipment can be effectively managed and ensure the successful completion of our projects.

Financial risks are inherent in project execution as new information emerges. We mitigate these risks by utilizing scheduling and forecasting tools, such as Primavera, for project management. Forecasts for project-specific activities are updated frequently using these tools and the project's overall progress is updated monthly. This approach supports accurate prediction of project completion and cost estimates throughout the process.

Risk of No Action:

If no action is taken, several risks could arise:

Equipment Damage: Operating substation transformers and other major equipment near or over capacity can lead to overheating and accelerated wear and tear, ultimately causing equipment failure.

Power Outages: The reliability of the power supply could be compromised, leading to more frequent and prolonged power outages for customers.

Safety Hazards: Overloaded equipment can pose safety risks, including the potential for fires or other hazardous conditions.

Increased Costs: The cost of emergency repairs and replacing damaged equipment can be significantly higher than the cost of proactive maintenance and upgrades.

Customer Dissatisfaction: Frequent power outages and unreliable service can lead to customer dissatisfaction and potential loss of trust in the utility provider.

Regulatory Non-Compliance: Failing to maintain equipment and ensure reliable service could result in non-compliance with regulatory standards, leading to fines and other penalties.

Limited Capacity for Growth: Without load reduction and system improvements, there may be limited capacity to accommodate new customer connections, hindering growth and development.

Taking proactive measures through programs like the Distribution Load Relief Program helps mitigate these risks and ensures a more reliable and efficient power supply.

Project Alternatives:

Alternative 1 - Load Transfer 0.38 MVA from Holland #320 to Holland #521 - \$0.65M, ISD Q4 2027 (solution does not reduce the Holland Transformer below 90% Normal Rating)

Alternative 2 - Load Transfer 0.37 MVA from Holland #320 to Holland #521 - \$0.50M, ISD Q4 2027 (solution does not reduce the Holland Transformer below 90% Normal Rating)

Alternative 3 - Load Transfer to 34.5kV Tap - \$0.47M, ISD Q4 2025 (does not adhere to current Avangrid Distribution Planning Criteria)

Alternative 4 (Selected Traditional) - Substation Rebuild - \$26.0M, ISD Q4 2029

Alternative 5 (Preferred) - NWA Solution - \$TBD, NWA solicitation process in progress.

If an NWA solicitation (Alternative 5) is unsuccessful, Alternative 4 provides the most robust and comprehensive mitigations to the identified needs.

Basis for Project Estimates

Estimates are prepared using historical estimating tools and are benchmarked against actual investments in similar projects to establish a basis for project initiation. These estimates are revised throughout the project as new information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,943	\$ -	\$ -	\$ 307	\$ 506	\$ 821	\$ 307	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 19,116	\$ -	\$ -	\$ 3,025	\$ 4,984	\$ 8,083	\$ 3,025	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 1,358	\$ -	\$ -	\$ 215	\$ 354	\$ 574	\$ 215	\$ -
# Internal, Overheads	\$ 1,359	\$ -	\$ -	\$ 226	\$ 350	\$ 557	\$ 226	\$ -
# Materials	\$ 712	\$ -	\$ -	\$ 113	\$ 186	\$ 301	\$ 113	\$ -
# Overheads - External	\$ 1,627	\$ -	\$ -	\$ 271	\$ 419	\$ 666	\$ 271	\$ -
Total	\$ 26,114	\$ -	\$ -	\$ 4,157	\$ 6,798	\$ 11,003	\$ 4,156	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

NYSEG - Elec Better

PROJECT INFORMATION

OpCo: NYSEG	Project ID: UI-N0010-NYSEG-ED	Charge Code: Electric Distribution	Project Sponsor: Shail, Joshua	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Reliability	Project Stage: IP4 Change	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

Betterments are projects that will improve the grid by improving reliability, operability, and flexibility of the grid. Projects come from ideas in Operations and ECC based on their knowledge about the real issues and challenges being faced by the system beyond just SAIFI allowing us to address SAIDI, CAIDI, Operability, Flexibility, Voltage Regulation, Loading and Safety.

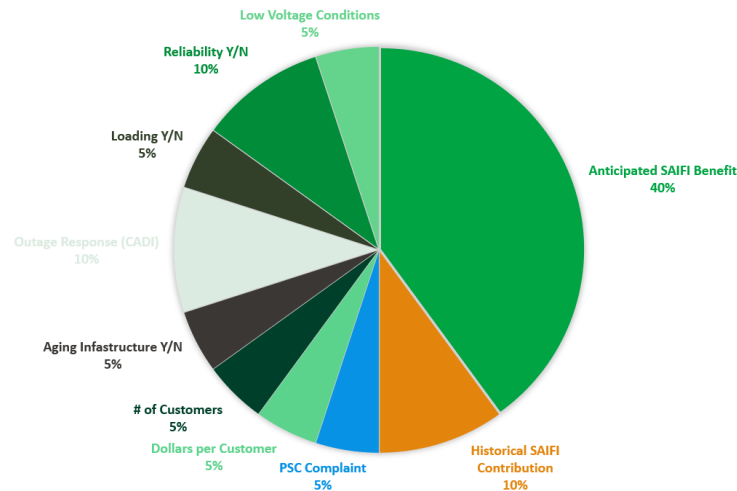
Project Scope:

Collection Method

Operations and ECC suggest projects based on their knowledge of system issues, such as those that appear in the weekly reliability tracker. Once the initial suggestion is given, then a detailed scope and cost estimate are developed.

Prioritization

Betterments is currently reevaluating all proposed projects using our updated prioritization methods. Project impacts, along with the historic SAIFI contribution, dollars per customer, and dollars per SAIFI benefit. These benefits are weighed and compared to competing projects to prioritize the projects with greatest impact. The prioritization breakdown is as follows; 60% Voltage, Loading, Reliability, Outage Response, Aging Infrastructure, Number of Customers, Dollars per Customer, and PSC Complaint, 10% Historical SAIFI Contribution, 40% Anticipated SAIFI Benefit. Conceptually the Betterments Program plans to break out 60% of the overall budget to named projects, with the remaining 40% being allocated for smaller division needs.



Project Benefits:

This approach offers significant benefits. The new prioritization method allows this program to refocus on both short- and long-term SAIFI benefits that will provide the NYSEG rate payers an improved customer experience. This method also enhances the Betterments program's project efficiency and ability to respond to division level and customer needs as they arise. This provides a clear methodology to choose the most impactful projects for both the customer and the company.

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION**Actual Capital Spent, all amounts shown below in thousands (\$000's)**

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 2,118	\$ 323	\$ 432	\$ 543	\$ 447	\$ 373		
# CIAC	\$ -781	\$ -104	\$ -93	\$ -97	\$ -273	\$ -214		
# External Services	\$ 16,511	\$ 3,917	\$ 6,807	\$ 3,135	\$ 2,222	\$ 429		
# Internal - Non-AC	\$ 13	\$ 2	\$ -	\$ -	\$ 0	\$ 11		
# Internal, Labor	\$ 6,583	\$ 1,596	\$ 1,485	\$ 1,748	\$ 1,262	\$ 491		
# Internal, Overheads	\$ 5,263	\$ 1,124	\$ 1,870	\$ 1,271	\$ 881	\$ 117		
# Materials	\$ 10,914	\$ 2,332	\$ 2,928	\$ 3,276	\$ 2,482	\$ -105		
# Overheads - External	\$ 8,141	\$ 1,631	\$ 2,547	\$ 2,015	\$ 1,639	\$ 308		
Total	\$ 48,762	\$ 10,822	\$ 15,976	\$ 11,891	\$ 8,661	\$ 1,411		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 5,183	\$ 206	\$ -	\$ 3	\$ 1,189	\$ 1,225	\$ 1,261	\$ 1,299
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 30,000	\$ 7,599	\$ -	\$ 14	\$ 5,351	\$ 5,512	\$ 5,677	\$ 5,847
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 2,600	\$ 1,442	\$ -	\$ 1	\$ 277	\$ 285	\$ 293	\$ 302
# Internal, Overheads	\$ 4,979	\$ 1,181	\$ -	\$ 2	\$ 833	\$ 842	\$ 941	\$ 1,180
# Materials	\$ 26,179	\$ 3,767	\$ -	\$ 14	\$ 5,354	\$ 5,514	\$ 5,680	\$ 5,850
# Overheads - External	\$ 5,221	\$ 1,367	\$ -	\$ 2	\$ 845	\$ 854	\$ 955	\$ 1,198
Total	\$ 74,162	\$ 15,562	\$ -	\$ 36	\$ 13,849	\$ 14,232	\$ 14,807	\$ 15,676

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 1,464	\$ -	\$ -	\$ 1	\$ 350	\$ 360	\$ 371	\$ 382
Materials	\$ 366	\$ -	\$ -	\$ 0	\$ 87	\$ 90	\$ 93	\$ 96
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,830	\$ -	\$ -	\$ 1	\$ 437	\$ 450	\$ 464	\$ 478

NYSEG Raylinski Tap 606(635T606)

PROJECT INFORMATION

OpCo:	Project ID:	Charge Code:	Project Sponsor:	Project Type:
NYSEG	PRJ-007416	Distribution	Rob McDonough	Program
Business Area:	Category:	IP Stage:	Start Date:	In-Service Date:
Electric Operation	Betterments	IP1	Jan-26	Dec-26

Project description:

Raylinski Tap 606 is a 34.5kV distribution mega-circuit tapped off the 601L (Mullberry-to-Coons Crossing), servicing 4,346 total customers. Along Staniak Rd, the lightly loaded Luther Forest 635 and the Raylinski Tap share single phase distribution customers. This location presents an opportunity to upgrade the line to three phase 34.5kV and make the Luther Forest 635 the normal source.

Project Scope:

Upgrade and convert approximately 1 miles of 3-phase 34.5kV along Staniak Rd:

- Conductor ~1 mile of 477 poly wire
- Install ~1 mile of 4/0 neutral wire
- Install ~30 poles
- Reprogram SCADA devices
- Remap new LF635 vs Raylinski 606

Project Benefits

This project benefits all 478 customers downstream of L45 P9 currently in a radial configuration. By constructing the 3-phase 635T606 along Staniak Rd the Company will see improved reliability metrics (CAID/SAIFI) on the Raylinski Tap 606 circuit. Additionally, this new construction will aid in mitigating the as-is 606 mega-circuit by shifting 478+ customers to the lightly loaded LF635.

NYSEG Raylinski Tap 606(635T606)

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007416	Charge Code: Distribution	Project Sponsor: Rob McDonough	Project Type: Program
Business Area: Electric Operation	Category: Betterments	IP Stage: IP1	Start Date: Jan-26	In-Service Date: Dec-26

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

NYSEG Raylinski Tap 606(635T606)

PROJECT INFORMATION

OpCo:	Project ID:	Charge Code:	Project Sponsor:	Project Type:
NYSEG	PRJ-007416	Distribution	Rob McDonough	Program
Business Area:	Category:	IP Stage:	Start Date:	In-Service Date:
Electric Operation	Betterments	IP1	Jan-26	Dec-26

5 Year Capital Plan, all amounts shown below in thousands (\$000's)

	Total	2024	2025	2026	2027
# AFUDC					
# CIAC	\$ -				
# Cost of Removal					
# External Service	\$ -				
# Internal, Labor	\$ -				
# Internal, Overheads (incl. Internal Non-AC)	\$ -				
# Materials	\$ -				
# Overheads - External	\$ -				
Total	\$ -	\$ -	\$ -	\$ 1,850,000	\$ -

Plant Additions, all amounts shown below in thousands (\$000's)

	Total	2024	2025	2026	2027
	\$ -				

NYSEG Pound Ridge 457

PROJECT INFORMATION

OpCo:	Project ID:	Charge Code:	Project Sponsor:	Project Type:
NYSEG	PRJ-007476	Distribution	Rob McDonough	Program
Business Area:	Category:	IP Stage:	Start Date:	In-Service Date:
Electric Operation	Betterments	IP1	Jan-26	Dec-26

Project description:

Stone Hill Rd is fed from the east in the town of Pound Ridge by the Pound Ridge 457 circuit and is fed from the west in the town of Bedford by the Cantitoe 497 circuit. There is an open point at P2448 between the two circuits. The large customer count of Millertown Rd is causing phase imbalance on both circuits. By extending three phase down Stone Hill Rd from both circuits a SCADA tie recloser can be installed. Two phases may need to be extended down Millertown Rd, further load studies are needed. The Cantitoe 497 is currently 2 phase wye where highlighted on Old Post Rd and must be upgraded to three phase, poles are newly set in this area and are framed for three phase.

Project Scope:

Recloser tie switch at P2448
Tree work needed- scope unknown
Upgrade 2ph 4/0 with 3ph 477 P.AL and 4/0 B.AL neutral for approximately 7,500' (1.4 miles)-highlighted section
Upgrade 1ph 4/0 with 3ph 477 P.AL and 4/0 B.AL neutral for approximately 9,000' (1.7 miles)- Stone Hill Rd
Spot replace approximately 60 poles with 45'2 poles on Stone Hill Rd
Potentially extend an additional phase down Millertown Rd with potential pole replacements, requires load study and site visit to determine

Project Benefits

Cantitoe 497 was on the red circuit list in 2023 with a Saifi score of 0.00567571176509584
Pound Ridge 457 was on the yellow circuit list in 2023 with a Saifi score of 0.00308757559820515
Adds another tie between circuits for storm sectionalizing.
Fixes phase imbalance on Stone Hill Rd

NYSEG Pound Ridge 457

PROJECT INFORMATION

OpCo:	Project ID:	Charge Code:	Project Sponsor:	Project Type:
NYSEG	PRJ-007476	Distribution	Rob McDonough	Program
Business Area:	Category:	IP Stage:	Start Date:	In-Service Date:
Electric Operation	Betterments	IP1	Jan-26	Dec-26

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

NYSEG Pound Ridge 457

PROJECT INFORMATION

OpCo:	Project ID:	Charge Code:	Project Sponsor:	Project Type:
NYSEG	PRJ-007476	Distribution	Rob McDonough	Program
Business Area:	Category:	IP Stage:	Start Date:	In-Service Date:
Electric Operation	Betterments	IP1	Jan-26	Dec-26

5 Year Capital Plan, all amounts shown below in thousands (\$000's)

	Total	2024	2025	2026	2027
# AFUDC					
# CIAC	\$ -				
# Cost of Removal					
# External Service	\$ -				
# Internal, Labor	\$ -				
# Internal, Overheads (incl. Internal Non-AC)	\$ -				
# Materials	\$ -				
# Overheads - External	\$ -				
Total	\$ -	\$ -	\$ -	\$ 2,200,000	\$ -

Plant Additions, all amounts shown below in thousands (\$000's)

	Total	2024	2025	2026	2027
	\$ -				

NYSEG 2024 Betterment - Ridge Rd 501 Relocation

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-004958	Charge Code: Electric Distribution	Project Sponsor: Shail, Joshua	Project Type: Project
Business Area: Electric Operations	Rate Case Category Reliability	Project Stage: IP4 Change	Start Date: H1 2025	In-Service Date: H2 2025

Project description:

Circuit 501 is a 34kV distribution circuit out of Ridge Rd Substation in Horseheads North, NY supplying 1,556 customers. The circuit crosses Old Ithaca Rd and runs south then east through the woods before emerging back out and running along Main St.

Project Need

The section of 501 that goes through the woods past Old Ithaca Rd is difficult to access and prone to tree contact.

Project Scope:

Bring 501 out of the woods south of Old Ithaca Rd and run it along the roadside. The new section of the circuit will run along the same path as circuit 305 which will be underbuilt circuit 501.

Build 3,400' of new line with 477 ACSR from L-690 P-9 (circuit 305 structure) to L-690 P-30 (circuit 305 structure)

Remove the 4,600' of existing line that runs through the woods

Project Benefits:

This project benefits all 1,556 customers on circuit 501 by lessening the hazard posed by vegetation to cause faults on the line and additionally make the line more accessible to crews to repair when faults do occur, speeding restoration efforts.

BCA for this project is 2. This is higher than the IP2 BCA as a result of a change in the way the BCA is calculated.

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 3	\$ -	\$ -	\$ -	\$ -	\$ 3		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 29	\$ -	\$ -	\$ -	\$ -	\$ 29		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 148	\$ -	\$ -	\$ -	\$ -	\$ 148		
# Internal, Overheads	\$ 52	\$ -	\$ -	\$ -	\$ -	\$ 52		
# Materials	\$ 121	\$ -	\$ -	\$ -	\$ -	\$ 121		
# Overheads - External	\$ 102	\$ -	\$ -	\$ -	\$ -	\$ 102		
Total	\$ 456	\$ -	\$ -	\$ -	\$ -	\$ 456		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 40	\$ 40	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,026	\$ 1,026	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 20	\$ 20	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 78	\$ 78	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 79	\$ 79	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,242	\$ 1,242	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 28	\$ 28	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Materials	\$ 7	\$ 7	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 35	\$ 35	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

NYSEG Animal Guard Program

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-003454	Charge Code: Electric Distribution	Project Sponsor: Shail, Joshua	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Animal Guard program was developed to increase reliability and reduce the number of interruptions caused by animal contact. These installations contribute to System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) improvements.

This program will target the worst performing circuits across NYSEG for animal guard installation with the goal of increasing service reliability through minimizing animal contact on distribution transformers. Guards are to be installed on distribution transformer bushings, arresters, and LA brackets, if applicable.

Project Scope:

This program focuses on installing animal guards on pole-mounted distribution transformers. The guards will be installed on transformer bushings, arresters, and LA brackets, where applicable.

The Animal Guard Program is prioritized by ranking circuits from highest number of customers affected by distribution animal contacts to lowest. This program has had over 65% reduction to customers affected by distribution animal contacts following remediation of a circuit. NYSEG interrupted an average of 44,200 customers annually from distribution animal contacts in the past 3 years.

The following units and average unit costs will be addressed between 2025-2031:

2025 - 3,500 (units) / \$604 (unit cost)

2026 - 2,366 (units) / \$622 (unit cost)

2027 - 2,421 (units) / \$641 (unit cost)

2028 - 2,478 (units) / \$660 (unit cost)

2029 - 2,536 (units) / \$680 (unit cost)

2030 - 2,597 (units) / \$700 (unit cost)

2031 - 2,660 (units) / \$721 (unit cost)

Project Benefits:

This project will increase circuit reliability and reduce O&M costs by minimizing the number of animal caused service interruptions.

Project Risks and Mitigation Plan:

The Animal Guard program employs data driven decision-making, proactive inspections and systematic maintenance, aiming to reduce outages and safety risks. The program ensures compliance with regulatory standards, efficient budget management and transparent stakeholder communication. By prioritizing safety and reliability, NYSEG seeks to provide a more dependable electricity supply and improved service quality to its customers in the region.

Animal guard installations are simple, can be executed quickly, and the benefits are immediate. Material costs are low, as well as the one-time cost of installation when compared to ongoing O&M costs to repair service interruptions from animal contact on an as needed basis. From this standpoint, fixing animal guards to existing distribution transformers is a more proactive approach to improving and ensuring continued service reliability.

Risk of No Action:

If this program is not pursued, service interruptions due to animal contact will continue to occur, leading to higher O&M costs for necessary restorations and adversely affecting SAIFI metrics.

Project Alternatives:

The animal guard program focuses on protecting transformer bushings, with alternatives evaluated on a case-by-case basis.

Basis for Project Estimates

The financial plan is based on the average cost per animal guard, which includes expenses for construction crews, internal labor, materials, and applicable overheads for standard installations.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 309	\$ -	\$ -	\$ 137	\$ 103	\$ 69		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 10,636	\$ -	\$ -	\$ 4,777	\$ 2,588	\$ 3,270		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 6	\$ -	\$ -	\$ -	\$ 3	\$ 2		
# Internal, Overheads	\$ 1,715	\$ -	\$ -	\$ 715	\$ 479	\$ 522		
# Materials	\$ 1,925	\$ -	\$ -	\$ 830	\$ 966	\$ 129		
# Overheads - External	\$ 2,863	\$ -	\$ -	\$ 1,171	\$ 931	\$ 760		
Total	\$ 17,454	\$ -	\$ -	\$ 7,630	\$ 5,071	\$ 4,753		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 11,146	\$ 1,943	\$ 1,353	\$ 1,421	\$ 1,492	\$ 1,566	\$ 1,644	\$ 1,727
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 959	\$ 178	\$ 136	\$ 113	\$ 112	\$ 116	\$ 133	\$ 171
# Materials	\$ 1,091	\$ 171	\$ 119	\$ 131	\$ 144	\$ 159	\$ 174	\$ 192
# Overheads - External	\$ 971	\$ 171	\$ 140	\$ 116	\$ 115	\$ 119	\$ 136	\$ 175
Total	\$ 14,166	\$ 2,464	\$ 1,748	\$ 1,781	\$ 1,863	\$ 1,960	\$ 2,088	\$ 2,264

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Transmission Reinforcement Program

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-003857	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The NYSEG Transmission Reinforcement Program is crucial to the long-term viability of the NYSEG transmission system and its ability to serve customer load growth conditions projected due in part to state clean energy goals. The program identified several system upgrades that are necessary to address current and forecasted system constraints within the NYSEG Transmission system. This program covers two main categories of projects: (1) Projects identified in the NYSEG Transmission Local Area Study (LAS), and (2) Projects identified through the NERC TPL-001-5 compliance assessment ("TPL Study"). Both types of area studies identified a wide range of reliability criteria violations (including thermal overloads, severe voltage violations or voltage collapse) which pose significant risks to the reliability of NYSEG's bulk transmission system.

NYSEG Transmission LAS

The NYSEG Transmission LAS (attached) is a comprehensive study designed to demonstrate that the portion of the non-Bulk Electric System (non-BES) transmission system owned by NYSEG is compliant with the applicable Local Transmission Planning Criteria. To achieve this objective, NYSEG performed a comprehensive planning assessment of the non-BES transmission system to determine if any potential current or future system violations ("Needs") exist. For those instances where Needs were identified, long-term solutions were developed. All long-term solutions were tested against and comply with the Bulk Electric System (BES) and non-BES Planning Criteria.

The NYSEG Transmission LAS identified 81 projects across the all NYSEG divisions. In total, based on external projections of load growth through 2031, NYSEG will need to upgrade 27 miles of transmission line, 10 transformers, 18 capacitors, and 7 substations. Asset Condition will be assessed on a project-specific basis.

NYSEG NERC TPL-001-5 Compliance Assessment

The TPL Study (attached) focused on BES system violations. These critical transmission upgrades are driven by the need to address higher forecasted winter peak loads, which were not forecasted in previous NERC TPL studies. The projects include enhancing substation infrastructure, adding reactive power support, and constructing new transmission lines. Collectively, these projects aim to improve the reliability, capacity, and stability of the NYSEG bulk transmission system, ensuring it can meet the increased demand and maintain compliance with NERC TPL-001 standards.

The TPL Study is focused on adherence to the performance criteria established in NERC TPL-001-5. It does not include an assessment of Asset Condition. BES projects from the TPL assessment are preliminarily scoped based on reliability-only needs, and scopes are later adapted to include mitigation for relevant asset condition needs and be right-sized to maximize local system capacity.

Project Scope:

The scope of the Transmission Reinforcement Program is broken down by division and by equipment type. Across all NYSEG divisions, there are 27 miles of transmission line (15 miles of 115 kV and 12 miles of 34.5 kV and 46 kV) that need to be upgraded. 10 transformers require replacement, predominantly at the 115/34 kV voltage levels class. To minimize cost and defer more extensive transmission upgrades, 18 capacitors need to be added to the system at the 115 kV, 46 kV, and 34 kV, voltage levels. 7 substations will require significant upgrades which range from expanding the existing footprint with the new transformers and capacitors previously discussed to performing a full rebuild when the existing site is no longer practical for supporting expansion.

Auburn LAS: State Street 115/34.5 kV transformer upgrades (1 new, 1 replacement), install 34.5 kV capacitors at Weedsport, Clinton Corn substation upgrades.

Binghamton LAS: Lounsberry full substation rebuild with 115 kV AIS Ring BUS, 12 kV GIS, new 115/12 kV transformer.

Brewster LAS: Upgrade 115/46 kV transformers at Pawling (x2) and Croton Falls, install 46 kV capacitors at Dingle Ridge, Crafts, and Pound Ridge substation.

Elmira LAS: Upgrade approximately 3 miles of 34.5 kV line between Erwin Junction and Presho substations with terminal upgrades at Presho. New 115/34.5 kV transformer at Montour Falls substation.

Geneva LAS: Install 115 kV capacitors at Border City and Haley Road substations, new 34.5 kV capacitor at Milo substation.

Hornell LAS: Install 34.5 kV capacitor at Howard substation and 34.5 kV Static Var Compensator at Bennett substation.

Ithaca LAS: Install 34.5 kV capacitors at Cayuga Heights, Locke, and Peruville.

Lancaster LAS: Install two new transformers at Stolle Road substation, Rebuild South Park substation with new 115/34.5 kV transformers, upgrade Cobble Hill with new 115 kV terminals.

Liberty LAS: Upgrade 34.5 kV line between Hilldale and W. Woodbourne (4.5 miles) and between Ferndale to Liberty (3.5 miles). Add new 115/34.5 kV transformer to West Woodbourne, add 34.5 kV capacitors at Old Falls, Grossinger, White Lake, and Callicoon. Rebuild Hilldale substation with 34.5 kV straight bus.

Mechanicville LAS: New 115 kV line from Falls Park to Klinekill (15 miles). New 115/34.5 kV transformers at Klinekill substation.

Plattsburgh LAS: New 34.5 kV capacitor at Peru substation.

TPL-001 Compliance Assessment

The conceptual projects developed as part of the 2023 TPL-001 Compliance Assessment includes transmission upgrades needed to address identified system needs within the next 10 years. The projects are currently in a conceptual stage; the scope and schedule will be refined as detailed engineering activities are performed.

The BES projects included in this program are described below:

Binghamton TPL

North Endicott substation upgrade (BG-B): rebuild as 115kV, 3-bay BAAH (AIS) and add 2, 12 MVar 34.5 kV shunt capacitors.

South Owego Reactive Power Support (BG-C): Add 1, +/-50 MVar 115 kV STATCOM.

115kV Line 945 Uprate (BG-D): Uprate 115kV line 945 (Etna to Clarks Corners).

115kV Line 947 Uprate (BG-E): Uprate 115kV line 947 (Ranch Hill to Castle Garden).

Brewster TPL

Pawling Substation Breaker Addition (BR-A): Install bus-tie breaker and line breaker.

Elmira TPL

West Erie Reinforcement (EB-A): Rebuild West Erie as 115 kV, 3-bay BAAH and build new 115 kV line from West Erie to Hickling.

Geneva TPL

New 115kV line Sleight Road to S126: Build new 115kV line from Sleight Rd to RG&E Station 126.

Hornell TPL

Bennett Substation Reactive Power Support (HR-B): Install one (1) 30 MVar STATCOM at Bennett substation.

Lancaster TPL

Cobble Hill Substation Upgrade (LN-C): Rebuild as 115kV, 3-bay BAAH (AIS).

Line 706 Uprate (LN-D): Uprate Line 706 (Stolle Road to Girdle Road).

Mechanicville/Berkshire TPL

New 115kV Line Klinekill to Falls Park: Build new 115 kV transmission line from Klinekill to Falls Park; Install one (1) new 115/34.5kV transformer (50MVA) at Klinekill; Install one (1) new 20MVar 115kV shunt capacitor at Klinekill and one (1) new 10MVar 34.5kV shunt capacitor at Stephentown.

Oneonta TPL

New 115kV Line Brothertown to Richfield Springs (ON-B): Build a new 115 kV line from Brothertown to Richfield Springs and Install one (1), 50 MVar STATCOM at Brothertown.

Grand George Substation Upgrade (ON-E): Add two (2) 115kV circuit breakers at Grand Gorge and Belleayre, respectively; Install one (1), 115kV 8MVar capacitor at Grand Gorge; Add MODs at Windham and Arkville substations.

Fraser 3rd Transformer Addition (ON-F): Install a 3rd 345/115kV transformers at Fraser.

Plattsburgh TPL

Flatrock and Hallock Hill Reactive Power Support: Install two (2), 30MVar 115kV capacitors at Flatrock; Install two (2), 10MVar 46kV capacitors at Hallock Hill.

Project Benefits:

These projects will enhance the reliability, capacity, and stability of NYSEG's BES and non-BES transmission system. Resolving these Needs improves customer reliability, reduces risk of equipment damage, replaces aging infrastructure, and creates capacity for local load growth. SAIFI and SAIDI are expected to improve, protection equipment will be modernized, and non-BES transmission resiliency will improve.

The Transmission Reinforcement projects identify the most immediate system reliability Needs on the BES and non-BES transmission system.

These projects form the backbone on top of which the Comprehensive Area Studies are performed. The combination of these two study efforts leads to resolving immediate Needs that exist on the network today, while "right-sizing" projects to support long-term load growth when applicable.

Specific quantifiable benefits (SAIFI improvement, SAIFI avoidance, capacity gained, etc.) are calculated on a per-project basis prior to final internal budget approval.

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to capacity constraints, resulting in worsening voltage violations and reliability issues. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if reliability criteria violations are forecasted to occur prior to project completion.

(2) Actual load growth may not align with forecasted values. If actual load growth is materially lower/slower or higher/faster than NYSEG's forecast indicated, there may be risks related to overbuilding or underbuilding, respectively. Mitigation measures of minimize the risk of overbuilding include prioritizing the projects based on urgency and severity, and implementing projects in phases, allowing for adjustment based on the actual load growth. To mitigate the risk of underbuilding, NYSEG designs infrastructure with scalability in mind, allowing for future expansions without significant additional costs.

(3) Further assessment of project-specific risks is performed during the comprehensive solution assessment, which is required as part of the internal budget approval process. Typical project risks that are evaluated include (but are not limited to) ground water monitoring, soil contamination, traffic control, energized equipment, and working in confined spaces.

The Transmission Reinforcement projects address system Needs that exist today as well as those that are expected to develop in the near future. As long as these risks continue unmitigated, there is an elevated risk to customer reliability and equipment security. Additionally, until these Needs are resolved, they are restricting the capacity that is available for load growth in the relevant areas. Delaying these projects may suppress economic growth in the affected region.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth. Deferring action on these projects can constrain the ability to operate the system effectively during periods of high load.

NYSEG is required to have Correction Action Plans for identified system Needs. Taking no action could result in failure to comply with NERC TPL-001 standards which could result in penalties and increased scrutiny from regulatory bodies.

Individual projects within this program have specific alternative considerations. A pre-requisite to assigning any funding to a project is the System Review Group to review the alternative approaches to each specific project and reach agreement on the selected alternative. This judgement is made based on cost and total benefits (reliability, capacity gain, maintenance and construction risk, etc.) and documented with the project-specific files.

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 275,433	\$ 5,000	\$ -	\$ -	\$ 16,393	\$ 18,020	\$ 77,062	\$ 158,958
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 24,603	\$ -	\$ -	\$ -	\$ 1,756	\$ 6,885	\$ 8,385	\$ 7,577
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 25,537	\$ -	\$ -	\$ -	\$ 1,823	\$ 7,146	\$ 8,703	\$ 7,865
Total	\$ 325,573	\$ 5,000	\$ -	\$ -	\$ 19,972	\$ 32,051	\$ 94,150	\$ 174,400

[illegible]

Lancaster Division Substation Upgrade - Wehrle Drive Substation

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-004827	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP2 Technical	Start Date: Ongoing	In-Service Date: H2 2027

Project description:

The Local Transmission Planning (LTP) study identifies where the exposure to customer interruption warrants further mitigations.

The loss of load criteria are:

Limit load loss between breakers to 25 MW for single line and transformer design contingencies

Limit load to 10 MW between automatic sectionalizing schemes.

The Local Transmission Planning study identified an N-1 contingency for an outage on Line 514 that results in lost load of 25.57 MW affecting 3,951 customers.

This project will address this concern due to loss of load.

Project Scope:

Sectionalize Line 514 with Two Reclosers

Cost Estimate (+50/-25%): \$1.6 M, ISD 2026, BCA 28.25

Scope

(2) 630A1 34.5 kV reclosers. Reclosers will function as an auto-restoration scheme.

Fiber optic cable will be run between the new reclosers for new protection and control scheme.

Project Benefits:

Loss of one line leaves both transformers in service.

Lowest cost Alternative considered.

SAIFI Avoidance of 0.2291% (excluding storms) and 0.3353% (including storms)

By systematically reducing load on a heavily loaded substations, NYSEG can further enhance reliability, extend equipment lifespan, improve efficiency, and maintain better power quality. It also leads to cost savings by avoiding the need for frequent repairs, replacements, or costly upgrades, and helps in complying with regulatory standards. Overall, effective load management ensures a more resilient, efficient, and cost-effective power distribution system.

Project Risks and Mitigation Plan:

Risks exist in project execution, particularly regarding engineering and material procurement. To ensure materials are received on time, we will proactively order long lead materials.

Weather delays pose a risk in distribution construction as our resources frequently support storm restoration efforts. We mitigate these weather-related delays by incorporating contingency into our construction schedules.

The health and safety of our workers are a primary concern. Risks associated with traffic control, working with energized equipment, slips, and trips are common on most projects. We mitigate these risks with project-specific health and safety plans.

Many projects involve de-energizing existing substation equipment to facilitate replacements or upgrades. This process inherently carries risks, such as potential power outages and the safety of personnel working on de-energized equipment. To mitigate these risks, we coordinate and utilize mobile substations in applicable scenarios. Mobile substations allow for the temporary transfer of load, ensuring continuous power supply and minimizing disruptions to customers. Additionally, detailed planning and coordination are essential to ensure the safe and efficient use of mobile substations. This includes thorough risk assessments, clear communication with all stakeholders, and adherence to strict safety protocols. By implementing these measures, we can effectively manage the risks associated with de-energizing substation equipment and ensure the successful completion of our projects.

Financial risks are inherent in project execution as new information emerges. We mitigate these risks by utilizing scheduling and forecasting tools, such as Primavera, for project management. We continuously forecast project-specific activities using these tools and update the project progress monthly. This approach allows us to accurately predict project completion and estimate costs at completion.

Risk of No Action:

If no action is taken, several risks could arise:

Equipment Damage: Operating substation transformers and other major equipment near or over capacity can lead to overheating and accelerated wear and tear, ultimately causing equipment failure.

Power Outages: The reliability of the power supply could be compromised, leading to more frequent and prolonged power outages for customers.

Safety Hazards: Overloaded equipment can pose safety risks, including the potential for fires or other hazardous conditions.

Increased Costs: The cost of emergency repairs and replacing damaged equipment can be significantly higher than the cost of proactive maintenance and upgrades.

Customer Dissatisfaction: Frequent power outages and unreliable service can lead to customer dissatisfaction and potential loss of trust in the utility provider.

Regulatory Non-Compliance: Failing to maintain equipment and ensure reliable service could result in non-compliance with regulatory standards, leading to fines and other penalties.

Limited Capacity for Growth: Without load reduction and system improvements, there may be limited capacity to accommodate new customer connections, hindering growth and development.

Taking proactive measures through programs like the Distribution Load Relief Program helps mitigate these risks and ensures a more reliable and efficient power supply.

Project Alternatives:

Alternative 2 - Sectionalize Line 514 Bus with Tie Breaker - Alternative Dismissed

One (1) 1,200A 34.5 kV vacuum circuit breaker

One (1) concrete pad foundation for breaker

Rework structural steel bracing to accommodate breaker placement

Two (2) three-pole disconnect switches.

Relay upgrades at Wehrle and remote ends

Basis for Project Estimates

Estimates are prepared using historical estimating tools and are benchmarked against actual investments in similar projects to establish a basis for project initiation. These estimates are revised throughout the project as new information becomes available.

FINANCIAL INFORMATION**Actual Capital Spent, all amounts shown below in thousands (\$000's)**

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 16	\$ -	\$ -	\$ 16	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 848	\$ -	\$ -	\$ 848	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 100	\$ -	\$ -	\$ 100	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 528	\$ -	\$ -	\$ 528	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 97	\$ -	\$ -	\$ 97	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,589	\$ -	\$ -	\$ 1,589	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ 93	\$ -	\$ -	\$ 46	\$ 47	\$ -	\$ -	\$ -

Livingston Manor Automatic Throwover Scheme

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006167	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP3 Partial Approval	Start Date: H1 2027	In-Service Date: H2 2027

Project description:

This project is a low cost, high benefit project to improve reliability for over 1,700 NYSEG customers supplied by the Livingston Manor substation through sectionalizing at the station's 34.5 kV bus with 34.5 kV reclosers programmed as SCADA switches.

Transmission Planning's Local Area Study (LAS) identified areas of high customer interruption exposure ("Loss of Load" criteria). Loss of Load needs are prioritized based on impact (MW affected, circuit length, customer count) and solution complexity/cost. This project was identified to have high impact and low complexity.

Reliability Concern:

A transmission system loss of load sectionalization criteria violation exists

NYSEG transmission planning criteria limits the load loss exposure between automated sectionalizing devices to 10 MW. Upgrading/replacing the switches at Livingston Manor substation with reclosers programmed as automated SCADA switches mitigates this violation and improves system reliability.

Project Scope:

Replace two (2) 34.5 kV switches, 34616 and 34619, with 34.5 kV reclosers programmed as automated SCADA switches. Install disconnect and bypass switches on each new device to facilitate maintenance.

Project Benefits:

This project will resolve a loss of load criteria violation where the amount of load loss under N-1 contingency conditions will be reduced to within acceptable limits. The load loss risk during an N-1 contingency event will reduce from ~11.5 MW to ~7 MW (~39% reduction) and the number of customers affected will be reduced from ~4,700 customers to ~3,000 customers (~32% reduction).

Project Risks and Mitigation Plan:

1. Delays in Project Implementation: Project delays could lead to an increase in frequency and/or duration customer outages, resulting in worsening reliability performance. Weather delays are also a risk in construction due to personnel safety concerns. These risks will be addressed by incorporating contingency into our construction schedules. To mitigate this risk, the project team conducts thorough field scouting and feasibility assessments before finalizing device locations. Long lead-time equipment delays can also adversely impact project schedules. Equipment sourcing risks will be mitigated by identifying proposed equipment subject to long lead times and ordering such equipment proactively, as appropriate, to minimize the risk of project delays.
2. Budget Risks: Another risk is the possibility of budget overruns due to unexpected costs associated with device installation, reprogramming, or adding communications. To manage this risk, regular budget reviews and cost tracking are implemented to ensure the project remains within the allocated budget.
3. Planned Outage Management: Due to peak load N-1 constraints that currently exist in the area, it may be challenging to coordinate scheduled outages to accommodate the project. To mitigate this, the project will have to be planned well in advance to have communications between the relevant stakeholders to secure additional resources such as a mobile transformer to temporarily serve customers.

Risk of No Action:

The risk of not implementing this project is the continued exposure of approximately 4,700 customers (~11.5 MW) for an N-1 contingency which could negatively impact the Company's SAIFI metrics in the event of an outage. Losing more than 10 MW of load for an N-1 contingency event is a violation of Avangrid's loss of load criteria.

Project Alternatives:

One alternate is to expand the Livingston Manor substation to add a second 115/34.5 kV transformer with highside and lowside breakers, and add two 115 kV breakers (one on each section of Line 955). By inspection, this alternative would significantly increase the cost to achieve comparable results as the preferred solution. The Company did not explore a detail cost estimate for this alternative due to the higher cost and no additional commensurate benefit when compared to the preferred solution.

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 16	\$ -	\$ -	\$ 16	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 848	\$ -	\$ -	\$ 848	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 100	\$ -	\$ -	\$ 100	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 528	\$ -	\$ -	\$ 528	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 97	\$ -	\$ -	\$ 97	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,589	\$ -	\$ -	\$ 1,589	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Spencer Automatic Throw-Over Scheme

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006171	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2027

Project description:

This project is a low cost, high benefit project to improve reliability for over 1,200 NYSEG customers supplied by the Spencer substation by sectionalizing 34.5 kV Line 530 with reclosers capable of implementing an automatic throw-over scheme at the Spencer substation.

Transmission Planning's Local Area Study (LAS) identified areas of high customer interruption exposure ("Loss of Load" criteria). Loss of Load needs are prioritized based on risk (MW affected, circuit length, customer count) and solution complexity. The Spencer Automatic Throwover Project was identified to have high risk and low complexity.

Reliability Concern:

The 2021 Avangrid NY Local Area Study (LAS) identified a N-1 contingency for an outage on Line 915 that results in lost load of approximately 10.8 MW affecting approximately 5,100 customers.

Project Scope:

Install the new reclosers capable of supporting an automatic throw-over scheme (reclosers acting as SCADA switches) as close as physically feasible to the 34.5 kV tap into Spencer substation.

Implement an automatic throw-over scheme so that upon loss of voltage at Spencer (after any reclosing at Candor and South Owego occurs) the new reclosers operate to restore Spencer from Coddington.

Install disconnect and bypass switches on each device.

Project Benefits:

This project ensures customers at Spencer (~1200) will be quickly re-energized for any transmission fault and will resolve a loss of load violation. The load loss during an N-1 contingency event will be reduced from ~11 MW (~5,100 customers) to ~8 MW (~3,900 customers).

The addition of these reclosers improve operator visibility in this region. While the customers at Spencer substation benefit most directly from this project, under various fault conditions, other customers at nearby taps are expected to indirectly benefit from improved restoration times.

Project Risks and Mitigation Plan:

Having a long outage duration during project is a potential risk. This risk can be mitigated by creating a temporary operating procedure to safely and reliably serve Spencer substation from Coddington substation via line 530 while switch on line 530 between Spencer and Candor is being replaced. There is also a need to deconflict schedules with any other projects going on in the region (no specific projects identified at this time).

Risk of No Action:

The risk of not implementing this project is the continued exposure to a loss of approximately 5,100 customer (~11 MW) for an N-1 contingency which negatively impacts the company's SAIFI score. Losing more than 10 MW of load for an N-1 contingency event is a violation of Avangrid's loss of load criteria.

Project Alternatives:

One alternative could be to expand the Spencer substation to add breakers on the 34.5 kV line 530. By inspection, this alternative would significantly increase the cost to achieve the comparable results as the preferred solution. Transmission Planning did not explore a detailed cost estimate for this project due to the higher cost and no significant additional reliability benefit when compared to the preferred solution.

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 16	\$ -	\$ -	\$ 16	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 848	\$ -	\$ -	\$ 848	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 100	\$ -	\$ -	\$ 100	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 528	\$ -	\$ -	\$ 528	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 97	\$ -	\$ -	\$ 97	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,589	\$ -	\$ -	\$ 1,589	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Stryker Ave Substation Upgrade

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006172	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2027

Project description:

This project is a low cost, high benefit project to improve reliability for over 4,700 NYSEG customers supplied by the Stryker Ave substation through sectionalizing near the station.

Replace switches 51076 (between Stryker Ave and Franklin St) and 51079 (between Stryker Ave and Swift St) with switches/reclosers that can perform an automatic throw-over scheme for loss of subtransmission source into Stryker Ave.

Transmission Planning's Local Area Study (LAS) identified areas of high customer interruption exposure ("Loss of Load" criteria). Loss of Load needs are prioritized based on risk (MW affected, circuit length, customer count) and solution complexity. This project was identified to have high-benefit and low complexity.

Reliability Concern:

A loss of load (~16 MW and ~7,400 customers) violation exists for a fault on the 34.5 kV line 506. This is a reliability violation and upgrading/replacing the switches at Stryker Ave substation with switches capable of automatic load throw over prevents this violation, and reduces SAIFI impacts for subtransmission faults making the system more reliable.

Project Scope:

Replace switches 51076 (between Stryker Ave and Franklin St) and 51079 (between Stryker Ave and Swift St) with switches/reclosers that can perform an automatic throw-over scheme for loss of subtransmission source into Stryker Ave.

Project Benefits:

When the normal feed into Stryker Ave. experiences an unplanned outage the automation throwover scheme at Stryke Ave. would be configured to automatically open the switch/recloser towards Wright Ave. and then close the normally open switch/recloser towards State St. re-energizing customers. Without this scheme in place de-energized customers at Stryke Avenue would be remain de-energized until crews arrived to repair and restore the transmission line and/or manually sectionalize at Stryker Avenue.

This project will resolve a loss of load violation where the amount of load loss under N-1 contingency conditions will be significantly reduced making the transmission network more reliable. The load loss during an N-1 contingency event will reduce from ~16 MW to ~5MW and the number of customers without service will be significantly reduced from ~7,400 customers to ~2,700 customers.

Project Risks and Mitigation Plan:

Having a long outage duration during project is a potential risk. This risk can be mitigated by creating a temporary operating procedure to safely and reliably serve Stryker Ave substation from State Street substation via lines 509 and 510 while switch 51079 is being replaced.

Risk of No Action:

The risk of not implementing this project is the continued exposure to de-energizing approximately 7,400 customer (~16 MW) for a N-1 contingency subtransmission line fault. In addition, the violation of NYSEG's Loss of Load Criteria will not be resolved.

Project Alternatives:

One alternate is to expand the Stryker Ave substation to add breakers on the incoming 34.5 kV subtransmission lines. However this alternative was not pursued as it would significantly increase the cost to achieve comparable results as the preferred solution. Due to the higher cost without significant material benefit a detailed cost estimate for this alternative was not pursued.

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 16	\$ -	\$ -	\$ 16	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 848	\$ -	\$ -	\$ 848	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 100	\$ -	\$ -	\$ 100	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 528	\$ -	\$ -	\$ 528	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 97	\$ -	\$ -	\$ 97	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,589	\$ -	\$ -	\$ 1,589	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

34.5 kV NYSEG Line 455 Upgrades

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-004057	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

Line 455 is an 8.7-mile 34.5 kV transmission line in NYSEG's Binghamton division. This transmission line currently provides a peak load of about 25.9 MVA of power to 8,998 customers. Northside Substation is the source for Line 455. The line has distribution under-build for approximately 4.9 miles. There are six different distribution circuits that jump off and on the Line 455 structures. Line 455 is roadside for about 1.2 miles. The oldest parts of the transmission line were built in the 1940s. The Line 344 Upgrade project will mitigate the reliability needs, asset condition needs, and operational constraints outlined below.

Reliability Needs

There have been 12 outages on Line 455 from January 2020 to September 2022. 11 out of these 12 outages occurred between Morningside Heights and Chenango Bridge. There is no ROW here, only pole rights on this section of Line 455. Most of the line is trimmed to a 40-foot width or less. There are many "danger trees" in this area.

The majority of the "Company Equipment" SAIFI contribution is defective insulators.

Line 455's impact to total NYSEG SAIFI: 0.99% (2020), 0.63% (2021), 0.68% (2022)

Total NYSEG SAIFI: 1.38 (2020), 1.45 (2021), 1.13 (2022)

Distribution under-build outages collocated on Line 455 poles didn't significantly contribute to SAIFI. Less than 2% of total Line SAIFI - 0.0001 (2020), 0.000011 (2021), 0.000017 (2022).

Asset Condition Needs

The structures on Line 455 are an average of 46 years old. 6 out of 228 structures (3%) are considered danger poles and should be replaced as soon as possible. 53 out of 228 structures (23%) failed visual inspection and are considered reject poles. On top of the 59 structures that require replacement, there 58 additional structures with TLDs (25%). These TLDs include items like arm or insulator replacements and pole, arm, hardware, conductor, shield wire or guy repairs I.E. repairs that are not severe enough to warrant a pole replacement.

IEEE Reference Study: Aged ACSR Conductors Part II – Prediction of Remaining Life

For planning purposes, a mean useful life of 70 years is considered valid for existing ACSR conductors. Existing conductors with single layer steel cores last about 12 years less (58 years) than those with two layers. 4.6 miles of Line 455 has conductor over the age of 70.

Lightning Protection: 2.3 miles of Line 455 (from Nowlan Road Substation to Bevier Street Substation) does not have shield wire and is more susceptible to lightning strike related outages and damages.

PCB Filled Transformers: Identified high priority PCB transformers on Line 455 at two locations (Structure 89 and 95 in Chenango, FLOC: 9301-L1098-0405-0012-ED00082 & 9301-L1098-0405-0012-ED00088)

Right of Way & Vegetation Trimming: Where the ROW is pole rights only (47% of the line), there are no defined vegetation trimming rights in these sections. Effective vegetation management practice requires 80 to 100 feet in off-road rural areas and 20 to 40 feet in residential/roadside areas.

Operational Constraints

Working Clearances: Can't complete climbing inspections for tangent structures with horizontal post insulators. Limited by 2'10" Minimum Approach Distance (Avangrid Networks Safety Handbook 2.13.1.e & Table 2, OSHA 1910.269)

Distribution Under-build:

- Significant difficulty to avoid distribution when needing to work on transmission above
- Can't get bucket mounted conductor lift tool in between to work on pole or change insulators or arms
- Insufficient vertical clearances in many cases to use hot stick methods without also moving distribution conductors

Project Scope:

Reconductor & Selected Structure Replacements (\$30.7 M, ISD 2030): Reconductor Line 455 from Chenango Bridge to Nowlan to Bevier (4.6 miles) to remove 72 and 96-year-old conductor. Perform in-kind structure replacements as required to mitigate visual, structural, or clearance failures. Based on the asset condition data collected, it's assumed 45% of structures would need to be replaced. SAIFI Avoidance: 0.012-0.013 per year after the project is in service.

The five- or 10-year inspection cycles would likely indicate that some of the remaining untouched structures need replacement (No deferred maintenance costs like a full rebuild).

Converts 'pole rights only' easements to ROW where transmission line isn't road-side or ROW does not exist (4.2 miles).

The 2.3 miles of transmission line without lightning protection would remain without lightning protection.

Assumes no additional structural overloads as a result of the reconductor.

Project Benefits:

Addresses all deficient infrastructure.

Converts 'pole rights only' easements to ROW where transmission line isn't road-side or ROW does not exist (4.2 miles). This gives the company the ability to better execute the vegetation management program, provides better access for maintenance, and improves outage response time.

Project Risks and Mitigation Plan:

Top risks associated with the project would be worker injury during construction. This risk can be mitigated by instituting a Health and Safety Plan (HASP).

This project is in the pre-conceptual stage, a risk register has not been created for this project.

If the Line 455 project were not to move forward, there is another project in the area that has already proven to mitigate outages. This is the Chenango Bridge & Kattelville Sectionalizing Upgrades project. Since installation of this project, there were not any outages on Line 455 in 2024.

Chenango Bridge & Kattelville Sectionalizing Upgrades Project Initiating Needs:

Reliability: The 2021 Local Transmission Plan identified a loss of load that exceeds that 25 MW loss of load criteria for some faults on Line 455.

Asset Condition: Circuit breakers and associated relaying are in poor condition at Chenango Bridge & Kattelville.

Chenango Bridge & Kattelville Sectionalizing Upgrades Project Solutions:

Kattelville: Replace recloser with breaker on Line 422, In-and-out Line 426 and install new breakers

Chenango Bridge: Add breakers for Line 454 and 455

Move normally open point on 426 from Kattelville to Chenango Bridge.

Capabilities Gained by Chenango Bridge & Kattelville Sectionalizing Upgrades Project:

For loss of the 455 Line from Northside, all of Chenango Bridge 4.8 kV load and 428 Line can automatically be fed from Kattelville

Improved fault location/sectionalizing

Criteria load loss exposure now 7.3 MVA at Morningside Heights

Potential Impact of the Chenango Bridge & Kattelville Sectionalizing Upgrades project:

There were 12 outages on Line 455 from 2020 to June 2022 with a total SAIFI impact of 0.01388

For each of the faults the proposed scheme would have eliminated all customer outages > 5 minutes.

There would be momentary interruptions (perhaps < 1 min) as the schemes operated to locate.

Risk of No Action:

Continued outages and customer interruptions due to vegetation, failed equipment or lightning strikes.

Operational constraints will continue (Working Clearances: Can't complete climbing inspections for tangent structures with horizontal post insulators.

Limited by 2'10" Minimum Approach Distance (Avangrid Networks Safety Handbook 2.13.1.e & Table 2, OSHA 1910.269)

Distribution Under-build:

Significant difficulty to avoid distribution when needing to work on transmission above

Can't get bucket mounted conductor lift tool in between to work on pole or change insulators or arms

Insufficient vertical clearances in many cases to use hot stick methods without also moving distribution conductors).

Project Alternatives:

Full Rebuild (\$48.0 M, ISD 2030): Rebuild Line 455 on the existing centerline with 477 Pelican ACSR and OPGW. The line would be rebuilt with wood poles in a davit arm delta configuration. Angle and deadend structures would employ the use of guy wires where possible. Avoidance: 0.016-0.018 per year after the project is in service.

This alternative addresses all aging infrastructure and the line will be built in accordance with Avangrid standards.

OPGW provides an enhanced future communication path for protection and control system upgrades.

Converts 'pole rights only' easements to ROW where transmission line isn't road-side or ROW does not exist (4.2 miles).

Yields the longest lasting solution.

Despite the benefits of this alternative, it was not selected as there is a minimal SAIFI improvement from the selected alternative and it would cost about 50% more.

Basis for Project Estimates

These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, Avangrid Master Service Agreement rates from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Escalation rates are based upon current U.S. inflation rates. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 2,139	\$ -	\$ 345	\$ 388	\$ 369	\$ 818	\$ 219	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 21,040	\$ -	\$ 3,399	\$ 3,815	\$ 3,631	\$ 8,043	\$ 2,153	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 1,495	\$ -	\$ 242	\$ 271	\$ 258	\$ 572	\$ 153	\$ -
# Internal, Overheads	\$ 1,713	\$ -	\$ 350	\$ 310	\$ 277	\$ 601	\$ 175	\$ -
# Materials	\$ 783	\$ -	\$ 126	\$ 142	\$ 135	\$ 299	\$ 80	\$ -
# Overheads - External	\$ 2,037	\$ -	\$ 416	\$ 369	\$ 329	\$ 715	\$ 208	\$ -
Total	\$ 29,207	\$ -	\$ 4,879	\$ 5,294	\$ 4,998	\$ 11,048	\$ 2,987	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Proactive Planning - Ferndale

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006419	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

Overview: The Ferndale Project aims to address urgent capacity constraints and reliability issues within the Liberty Division, located the Towns of Liberty and Fallsburg, Sullivan County. The project involves significant upgrades to the 115/34.5 kV Ferndale Substation to address the existing transmission and distribution capacity constraints identified in the facilities near Ferndale Substation (Liberty Division). These pre-existing system needs have been further intensified by several customer load requests submitted in recent years. The total load requests studied amount to 7.6 MW, with 12% from transportation electrification, 34% from heat pump electrification, and the remaining 58% from economic development initiatives.

Current State Needs Assessment: The Swan Lake and Hilldale Substations, constructed in 1955 and 1956 respectively, face significant reliability issues due to equipment thermal overloading and system voltage reliability criteria violations. The Swan Lake Substation's 34.5/4.8 kV transformer bank #1 is loaded to 130% of its summer Normal rating based on the peak historical 3-year average, and 164% if queued loads are included. The Hilldale Substation's 34.5/12.5 kV transformer bank #1 is loaded to 103% of its summer Normal rating based on the peak historical 3-year average, and 133% if queued loads are included. Additionally, the Liberty #142 distribution circuit is loaded to 101% of its summer Normal rating based on the peak historical 3-year average, and 136% if queued loads are included, and the Grossinger #210 distribution circuit cannot support any additional loads without causing new low voltage violations that cannot be rectified within the Avangrid Distribution Planning Criteria. The 4.8 kV and 12.5 kV systems do not have adequate N-1 capabilities and cannot be fully backed-up through neighboring circuit field tie switching. The area's distribution system and 34.5 kV transmission system are constrained by N-1 thermal and low voltage limits, making it unable to support new load growth from electrification and economic development. The proposed Ferndale 115/34.5/12.5 kV Substation Upgrade Project is designed to: (1) mitigate existing voltage and thermal needs, (2) accommodate current load requests, and (3) incorporate additional capacity to account for future load growth. One solution alternative was developed and evaluated against several factors, including future expandability (both electric and physical), ability to address immediate electrification needs, execution certainty, and capacity headroom benefits based on known forecasting data. The Ferndale Substation serves customers in Disadvantaged Communities and in Potential Environmental Justice Areas.

Project Scope:

The selected project proposal involves expanding the existing 115/34.5 kV Ferndale Substation to include a new 115/12.5 kV 50 MVA distribution transformer and the installation of a new 115 kV high-side transformer (T1) breaker. Additionally, this project will install a 15 kV GIS (operating at 12.5 kV), which will connect three new 12.5 kV distribution circuits created by partial load transfers from the Swan Lake, Liberty, and Grossinger Substations. These load transfers will offload 14.9 MVA of load from an overloaded 34.5 kV transmission line and distribution circuit that cannot support new load growth from electrification and economic development requests. The load transfers are as follows:

1. Transfer 3.5 MVA of 4.8 kV load from Swan Lake to Ferndale Sub.
2. Transfer 3.0 MVA of 4.8 kV load from Liberty to Ferndale Sub.
3. Transfer 8.4 MVA of existing 12.5 kV load from Grossinger to Ferndale Sub.

The selected project proposal also considers the possible implementation of non-wires alternative solutions at both Swan Lake and Hilldale to reduce the traditional scope of work and costs associated with required system upgrades driven by planned customer electrification requests. This proposal offers more system capacity benefits compared to other alternatives, as the non-wires alternatives will further alleviate the existing distribution peak loads while minimizing the demand on the currently strained 34.5 kV transmission system in the area. Based on the existing peak load demands, the non-wires alternative solutions are expected to provide a minimum of 1 MVA of peak load relief at both the Swan Lake and Hilldale substations, for a total peak load relief of 2 MVA on the 34.5 kV transmission system.

Project Benefits:

The proposed project will mitigate identified reliability, asset condition, and capacity-driven needs within Disadvantaged Communities and Potential Environmental Justice Areas, allowing for additional load growth over time. Prospective customers will benefit from the immediate advancement of this project, which is the basis for it being considered as part of the urgent phase portion of the proactive planning proceeding.

Reliability: The project will significantly enhance system reliability by providing N-1 contingency headroom at all levels, Transmission, Substation and Distribution. By upgrading the infrastructure and adding redundancy, the project will ensure continuous service even during faults or maintenance activities. This is particularly important for the Towns of Liberty and Fallsburg, which are experiencing rapid growth and increased demand for reliable power supply.

Asset Condition: A summary of major electrical equipment asset condition needs at Ferndale has been identified in accordance with the AVANGRID 2023 transformer and breaker assessments. One 34.5 kV circuit breaker, installed in 1964, is rated in poor condition. Two 115 kV circuit breakers, installed in 1960 and 1975 respectively, are rated in very poor condition. These components are included as part of the 2025 Breaker Replacement Program with an in-service date of 2027.

Capacity Headroom: The project will relieve voltage and thermal constraints on the 34.5 kV transmission system by feeding load directly from Ferndale's 115 kV. Long-term benefits include reliability improvements (N-1) and capacity (headroom for electrification and business development). The maximum N-0 capacity gained on the distribution system is 45.2 MVA, and the maximum N-1 capacity gained on the transmission system is 25.2 MVA. The alternative selected at Ferndale provides the most cost-effective solution to resolving the capacity constraints while allowing for future growth/hosting capacity in the Liberty area.

Expandability: The proposed project is expandable by adding new 12.5 kV circuits to pull more distribution load to the new Ferndale source. As additional distribution circuits are extended from this source, the 34.5 kV capacity constraints will be further reduced.

Project Risks and Mitigation Plan:

This project's key risk is the ability to execute the project in the existing parcel. The substation has enough space to execute the proposed scope but will need to be phased to ensure the substation remains in service throughout the project. This can be mitigated by a detailed outage and construction sequence plan.

Risk of No Action:

Opting to take no action on the proactive planning urgent project filing will significantly delay the ability to support electrification driven by customer load interconnection requests in an area already facing voltage, thermal, asset, and reliability challenges. The existing 34.5 kV transmission system serving the Ferndale Substation and distribution network is fully constrained, necessitating urgent system capacity upgrades to accommodate current load interconnection requests in the surrounding Ferndale area.

The risk of inaction includes potential delays or postponements of residential housing developments and commercial buildings with high electrification loads for several years. This inaction hinders electrification initiatives and economic development in the area, potentially leading to increased reliance on backup generators (fossil fuels) until major system upgrades are completed.

Project Alternatives:

An alternative solution for the Ferndale project does not incorporate non-wires alternatives and instead focuses on transferring more load from an overloaded transmission line and distribution circuits in the Ferndale area. The existing Ferndale Substation would be expanded to include a new 115/12.5 kV 50 MVA distribution transformer, the installation of a new 115 kV bank #1 high-side breaker, and a 15 kV GIS serving three new 12.5 kV distribution circuits. These circuits would facilitate partial load transfers from the Swan Lake, Liberty, Grossinger, Hilldale, and White Sulphur Springs substations. The load transfers would offload 18.5 MVA from an overloaded 34.5 kV transmission line and distribution circuit that cannot support new load growth from electrification and economic development requests. The alternative load transfers would be as follows:

1. Transfer 6.2 MVA of existing and queued load from Swan Lake to Ferndale Substation.
2. Transfer 0.7 MVA of existing and queued load from Liberty to Ferndale Substation.
3. Transfer 8.4 MVA of existing and queued load from Grossinger to Ferndale Substation.
4. Transfer 3.2 MVA of existing and queued load from Hilldale to Ferndale Substation.

This strategy focuses on more load transfers and retires the White Sulphur Springs Tap by transferring 1.5 MVA of load to the Ferndale Substation. It does not include non-wires alternatives for Swan Lake and Hilldale, and offers fewer system capacity benefits. While the initial investment of \$44.9M is higher than the selected alternative, it eliminates a tap circuit that would no longer require maintenance. The maximum N-0 capacity gained on the distribution system is 39.1 MVA, and the maximum N-1 capacity gained on the transmission system is 19.1 MVA.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects at NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 338	\$ -	\$ 188	\$ 132	\$ 18	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 18,153	\$ -	\$ 10,189	\$ 6,991	\$ 973	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 2,116	\$ -	\$ 1,110	\$ 890	\$ 116	\$ -	\$ -	\$ -
# Materials	\$ 11,168	\$ -	\$ 6,209	\$ 4,353	\$ 606	\$ -	\$ -	\$ -
# Overheads - External	\$ 2,065	\$ -	\$ 1,083	\$ 868	\$ 113	\$ -	\$ -	\$ -
Total	\$ 33,840	\$ -	\$ 18,779	\$ 13,234	\$ 1,827	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Hosting Capacity Automation

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006716	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The company seeks to develop and implement a highly automated and comprehensive end-to-end solution to integrate and streamline different existing and future tools and processes to run Hosting Capacity (HC) analyses and update HC maps for Load and Distributed Generation (DG) on a bi-weekly basis. The existing process to run the HC analysis and publish the maps requires a significant amount of manual intervention and effort, and is currently not sustainable to support an increase in frequency of updates.

This project would be to identify a System Integrator to develop a solution and process leveraging existing tools and identifying new ones that would support an automated HC refresh at the company.

Project Scope:

Integration and Automation: Develop and implement a solution to integrate existing and proposed new tools (as well as define necessary processes to automate as much as possible the hosting capacity analysis and map creation and publishing). Proposed solutions must leverage existing CYME and CYME Gateway platforms.

Data Quality and Validation: Implement new and/or propose improvements to existing processes to correct data in source systems and maintain accurate data.

Quality Assurance: Solution must include tools or components to enable Planners to perform expedited data validation.

Hourly Analysis: Solution should enable implementation of 576 to 8760 hourly hosting capacity analyses for load and generation.

Trigger-Based Updates: Use Rules and thresholds to limit the scope of each refresh to distribution circuits that have experienced a significant change.

Training, Documentation & Change Management: Provide detailed documentation for new and improved processes and integrations as well as provide training to Avangrid personnel and develop change management strategies.

Hardware and Software: Hardware, software and network requirements to support the integration and automation of the different systems.

Project Benefits:

The project will significantly reduced the time duration for refreshing HC maps and alleviate the resource demands for the planning teams of performing these analyses. An automated HC process will deliver value to customers and developers within the service territory by enabling access to more frequent updates to system capacity. It is expected that any model clean up and validation steps could be leveraged when performing other CYME analyses, expediting analysis results across the suite of CYME analysis modules.

Project Risks and Mitigation Plan:

Risks related to this project include vendor resource availability, internal resource availability and data availability.

With thorough communication with the selected vendor and clear expectations set from the onset of the project, it is expected that the risk related to vendor resource availability would be mitigated.

With clear expectations of internal resource requirements set from the onset of the project, it is expected that the risk related to internal resource availability would be mitigated.

Data availability is a common issue when performing this analysis. This risk could be mitigated by engaging the necessary groups and building the data pathways and integration. Setting a clear expectation to the vendor and including improvements in the data process at the company, it is expected that the system integrator take on these challenges and propose solutions when data availability is a challenge.

Risk of No Action:

As a result of No Action in regard to this project, the company will be limited in its ability to meet the increasing expectations related to frequency of update to public facing hosting capacity maps. The company would be unable to deliver updates to these maps in a reasonable time frame and continue to experience resource constraints whenever updating these analyses.

Afton Sub - Add new 34.5kV Circuit

PROJECT INFORMATION

OpCo: NYSEG	Project ID: UH-N0000252-NYSEG-ED	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Reliability	Project Stage: 0	Start Date: H1 2027	In-Service Date: H2 2029

Project description:

Overview: The Afton 34.5kV Line Addition project, initiated in 2010, aimed to address reliability and compliance issues on the 34.5kV distribution circuit. Initially, the project planned to split approximately 2,000 customers into two circuits, with 1,200 customers to the north and 800 to the south of the Afton substation.

Current State Needs Assessment

Partial Completion: An old spare 34.5kV recloser was used to split the circuit into two due to urgency.

Remaining Work: The new 34.5kV breaker installation and system protection upgrades are still pending.

Proposed Scope: Complete the remaining work and address asset condition issues identified in the 2022 comprehensive needs assessment for the Afton substation including the aged 34.5kV recloser in poor condition, the 34.5kV ground bank with severe tank corrosion, and obsolete electromechanical relays with limited capabilities and no manufacturer support.

Project Scope:

Replace the aged 34.5kV recloser with a new dedicated breaker for the 34.5kV distribution circuit.

Replace the existing 34.5kV ground bank in-kind.

Relocate and replace all existing yard relays into the new control house.

Replace the existing substation fence and repair the 115kV structure foundations.

Project Benefits:

Reliability: Enhances system reliability by reducing outages by 50% for all customers and supporting load growth in the Afton area.

Asset Condition: Addresses major electrical equipment needs identified in the AVANGRID 2021 assessments.

This project will complete the work started in 2010, improving overall system performance and reliability.

Project Risks and Mitigation Plan:

Risk: Working in an energized substation yard during construction.

Mitigation: Develop and discuss detailed construction sequence and outage plans with the Energy Control Center and the execution team before starting construction.

Risk of No Action:

Increased Exposure: Greater risk to reliability and asset health at the Afton substation.

Operational Challenges: Partially constructed state and further delays would complicate routine Operation & Maintenance activities.

Project Alternatives:

Construct a new medium voltage GIS to accommodate the new 34.5kV circuit.

Retire all existing 34.5kV AIS bay structures and equipment, except for the 34.5kV voltage regulators.

Replace the existing substation fence and repair the 115kV structure foundations.

This alternative was not selected due to it's higher estimated cost.

Basis for Project Estimates

Components: Internal labor, external resources, materials, engineering (internal and external), and applicable overheads costs.

Sources: Historical man-hour data, construction costs for similar activities, budgetary quotes from suppliers, and analogous cost estimates from similar NYSEG projects.

Review Process: The total project cost is a combination of prior years spend and future cost estimate. Estimates are regularly reviewed and updated as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 346	\$ 56	\$ 66	\$ 64	\$ 76	\$ 85		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 19	\$ -	\$ 5	\$ 14	\$ -	\$ -		
# Internal, Overheads	\$ 3	\$ -	\$ 1	\$ 2	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ 8	\$ -	\$ 2	\$ 6	\$ -	\$ -		
Total	\$ 376	\$ 56	\$ 74	\$ 85	\$ 76	\$ 85		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 63	\$ -	\$ -	\$ 4	\$ 36	\$ 23	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,323	\$ -	\$ -	\$ 233	\$ 1,882	\$ 1,208	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 366	\$ -	\$ -	\$ 27	\$ 208	\$ 131	\$ -	\$ -
# Materials	\$ 2,069	\$ -	\$ -	\$ 145	\$ 1,172	\$ 752	\$ -	\$ -
# Overheads - External	\$ 354	\$ -	\$ -	\$ 27	\$ 201	\$ 127	\$ -	\$ -
Total	\$ 6,175	\$ -	\$ -	\$ 437	\$ 3,497	\$ 2,241	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Proactive Planning - Kent Falls

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006420	Charge Code: Electric	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Planning and Coordination	Rate Case Category Reliability	Project Stage: IP3 Partial Approval	Start Date: H1 2026	In-Service Date: H1 2029

Project description:

Overview: The Kents Falls Project aims to address urgent capacity constraints and reliability issues at Kents Falls, located in the Town of Plattsburgh, Clinton County. The project involves significant upgrades to the 115/34.5 kV infrastructure and the installation of a new 34.5kV distribution line to support new customer connections and future load growth. The total load requests studied amount to 20 MW.

Current State Needs Assessment: Kents Falls and Hammond Lane/South Junction, constructed in 1985 and 1989 respectively, face significant reliability issues due to equipment thermal overloading and system voltage reliability criteria violations. The 46kV sub-transmission feeding Hammond Lane and South Junction substations is capacity constrained. Hammond Lane and South Junction transformers are loaded to 79% and 44% respectively of their summer Normal rating based on the peak historical 3-year average, and 107% and 145% if queued loads are included, making it unable to support new load growth from electrification and economic development.

The proposed Kents Falls Upgrade Project is designed to: (1) Mitigate existing voltage and thermal needs, (2) Accommodate current load requests, and (3) Incorporate additional capacity for future load growth. Two solution alternatives were developed and evaluated against several factors, including future expandability, ability to address immediate electrification needs, execution certainty, and capacity headroom benefits using known forecasting data. Kents Falls serves customers in Disadvantaged Communities and Potential Environmental Justice Areas.

Project Scope:

The selected project proposal expands the Kents Falls substation to include a new 115/34.5 kV, 50 MVA distribution transformer with dedicated high and low side breakers. This project will also install a new 30 MVA 115 KV shunt capacitor at the Kents Falls 115 kV bus and create a new 34.5kV circuit position with the capability to expand in the future. The proposal also includes building a new 34.5 kV distribution circuit approximately 8.8 miles long (with a set of switched capacitors) to serve two new Schluter locations. This proposal will increase capacity in a location near a major New York State highway, I-87, off exit 36 as well as near the Plattsburgh International Airport which are both desirable locations for EV charging stations.

Project Benefits:

The proposed project will mitigate identified reliability, asset condition, and capacity-driven needs, within Disadvantaged Communities and Potential Environmental Justice Areas, allowing for additional load growth over time. Prospective customers will benefit from the immediate advancement of this project, which is the basis for it being considered as part of the urgent phase portion of the proactive planning proceeding.

Reliability: The project will significantly enhance system reliability by providing N-1 contingency headroom at all levels, Transmission, Substation and Distribution. By upgrading the infrastructure and adding redundancy, the project will ensure continuous service even during faults or maintenance activities. This is particularly important for the Town of Plattsburgh, which is experiencing rapid growth and increased demand for reliable power supply. Additionally, the proposed project will reduce outages due to existing equipment in poor condition.

Capacity Headroom: The project will relieve voltage and thermal constraints on the 46 kV transmission system by moving load to the 115 kV transmission system. This will add capacity headroom for electrification and business development. The maximum N-0 capacity gained on the distribution system is 32.5 MVA, and the maximum N-1 capacity gained on the transmission system is 30 MVA. The alternative selected at Kents Falls provides the most cost-effective solution to resolving the capacity constraints while allowing for future growth/hosting capacity in the Plattsburgh area.

Expandability: Future expandability to adjacent distribution circuits will reduce 46 kV transmission capacity constraints. The Kents Falls 50 MVA substation transformer has the capacity to support an additional 30 MVA of new load upon adding a new circuit position. This will provide the necessary capacity to accommodate future load growth and ensure reliable power supply to the area.

Project Risks and Mitigation Plan:

This project's key risk is the ability to expand the substation to the north in the existing parcel approximately 30 ft and as well as foreign utility coordination (NYPA). The site's elevation to the north decreases quickly which may require a retaining wall. The project will also need to be phased to ensure the substation remains in service throughout the project. This can be mitigated by a conceptual grading plan as well as a detailed outage and construction sequence plan. Lastly, the substation connects directly to the NYPA 115 kV Saranac Substation, and their input must be included in the outage and construction sequence plan.

Risk of No Action:

The decision to take no action regarding the proactive planning urgent project filing effectively delays the ability to support electrification driven by a large customer load interconnection request. The risk of inaction suppresses electrification initiatives and economic development in a disadvantaged community, potentially resulting in up to 350 jobs being relocated outside New York State. It could also limit future expansion in the area and lead to the relocation of Schluter's North American headquarters.

Project Alternatives:

An alternative solution is to build a new 115 kV line from Kents Falls to a new 115/34.5 kV substation closer to New York State highway I-87, Plattsburgh International Airport, and Schluter's customer load interconnection requests. This requires a new 115 kV Line approximately 6.1 miles in length, installing a new 50 MVA 115/34.5 kV LTC substation near Pleasant Ridge Rd, and installing one new 34.5 kV distribution circuit position, along with building a new 34.5 kV distribution circuit approximately 2.7 miles long.

This strategy focuses on building a new substation and bringing a new 115 kV transmission source directly to an area constrained by a 46 kV transmission line. This strategy has reduced capacity benefits in the Kents Falls area (due to building the station off a radial line) while focusing on building a new substation and extending a 115 kV line versus expanding an existing substation. This alternative results in a capacity gain of 32.5 MVA (N-0) and 15.5 MVA (N-1).

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects at NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 2,449		\$ 289	\$ 753	\$ 1,326	\$ 81		
# CIAC	\$ -							
# External Services	\$ 28,235		\$ 4,897	\$ 11,121	\$ 11,904	\$ 313		
# Internal - Non-AC	\$ -							
# Internal, Labor	\$ 120		\$ 120					
# Internal, Overheads	\$ 2,078		\$ 391	\$ 982	\$ 692	\$ 13		
# Materials	\$ 6,241		\$ 807	\$ 4,138	\$ 1,296			
# Overheads - External	\$ 3,173		\$ 627	\$ 1,429	\$ 1,095	\$ 22		
Total	\$ 42,296	\$ -	\$ 7,131	\$ 18,423	\$ 16,313	\$ 429	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG SUB T Reclosers

PROJECT INFORMATION

OpCo: NSYEG	Project ID: PRJ-007426	Charge Code: Electric Distribution	Project Sponsor: Mcdonough, Robert	Project Type: Project
Business Area: Electric Operations	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: H1 2027	In-Service Date: H2 2027

Project description:

Overview: Keuka substation is a 34/4kV distribution station in Wayne, NY serving 2,220 customers. Two 34kV lines connect to Keuka, 593 out of St Johns substation is the normal supply and 535 out of Bath substation is the alternate supply. Both lines connect to Keuka through manually operated disconnect switches. The project involves adding reclosers and a cap bank to automate the throwover of the station to the alternate supply when the normal supply is lost.

Current State Needs Assessment: The normal and alternate supplies to Keuka cannot be switched remotely or automatically resulting in prolonged customer outages for a loss of the normal supply, prior to local crews performing manual switching to restore customers. When utilizing the alternate supply during system peaks there are low voltage conditions on the 34kV lines as a result of the additional load.

Project Scope:

Install two 34kV Reclosers. One on each of the two lines coming into Keuka.

Install a 3.5 MVAR switched shut capacitor at Prattsburg substation.

Project Benefits:

All 2,220 customers supplied by Keuka are benefitted with improved reliability by automatic restoration in the event the normal supply to Keuka is lost. Additionally all the customers on the 535 line will be benefitted by the improved voltage support provided by the new cap bank at Prattsburg substation.

Project Risks and Mitigation Plan:

The project's key risks are in securing the necessary materials and the mobile substation(s) necessary to facilitate the work without customer outages.

The material procurement risks can be mitigated by purchasing the materials in advance of construction. Securing the mobile risk can be mitigated by scheduling the mobile ahead of time and scheduling the construction for less busy times of the years where not all the mobiles are deployed.

Risk of No Action:

No action would leave the current condition as it is where the customer's out of Keuka will experience prolonged outages when a loss of supply to Keuka occurs. The length of time of the outage would be the time for crews to perform switching at Keuka when loads are low enough, however during high load periods Keuka would stay off until repairs are made otherwise the customers on 535 would experience low voltage when the Keuka loads are added to the 535 line.

Project Alternatives:

One alternative would be to use breakers in lieu of reclosers, however this would result in higher overall project costs.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects at NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION**Actual Capital Spent, all amounts shown below in thousands (\$000's)**

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -							
# CIAC	\$ -							
# External Services	\$ -							
# Internal - Non-AC	\$ -							
# Internal, Labor	\$ -							
# Internal, Overheads	\$ -							
# Materials	\$ -							
# Overheads - External	\$ -							
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -							
Materials	\$ -							
Other O&M	\$ -							
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 224			\$ 224				
# CIAC	\$ -							
# External Services	\$ 1,010			\$ 1,010				
# Internal - Non-AC	\$ -							
# Internal, Labor	\$ 52			\$ 52				
# Internal, Overheads	\$ 168			\$ 168				
# Materials	\$ 1,010			\$ 1,010				
# Overheads - External	\$ 170			\$ 170				
Total	\$ 2,635	\$ -	\$ -	\$ 2,635	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 66			\$ 66				
Materials	\$ 17			\$ 17				
Other O&M	\$ -							
Total	\$ 83	\$ -	\$ -	\$ 83	\$ -	\$ -	\$ -	\$ -

NYSEG CAS Auburn Southern Loop

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006661	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2030

Project description:

The Auburn Southern Loop Comprehensive Area Study identified a number of system upgrades that are necessary to address current and forecasted system constraints within the electric system region consisting of 3 substations: Scipio, Genoa, and Aurora, along with 3 distribution tap circuits, all located within Cayuga county. The Study utilized an integrated system evaluation approach wherein a targeted transmission planning assessment of relevant facilities was performed. This assessment determined how the solutions developed to address the distribution system needs should be optimized to respect, or incorporate, necessary upgrades to nearby transmission or substation facilities.

Area Overview: The electric system within the Area serves approximately 3,400 customers with a summer peak load of 14.7 MVA. The Southern Loop Area includes 9 distribution feeders with operating voltages of 4.8 kV, 12.5 kV, and 34.5 kV. The electric transmission system in this area is served by networked 34.5 kV subtransmission lines. Their 115 kV sources are Wright Ave in the north, and Cayuga/Milliken in the south. The Area currently has very limited available capacity and is forecasted to undergo significant winter peak load growth, primarily due to building and transportation electrification. The high forecasted load growth necessitates proactive grid expansion to address capacity constraints and support electrification and economic development in the Southern Loop Area. Forecasted load growth based on the NYISO Gold Book and internal forecasting indicates the following:

- Winter Peak Load Growth: 15.2% by 2029 and 44.5% by 2034
- Summer Peak Load Growth: 0.3% by 2029 and 5.6% by 2034

Needs Assessment:

Voltage and Thermal:

- 30% of customers will experience undervoltage by 2034; 50% by 2044.
- 9 grid assets, including the transformers at Scipio and Aurora substations, will be overloaded by 2034.

Reliability:

- Limited N-1 backup capabilities due to different feeder operating voltages, lack of tie reclosers, and inability of existing tied circuits to backup each other without equipment overload.

Asset Condition:

- 3 out of 6 circuit breakers in the Area are in poor or very poor condition.
- 1,542 (26%) of distribution poles equal to or greater than 60 years old.

Project Scope:

The conceptual project developed as part of The Study includes distribution and transmission upgrades needed to address all identified system needs in the Area within the next 10 years, while considering a 20-year horizon for right-sizing purposes (e.g., selecting 14 MVA transformers as the replacement at Scipio, Genoa, and Aurora Substations). The project will optimize the distribution voltage class in the area by partially converting 4.8 kV and 34.5kV circuits to 12.5 kV, improving reliability under N-1 conditions and allowing for expandability in support of future load growth. The project is currently in a conceptual state; the scope and schedule will be refined as preliminary and detailed engineering activities are performed.

Distribution Upgrades:

1. Upgrade 34.5/4.8 kV 3.2 MVA transformer bank at Scipio to a 34.5/12.5 5kV 14 MVA transformer with LTC.
2. Upgrade 34.5/4.8 kV 3.45 MVA transformer bank at Genoa to a 34.5/12.5 5kV 14 MVA transformer with LTC.
3. Upgrade 34.5/12.5 kV 6.44 MVA transformer bank at Aurora to a 34.5/12.5 5kV 14 MVA transformer with LTC.
4. Install/Replace 11 circuit breakers at Scipio (4), Genoa (4), and Aurora (3).
3. Convert ~45 miles of three-phase overhead line from 4.8 kV to 12.5 kV
4. Convert ~50 miles of single-phase overhead line from 4.8 kV to 12.5 kV
5. Install 16 voltage regulators.
6. Install/Replace 21 step transformers.
7. Install 1 switched capacitor banks.
8. Install 5 SCADA-operable reclosers.

Transmission Upgrades:

1. Expand the Scipio substation to support a new 115kV bus, which is to be connected to the existing Line 973 that passes by the station.
2. Construct a new 115kV ring bus at or adjacent to the existing Scipio substation.
3. Install two new 50MVA 115/34kV transformers at the Scipio substation.
4. Install a new 10 MVAR capacitor on the 115kV bus at Scipio substation (two blocks of 5 MVAR).
5. Install a new 3 MVAR capacitor on the 34.5 kV bus at Aurora substation.
6. Replace breaker 52032 at Wright Ave substation with a normally open 34.5kV breaker.
7. Normally close 52186 switch on L521 at Stewarts Corner.
8. Normally open 52176 switch at Genoa substation.

Project Benefits:

The primary driver of this project is to address emergent capacity constraints within the Area. In addition to resolving these capacity constraints, the project will also address voltage, reliability and asset condition needs within the Southern Loop Area.

Capacity: The project will relieve significant voltage and thermal constraints both on the distribution system and on the 34.5 kV transmission system serving the Area. The project will result in 28 MVA of additional capacity in the Area, providing sufficient capacity to support significant load growth and N-1 redundancy for all feeders.

Voltage Support: All existing voltage needs, and all forecasted voltage through 2034 are addressed by the proposed system upgrades. Some 2044 forecasted voltage needs are left unresolved as preemptively implementing the requisite solution could negatively impact system performance prior to the needs emergence.

Reliability: The project will enhance system reliability and operability by providing N-1 backup capabilities for all eight distribution feeders in the Area. By standardizing circuit voltage at 12.5 kV, installing SCADA tie reclosers, and enhancing system capacity, the project will improve system performance under outage conditions and will also provide additional operational flexibility, including for maintenance activities.

Asset Condition: Preliminary electrical equipment asset condition needs in the Southern Loop Area were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. 3 out of 6 circuit breakers are in poor, or very poor condition in the Southern Loop Area. Equipment that is in poor, or very poor condition have exceeded their useful life and should be replaced to limit the risk of equipment-related outages. Such equipment are included for replacement or retirement in the conceptual solution. Site inspections will be performed to identify any additional asset condition needs.

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to capacity constraints, resulting in worsening voltage violations and reliability issues. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) Actual load growth may not align with forecasted values. If actual load growth is materially lower/slower or higher/faster than NYSEG's forecast indicated, there may be risks related to overbuilding or underbuilding, respectively. The principal concern related to overbuilding is that it can negatively impact system cost-efficiency by resulting in investments which are more costly or are deployed earlier than is strictly required to satisfy system demands. Overbuilding risk was mitigated by focusing specifically on 5-10year needs and was expandable to meet 20-year needs. Additionally, overbuild risks are offset by the fact that this project will provide immediate benefits to reliability and resiliency, as well as create capacity headroom for electrification projects such as for nearby school buses.

With regards to underbuilding risk, the primary concern is that the cost-efficiency of projects can be severely impacted if a relatively new project must be re-worked in a way that results in redundancies or an overhaul of prior developed scope. To minimize underbuilding risk, NYSEG designed the project such that project components were either right-sized, or were scalable, to be sufficient to satisfy expected system needs for at least 20 years (i.e., 2044). Right-sizing solutions for future load growth is an effective method for mitigating underbuilding risk in instances where (1) there is limited space for adding additional facilities and (2) the incremental cost of installing higher-capacity equipment does not materially increase total project costs.

Risk of No Action:

The Area is currently facing multiple challenges: thermal constraints (Scipio and Aurora substations), asset condition concerns (circuit breakers and poles), and N-1 reliability deficiencies. Opting to take no action on the proposed Comprehensive Area Solution would mean that short-term and/or operational solutions for current system constraints would need to be developed as an interim measure to ensure that the electric system can be operated within acceptable reliability and safety limits. Pursuing short-term solutions instead of a comprehensive solution may result in a less cost-efficient buildout of infrastructure, especially if comprehensive action is significantly delayed.

There is also a risk that unmitigated load growth in the Area could drive system constraints could to a point where the electric system is, in effect, inoperable due to excessive demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth, leading to significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's CLCPA goals because there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

An alternative solution was developed which involves upgrading the Scipio, Genoa, and Aurora substation transformers to 34.5/12.5 kV 14 MVA. The Scipio 605 and 606, Genoa 603 and 604, and Aurora 707 feeder circuits would be fully converted from 4.8 kV to 12.5 kV. This alternative solution was not selected because it is more limited in terms of providing additional circuit ties to the Southern Loop Area.

1. Upgrade 34.5/4.8 kV 3.2 MVA transformer bank at Scipio to a 34.5/12.5 5kV 14 MVA transformer with LTC.
2. Upgrade 34.5/4.8 kV 3.45 MVA transformer bank at Genoa to a 34.5/12.5 5kV 14 MVA transformer with LTC.
3. Upgrade 34.5/12.5 kV 6.44 MVA transformer bank at Aurora to a 34.5/12.5 5kV 14 MVA transformer with LTC.
4. Install/Replace 11 circuit breakers at Scipio (4), Genoa (4), and Aurora (3).
5. Convert ~25 miles of three-phase overhead line from 4.8 kV to 12.5 kV.
6. Convert ~109 miles of single-phase overhead line from 4.8kV to 12.5 kV.
7. Install 3 voltage regulators.
8. Install/Replace 5 step transformers.

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG CAS Plattsburgh Ashley

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-001245	Charge Code: Electric Distribution	Project Sponsor: Balch, Bruce	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2031

Project description:

The Ashley Road Comprehensive Area Study identified a number of system upgrades that are necessary to address current and forecasted system constraints within the electric system region consisting of four substations: Beekmantown, Hyde Road, West Chazy, and Woodruff Pond, all located within the Clinton County. The Study utilized an integrated system evaluation approach wherein a targeted transmission planning assessment of relevant facilities was performed. This assessment determined how the solutions developed to address the distribution system needs should be optimized to respect, or incorporate, necessary upgrades to nearby transmission or substation facilities.

Area Overview: The electric system within the Area serves approximately 5,200 customers with a peak load of 20.5 MVA, as observed in 2023. The Ashley Road Area includes 6 distribution feeders with operating voltages of 4.8 kV and 12.5 kV. These substations are fed by a single 46 kV sub-transmission line with no automatic redundancy in the event of a fault. The Area currently has very limited available capacity and is forecasted to undergo significant winter peak load growth, primarily due to building and transportation electrification. The high forecasted load growth necessitates proactive grid expansion to address capacity constraints and support electrification and economic development in the Ashley Road Area. Forecasted load growth based on the NYISO Gold Book and internal forecasting indicates the following:

- Winter Peak Load Growth: 12.6% by 2029 and 41.4% by 2034
- Summer Peak Load Growth: -2.1% by 2029 and 3.1% by 2034

Needs Assessment:

Voltage and Thermal:

- 26% of customers will experience undervoltage by 2034; 49% by 2044.
- 16 grid assets including the transformers at Beekmantown, Hyde Road and West Chazy substations will be overloaded or borderline overloaded by 2034.
- Thermal overload on 46 kV subtransmission line 878 (Sciota Flatrock to Hyde Road); 106% Winter Normal by 2034.
- Thermal overload on 46 kV subtransmission line 878 (Sciota Flatrock to Hyde Road); 109% Summer Normal by 2034.
- Low voltage at Hyde Road 46 kV (0.94 pu), West Chazy 46 kV (0.93 pu), and Beekmantown 46 kV (0.92 pu) by Winter 2034.

Reliability:

- No N-1 backup capabilities are available for the 6 feeder circuits in the Ashley Road Area due to differing feeder voltage classes and a lack of tie points.
- Beekmantown 133 had a zone of 777 customers and West Chazy 136 had a zone of 998 customers which both exceed the distribution planning sectionalization criteria.
- A fault on 46 kV subtransmission line 878 results in the Loss of 19.1 MW of load; Restoration must be done manually (Winter 2034, load is beyond loss of load criteria by Summer 2029).

Asset Condition:

- 729 (15%) distribution poles equal to or greater than 60 years old.
- 3 out of 5 circuit breakers in the Area are in poor, or very poor condition.

Project Scope:

The conceptual project developed as part of The Study includes distribution and transmission upgrades needed to address all identified system needs in the Area within the next 10 years, while considering a 20-year horizon of load growth for capacity right-sizing. The project will retire Beekmantown and West Chazy substations and reroute their feeders into Ashley Rd Substation. Ashley Rd will be expanded to accommodate the additional infrastructure required to be converted from a Transmission only substation to a Transmission and Distribution substation. In addition, Beekmantown 133 and West Chazy 136 will be converted from 4.8 kV to 12.5 kV, optimizing the distribution voltage class in the area. These conversions ensure that all feeders have N-1 support, improving reliability and allowing for expandability in support of future load growth. The project is currently in a conceptual state; the scope and schedule will be refined as preliminary and detailed engineering activities are performed.

System Upgrades:

1. Upgrade 46/12.5 kV 8.4 MVA transformer bank and 328A bus regulator bank at Hyde Road to a 46/12.5kV 14 MVA transformer with LTC.
2. Install a new 12.5 kV GIS bus at Ashley Rd
3. Extend the 115 kV bus in the Ashley Rd 115 kV substation
4. Install a new 115 kV breaker to complete a new bay in the Ashley Rd 115 kV BAAH
5. Install new 115/12.5 kV 50 MVA transformer at Ashley Rd Substation.
6. Install 3 new 12.5 kV circuit breakers at Ashley Rd

7. Replace/Install 4 circuit breakers at Hyde Road
8. Reroute Beekmantown 133 and West Chazy 136 to Ashley Rd; Retire Beekmantown and West Chazy substations
9. Convert ~18 miles of three-phase overhead line from 4.8 kV to 12.5 kV.
10. Convert ~60 miles of single-phase overhead line from 4.8 kV to 12.5 kV.
11. Reconductor ~17 miles of overhead distribution line
12. Install 6 voltage regulators.
13. Install 4 switched capacitor banks.
14. Install 7 SCADA-operable reclosers.

Project Benefits:

The primary driver of this project is to address emergent capacity constraints within the Area. In addition to resolving these capacity constraints, the project will also address voltage, reliability and asset condition needs within the Ashley Road Area.

Capacity: The project will relieve significant voltage and thermal constraints both on the distribution system and on the 46 kV transmission system serving the Area. The project will result in 18.17 MVA of additional capacity across the Ashley Road Area, providing sufficient capacity to support significant load growth and N-1 redundancy for all feeders.

Voltage Support: All existing voltage needs and projected voltage issues through 2034 due to load growth are addressed by the proposed system upgrades. The upgrade has been right-sized to address the projected voltage issues in 2044.

Reliability: The project will enhance system reliability and operability by providing N-1 backup capabilities for all seven distribution feeders in the Area. By standardizing circuit voltage at 12.5 kV, installing SCADA tie reclosers, and enhancing system capacity, the project will improve system performance under outage conditions and will also provide additional operational flexibility, including for maintenance activities.

Asset Condition: Preliminary electrical equipment asset condition needs in the Ashley Road Area were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. 3 out of 5 circuit breakers are in poor, or very poor condition. Equipment that is in poor, or very poor condition have exceeded their useful life and should be replaced to limit the risk of equipment-related outages. Such equipment is included for replacement or retirement in the conceptual solution.

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to capacity constraints, resulting in worsening voltage violations and reliability issues. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) Actual load growth may not align with forecasted values. If actual load growth is materially lower/slower or higher/faster than NYSEG's forecast indicated, there may be risks related to overbuilding or underbuilding, respectively. The principal concern related to overbuilding is that it can negatively impact system cost-efficiency by resulting in investments which are more costly or are deployed earlier than is strictly required to satisfy system demands. Overbuilding risk was mitigated by focusing specifically on 5-10 year needs, which could be expandable to meet 20-year needs. Additionally, overbuild risks are offset by the fact that this project will provide immediate benefits to reliability and resiliency, as well as create capacity headroom for electrification projects such as for nearby school buses.

With regards to underbuilding risk, the primary concern is that the cost-efficiency of projects can be severely impacted if a relatively new project must be re-worked in a way that results in redundancies or an overhaul of prior developed scope. To minimize underbuilding risk, NYSEG designed the project such that project components were either right-sized, or were scalable, to be sufficient to satisfy expected system needs for at least 20 years (i.e., 2044). Right-sizing solutions for future load growth is an effective method for mitigating underbuilding risk in instances where (1) there is limited space for adding additional facilities and (2) the incremental cost of installing higher-capacity equipment does not materially increase total project costs.

Risk of No Action:

The Area is currently facing multiple challenges: voltage issues (Hyde Road 417, West Chazy 136 and Woodruff Pond 460), thermal constraints (Hyde Road and West Chazy substations), asset condition concerns (circuit breakers and poles), and N-1 reliability challenges. Opting to take no action on the proposed Comprehensive Area Solution would mean that short-term and/or operational solutions for current system constraints would need to be developed as an interim measure to ensure that the electric system can be operated within acceptable reliability and safety limits. Pursuing short-term solutions instead of a comprehensive solution may result in a less cost-efficient buildout of infrastructure, especially if comprehensive action is significantly delayed.

There is also a risk that unmitigated load growth in the Area could drive system constraints to a point where the electric system is, in effect, inoperable due to excessive demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth, leading to significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's CLCPA goals because there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

An alternative solution was developed which involves keeping and rebuilding the Beekmantown and West Chazy substations. The existing substation transformer banks at Beekmantown, Hyde Road, and West Chazy would be upgraded to 46/12.5 kV, with Beekmantown 133 and West Chazy 136 being fully converted from 4.8 kV to 12.5 kV. This alternative solution was not selected due to physical constraints found in expanding West Chazy and Beekmantown.

1. Replace 3 substation transformer and voltage regulator banks with 46/12.5 kV transformers with LTC at Beekmantown (14 MVA), Hyde Road (22.4 MVA) and West Chazy (14 MVA).
2. Install/replace 12 circuit breakers at Beekmantown (4), Hyde Road (4), and West Chazy (4)
3. Convert ~15 miles of three-phase overhead line from 4.8 kV to 12.5 kV.
4. Convert ~62 miles of single-phase overhead line from 4.8 kV to 12.5 kV.
5. Reconductor ~13 miles of overhead distribution line.
6. Install 7 voltage regulators.
7. Install 6 switched capacitor banks.
8. Install 8 SCADA-operable reclosers.

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG CAS Hornell Arkport

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006660	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2031

Project description:

The Arkport Comprehensive Area Study identified a number of system upgrades that are necessary to address current and forecasted system constraints within the electric system region consisting of four substations: Arkport, Canaseraga, Moraine Rd, and Webbs Crossing, all located within the Allegany and Steuben counties. The Study utilized an integrated system evaluation approach, performing a targeted transmission planning assessment to determine how solutions developed to address distribution system needs should be optimized to incorporate necessary upgrades to nearby transmission and/or substation facilities.

Area Overview: The electric system within the Area serves approximately 4,100 customers with a peak load of 16.9 MVA. The Area includes 7 distribution feeders with operating voltages of 4.8 kV, 12.5 kV, and 34.5 kV. The electric transmission system in this area is served by networked 34.5 kV subtransmission lines. Their 115 kV sources are Moraine Rd in the north, and Bennett in the south. The Area currently has very limited available capacity and is forecasted to undergo significant winter peak load growth, primarily due to building and transportation electrification. The high forecasted load growth necessitates proactive grid expansion to address capacity constraints and support electrification and economic development in the Arkport Area. Forecasted load growth based on the NYISO Gold Book and internal forecasting indicates the following:

- Winter Peak Load Growth: 12.6% by 2029 and 41.4% by 2034
- Summer Peak Load Growth: -2.1% by 2029 and 3.1% by 2034

Needs Assessment:

Voltage and Thermal: The Arkport Area is forecasted to experience significant thermal and voltage violations within the 5-10 year planning horizon:

- 17% of customers will experience undervoltage by 2034; 48% by 2044.
- 6 grid assets including the transformers at Arkport and Webbs Crossing substations will be overloaded by 2034.
- Queued load (Lismore Dairy) cannot be accommodated without overloading the 3 MVA transformer bank at Arkport.

Reliability:

- Limited N-1 backup capabilities due to different feeder operating voltages, lack of tie reclosers, and inability of existing tied circuits to backup each other without equipment overload.
- Sectionalization criteria: zones exceeding or with almost 500 customers in Canaseraga 219, Moraine Rd 543 and Webbs Crossing 281.

Asset Condition:

- 1,064 (15%) of distribution poles equal to or greater than 60 years old.
- 1 out of 14 substation transformers in the Area is in poor condition.

Project Scope:

The conceptual project developed as part of this Study includes distribution and transmission upgrades needed to address all identified system needs in the Area within the next 10 years, while considering a 20-year horizon for right-sizing purposes. The project will convert Arkport into a switching station, eliminating the transformer and feeding Arkport 220 in 34.5 kV, as well as retire Canaseraga, connecting the existing load in 34.5 kV directly into Moraine Rd 543, which already feeds Canaseraga. In addition, the existing 34.5/4.8 kV transformer bank at Webbs Crossing will be upgraded to 34.5/12.5 kV, optimizing the distribution voltage class in the area. These conversions ensure that all feeders have N-1 support, improving reliability and allowing for expandability in support of future load growth. The project is currently in a conceptual state; the scope and schedule will be refined as preliminary and detailed engineering activities are performed.

Distribution Upgrades:

1. Upgrade 34.5/4.8 kV 5 MVA transformer and circuit voltage regulator banks at Webbs Crossing to a 34.5/12.5 5kV 14 MVA transformer with LTC.
2. Retire 2 substation transformers at Arkport and Canaseraga.
3. Replace Arkport 220 and Webbs Crossing 360 circuit voltage regulator banks.
4. Install/Replace 7 circuit breakers at Arkport (3) and Webbs Crossing (4).
5. Convert ~33 miles of three-phase overhead line from 4.8 kV to 12.5 or 34.5 kV.
6. Convert ~98 miles of single-phase overhead line from 4.8 kV to 12.5 or 34.5 kV.
7. Install 11 voltage regulators.
8. Install/Replace 15 step transformers.
9. Install 6 switched capacitor banks.
10. Install 9 SCADA-operable reclosers.

Transmission Upgrades:

1. Expand Moraine Rd substation to add a second 115/34.5 kV transformer.
2. Install approximately 7 miles of new overhead 34.5 kV subtransmission line.
3. Expand Webbs Crossing substation to accommodate the new 34.5 kV subtransmission line.
4. Replace 54016 at Webbs Crossing substation with a normally closed 34.5 kV breaker.
5. Install a new 7 MVAR capacitor on the 34.5 kV bus at Webbs Crossing substation (two blocks of 3.5 MVAR).
6. Install a new 9 MVAR capacitor on the 34.5 kV bus at Atlanta substation (two blocks of 4.5 MVAR).
7. Install a new 3.5 MVAR capacitor on the 34.5 kV bus at Troupsburg substation.

Project Benefits:

The primary driver of this project is to address emergent capacity constraints within the Area. In addition to resolving these capacity constraints, the project will also address voltage, reliability and asset condition needs within the Arkport Area.

Capacity: The project will relieve significant voltage and thermal constraints both on the distribution system and on the 34.5 kV transmission system serving the Area. The project will result in 50 MVA of additional capacity across the Arkport Area, providing sufficient capacity to support significant load growth and N-1 redundancy for all feeders.

Voltage Support: All existing voltage needs and projected voltage issues through 2034 due to load growth are addressed by the proposed system upgrades. The upgrade has been right-sized to address the projected voltage issues in 2044.

Reliability: The project will enhance system reliability and operability by providing N-1 backup capabilities for all seven distribution feeders in the Area. By standardizing circuit voltage at 12.5 kV or 34.5 kV, installing SCADA tie reclosers, and enhancing system capacity, the project will improve system performance under outage conditions and will also provide additional operational flexibility, including for maintenance activities.

Asset Condition: Preliminary electrical equipment asset condition needs in the Arkport Area were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. 1 out of 14 substation transformers is in poor condition in the Area. Equipment that is in poor, or very poor condition have exceeded their useful life and should be replaced to limit the risk of equipment-related outages. Such equipment is included for replacement or retirement in the conceptual solution. Site inspections will be performed to identify any additional asset condition needs.

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to capacity constraints, resulting in worsening voltage violations and reliability issues. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) Actual load growth may not align with forecasted values. If actual load growth is materially lower/slower or higher/faster than NYSEG's forecast indicated, there may be risks related to overbuilding or underbuilding, respectively. The principal concern related to overbuilding is that it can negatively impact system cost-efficiency by resulting in investments which are more costly or are deployed earlier than is strictly required to satisfy system demands. Overbuilding risk was mitigated by focusing specifically on 5-10year needs and was expandable to meet 20-year needs. Additionally, overbuild risks are offset by the fact that this project will provide immediate benefits to reliability and resiliency, as well as create capacity headroom for electrification projects such as for nearby school buses.

With regards to underbuilding risk, the primary concern is that the cost-efficiency of projects can be severely impacted if a relatively new project must be re-worked in a way that results in redundancies or an overhaul of prior developed scope. To minimize underbuilding risk, NYSEG designed the project such that project components were either right-sized, or were scalable, to be sufficient to satisfy expected system needs for at least 20 years (i.e., 2044). Right-sizing solutions for future load growth is an effective method for mitigating underbuilding risk in instances where (1) there is limited space for adding additional facilities and (2) the incremental cost of installing higher-capacity equipment does not materially increase total project costs.

Risk of No Action:

The Area is currently facing multiple challenges: voltage issues (Arkport 220, Moraine Rd 580, Webbs Crossing 280), thermal constraints (Arkport and Webbs Crossing Substations), asset condition concerns (substation transformers and poles), and N-1 reliability deficiencies. Opting to take no action on the proposed Comprehensive Area Solution would mean that short-term and/or operational solutions for current system constraints would need to be developed as an interim measure to ensure that the electric system can be operated within acceptable reliability and safety limits. Pursuing short-term solutions instead of a comprehensive solution may result in a less cost-efficient buildout of infrastructure, especially if comprehensive action is significantly delayed.

There is also a risk that unmitigated load growth in the Area could drive system constraints to a point where the electric system is, in effect, inoperable due to excessive demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth, leading to significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's CLCPA goals because there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

An alternative solution was developed which involves upgrading the Arkport, Canaseraga and Webbs Crossing substation transformers to 34.5/12.5 kV 14 MVA. The Arkport 220, Canaseraga 219, Webbs Crossing 280 and Webbs Crossing 281 feeder circuits would be fully converted from 4.8 kV to 12.5 kV with 33 miles of three-phase voltage conversions. This alternative solution was not selected because it is not the most cost-effective option overall, especially when accounting for the costs of two additional substation transformers in Arkport and Canaseraga. Furthermore, it is slightly more limited in terms of providing additional circuit ties to the Arkport Area.

1. Replace 4 transformer and circuit voltage regulator banks at Arkport, Canaseraga and Webbs Crossing to 34.5/12.5 5kV 14 MVA transformers with LTC.

2. Install/Replace 12 circuit breakers at Arkport (3), Canaseraga (3), and Webbs Crossing (6)
3. Convert ~33 miles of three-phase overhead line from 4.8kV to 12.5
4. Convert ~122 miles of single-phase overhead line from 4.8kV to 12.5
5. Install 9 voltage regulators
6. Replace 1 step transformers
7. Install 6 switched capacitor banks
8. Install 5 SCADA-operable reclosers

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 115,384	\$ -	\$ -	\$ -	\$ 6,422	\$ 18,329	\$ 37,782	\$ 52,851
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 46,153	\$ -	\$ -	\$ -	\$ 2,569	\$ 7,331	\$ 15,113	\$ 21,141
# Internal, Overheads	\$ 15,778	\$ -	\$ -	\$ -	\$ 761	\$ 2,128	\$ 4,772	\$ 8,117
# Materials	\$ 35,897	\$ -	\$ -	\$ -	\$ 1,998	\$ 5,702	\$ 11,754	\$ 16,443
# Overheads - External	\$ 24,586	\$ -	\$ -	\$ -	\$ 1,186	\$ 3,316	\$ 7,436	\$ 12,648
Total	\$ 237,798	\$ -	\$ -	\$ -	\$ 12,935	\$ 36,806	\$ 76,857	\$ 111,199

[illegible]

NYSEG CAS Geneva McDougall

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006662	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2029

Project description:

The MacDougall Comprehensive Area Study identified a number of system upgrades that are necessary to address current and forecasted system constraints within the electric system region consisting of three substations: MacDougall, Sampson, and Seneca Ordinance, all located within the Town of Romulus in Seneca County. The Study utilized an integrated system evaluation approach wherein a targeted transmission planning assessment of relevant facilities was performed. This assessment determined how the solutions developed to address the distribution system needs should be optimized to respect, or incorporate, necessary upgrades to nearby transmission or substation facilities.

Area Overview: The electric system within the Area serves approximately 2,500 customers with a peak load of 9.4 MVA, observed in 2023. The Area includes eight distribution feeders with voltage classes of 4.8 kV, 7.2 kV, and 12.5 kV. The electric transmission system in this area is served by long radial 34.5 kV subtransmission lines which are far from their 115 kV transmission sources. The Area currently has very limited available capacity and is forecasted to undergo significant winter and summer peak load growth, primarily due to building and transportation electrification. The high forecasted load growth necessitates proactive grid expansion to address capacity constraints and support electrification and economic development in the MacDougall Area. Forecasted load growth based on the NYISO Gold Book and internal forecasting indicates the following:

- Winter Peak Load Growth: 14% by 2029 and 44% by 2034
- Summer Peak Load Growth: -2.1% by 2029 and 3.1% by 2034

Needs Assessment:

Voltage and Thermal: The MacDougall Area is forecasted to experience significant thermal and voltage violations within the 5-10 year planning horizon:

- 61% of customers will experience undervoltage by 2034; 83% by 2044.
- 10 grid assets, including both Bank #1 and Bank #2 transformers at MacDougall Substation will be overloaded by 2034.
- Queued load (Sampson State Park Expansion) cannot be accommodated without overloading the 1 MVA transformer bank at Sampson Substation.

Reliability: No N-1 backup capabilities are available for the 8 feeder circuits in the MacDougall Area due to differing feeder voltage classes and a lack of tie points.

Asset Condition:

- 1,044 (28%) of distribution poles in the Area are greater than 60 years old.
- Four out of seven circuit breakers in the Area are in poor, or very poor condition.

Project Scope:

The conceptual project developed as part of The Study includes distribution and transmission upgrades needed to address all identified system needs in the Area within the next 10 years, while considering a 20-year horizon for right-sizing purposes (e.g., selecting a 14 MVA transformer as the replacement at MacDougall Substation). The project will eliminate the Sampson Substation, which has a 1 MVA transformer that cannot support load growth, by transferring 0.75 MVA of existing load and 0.75 MVA of queued load to the Seneca Ordinance Substation. This proposal also optimizes the distribution voltage class in the area by partially converting 4.8 kV and 7.2 kV circuits to NYSEG's standard 12.5 kV voltage class, improving reliability under N-1 conditions and allowing for expandability in support of future load growth. The project is currently in a conceptual state; the scope and schedule will be refined as preliminary and detailed engineering activities are performed. The transmission upgrades proposed for the Geneva MacDougall and Ithaca Northern Loop studies are identical due to the area being a 34.5 kV subtransmission system interconnected with normally open points.

Distribution Upgrades:

1. Install a 14 MVA Type 3 LTC power transformer at MacDougall Substation.
2. Retire Sampson Substation and transfer load to Seneca Ordinance Substation.
3. Replace/install 10 circuit breakers at MacDougall (4 breakers) and Seneca Ordinance (6 breakers) substations.
4. Reconductor approximately 35 miles of overhead distribution line.
5. Convert approximately 20 miles of overhead line from 4.8/7.2 kV to 12.5 kV.
6. Build approximately 3 miles of new 12.47 kV overhead lines.
7. Install 12 new stepdown banks.
8. Install 7 new switched capacitor banks.
9. Install 13 voltage regulators.
10. Install 7 SCADA-operable tie reclosers.

Transmission Upgrades:

1. Reconfigure Milliken Substation to add two new 115 kV bays.
2. Construct a new 115/34.5 kV expandable substation with:
 - a. Four-breaker 115 kV ring bus.
 - b. Two Type #11 - 115/34.5 kV – 50 MVA power transformers.

- c. Two 34.5 kV straight buses with a normally closed tie breaker.
3. Install approximately 3.4 miles total of new overhead 115 kV line between Milliken and the new substation (1.7 miles each for two circuits).
4. Install approximately 3.4 miles total of new 115 kV submarine cable between Milliken and the new substation (1.7 miles each for two circuits).
5. Replace 56859 at MacDougall Substation with a normally open 34.5 kV breaker.
6. Replace 55579 at Willard Substation with a normally open 34.5 kV breaker.

Project Benefits:

The primary driver of this project is to address emergent capacity constraints within the Area. In addition to resolving these capacity constraints, the project will also address voltage, reliability, and asset condition needs within the MacDougall Area.

Capacity: The project will relieve significant thermal constraints both on the distribution system and on the 34.5 kV transmission system serving the Area. It will result in 8.4 MVA of additional capacity at MacDougall Substation, providing sufficient capacity to support significant load growth and serve as a backup source for feeders out of Seneca Ordinance Substation.

Voltage Support: All existing voltage needs and projected voltage issues through 2034 due to load growth are addressed by the proposed system upgrades. The upgrade has been right-sized to address the projected voltage issues in 2044.

Reliability: The project will enhance system reliability and operability by providing N-1 backup capabilities for all eight distribution feeders in the Area. By standardizing circuit voltage at 12.5 kV, installing SCADA tie reclosers, and enhancing system capacity, the project will improve system performance under outage conditions and provide additional operational flexibility, including for maintenance activities.

Asset Condition: Preliminary electrical equipment asset condition needs in the MacDougall Area were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. Four out of seven circuit breakers are in poor or very poor condition in the MacDougall Area. Equipment in poor or very poor condition has exceeded its useful life and should be replaced to limit the risk of equipment-related outages. Such equipment is included for replacement or retirement in the conceptual solution. Site inspections will be performed to identify any additional asset condition needs.

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to capacity constraints, resulting in worsening voltage violations and reliability issues. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include, mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) Actual load growth may not align with forecasted values. If actual load growth is materially lower/slower or higher/faster than NYSEG's forecast indicated, there may be risks related to overbuilding or underbuilding, respectively. The principal concern related to overbuilding is that it can negatively impact system cost-efficiency by resulting in investments which are more costly or are deployed earlier than is strictly required to satisfy system demands. Overbuilding risk was mitigated by focusing specifically on 5-10year needs and was expandable to meet 20-year needs. Additionally, overbuild risks are offset by the fact that this project will provide immediate benefits to reliability and resiliency, as well as create capacity headroom for electrification projects such as for nearby school buses (i.e., Romulus Central School District).

With regards to underbuilding risk, the primary concern is that the cost-efficiency of projects can be severely impacted if a relatively new project must be re-worked in a way that results in redundancies or an overhaul of prior developed scope. To minimize underbuilding risk, NYSEG designed the project such that project components were either right-sized, or were scalable, to be sufficient to satisfy expected system needs for at least 20 years (i.e., 2044). Right-sizing solutions for future load growth is an effective method for mitigating underbuilding risk in instances where (1) there is limited space for adding additional facilities and (2) the incremental cost of installing higher-capacity equipment does not materially increase total project costs. This project incorporated a right-sizing philosophy by selecting a 14 MVA transformer for the replacement at MacDougall Substation.

Risk of No Action:

The Area is currently facing multiple challenges: voltage issues (MacDougall circuit 702 and Seneca Ordinance circuit 201), thermal constraints (MacDougall and Sampson Substations), asset condition concerns (Circuit Breakers), and N-1 reliability deficiencies. Opting to take no action on the proposed Comprehensive Area Solution would mean that short-term and/or operational solutions for current system constraints would need to be developed as an interim measure to ensure that the electric system can be operated within acceptable reliability and safety limits. Pursuing short-term solutions instead of a comprehensive solution may result in a less cost-efficient buildout of infrastructure, especially if comprehensive action is significantly delayed.

There is also a risk that unmitigated load growth in the Area could drive system constraints to a point where the electric system is, in effect, inoperable due to excessive demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth, leading to significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's CLCPA goals because there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

An alternative solution was developed which pursued full, rather than partial, voltage conversions of the 4.8 kV and 7.2 kV distribution facilities fed from MacDougall and Seneca Ordinance Substations. The most significant difference between the scopes of work for the preferred solution and the evaluated alternative is that the alternative solution requires significantly more reconductoring (~60 mi. vs. ~35 mi.) and voltage conversions (~40 mi. vs. ~20 mi.) than the preferred solution but also requires less voltage regulation and step-down banks. This alternative was not selected because of its significantly higher total cost (~\$90M vs. ~\$64M).

1. Install a 14 MVA Type 3 LTC power transformer at MacDougall Substation.
2. Retire Sampson Substation and transfer load to Seneca Ordinance Substation.
3. Replace/Install 10 circuit breakers at MacDougall (4 breakers) and Seneca Ordinance (6 breakers) substations.
4. Reconductor ~60 miles of overhead distribution line.
5. Convert ~40 miles of overhead line from 4.8/7.2 kV to 12.5 kV.
6. Build ~3 miles of new 12.47 kV overhead lines.
7. Install 2 new stepdown banks.
8. Install 8 new switched capacitor banks.
9. Install 9 voltage regulators.
10. Install 7 SCADA-operable tie reclosers.

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 66,821	\$ -	\$ -	\$ 2,294	\$ 16,764	\$ 33,962	\$ 13,800	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 11,137	\$ -	\$ -	\$ 382	\$ 2,794	\$ 5,660	\$ 2,300	\$ -
# Internal, Overheads	\$ 5,924	\$ -	\$ -	\$ 216	\$ 1,478	\$ 2,934	\$ 1,297	\$ -
# Materials	\$ 11,137	\$ -	\$ -	\$ 382	\$ 2,794	\$ 5,660	\$ 2,300	\$ -
# Overheads - External	\$ 7,843	\$ -	\$ -	\$ 286	\$ 1,956	\$ 3,884	\$ 1,717	\$ -
Total	\$ 102,861	\$ -	\$ -	\$ 3,561	\$ 25,786	\$ 52,100	\$ 21,414	\$ -

[illegible]

NYSEG CAS Ithaca Northern Loop

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006663	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2034

Project description:

The Ithaca Northern Loop Comprehensive Area Study identified several system upgrades necessary to address current and forecasted system constraints within the electric system region consisting of seven substations: Burdett, County Hospital, Interlaken, Ovid, Trumansburg, Valois, and Willard. The Northern Loop Area is located in the northwest third of the Ithaca division. The study utilized an integrated system approach, evaluating both transmission and distribution needs. This method enables the proposed distribution solutions to incorporate necessary transmission and substation upgrades, optimizing the cost efficiency of the total system solution.

Area Overview: The electric distribution system within the Area serves approximately 12,200 customers with a peak load of 35.4 MVA as observed in 2023. The Northern Loop includes 11 distribution feeders with operating voltages of 4.8 kV and 34.5 kV. The electric transmission system in this area is served by long radial 34.5 kV subtransmission lines, which are far from their 115 kV transmission sources. The Area has very limited remaining capacity and is forecasted to undergo significant winter peak load growth driven by building and transportation electrification. The high forecasted load growth necessitates proactive system improvements to address capacity and voltage constraints, supporting electrification and economic development in the Northern Loop Area. Forecasted load growth based on the NYISO Gold Book and internal forecasting indicates the following:

- Winter Peak Load Growth: 13% by 2029 and 41% by 2034.
- Summer Peak Load Growth: -2.1% by 2029 and 3.1% by 2034.

Needs Assessment:

Voltage and Thermal: The Ithaca Northern Loop Area is forecasted to experience significant thermal and voltage violations within the 5-10 year planning horizon:

- 62% of customers will experience undervoltage by 2034; 85% by 2044.
- 51 grid assets, including 4 of 6 substation transformers, and 6 of 8 substation regulators will be overloaded by 2034.

Reliability: No N-1 backup capabilities are available for the 11 feeder circuits in the Northern Loop Area due to differing feeder voltage classes and a lack of tie points.

Asset Condition:

- 4,270 (30%) of distribution poles in the Northern Loop Area are greater than 60 years old.
- 6 out of 10 circuit breakers in the Area are in poor, or very poor condition.
- 1 out of 18 substation transformers in the Area are in fair, poor, or very poor condition.

Project Scope:

Proposed Transmission and Distribution upgrades were designed to resolve all anticipated system needs under the forecasted 2034 load profile. Where possible, assets were sized up such that they could accommodate the 2044 forecasted load values. The selected alternative calls for; retiring the Ovid substation and feeding its customers with the Willard substation. Converting County Hospital 736, Burdett 702, and Valois 719 from 4.8kV to 12.47kV. Converting Interlaken, Trumansburg, and Willard (Including Ovid) to 34.5kV. These conversions ensure that all feeders have N-1 support from a different substation, as well as creating the necessary capacity headroom for forecasted growth. The transmission upgrades proposed for the Geneva MacDougall and Ithaca Northern Loop studies are identical due to the area being a 34.5 kV subtransmission system interconnected with normally open points. The project is currently in a conceptual state; the scope and schedule will be refined as preliminary and detailed engineering activities are performed.

Distribution Upgrades:

1. Retire Ovid substation
2. Replace 3 Substation power transformers
3. Replace 4 Substation regulator banks
4. Install 11 new breakers
5. Perform 81 miles of 3-PH voltage conversion
6. Perform 226 miles of 1-PH voltage conversion
7. Install 36 new regulators
8. Install 47 new step banks
9. Install 11 new switched caps
10. Install 27 new reclosers

Transmission Upgrades:

1. Reconfigure Milliken substation to add two new 115 kV bays
2. Construct a new 115/34.5 kV expandable substation with:
 - a. A four breaker 115 kV ring bus
 - b. Two Type #11 - 115/34.5 kV – 50 MVA power transformers
 - c. Two 34.5 kV straight buses with a normally closed tie breaker
3. Install approximately 3.4 miles total of new overhead 115 kV line between Milliken and the new substation (1.7 miles each for two circuits)
4. Install approximately 3.4 miles total of new 115 kV submarine cable between Milliken and the new substation (1.7 miles each for two circuits)
5. Replace 56859 at McDougall substation with a normally open 34.5 kV breaker
6. Replace 55579 at Willard substation with a normally open 34.5 kV breaker

Project Benefits:

The primary driver of this project is to address emergent capacity constraints within the Area. In addition to resolving these capacity constraints, the project will also address voltage, reliability, and asset condition needs within the Northern Loop Area.

Capacity: The proposed solution relieves significant thermal constraints both on the distribution system and on the 34.5 kV transmission system. Proposed mitigations provide 86.1 MVA of additional N-0 capacity across the Northern Loop Area, providing sufficient capacity to support significant load growth and N-1 redundancy for all feeders.

Voltage Support: All existing voltage needs, and all forecasted voltage through 2034 are addressed by the proposed system upgrades. Some 2044 forecasted voltage needs are left unresolved as preemptively implementing the requisite solution could negatively impact system performance prior to the needs emergence.

Reliability: The project will enhance system reliability and operability by providing N-1 backup capabilities for all eight distribution feeders in the Area. By increasing operating voltages and installing SCADA tie reclosers, each feeder will have at minimum one back up feed from a different substation. The proposed solution will improve system performance under outage conditions and will also provide additional operational flexibility, including for maintenance activities.

Asset Condition: Preliminary electrical equipment asset condition needs in the Northern Loop Area were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. 6 out of 10 circuit breakers are in "Poor", or "Very Poor" condition in the Northern Loop Area. Additionally, 1 out of 18 substation transformers carry "Poor", or "Very Poor" equipment ratings. Equipment that is in poor, or very poor condition have exceeded their useful life and should be replaced to limit the risk of equipment-related outages. Such assets are identified for replacement or retirement in the proposed solution. Site inspections will be performed to identify any additional asset condition needs.

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to capacity constraints, resulting in worsening voltage violations and reliability issues. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include, mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) Actual load growth may not align with forecasted values. If actual load growth is materially lower/slower or higher/faster than NYSEG's forecast indicated, there may be risks related to overbuilding or underbuilding, respectively. The principal concern related to overbuilding is that it can negatively impact system cost-efficiency by resulting in investments which are more costly or are deployed earlier than is strictly required to satisfy system demands. Overbuilding risk was mitigated by proposing solutions to meet 10 year needs, with sufficient capacity to eventually meet 20 year needs. Additionally, overbuild risks are offset by the fact that this project will provide immediate benefits to reliability and resiliency, as well as create capacity headroom for electrification projects such as for nearby school buses. (i.e., Seneca Central School District).

With regards to underbuilding risk, the primary concern is that the cost-efficiency of projects can be severely impacted if a relatively new project must be re-worked in a way that results in redundancies or an overhaul of prior developed scope. To minimize underbuilding risk, NYSEG designed the project such that project components were either right-sized, or were scalable, to be sufficient to satisfy expected system needs for at least 20 years (i.e., 2044). Right-sizing solutions for future load growth is an effective method for mitigating underbuilding risk in instances where (1) there is limited space for adding additional facilities and (2) the incremental cost of installing higher-capacity equipment does not materially increase total project costs. This project incorporated a right-sizing philosophy in selecting transformer, regulator, and conductor sizes.

Risk of No Action:

The Area is facing multiple existing challenges: voltage issues (Valois 719, Ovid 715), thermal constraints (Trumansburg, Valois substations), asset condition concerns (Circuit Breakers, transformers, and poles), and N-1 reliability challenges. Opting to take no action on the proposed Comprehensive Area Solution would mean that short-term and/or operational solutions for current system constraints would need to be developed as an interim measure to ensure that the electric system can be operated within acceptable reliability and safety limits. Pursuing short-term solutions instead of a comprehensive solution may result in a less cost-efficient buildout of infrastructure, especially if comprehensive action is significantly delayed.

There is also a risk that unmitigated load growth in the Area could drive system constraints to a point where the electric system is, in effect, inoperable due to excessive demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth, leading to significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action would also impact the accomplishment of the State's electrification goals because there is insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This will result in higher costs to customers, plus electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

Project Alternatives:

An alternative solution was developed which differs from the preferred solution in four major ways:

1. All voltage conversions are total conversions without step banks on spur lines.
2. Ovid substation is not retired and is instead converted to 34.5 kV distribution.
3. Interlaken substation is split into two feeders, north and south. The northern feeder is 34.5kV distribution and has ties with Ovid and Valois. The Southern feeder is 12.47 kV and has a tie with Trumansburg.
4. Trumansburg substation is converted to 12.47 kV and has a tie with Interlaken South.

The alternative solution was not selected due to the limited N-1 capacity of the 12.47 kV Trumansburg station, and the \$220 million increase in distribution line expenses. The increases cost is driven by: a 25 mile increase in 3 phase voltage conversions, a 247 mile increase in 1 phase voltage conversions, and a 1 mile increase in new line construction. The associated cost increases were not offset by the decrease in distribution line equipment; 38 fewer step banks, 31 fewer regulators, and 1 less recloser.

Alternative Distribution Upgrades:

1. Split Interlaken into two feeders; North (34.5 kV) and South (12.47 kV)
2. Replace 6 Substation power transformers
3. Replace 3 Substation regulator banks
4. Install 14 new breakers
5. Perform 105 miles of 3-PH voltage conversion
6. Perform 475 miles of 1-PH voltage conversion
7. Install 6 new regulators
8. Install 9 new step banks
9. Install 12 new switched caps
10. Install 26 new reclosers

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 159,180	\$ -	\$ -	\$ -	\$ -	\$ 19,942	\$ 49,511	\$ 89,726
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 63,672	\$ -	\$ -	\$ -	\$ -	\$ 7,977	\$ 19,805	\$ 35,890
# Internal, Overheads	\$ 22,350	\$ -	\$ -	\$ -	\$ -	\$ 2,316	\$ 6,254	\$ 13,780
# Materials	\$ 49,523	\$ -	\$ -	\$ -	\$ -	\$ 6,204	\$ 15,404	\$ 27,915
# Overheads - External	\$ 34,825	\$ -	\$ -	\$ -	\$ -	\$ 3,608	\$ 9,745	\$ 21,472
Total	\$ 329,549	\$ -	\$ -	\$ -	\$ -	\$ 40,047	\$ 100,718	\$ 188,783

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG CAS Liberty Hilldale

PROJECT INFORMATION

OpCo:	Project ID:	Charge Code:	Project Sponsor:	Project Type:
NYSEG	PRJ-006664	Electric Distribution	0	0
Business Area:	Rate Case Category	Project Stage:	Start Date:	In-Service Date:
Planning & Coordination	Reliability	0	Ongoing	H2 2031

Project description:

The Hilldale Comprehensive Area Study identified a number of system upgrades that are necessary to address current and forecasted system constraints within the electric system region consisting of five (5) substations: Hilldale, Neversink, Oldfalls, Mountindale and Concord substations, all located within the Town of Fallsburg in Sullivan County. The Study utilized an integrated system evaluation approach wherein a targeted transmission planning assessment of relevant facilities was performed to determine how the solutions developed to address the distribution system needs should be optimized to respect, or incorporate, necessary upgrades to nearby transmission or substation facilities

Area Overview: The electric system within the Area serves approximately 12,470 customers with a peak load of 78.5 MVA, observed in 2023. The Area includes eleven (11) distribution feeders with voltage classes of 4.8 kV, 8.32 kV, and 12.5 kV. The Area has very limited remaining capacity and is forecasted to undergo significant winter peak load growth driven by building and transportation electrification. The high forecasted load growth necessitates proactive grid expansion to address capacity constraints and support electrification and economic development in the Hilldale Area. Forecasted load growth based on the NYISO Gold Book and internal forecasting indicates the following:

- Winter Peak Load Growth: 15.2% by 2029 and 44.5% by 2034.
- Summer Peak Load Growth: -0.3% by 2029 and 5.6% by 2034.

Needs Assessment:

Voltage and Thermal: The Hilldale Area is forecasted to experience significant thermal and voltage violations within the 5–10-year planning horizon:

- 46.2% of customers will experience undervoltage by 2034; 76.4% by 2044.
- 70 grid assets, including all 6 Substation transformers will be overloaded by 2034.
- Due to capacity constraints, most substations in the Hilldale area are unable to accommodate additional load.

Reliability: No N-1 backup capabilities are available for the 7 feeder circuits in the Hilldale Area due to differing feeder voltage classes and a lack of tie points.

Asset Condition:

- 1,869 (24%) of distribution poles equal or greater than 60 years old.
- 2 out of 11 breakers are in poor, or very poor conditions.

Project Scope:

The conceptual project developed as part of The Study includes distribution and transmission upgrades needed to address all identified system needs in the Area within the next 10 years, while considering a 20-year horizon for right-sizing purposes. The proposed upgrades include: upgrading the 34.5/12.47 kV 10.5 MVA transformer to a 34.5/12.47 kV 22.4 MVA bank at Hilldale Substation; converting Neversink 180 from 4.8 kV to 12.5 kV and installing a new 34.5/12.47 kV 14 MVA transformer at Neversink Substation; installing a new 115/12.47 kV 37 MVA transformer at West Woodbourne Substation to relieve some load off Oldfalls Substation; retiring transformer #2 and utilizing transformer #1 to feed the remaining load at Oldfalls Substation; installing a new 115/12.47 kV transformer at Mountindale; and installing a new 34.5/12.47 kV 14 MVA transformer at Concord Substation and converting Concord 196, 197, and 198 circuits from 4.8 kV to 12.47 kV. These proposals ensure that all the feeders have the same voltage class, which will improve reliability under N-1 conditions and allow for expandability in support of future load growth. The project is currently in a conceptual state; the scope and schedule will be refined as preliminary and detailed engineering activities are performed.

Distribution Upgrades:

1. Install 22.4 MVA Type 5, 37 MVA Type 6, and 14 MVA Type 3 LTC transformers at Hilldale, Neversink, West Woodbourne, Mountindale, and Concord substations.
2. Reconductor 17.37 miles of overhead line at 12.47 kV with 477 AL.
3. Install 4.69 miles of new overhead line with 477 AL.
4. Rebuild and reconductor 0.32 miles of overhead line with 477 AL.
5. Reconductor 4.91 miles of overhead line at 12.47 kV with 1/0 and 1/0 (N).
6. Reconductor 1.46 miles of overhead line at 12.47 kV with 4/0 and 4/0 (N).
7. Convert and rebuild 3.03 miles of overhead line with 477 AL.
8. Convert 65.855 miles of overhead line from 4.8 kV to 12.47 kV with 1/0 and 1/0 (N).
9. Convert 0.9 miles of overhead line from 4.8 kV to 12.47 kV with 4/0 and 4/0 (N).
10. Convert 40.59 miles of overhead line from 4.8 kV to 12.47 kV by adding 1/0 (N).
11. Convert 6.19 miles of overhead line from 4.8 kV to 12.47 kV by adding 4/0 (N).
12. Convert 14.3 miles of overhead line from 4.8 kV to 12.47 kV with 477 AL and 4/0 (N).
13. Convert 3.43 miles of underground cable from 4.8 kV to 12.47 kV (mostly private service) by adding 1/0 AL (N).
14. Install fourteen (14) new SCADA reclosers.
15. Install communications to one (1) existing recloser.
16. Install two (2) single-phase 15 kV regulator banks.
17. Install seven (7) three-phase 15 kV regulator banks.
18. Install seven (7) new breakers.

Project Benefits:

The primary driver of this project is to address emergent capacity constraints within the Area. In addition to resolving these capacity constraints, the project will also address reliability and asset condition needs within the Hilldale Area.

Capacity: The project will relieve significant voltage and thermal constraints both on the distribution system and on the 34.5 kV transmission system serving the Area. The project will result in additional capacity at all the Substations in the Hilldale area, providing sufficient capacity to support significant load growth and N-1 redundancy for all feeders.

Reliability: The project will enhance system reliability and operability by providing N-1 backup capabilities for all eight distribution feeders in the Area. By standardizing circuit voltage at 12.5 kV, installing SCADA tie reclosers, and enhancing system capacity, the project will improve system performance under outage conditions and will also provide additional operational flexibility, including for maintenance activities.

Asset Condition: Preliminary electrical equipment asset condition needs in the Hilldale Area were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. Two (2) out of eleven (11) circuit breakers poor, or very poor conditions in the Hilldale Area. Equipment that is in poor, or very poor condition have exceeded their useful life and should be replaced to limit the risk of equipment-related outages. Such equipment are included for replacement or retirement in the conceptual solution. Site inspections will be performed to identify any additional asset condition needs.

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to capacity constraints, resulting in worsening voltage violations and reliability issues. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include, mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) Actual load growth may not align with forecasted values. If actual load growth is materially lower/slower or higher/faster than NYSEG's forecast indicated, there may be risks related to overbuilding or underbuilding, respectively. The principal concern related to overbuilding is that it can negatively impact system cost-efficiency by resulting in investments which are more costly or are deployed earlier than is strictly required to satisfy system demands. Overbuilding risk was mitigated by proposing solutions to meet 10 year needs, with sufficient capacity to eventually meet 20-year needs. Additionally, overbuild risks are offset by the fact that this project will provide immediate benefits to reliability and resiliency, as well as create capacity headroom for electrification projects such as for nearby school buses.

With regard to underbuilding risk, the primary concern is that the cost-efficiency of projects can be severely impacted if a relatively new project must be re-worked in a way that results in redundancies or an overhaul of prior developed scope. To minimize underbuilding risk, NYSEG designed the project such that project components were either right-sized, or were scalable, to be sufficient to satisfy expected system needs for at least 20 years (i.e., 2044). Right-sizing solutions for future load growth is an effective method for mitigating underbuilding risk in instances where (1) there is limited space for adding additional facilities and (2) the incremental cost of installing higher-capacity equipment does not materially increase total project costs.

Risk of No Action:

The risk of no action at all on this project is significant, as this area is already facing multiple challenges: voltage issues (Oldfalls 283, 284, 288, Neversink 180, Concord 197, Mountindale 207) thermal constraints (Hilldale Neversink, Oldfalls Mountindale and concord substations), asset condition concerns (Breakers, Regulators), and N-1 reliability challenges. Opting to take no action on the proposed distribution and transmission upgrades would severely limit the area's ability to support electrification driven by substantial customer load growth. Without the necessary system capacity upgrades, the area will be unable to accommodate the load growth driven by electrification and economic development. The majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. In general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth causing significant overload and undervoltage conditions with very limited operational mitigations available.

There is also a risk that unmitigated load growth in the Area could drive system constraints could to a point where the electric system is, in effect, inoperable due to excessive demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth, leading to significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's CLCPA goals because there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

The Hilldale Comprehensive Area Study will be evaluated for alternative solutions in Q2 2025. Project alternatives may seek to include additional project scope beyond existing upgrades proposed where it is justified and supported. Such additional scope may include addressing needs such as, but not limited to, improving power quality, replacing overloaded equipment, or replacing aging infrastructure. Project alternatives may also include the consideration of solutions such as selective undergrounding, where appropriate and cost-efficient.

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG CAS Binghamton CN Bridge

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006670	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The Chenango Bridge Comprehensive Area Study identified a number of system upgrades necessary to address current and forecasted system constraints within the electric system region consisting of three substations: Chenango Bridge, Morningside Heights, and Nowlan Road, all located within Broome County. The Study utilized an integrated system evaluation approach wherein a targeted transmission planning assessment of relevant facilities was performed to determine how the solutions developed to address the distribution system needs should be optimized to respect or incorporate necessary upgrades to nearby transmission or substation facilities.

Area Overview: The electric system within the Area serves approximately 7,337 customers with a peak load of 25.7 MVA, observed in 2023. The Area includes nine distribution feeders with a voltage class of 4.8 kV and two tap circuits with a voltage class of 34.5 kV. The Area currently has very limited available capacity and is forecasted to undergo significant winter and summer peak load growth, primarily due to building and transportation electrification. The high forecasted load growth necessitates proactive grid expansion to address capacity constraints and support electrification and economic development in the Chenango Bridge Area. Forecasted load growth based on the NYISO Gold Book and internal forecasting indicates the following:

- Winter Peak Load Growth: 15.2% by 2029 and 44.5% by 2034
- Summer Peak Load Growth: 0.3% by 2029 and 5.6% by 2034

Needs Assessment:

Voltage and Thermal: The Chenango Bridge Area is forecasted to experience significant thermal and voltage violations within the 5–10-year planning horizon:

- 17.1% of customers will experience undervoltage by 2034; 34.8% by 2044.
- 16 grid assets, including the substation transformer at Morningside Heights Substation, will be overloaded by 2034.
- Due to capacity constraints, most substations in the Chenango Bridge area are unable to accommodate additional large loads.

Reliability: No N-1 backup capabilities are available for the 9 feeder circuits in the Chenango Bridge Area due to voltage and thermal constraints.

Asset Condition:

- 1536 (31%) of distribution poles in the Area are greater than 60 years old.
- Four out of seven circuit breakers in the Area are in poor, or very poor condition

Project Scope:

The conceptual project developed as part of The Study includes distribution and transmission upgrades needed to address all identified system needs in the Area within the next 10 years, while considering a 20-year horizon for right-sizing purposes (e.g., selecting a 14.1 MVA transformer as the replacement at Chenango Bridge and Nowlan Road Substations). This proposal also optimizes the distribution voltage class in the area by converting 4.8 kV circuits to NYSEG's standard 12.5 kV voltage class, improving reliability under N-1 conditions and allowing for expandability in support of future load growth. The project is currently in a conceptual state; the scope and schedule will be refined as preliminary and detailed engineering activities are performed.

Distribution Upgrades:

1. Install a 14 MVA Type 3 power transformer with LTC at Chenango Bridge and Nowlan Road Substation.
2. Install a 10 MVA Type 2 power transformer with LTC at Morningside Heights Substation.
3. Replace/Install 9 circuit breakers at Chenango Bridge, Morningside Heights, Nowlan Road Substation.
4. Reconductor ~26 miles of overhead distribution line.
5. Convert ~77 miles of overhead line from 4.8 kV to 12.5 kV.
6. Install 2 voltage regulators.

Project Benefits:

The primary driver of this project is to address emergent capacity constraints within the Area. In addition to resolving these capacity constraints, the project will also address reliability and asset condition needs within the Chenango Bridge Area.

Capacity: The project will relieve significant voltage and thermal constraints both on the distribution system and on the 34.5 kV transmission system serving the Area. The project will result in additional capacity at all the Substations in the Chenango Bridge area, providing sufficient capacity to support significant load growth and N-1 redundancy for all feeders.

Reliability: The project will enhance system reliability and operability by providing N-1 backup capabilities for all nine distribution feeders in the Area. By standardizing circuit voltage at 12.5 kV, installing SCADA tie reclosers, and enhancing system capacity, the project will improve system performance under outage conditions and will also provide additional operational flexibility, including for maintenance activities.

Asset Condition: Preliminary electrical equipment asset condition needs in the Hilldale Area were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. Two out of eleven circuit breakers poor, or very poor conditions in the Chenango Bridge Area. Equipment that is in poor, or very poor condition have exceeded their useful life and should be replaced to limit the risk of equipment-related outages. Such equipment are included for replacement or retirement in the conceptual solution. Site inspections will be performed to identify any additional asset condition needs.

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to capacity constraints, resulting in worsening voltage violations and reliability issues. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if overloads are forecasted to occur prior to project completion. Such measures can include, mobile transformers, temporary load transfers, mobile transformer deployment, or back-up generators.

(2) Actual load growth may not align with forecasted values. If actual load growth is materially lower/slower or higher/faster than NYSEG's forecast indicated, there may be risks related to overbuilding or underbuilding, respectively. The principal concern related to overbuilding is that it can negatively impact system cost-efficiency by resulting in investments which are more costly or are deployed earlier than is strictly required to satisfy system demands. Overbuilding risk was mitigated by proposing solutions to meet 10 year needs, with sufficient capacity to eventually meet 20-year needs. Additionally, overbuild risks are offset by the fact that this project will provide immediate benefits to reliability and resiliency, as well as create capacity headroom for electrification projects such as for nearby school buses.

With regards to underbuilding risk, the primary concern is that the cost-efficiency of projects can be severely impacted if a relatively new project must be re-worked in a way that results in redundancies or an overhaul of prior developed scope. To minimize underbuilding risk, NYSEG designed the project such that project components were either right-sized, or were scalable, to be sufficient to satisfy expected system needs for at least 20 years (i.e., 2044). Right-sizing solutions for future load growth is an effective method for mitigating underbuilding risk in instances where (1) there is limited space for adding additional facilities and (2) the incremental cost of installing higher-capacity equipment does not materially increase total project costs.

Risk of No Action:

The risk of no action at all on this project is significant, as this area is already facing multiple challenges: voltage issues (Chenango Bridge 428, 741, and 742; Morningside Heights 674 and 675; Nowlan Road 226 and 227), thermal constraints (Morningside Heights Substation), asset condition concerns (Breakers, Regulators, Conductors), and N-1 reliability challenges. Opting to take no action on the proposed distribution and transmission upgrades would severely limit the area's ability to support electrification driven by substantial customer load growth. Without the necessary system capacity upgrades, the area will be unable to accommodate the load growth driven by electrification and economic development. The majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. In general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth causing significant overload and undervoltage conditions with very limited operational mitigations available.

There is also a risk that unmitigated load growth in the Area could drive system constraints could to a point where the electric system is, in effect, inoperable due to excessive demand. In severe instances, such conditions may require emergency actions by system operators. It is noteworthy that the majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. This is important because, in general, NYSEG does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth, leading to significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's CLCPA goals because there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

Project Alternatives:

The Chenango Bridge Comprehensive Area Study will be evaluated for alternative solutions in Q2 2025. Project alternatives may seek to include additional project scope beyond existing upgrades proposed where it is justified and supported. Such additional scope may include addressing needs such as, but not limited to, improving power quality, replacing overloaded equipment, or replacing aging infrastructure. Project alternatives may also include the consideration of solutions such as selective undergrounding, where appropriate and cost-efficient.

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at NYSEG. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 134,324	\$ -	\$ -	\$ 3,584	\$ 33,145	\$ 59,573	\$ 37,628	\$ 393
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 44,775	\$ -	\$ -	\$ 1,195	\$ 11,048	\$ 19,858	\$ 12,543	\$ 131
# Internal, Overheads	\$ 12,042	\$ -	\$ -	\$ 338	\$ 2,935	\$ 5,170	\$ 3,553	\$ 45
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 19,928	\$ -	\$ -	\$ 560	\$ 4,857	\$ 8,556	\$ 5,879	\$ 75
Total	\$ 211,068	\$ -	\$ -	\$ 5,677	\$ 51,986	\$ 93,157	\$ 59,603	\$ 644

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

New Centerport Substation (Port Byron - Load relief)

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-004088	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: H1 2025	In-Service Date: H2 2027

Project description:

The Port Byron and Weedsport substation transformers were identified under the Distribution Load Relief (DLR) program, which is designed to focus on conducting system wide facility surveys on substation transformers that are overloaded and/or beginning to exceed 90% capacity. This program devises a mitigation strategy to address these overload conditions.

Project Reliability Needs:

Distribution:

Port Byron 5 MVA 34.5/4.8 kV transformer bank #1 overloaded to 107% of CNR under 5-year historic average peak loading

Weedsport 5 MVA 34.5/4.8 kV transformer bank #1 overloaded to 97.5% of CNR under 5-year historic average peak loading

Transmission:

Low voltage reliability criteria violations identified under current-year peak load.

N-0 Needs – 34.5 kV system low voltage violations (<0.95 pu)

N-1 Needs – Widespread low voltage violations as low as 0.82 pu

Violations exacerbated by any future load growth at Port Byron and Weedsport.

Project Asset Needs:

Port Byron:

Transformer 1T: The 3-1ph transformers have good health index scores. However, the 65-year-old transformers show noticeable rust/ corrosion on tanks and radiators. Also, there is no visible primary oil containment for these transformers. Breakers: One (1) distribution breaker is assessed as fair (HI 3) in Health condition. This is a Westinghouse oil circuit breaker that was installed in 1995 for 4.8 kV distribution circuit 633. Structures and Foundations: The 34.5 kV & 4.8 kV box structures are in fair condition with depleted galvanized coatings on most members/bracing. Many foundations are in poor condition with heavy signs of deterioration from spalling, cracks, & scaling especially on the 34.5 kV level. Switches & Insulators: All 34.5kV and 13.2 kV switches have gray porcelain insulators and have no visual concerns. Protection: Utilizes outdoor cabinets and self-containment breakers (No control House). Mixture of microprocessors and obsolete electromechanical relays.

Weedsport:

Transformer 1T: The 3-1ph transformers have fair Health Index (HI-3) scores. However, the 74-year-old transformers shows noticeable rust/corrosion on tanks, radiators and bushing. Also, there is no visible primary oil containment for these transformers. Breakers: The two (2) distribution breakers are assessed as very poor (HI 5) in Health condition. These are General Electric oil circuit breakers, installed in 1955 & 1960 for 4.8kV distribution circuit 628 and 629, respectively. Structures and Foundations: The 34.5kV & 4.8kV box structures are in fair condition with depleted galvanized coatings on most members/bracing. Many foundations are in poor condition with heavy signs of deterioration from spalling, cracks, & scaling. Switches & Insulators: All 34.5kV and 13.2 kV switches have gray porcelain insulators and have no visual concerns. Protection: Utilizes outdoor cabinets and self containment breakers (No control House). Mostly obsolete electromechanical relays.

The Port Byron circuits 611 & 633 serve approx. 1,739 customers, with 5-year average peak loading of 5.35 MVA, while the Weedsport circuits 628 & 629 serve approx. 1,545 customers, with 5-year average peak loading of 4.88 MVA.

Project Scope:

New Centerport Substation with partial load transfers from Port Byron & Weedsport to the new Centerport Substation.

- Construct a new MV GIS substation with 34.5/12-4.8kV 22.4MVA LTC transformer at/near existing Centerport tap.
- Install a new 8 MVar 34.5 kV Capacitor bank at Centerport
- Transfer approx. 3 MVA of existing 4.8 kV load from Port Byron to new Centerport
- Transfer approx. 1.6 MVA of existing 4.8kV load from Weedsport to new Centerport.
- Replace 4.8kV circuit breaker 62812 at Weedsport with a new 15kV 1200A rated vacuum breaker

Project Benefits:

- Mitigate thermal overload (N-0) on T1 at Port Byron & Weedsport
- Capacitors mitigate low voltage concerns on the 34.5kV system
- Allows for future load growth/hosting capacity including DER integration at both Port Byron & Weedsport area
- Provides better 34.5 kV sectionalizing capabilities and speeds up restoration efforts in an event of a fault on the 34.5 kV system, thereby reducing loss of load exposure for a transmission line fault.
- Provides N-1 contingency support capabilities to/from adjacent substations or nearby circuits.
- Allows for future expendability to provide full N-1 capability
- Supports the long term plan to upgrade the 4.8kV system to 12.5kV, retire of existing Port Byron & Weedsport substation facilities and fully absorb their loads/customers.
- Limited/No mobile required utilizes the 4.8kV winding to allow for time and help facilitate a smooth transition of the 4.8kV conversion to 12.5kV in the future.
- Shortest delivery timeline (no circuit conversion is involved)
- Allow for future consolidation of Port Byron and Weedsport substations into a single substation, which would result in additional O&M cost savings

Project Risks and Mitigation Plan:

Unforeseen subsurface conditions:

The property we are currently pursuing to purchase appeared to be located over a principal aquifer according to the EAF mapper. The EAF mapper is a screening tool intended to assist project sponsors and reviewing agencies in preparing an environmental assessment form. Although the EAF mapper provides the most up-to-date digital data available to DEC, it should be verified for accuracy. We also reviewed the Web soil survey to determine the depth to water table. According to the Web soil survey, the depth to water table ranges from 21.29 inches to 53.94 inches. Prior to any land negotiations, they landowner has allowed us to perform a ground water study to determine actual water depths. Groundwater was encountered in each of the test borings during drilling at depths ranging from approximately 9.0 feet bgs to 10.0 bgs. If groundwater is encountered during construction, the use of local sumps and pumps should be adequate to control groundwater fluctuations. If continuous pumping of infiltrating water is required, the pump shall be placed within crushed stone in a sump area that is dug outside of the planned foundation footprint. Perched or trapped water may be encountered within soil layers of differing gradation, particularly within fill layers. Groundwater levels will fluctuate due to seasonal affects and/or construction related activities. The project team will continue to monitor these conditions and follow the recommendations provided by LaBella's Geotechnical Engineers. We will also ensure that the construction RFP includes dewatering as part of the construction contractors' scope of work.

Risk of No Action:

The decision to take 'no action' regarding the build of a new substation near the Centerport tap will result in the following:

- Port Byron transformers are currently overloaded and Weedsport transformers are projected to be overload in the near future.
- Voltage and thermal constraints on the network.
- No contingency support to the nearby substations and circuits to reduce outages and speed up restoration time for customers.
- Future load growth/ hosting capacity including DER integration at both Port Byron and Weedsport areas will be minimal.
- Will not allow for consolidation of Port Byron and Weedsport substations into a single substation, which could result in Capital and future O&M cost savings.
- No support for the long-term plan to upgrade the 4.8kV system to 12.5kV, retire of existing Port Byron & Weedsport substation facilities and fully absorb their loads/customers.

Project Alternatives:

Alt 1: Port Byron substation rebuild with partial load transfer from Weedsport to Port Byron:

- Rebuild Port Byron to a new MV GIS substation with 34.5/12 4.8kV 22.4MVA LTC transformer
- Install a new 8MVar 34.5kV Capacitor bank at Port Byron
- Fully convert approx. 13 miles of the two Port Byron 4.8kV circuits to 12kV.
- Partially convert approx. 0.65 miles of Weedsport 4.8kV #629 circuit to 12kV and transfer approx. 1 MVA of Load from Weedsport to Port Byron.
- Replace 4.8kV circuit breaker 62812 at Weedsport with a new 15kV 1200A rated vacuum breaker

Alt 2: Weedsport substation rebuild with full load transfer from Port Byron to Weedsport:

- Rebuild Weedsport to a new MV GIS substation with 34.5/12 4.8kV 22.4MVA LTC transformer
- Install 2 x 6 MVar 34.5kV capacitor banks at Weedsport
- Fully convert approx. 10 miles of the two Weedsport 4.8kV circuits to 12kV.
- Fully convert approx. 13 miles of the two Port Byron 4.8kV circuits to 12kV and transfer approx. 7 MVA of Load to Weedsport.

Alt 3 (Selected): \$34M- New Centerport substation with partial load transfers from Port Byron & Weedsport to New Centerport substation:

- Construct a new MV GIS substation with 34.5/12 4.8kV 22.4MVA LTC transformer at/near existing Centerport tap.
- Install a new 8MVar 34.5kV Capacitor bank at Centerport
- Transfer approx. 3 MVA of existing 4.8kV load from Port Byron to New Centerport
- Transfer approx. 1.6 MVA of existing 4.8kV load from Weedsport to New Centerport.
- Replace 4.8kV circuit breaker 62812 at Weedsport with a new 15kV 1200A rated vacuum breaker.

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates within the estimating workbook are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Wales 325

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007414	Charge Code: Distribution	Project Sponsor: Rob McDonough	Project Type: Program
Business Area: Electric Operation	Category: Betterments	IP Stage: IP1	Start Date: H1 2026	In-Service Date: H2 2026

Project description:

Wales 325 is a 4.8kV delta distribution circuit (NYSEG Lancaster Division) which is Wales, NY servicing 1,114 total customers. Wales 325 was a yellow circuit in year 2022, and in the last 5 years, it shows up as a red circuit. New customer load is not able to be added because of the voltage drop and low fault current causing flicker for existing customers, and difficult coordination. Distribution planning, Eric Judd, analyzed the circuit and came up with a game plan for this circuit to continue to add new customers by doing reconductoring (shown below). This part of Wales 325 already has 2 line regulators so it is already maxed out for ways to keep voltage at a proper level.

The Wales bank (92% loaded) can get a 10% load relief with the additional work below. A 800 foot gap can be closed at the end of two circuits that are natural 4.8kv delta. Along Route 20A, East Aurora 342 ends at Line 577 Pole 582 and Wales 325 ends at Line 577 Pole 587. There can be a directional bore done to close this gap since it is intersected by the East Aurora Expressway Route 400. Load transfer with East Aurora 342 of (239 customers) which is the tail end of the Wales 325. New Open would be Line 577 Pole 613. This would drop about 500kva which is 10% of load on Wales Bank (Load Relief) and it also improves the fault current to customers on Reiter road.

Project Scope:

Reconductor Wales 325

Approximately 95 spans of reconductor

Reconductor Big Tree road (Route 20A) from Line 577 Pole 641 to Line 577 Pole 587 (approx. 56 spans) 9,000 feet

Reconductor Reiter Road from Line 679 Pole 132 to Line 679 Pole T152 (20 spans) and Line 679 Pole 1 to Pole 14 (about 19 spans) 10,000 feet in all

About 20 pole replacements for substandard poles

Upgrade existing shunt capacitor on Line 278 Pole 2 to a 150KVAR switched capacitor

Replace upstream 85N fuse with SCADA recloser at Line 679 Pole 1

Install N.O. Scada device at Line 577 Pole 613 (Wales 325 and East Aurora 342)

Close Gap - Approximately 800 feet of directional bore – 500MCM CU wire

Project Benefits:

This project has direct benefits to 276 customers on Wales 325 that are currently downstream of the reconductor project, starting at Line 577 Pole 641. These customers will not have degradation of voltage as new customers come online and the entire circuit of 1,114 customers will be able to avoid flicker from customers that are only adding 300kva. There is also the redundancy benefit for East Aurora 342 with 1,119 customers that do not have a backup source from this direction. There is also the redundancy benefit on East Aurora 343 for the 142 customers on Blakely Corners road (single phase spur). They will now have a backup source all the way back to Line 954 Pole 142. Right now there is no backup source for this spur line

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 122,408	\$ -	\$ 122,408	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 550,917	\$ -	\$ 550,917	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 28,478	\$ -	\$ 28,478	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 107,637	\$ -	\$ 107,637	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 551,181	\$ -	\$ 551,181	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 108,645	\$ -	\$ 108,645	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,469,266	\$ -	\$ 1,469,266	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Stolle Rd 551

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007415	Charge Code: Distribution	Project Sponsor: Rob McDonough	Project Type: Program
Business Area: Electric Operation	Category: Betterments	IP Stage: IP1	Start Date: H1 2026	In-Service Date: H2 2026

Project description:

Stolle Rd 551 is a 34.5kv distribution circuit (NYSEG Lancaster Division) which is in Alden, NY servicing 1,910 total customers. There are no other 34.5kv circuits that can backup this circuit during outages (except one tie at the head-end of the circuit from Girdle 554). This was a red circuit in year 2024 (53rd worst circuit in NYSEG), and it has been a red circuit in 2 of the last 3 years. DAP Automation is installing Scada devices on this circuit, but this circuit will not have a source to backfeed customers once they are sectionalized. Fortunately, this circuit has its own 11 mile loop for 34.5kv. Unfortunately there is a one gap which is only composed of single phase 4.8kv distribution. By converting this 17 span section on Clinton Street L-494 P-517 to P-534 from 4.8kv single phase to 34.5kv 3-phase, it will allow the 11 mile loop to be the same voltage. Any outage can be sectionalized and backed from itself on this loop. No easements are needed. Field Notes are already taken.

A second portion of upgrades on Stolle Rd 551, would be support for Cemetery Rd 492 and Alden 264. Currently, there is a 1000kva step bank 19.9/7.2kv serving 66 customers along Townline Road. If this step bank was upgraded to a 5000kva step pad, then it would be able to support other circuits in the area. This step would be able to

take over 434 customers on Broadway (L-313 P-186 to P-236), which would reduce customers below 2500C on Cemetery 492 as well as reduce load for better N-1 redundancy on Cemetery Bank. Cemetery 492 was a red circuit in year 2022. It also allows Cemetery 492 to have a better emergency support of Cemetery 490 (yellow circuit in year 2023). Where Stolle interfaces Alden 264 on Broadway, a 1500kva step bank can then be established to use for emergency backup of Alden 264 from the backend. DAP group added scada devices to Alden 264 in year 2024, but there is no back-up source from the backend.

Project Scope:

Voltage conversion on Clinton St and Upgrade to Step pad on Townline Road:

Add 3rd phase on Clinton St L-494 P-515 to P-534 (20 spans) plus tree trimming

Add Neutral where needed on 17 spans of P-518 to P-534

Replace 5 substandard distribution poles

Replace 11 overhead tanks along Clinton St with 19.9kv rated tanks

Install 1 Step pad 1-5000kva at L-513 P-166 Townline Rd (remove 1000kva step bank)

Install 1 Platform 3-500kva at L-313 P-237 Broadway – 7.2-4.8kv

Add One N.O. Scada device at L-313 P-238 Normal Open break (Stolle 551 and Alden 264)

Project Benefits:

The entire group of 1910 customers on Stolle 551 will have redundancy by having a loop distribution of itself. The 409 customers (Cemetery 492) will now have redundancy with Both Cemetery 492 and Stolle 551. The 332 customers on Alden 264 will have redundancy that are downstream of L-313 P-262 which previously did not have a backfeed source. Our distribution capacity increased by 4000kva with the changeout to a larger step bank

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 114	\$ -	\$ 114	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 514	\$ -	\$ 514	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 27	\$ -	\$ 27	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 100	\$ -	\$ 100	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 514	\$ -	\$ 514	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 101	\$ -	\$ 101	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,371	\$ -	\$ 1,371	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Raylinski Tap 606(635T606)

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007416	Charge Code: Distribution	Project Sponsor: Rob McDonough	Project Type: Program
Business Area: Electric Operation	Category: Betterments	IP Stage: IP1	Start Date: H1 2026	In-Service Date: H2 2026

Project description:

Raylinski Tap 606 is a 34.5kV distribution mega-circuit tapped off the 601L (Mullberry-to-Coons Crossing), servicing 4,346 total customers. Along Staniak Rd, the lightly loaded Luther Forest 635 and the Raylinski Tap share single phase distribution customers. This location presents an opportunity to upgrade the line to three phase 34.5kV and make the Luther Forest 635 the normal source.

Project Scope:

Upgrade and convert approximately 1 miles of 3-phase 34.5kV along Staniak Rd:

- Conductor ~1 mile of 477 poly wire
- Install ~1 mile of 4/0 neutral wire
- Install ~30 poles
- Reprogram SCADA devices
- Remap new LF635 vs Raylinski 606

Project Benefits:

This project benefits all 478 customers downstream of L45 P9 currently in a radial configuration. By constructing the 3-phase 635T606 along Staniak Rd the Company will see improved reliability metrics (CAID/SAIFI) on the Raylinski Tap 606 circuit. Additionally, this new construction will aid in mitigating the as-is 606 mega-circuit by shifting 478+ customers to the lightly loaded LF635.

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 151	\$ -	\$ 151	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 679	\$ -	\$ 679	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 35	\$ -	\$ 35	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 133	\$ -	\$ 133	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 680	\$ -	\$ 680	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 134	\$ -	\$ 134	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,812	\$ -	\$ 1,812	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Pound Ridge 457

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007476	Charge Code: Distribution	Project Sponsor: Rob McDonough	Project Type: Program
Business Area: Electric Operation	Category: Betterments	IP Stage: IP1	Start Date: H1 2026	In-Service Date: H2 2026

Project description:

Stone Hill Rd is fed from the east in the town of Pound Ridge by the Pound Ridge 457 circuit and is fed from the west in the town of Bedford by the Cantitoe 497 circuit. There is an open point at P2448 between the two circuits. The large customer count of Millertown Rd is causing phase imbalance on both circuits. By extending three phase down Stone Hill Rd from both circuits a SCADA tie recloser can be installed. Two phases may need to be extended down Millertown Rd, further load studies are needed. The Cantitoe 497 is currently 2 phase wye where highlighted on Old Post Rd and must be upgraded to three phase, poles are newly set in this area and are framed for three phase.

Project Scope:

Recloser tie switch at P2448
Tree work needed- scope unknown
Upgrade 2ph 4/0 with 3ph 477 P.AL and 4/0 B.AL neutral for approximately 7,500' (1.4 miles)-highlighted section
Upgrade 1ph 4/0 with 3ph 477 P.AL and 4/0 B.AL neutral for approximately 9,000' (1.7 miles)- Stone Hill Rd
Spot replace approximately 60 poles with 45'/2 poles on Stone Hill Rd
Potentially extend an additional phase down Millertown Rd with potential pole replacements, requires load study and site visit to determine

Project Benefits:

Cantitoe 497 was on the red circuit list in 2023 with a Saifi score of 0.00567571176509584
Pound Ridge 457 was on the yellow circuit list in 2023 with a Saifi score of 0.00308757559820515
Adds another tie between circuits for storm sectionalizing.
Fixes phase imbalance on Stone Hill Rd

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 180	\$ -	\$ 180	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 808	\$ -	\$ 808	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 42	\$ -	\$ 42	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 158	\$ -	\$ 158	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 808	\$ -	\$ 808	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 159	\$ -	\$ 159	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,155	\$ -	\$ 2,155	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Worst Performing Zones of Protection

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007428	Charge Code: Distribution	Project Sponsor: Rob McDonough	Project Type: Program
Business Area: Electric Operation	Category: Betterments	IP Stage: IP1	Start Date: H1 2027	In-Service Date: H2 2027

Project description:

NYSEG has failed the SAIFI reliability metric since 2018, this funding will be allocated reactively, guided by the data analytics teams previous years findings. We will design and execute small projects with a focus on capital improvement such as pole relocations from offroad to on road. These projects aims to identify and implement the most cost-effective strategies for short term SAIFI improvement, implementing percise, high impact improvements to reliability metrics, maximizing return on investment and deliver a better customer experience.

Project Scope:

Per project, ten poles or less will be relocated from back lot configuration, removing aging wire and secondary facilities, installing new roadside poles and triplex cable. This will limit tree contact, provide easier access for both lineman and vegetation crews, and increasing the safety of working conditions. This will also provide the ability to capitalize construction and vegetation costs for new areas of ROW to our current trimming specifications.

Project Benefits:

These projects will benefit all customers in these specific zones of protection by reducing potential outages from tree contacts, providing upgraded infrastructure, and allowing easier access to facilities if an outage does occur. These projects will also improve reliability for customers downstream who may be outside that specific zone of protection

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 773	\$ -	\$ 73	\$ 78	\$ 149	\$ 153	\$ 158	\$ 162
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,478	\$ -	\$ 331	\$ 349	\$ 669	\$ 689	\$ 710	\$ 731
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 180	\$ -	\$ 17	\$ 18	\$ 35	\$ 36	\$ 37	\$ 38
# Internal, Overheads	\$ 602	\$ -	\$ 70	\$ 58	\$ 104	\$ 105	\$ 118	\$ 147
# Materials	\$ 3,479	\$ -	\$ 331	\$ 349	\$ 669	\$ 689	\$ 710	\$ 731
# Overheads - External	\$ 611	\$ -	\$ 71	\$ 59	\$ 106	\$ 107	\$ 120	\$ 150
Total	\$ 9,123	\$ -	\$ 892	\$ 910	\$ 1,731	\$ 1,779	\$ 1,851	\$ 1,959

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Engineering and Material LLTs for 2028 Projects

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007420	Charge Code: Distribution	Project Sponsor: Rob McDonough	Project Type: Program
Business Area: Electric Operation	Category: Betterments	IP Stage: IP1	Start Date: H1 2027	In-Service Date: H2 2027

Project description:

Based on the Prioritization Tool and information from the Data Analytics Team, projects will be selected that fall under the Betterment Project Definition. This budget will be allocated to complete detailed engineering and design for projects scheduled for execution in the following year.

Project Scope:

This budget will be allocated to complete detailed engineering and design for projects scheduled for execution in the following year. The scope includes preparing Detailed IP2 presentations, conducting load studies, submitting permit applications, and performing environmental reviews. As the engineering plans are finalized, procurement of long lead-time materials such as reclosers, regulators, capacitor banks, large transformers, and specialty items (e.g., bundled cable) that are not commonly stocked will be initiated. This approach ensures that all necessary components are available when needed, facilitating smooth project execution and adherence to timelines.

Project Benefits:

Using this approach offers several significant benefits. By allocating the budget for detailed engineering and design in advance, projects are meticulously planned, reducing the risk of unforeseen issues during execution. This proactive planning includes essential tasks such as load studies, permit applications, and environmental reviews, ensuring compliance and readiness. Additionally, securing long lead-time materials early, such as reclosers, regulators, and large transformers, prevents delays caused by supply chain disruptions. This method enhances project efficiency, maintains timelines, and ultimately leads to cost savings by avoiding last-minute purchases and rushed decisions. Overall, this approach fosters a well-organized, streamlined project execution process.

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,071	\$ -	\$ 245	\$ 204	\$ 149	\$ 153	\$ 158	\$ 162
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 4,818	\$ -	\$ 1,102	\$ 918	\$ 669	\$ 689	\$ 710	\$ 731
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 249	\$ -	\$ 57	\$ 47	\$ 35	\$ 36	\$ 37	\$ 38
# Internal, Overheads	\$ 859	\$ -	\$ 232	\$ 152	\$ 104	\$ 105	\$ 118	\$ 147
# Materials	\$ 4,821	\$ -	\$ 1,102	\$ 919	\$ 669	\$ 689	\$ 710	\$ 731
# Overheads - External	\$ 872	\$ -	\$ 235	\$ 155	\$ 106	\$ 107	\$ 120	\$ 150
Total	\$ 12,689	\$ -	\$ 2,973	\$ 2,395	\$ 1,731	\$ 1,779	\$ 1,851	\$ 1,959

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE Overloaded Step Banks

PROJECT INFORMATION

OpCo: RGE	Project ID: PRJ-007429	Charge Code: Distribution	Project Sponsor: Rob McDonough	Project Type: Program
Business Area: Electric Operation	Category: Betterments	IP Stage: IP1	Start Date: H1 2026	In-Service Date: H2 2026

Project description:

Many customers are fed beyond stepbanks, consequently failure of a stepbank results in a large outage in areas that often have limited or no ability to tie to alternate sources. Frequently the cause of stepbank failure is the result of sustained overloads due to load growth during summer peak.

Project Scope:

Identify 12 single phase stepbanks that are the most overloaded

****Extremely overloaded stepbanks may require engineering and design for a downstream conversion****

Replace those stepbanks with the appropriate size KVA stepbank which addresses the existing peak load and allows a buffer for future load growth

Other locations identified will be organized and prepped work for future year's betterment spending

Project Benefits:

This prevents unscheduled outages in summertime during heat waves. Minimum outage time is usually 4 hours. Example : a 333kva step bank that is overloaded and fails, will usually have 150 customers. That equates to a minimum hit of 600 customer hours. Ten locations like this will save 10 locations x 600 customer-hours = 6000 customer-hours. Outage is prevented if you install a 500kva tank proactively ahead of time.

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 163	\$ -	\$ -	\$ 163	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 735	\$ -	\$ -	\$ 735	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 38	\$ -	\$ -	\$ 38	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 122	\$ -	\$ -	\$ 122	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 735	\$ -	\$ -	\$ 735	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 124	\$ -	\$ -	\$ 124	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,916	\$ -	\$ -	\$ 1,916	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Mapleton 520

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007421	Charge Code: Distribution	Project Sponsor: Rob McDonough	Project Type: Program
Business Area: Electric Operation	Category: Betterments	IP Stage: IP1	Start Date: H1 2027	In-Service Date: H2 2027

Project description:

In NYSEG Auburn Division, the 520 and 521 transmission line provides power to multiple substations.

Maple Tap 520 290 customers

Union Springs 609 1005 customers

Scipio 605/606 837 customers

Genoa 603/604..... 778 customers

Moravia Sub (Ithaca)

Cayuga/Milliken (Ithaca)

These two transmission lines are the #1 problem child for Auburn division on SAIFI. By automation, the plan below would eliminate many issues by allowing the 520 and 521 to sectionalize through motor ops and scada devices to isolate faults.

There is already an active project to automate the 521 for Ithaca Division at Milliken Sub and Moravia Sub. This would include the 52102 on Bartnick road in Geneva Division

Project Scope:

Add 34.5kv SCADA devices (in place of manual switch).

520T521 – West of Mapleton Tap

52016 - North of Mapleton Tap

52186 - Stewarts Corner (N.O.)

Add Motor Ops to Manual Switches at substations

52039 & 52836 N.O. – Union Springs Sub

52176 & 52179 – Genoa Sub

Program for auto restoration

Project Benefits:

Allow for quicker Restoration of different substations. About 2910 customers would be benefitted from this betterment.

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 131	\$ -	\$ -	\$ 131	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 588	\$ -	\$ -	\$ 588	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 30	\$ -	\$ -	\$ 30	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 91	\$ -	\$ -	\$ 91	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 588	\$ -	\$ -	\$ 588	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 91	\$ -	\$ -	\$ 91	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,518	\$ -	\$ -	\$ 1,518	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Roll Road 545

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007422	Charge Code: Distribution	Project Sponsor: Rob McDonough	Project Type: Program
Business Area: Electric Operation	Category: Betterments	IP Stage: IP1	Start Date: H1 2027	In-Service Date: H2 2027

Project description:

Roll Rd 545 is a 34.5kv wye circuit in NYSEG Lancaster Division in town of Clarence. Roll Rd 545 has 2743 customers, and the area is growing with lots of residential new builds. It has been a red circuit in 2 of the last 4 years. There are lots of customers on the circuit that are downstream of step banks to change primary voltage to 12.47kv wye and 4.8kv delta. The step banks are a weak point and a source of failure. It would be best if these customers get moved over to a natural 12.47 kv wye circuit, which are readily be able to feed the underground 7.2kv customers without the use of step banks.

Wehrle 332 can reach Roll Rd 545 customers but first it must take over some of the 4.8kv customers on the Roll Rd 512. Roll Rd 512 is a yellow circuit with 1978 customers. Mark Labunsky of Dist Planning wrote a report 8/30/22 in order to reduce customer count on Roll Rd 545.

Convert section of Roll Rd 512 (Thompson Rd L-328 P1 to P-T144) from 4.8kv to 12.47kv wye; Convert section of Roll Rd 545 (Old Goodrich Rd L-324 P-1 to P-30) from 4.8kv to 12.47kv wye. This will give access for Wehrle 332 to steal an additional 110 customers (and growing) of Martha Vineyard subdivision which starts at L-357 P-86. Additionally on Greiner Rd L-358 P-40 to P-51B, by converting and reconductoring to 3phase 477AL to 12kV, this will take additional customers from Roll Rd 512 and also allow a natural 12.47kv wye tie between Wehrle 332 and Wehrle 335. This will take Wehrle 332 from 905 customers (add 560 customers) to 1465 customers, but all those customers will have a backup source now.

Project Scope:

Convert 6700 feet on Thompson rd by adding a neutral where needed, Line 328 Pole 1 to Pole T144

Convert 5700 feet on Old Goodrich rd by adding a neutral where needed, Line 324 Pole 1 to Pole 30.

Convert 3700 feet on Greiner rd by adding a neutral where needed, Line 358 Pole 40 to Pole 51B

Change tanks to dual voltage where needed on conversions

Reconductor 3700 feet from 1phase to 3phase 477Al on Greiner Rd for 13 spans Line 358 Pole 40 to Pole 51B and also Close gap for additional 1800 feet with new double circuit on Greiner Rd Line 358 Pole 51B to Pole 60

Project Benefits:

This will reduce the customer count on Roll Rd 545 and Roll Rd 512 by 560 customers. Both of these 34.5kv circuits have poor reliability and lose power very often because of the sensitive nature of 34.5kv with trees and tracking to ground. Also these customers become part of a natural 12.47kv wye circuit rather than be downstream of a step bank. Wehrle 332 will then have a 12.47kv wye backup source from the end of its circuit with the Wehrle 335 circuit. This gives all of these customers redundancy.

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 131	\$ -	\$ -	\$ 131	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 588	\$ -	\$ -	\$ 588	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 30	\$ -	\$ -	\$ 30	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 91	\$ -	\$ -	\$ 91	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 588	\$ -	\$ -	\$ 588	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 91	\$ -	\$ -	\$ 91	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,518	\$ -	\$ -	\$ 1,518	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

NYSEG Sylvan Lake 481

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007423	Charge Code: Distribution	Project Sponsor: Josh Shail	Project Type: Program
Business Area: Electric Operation	Category: Betterments	IP Stage: IP1	Start Date: H1 2027	In-Service Date: H2 2027

Project description:

The Sylvan Lake 481 circuit (green circuit) is a 13.2KV circuit. Once it reaches Beekman Elementary School on Lime Ridge Rd it turns back lot for approximately 16 poles. Work proposed to build a double circuit with the sylvan Lake 478 circuit along the readily accessible Green Haven Rd and Beekman Rd by spot replacing all poles and installing new conductors (highlighted yellow) and creating an open in the back lot section

Project Scope:

Spot replace approximately 35 poles with 50' CL2 poles.
Install approximately 6,000' (1.10 miles) of 3 phase 477 P.AL and 4/0 B.AL neutral
Create an open near L2141 P13 possibly a recloser for a Loop Scheme

Project Benefits:

The Sylvan Lake 481 circuit was a yellow circuit in 2023 with a Saifi score of 0.002493178 and feeds 1,614 customers. 1,500 customers are present after the back lot section. There is no access to the back lot section due to the Elementary School and Barton Orchards (farm). The back lot section should remain three phase as Barton Orchards frequently request upgrades on the property.

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 131	\$ -	\$ -	\$ 131	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 588	\$ -	\$ -	\$ 588	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 30	\$ -	\$ -	\$ 30	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 91	\$ -	\$ -	\$ 91	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 588	\$ -	\$ -	\$ 588	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 91	\$ -	\$ -	\$ 91	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,518	\$ -	\$ -	\$ 1,518	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Warners 526

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007424	Charge Code: Distribution	Project Sponsor: Rob McDonough	Project Type: Program
Business Area: Electric Operation	Category: Betterments	IP Stage: IP1	Start Date: H1 2027	In-Service Date: H2 2027

Project description:

Warners 526 (Also Called Whiting Tap 526) is a 34.5kV distribution circuit (NYSEG-AUBURN division) which is started at the Whiting Tap in Village of Jordan, NY (Near the town of Elbridge) servicing 1,139 total customers. There are 18 miles of 3 phase and 40 miles of single phase distribution.

Numerous failures have caused 786 customers to be without power when the fault goes back to the 526R3 Recloser device at L-1200 Pole 1A. -- Line 1200 Pole 1A FLOC 9301-L0816-3453-0004-ED00028 526R3. There are no backfeed options.

Downstream of recloser 526R3, there is one section that has gone out the most, and it has critical customers on it. This one section of offroad 34.5kv distribution has 288 customers downstream and it is hard to access. This section is Line 526 Pole 311 to Pole 349 (slightly longer than 2 miles).

Downstream of recloser 526R3, this circuit has a loop on itself for this 786 group of customers. Unfortunately the loop is composed of different voltages, which renders the loop un-usable.

On this loop is a 1500kva step bank at Line J46 Pole 127 that services 166 downstream customers at 4.8kV delta. The 4.8kv main 3-phase ends at Line J46 Pole 34 (which is 2.5 miles in distance along Warners Rd CR-173 and Brickyard Rd). If this stepbank is converted, then it improves reliability

Project Scope:

Voltage conversion of approximately 13,500 ft. of 3-phase 4.8kV to 34.5kv along CR-173:

Add 4/0 neutral wire, only in spans where it does not exist now

Change all insulators to 35kv rated insulators on 94 poles

Replace 20 substandard poles of the 94 pole locations

Replace one Cap bank for 34.5kv rating

Replace 26 overhead tanks with 34.5kv rated tanks, and 1-300kva padmount tank

Install 2 step banks for (2) single phase spurs that will remain as 4.8kv spurs

Install 4 scada devices which will allow the loop to have easy sectionalizing

Each section of loop can have automatic programming as sectionalizers

Project Benefits:

This project benefits all 768 customers that are downstream of 526R3 because it creates a loop. Any fault on loop can be sectionalized, and allow for the other customers to remain in power. This circuit is at the end of NYSEG service territory, so there are no other options for backfeed.

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
	\$ 131	\$ -	\$ -	\$ 131	\$ -	\$ -	\$ -	\$ -
# AFUDC								
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 588	\$ -	\$ -	\$ 588	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 30	\$ -	\$ -	\$ 30	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 91	\$ -	\$ -	\$ 91	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 588	\$ -	\$ -	\$ 588	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 91	\$ -	\$ -	\$ 91	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,518	\$ -	\$ -	\$ 1,518	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG Crellin 615 (615T630)

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007418	Charge Code: Distribution	Project Sponsor: Rob McDonough	Project Type: Program
Business Area: Electric Operation	Category: Betterments	IP Stage: IP1	Start Date: H1 2026	In-Service Date: H2 2026

Project description:

Klinekill 630 is a 34.5kV distribution circuit out of Klinekill Substation in Chatham, NY servicing 1,463 total customers. The Crellin 615 is a 34.5kV distribution tap sourced from the 615L just before Chatham Hilltop servicing 34 total customers.

At L140 P1223 the Klinekill 630 circuit splits north and south along White Mills Rd. The northern feed is radial continuing along White Mills Rd into US-66.

At L183 P1 the Crellin 615 tap is a radial feed continuing north along US-66.

Project Scope:

Construct approximately 2800 ft. of 3-phase 34.5kV along US-66:

- Conductor 2800 ft. of 477 poly wire
- Install 2800 ft. of 4/0 neutral wire
- Install 16 poles
- Install (1) 3ph 34.5kV

Project Benefits:

This project benefits all 408 customers that are downstream of 630YR1 on the Kline Kill 630, currently in a radial configuration. Additionally, all 34 customers served off the Crellin 615 will benefit from enhanced N-1 redundancy. By constructing the 3-phase 615T630 along US-66 the Company will improve circuit reliability (CAIDI/SAIFI) on both Klinekill 630 and Crellin 615 circuits.

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 122	\$ -	\$ 122	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 551	\$ -	\$ 551	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 28	\$ -	\$ 28	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 108	\$ -	\$ 108	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 551	\$ -	\$ 551	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 109	\$ -	\$ 109	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,469	\$ -	\$ 1,469	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Brothertown Road

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007270	Charge Code: Electric Distribution	Project Sponsor: Tiongco, Dindo	Project Type: Project
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace 3 x 46kV (83222, 1B-22 & 81222) at Brothertown Road Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing three (3) 46kV breakers (83222, 1B-22 & 81222) at Brothertown Road Substation. The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement.

Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 128	\$ 1	\$ 40	\$ 88	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 661	\$ 32	\$ 196	\$ 433	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 120	\$ 7	\$ 35	\$ 78	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 89	\$ 32	\$ 21	\$ 36	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 364	\$ 6	\$ 112	\$ 247	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 99	\$ 19	\$ 29	\$ 50	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,461	\$ 96	\$ 432	\$ 933	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Hancock

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007274	Charge Code: Electric Distribution	Project Sponsor: Tiongco, Dindo	Project Type: Project
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace one (1) 115kV (95532) breaker, one (1) 12.5 kV breaker (21532) and one (1) 4.8 kV (12) breaker at Hancock Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing one (1) 115kV (95532) breaker, one (1) 12.5 kV breaker (21532) and one (1) 4.8 kV (12) breaker. The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 86	\$ 5	\$ 81	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 563	\$ 163	\$ 400	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 106	\$ 35	\$ 72	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 199	\$ 163	\$ 34	\$ 2	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 257	\$ 30	\$ 228	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 148	\$ 99	\$ 47	\$ 3	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,361	\$ 495	\$ 861	\$ 5	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - West Elmira

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007278	Charge Code: Electric Distribution	Project Sponsor: Tiongco, Dindo	Project Type: Project
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace one (1) 34 kV (57532) breaker and three (3) 4.8 kV (10432, 11132 and C1-32) breakers at West Elmira Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an “in-kind” replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing one (1) 34 kV (57532) breaker and three (3) 4.8 kV (10432, 11132 and C1-32) breakers. The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI-4 and RI- 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,317 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement.

Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI-4 and RI-5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI-4 or RI-5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 133	\$ 0	\$ 47	\$ 85	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 665	\$ 11	\$ 234	\$ 420	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 120	\$ 2	\$ 42	\$ 75	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 71	\$ 11	\$ 25	\$ 35	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 374	\$ 2	\$ 133	\$ 239	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 90	\$ 6	\$ 35	\$ 49	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,453	\$ 32	\$ 516	\$ 905	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]



RG&E Electric Reliability

RG&E Distribution Load Relief Program

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-003853	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: H1 2026

Project description:

The RG&E Distribution Load Relief (DLR) Program was established to identify and address capacity constraints (thermal/voltage) on substation transformers and select distribution feeders. It aims to ensure the system remains fully operational under N-0 "all-lines-in" scenarios across the NYSEG distribution network. The program proposes cost-effective solutions that balance maximizing headroom benefits with project cost, complexity, and the number of remaining constraints in relation to annual budget allowances. The DLR Program focuses solely on mitigating existing capacity needs, excluding emergent or future anticipated needs like upgrades required for customer load interconnections or long-term system planning constraints. Advancing this program is essential for completing ongoing DLR projects and prioritizing new projects to ensure RGE is able to tackle immediate capacity limitations, provide system operators with a reliable system to meet peak load demands, and fulfill customer needs.

Project Scope:

This program aims to develop mitigation strategies to improve the condition of these assets, ensuring they do not exceed their Normal Rating. It focuses on conducting system-wide facility surveys and, based on the results, implementing strategies that may include adding fans, retrofitting upgrades, infield switching to shed load, load transfers, in-kind replacements, retiring smaller substations, or rebuilding substations. These comprehensive surveys will encompass electrical and structural assessments, which will be evaluated against individually weighted categories such as equipment age, transmission constraints, resiliency/flooding impacts, substation Protection & Control (P&C) assessments, substation reliability performance, etc.

Each year, all substations undergo a comprehensive review and are ranked based on a set of weighted metrics. These metrics include Normal Overload Percentage, Customer Count, Health Score, SAIFI Impact, Data Quality, and Interconnection Interest. The resulting weighted scores establish an "urgency" prioritization list for the Distribution Load Relief (DLR) program. Substations with the highest priority scores are the first to be considered for potential DLR projects. This prioritization list is dynamic and will continuously evolve to highlight emerging projects. Currently there are 18 substation transformers and 86 circuits identified on this list requiring mitigation. The RG&E Distribution Load Relief Program is requesting on average \$25M per year in order to address the needs from the prioritization list. This cost is based on the assumption of initiating 2-3 new projects annually, with an average cost of approximately \$10M per project. This results in the portfolio request of \$25M per year.

RG&E has identified 4 locations (substation transformer and individual circuits) that have reached or exceeded 90% capacity, with over 20% these locations exceeding 100% of their Normal Rating.

Locations & Preliminary Scope:

- Station 205 (includes Station 202): Transformer Replacement & Load Transfer (separated to specific project) - \$6.25M
- Station 16: Transformer Replacements (separated to specific project) - \$14.5M
- Station 45: Transformer Replacements (separated to specific project) - \$10.5M

Project Benefits:

The Distribution Load Relief (DLR) Program is a strategic initiative aimed at ensuring a continuous and reliable power supply for NYSEG customers. By addressing current system needs, the program mitigates risks associated with operating substation transformers and other major equipment near or over capacity. This results in enhanced equipment health, improved power service reliability, and the ability to accommodate additional customer connections, while preventing costly emergent asset failures.

By systematically reducing load on heavily loaded substations, the DLR Program enhances reliability, extends equipment lifespan, improves efficiency, and maintains better power quality. It also leads to cost savings by avoiding frequent repairs, replacements, or costly upgrades, and helps comply with regulatory standards. Overall, effective load management through this program ensures a more resilient, efficient, and cost-effective power distribution system.

Project Risks and Mitigation Plan:

Risks exist in project execution, particularly regarding engineering and material procurement. To ensure materials are received on time, we will proactively order long lead materials.

Weather delays pose a risk in distribution construction as our resources frequently support storm restoration efforts. We mitigate these weather-related delays by incorporating contingency into our construction schedules.

The health and safety of our workers are a primary concern. Risks associated with traffic control, working with energized equipment, slips, and trips are common on most projects. We mitigate these risks with project-specific health and safety plans.

Many projects involve de-energizing existing substation equipment to facilitate replacements or upgrades. This process inherently carries risks, such as potential power outages and the safety of personnel working on de-energized equipment. To mitigate these risks, we coordinate and utilize mobile substations in applicable scenarios. Mobile substations allow for the temporary transfer of load, ensuring continuous power supply and minimizing disruptions to customers. Additionally, detailed planning and coordination are essential to ensure the safe and efficient use of mobile substations. This includes thorough risk assessments, clear communication with all stakeholders, and adherence to strict safety protocols. By implementing these measures, we can effectively manage the risks associated with de-energizing substation equipment and ensure the successful completion of our projects.

Financial risks are inherent in project execution as new information emerges. We mitigate these risks by utilizing scheduling and forecasting tools, such as Primavera, for project management. We continuously forecast project-specific activities using these tools and update the project progress monthly. This approach allows us to accurately predict project completion and estimate costs at completion.

Risk of No Action:

If no action is taken, several risks could arise:

Equipment Damage: Operating substation transformers and other major equipment near or over capacity can lead to overheating and accelerated wear and tear, ultimately causing equipment failure.

Power Outages: The reliability of the power supply could be compromised, leading to more frequent and prolonged power outages for customers.

Safety Hazards: Overloaded equipment can pose safety risks, including the potential for fires or other hazardous conditions.

Increased Costs: The cost of emergency repairs and replacing damaged equipment can be significantly higher than the cost of proactive maintenance and upgrades.

Customer Dissatisfaction: Frequent power outages and unreliable service can lead to customer dissatisfaction and potential loss of trust in the utility provider.

Regulatory Non-Compliance: Failing to maintain equipment and ensure reliable service could result in non-compliance with regulatory standards, leading to fines and other penalties.

Limited Capacity for Growth: Without load reduction and system improvements, there may be limited capacity to accommodate new customer connections, hindering growth and development.

Taking proactive measures through programs like the Distribution Load Relief Program helps mitigate these risks and ensures a more reliable and efficient power supply.

Project Alternatives:

All individual projects will be reviewed through the NWA screening process.

Alternative 1 - Long term substation rebuild projects - \$15M, ISD Q4 2031(per project)

Alternative 2 - In-kind substation transformer replacements - \$5.0M, ISD Q4 2029 (per project)

These alternatives were not selected based on total cost and construction timeline.

Basis for Project Estimates

Estimates are prepared using historical estimating tools and are benchmarked against actual investments in similar projects to establish a basis for project initiation. These estimates are revised throughout the project as new information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:		Total	2020	2021	2022	2023	2024
	Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 75,395	\$ 2,000	\$ -	\$ 3,629	\$ 5,704	\$ 17,211	\$ 23,365	\$ 23,485
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 2,045	\$ -	\$ -	\$ 137	\$ 187	\$ 479	\$ 611	\$ 632
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 4,910	\$ -	\$ -	\$ 328	\$ 449	\$ 1,149	\$ 1,467	\$ 1,517
Total	\$ 82,350	\$ 2,000	\$ -	\$ 4,094	\$ 6,340	\$ 18,839	\$ 25,443	\$ 25,633

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Station 416 Load Relief

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-005892	Charge Code: Electric Transmission	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Electric Operations	Rate Case Category Reliability	Project Stage: IP2 Partial Approval	Start Date: H1 2026	In-Service Date: H2 2026

Project description:

Station 416 is a 34.5/12.47 kV substation constructed circa 1965. The substation has only one customer, the Rochester Institute of Technology. RIT is fed from both circuits 5103 and 5106 with a peak average load of 16.7 MVA. 1

The station is fed from two (2) 34.5 kV transmission lines; Line 779 from Station 80 and Line 744 from Station 33. There are two (2) 34.5 kV straight buses with a normally-open throwover switch.

L744 connects to Bus 1 and transformer 1T

L779 connects to Bus 2 and transformer 2T

The 1T Transformer is rated 14 MVA CNR/14.7 MVA Normal/18.2 MVA LTE. The peak average load on the 1T transformer is 9.8 MVA.

The 2T Transformer is rated 10.5 MVA CNR/11.025 MVA Normal/13.65 MVA LTE. The peak average load on the 2T transformer is 7 MVA.

The 12.47 kV yard consists of two (2) sections of metal clad switchgear with no tie breaker.

There are four (4) distribution circuits from the station.

Investigation into loading concerns within the area surrounding Station 416 began in response to an N-1 thermal violation present at Station 419, in which a fault on either 115kV transmission line or 115/12.47kV transformer would transfer the full load of the station onto either the 1T or 2T transformer, resulting in an overload on the remaining energized transformer.

Upon further investigation in the surrounding area, an N-1 thermal violation was identified at Station 416 where the 2T transformer would be unable to pick up all of the RIT load in the event of a 1T failure. Upon discussion with Transmission and Distribution Planning, an additional N-1 thermal violation was identified at Station 82, in which a failure on either the 3T or 4T transformer would transfer the full load of the Station 82 12kV yard onto the remaining energized transformer, overloading either 22.4 MVA transformer. A circuit tie currently exists between Station 82 circuit 5232 and Station 416 circuit 5104, however the Station 416 1T transformer would not have the N-1 capacity to make use of this circuit tie.

A long-term solution for the N-1 violation at Station 419 has already been IP2 approved as of February 20241, however this solution will not be in service until 2028, and does not address the violations present at Stations 416 or 82. Additionally, 8.2 MVA of queued load has been approved at Station 419 2, which will worsen the existing N-1 violation.

Project Scope:

Extend circuit 0419RO5246 West from Baily Ave Pole # 23A GIS ID 312149110 to pole 47, picking up 3.3 MVA of load from circuit 0419RO5244.

New circuit 0082RO5233 to tie with circuit 0419RO5246. Upon contingency at Station 419, entire circuit 0419RO5246 (10.3 MVA) would be transferred to Station 82. Replace transformer 2T at Station 416, upgrading it from 10.5 MVA to 14 MVA. Six (6) three-pole disconnect switches.

Extension of circuit 0416RO5105 East along existing segment of 0419RO5244 to John St Pole # T26 to tie with circuits 0419RO5244 and 0082RO5232. Upon contingency at Station 419, entire circuit 0419RO5244 (6.6 MVA) would be transferred to Station 416. Upon contingency at Station 82, entire circuit 0082RO5232 (5.8 MVA) would be transferred to Station 416.

Project Benefits:

Selected Alternative: Alternative 2; Solve existing N-1 constrain at Station 416. Provides solution to contingency violation and queued load capacity constraints at Station 419. Provides solution to contingency violation at Station 82. Create more future ties that could be utilize. Reduce the time for implementation than final and permanent solution (~2 years)

The objective of this project is to address N-1 thermal violations present at RGE Stations 416, 419 and 82, by adding load capacity at Station 416 and creating circuit ties that allow for the transfer of load out of Stations 419 and 82 upon contingency. This project is not suitable for an NWA solution due to project timeframe.

Project Risks and Mitigation Plan:

Risks exist in project execution particularly as it relates to engineering and material procurement. In order to ensure materials are received on time, we will order long lead materials in Q1 2025 to ensure they are received within 1 year of ordering (Poles, devices, wire, etc.).

Weather delays are a risk in distribution construction because our resources often support storm restoration efforts. We address these types of weather delay risks by incorporating contingency into our construction schedules.

Health and Safety of our workers are of a primary concern. Risks related to traffic control, working with energized equipment, slips and trips, etc. are a concern on most projects, we mitigate these risks with project specific health and safety plans.

Finanacial risks are always present with new information learned during project execution, financial risks are mitigated utilizing available scheduling and forecasting tools for project management (ie. Primavera), we forecast project specific activities in the living tool as the project progress and update monthly project progress to accurately forecast project completion including estimate at completion.

N-1 thermal violations present at RGE Stations 416, 419 and 82 upon a fault could cause a loss of power to RIT as well as, cascading long duration outage issues including further equipment failures.

Alternative 1 - Replace Station 416 2T Transformer, Construct 2 New Circuit Ties - \$6.6M, ISD Q3 2026

Estimates are prepared utilizing historical estimating tools comparing against actual investments in similar projects as basis for project initiation and are revised through the project as new information is received.

[illegible]

RGE Distribution Load Relief - Station 16

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006433	Charge Code: Electric Distribution	Project Sponsor: Gay, Ruben	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2029

Project description:

The RGE Distribution Load Relief (DLR) Program was established to identify and address thermal constraints in substation transformers and distribution feeders. This initiative aims to propose cost-effective solutions that mitigate these existing system needs, ensuring full N-0 "all-lines-in" operability across the RGE distribution system. The DLR Program will reduce the risk of utility equipment damage and/or failure which would negatively impact our customers. DLR projects are prioritized based on the consideration of weighted factors including, but not limited to, historic/forecasted thermal loading with respect to equipment ratings, asset health, and potential customer impacts.

Background: Station 16 is a 34.5/4.16 kV substation located in the Town of Webster. The 4.16kV is fed by a 6.67MVA transformer bank #1 and a 6.25MVA transformer bank #2. Bank #1 serves three 4.16kV distribution feeders, serving approximately 3,400 customers and 5.80 MVA of load. Bank #2 also serves three 4.16kV distribution feeders, serving approximately 1,900 customers and 6.75 MVA of load.

Needs:

- Station 16 Transformer Bank #1 is heavily loaded and nearing its thermal limits during peak conditions within the last three years (89% observed in 2024, 3-year average peak loading at 87%).
- Station 16 Transformer Bank #2 is heavily loaded and has exceeded its thermal limits during peak conditions within the last three years (110% observed in 2024, 3-year average peak loading at 108%).
- The dedicated transformer breakers for Bank#1 and Bank #2 have each been assessed with a "Poor" (HI-4) Health Score and are in need of replacement.

Project Scope:

The selected proposal involves substation upgrades only which are necessary to address the immediate system needs. The expected project in-service date is Q4 2028.

- Replace both Transformer Bank #1 and Bank #2 with 14MVA transformers
- Replace both Transformer Bank #1 and Bank #2 Foundations to accommodate new transformer installations
- Replace two (2) dedicated transformer breakers currently in poor health
- Use of Mobile Substation required for project duration

Project Benefits:

The primary driver of the project is to address current capacity-driven needs. In addition to mitigating these needs, the proposed project will also replace equipment identified to be in Poor condition, enhance reliability and resiliency, and create capacity to support future load growth on the Station 16 feeders.

Capacity: The project will relieve emergent thermal needs on the Station 16 Transformer Bank #1, which has been nearing overload within the last three years by reducing the transformer bank #1 loading to approximately 41% (53% thermal loading reduction). The project will also relieve emergent thermal needs on the Station 16 Transformer Bank #2, which has overloaded the last three years by reducing the transformer bank #2 loading to approximately 48% (56% thermal loading reduction). Resolving these thermal loadings need will provide immediate benefits to customers by limiting risks associated with equipment-related outages.

Reliability: The project will enhance system reliability by solving existing N-0 and N-1 thermal violations at the transformer level.

Asset Condition: Preliminary electrical equipment asset condition needs in Station 16 were identified in accordance with the AVANGRID 2023 transformer and breaker assessments. There are two (2) transformer breakers with a Poor (HI-4) Health Score. Equipment that is in poor, or very poor condition have exceeded their useful life and should be replaced to limit the risk of equipment-related outages. Such equipment are included for replacement or retirement in the conceptual solution. Site inspections will be performed to identify any additional asset condition needs.

Project Risks and Mitigation Plan:

Risks exist in project execution, particularly regarding engineering and material procurement. To ensure materials are received on time, we will proactively order long lead materials.

Weather delays pose a risk in distribution construction as our resources frequently support storm restoration efforts. We mitigate these weather-related delays by incorporating contingency into our construction schedules.

The health and safety of our workers are a primary concern. Risks associated with traffic control, working with energized equipment, slips, and trips are common on most projects. We mitigate these risks with project-specific health and safety plans.

Many projects involve de-energizing existing substation equipment to facilitate replacements or upgrades. This process inherently carries risks, such as potential power outages and the safety of personnel working on de-energized equipment. To mitigate these risks, we coordinate and utilize mobile substations in applicable scenarios. Mobile substations allow for the temporary transfer of load, ensuring continuous power supply and minimizing disruptions to customers. Additionally, detailed planning and coordination are essential to ensure the safe and efficient use of mobile substations. This includes thorough risk assessments, clear communication with all stakeholders, and adherence to strict safety protocols. By implementing these measures, we can effectively manage the risks associated with de-energizing substation equipment and ensure the successful completion of our projects.

Financial risks are inherent in project execution as new information emerges. We mitigate these risks by utilizing scheduling and forecasting tools, such as Primavera, for project management. We continuously forecast project-specific activities using these tools and update the project progress monthly. This approach allows us to accurately predict project completion and estimate costs at completion.

Risk of No Action:

If no action is taken, several risks could arise:

Equipment Damage: Operating substation transformers and other major equipment near or over capacity can lead to overheating and accelerated wear and tear, ultimately causing equipment failure.

Power Outages: The reliability of the power supply could be compromised, leading to more frequent and prolonged power outages for customers.

Safety Hazards: Overloaded equipment can pose safety risks, including the potential for fires or other hazardous conditions.

Increased Costs: The cost of emergency repairs and replacing damaged equipment can be significantly higher than the cost of proactive maintenance and upgrades.

Customer Dissatisfaction: Frequent power outages and unreliable service can lead to customer dissatisfaction and potential loss of trust in the utility provider.

Regulatory Non-Compliance: Failing to maintain equipment and ensure reliable service could result in non-compliance with regulatory standards, leading to fines and other penalties.

Limited Capacity for Growth: Without load reduction and system improvements, there may be limited capacity to accommodate new customer connections, hindering growth and development.

Taking proactive measures through programs like the Distribution Load Relief Program helps mitigate these risks and ensures a more reliable and efficient power supply.

Project Alternatives:

Alternative 1 - Transformer Replacements - \$15.0M (Preferred), ISD Q4 2028

Alternative 2 - Station 16 Rebuild - \$25.8M, ISD Q4 2030

Alternative 2 was not selected based on total cost and construction timeline.

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at RG&E. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 157	\$ -	\$ -	\$ 2	\$ 78	\$ 76	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 8,296	\$ -	\$ -	\$ 125	\$ 4,118	\$ 4,054	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 531	\$ -	\$ -	\$ 286	\$ 245	\$ -	\$ -	\$ -
# Materials	\$ 5,166	\$ -	\$ -	\$ 78	\$ 2,564	\$ 2,524	\$ -	\$ -
# Overheads - External	\$ 1,132	\$ -	\$ -	\$ 610	\$ 523	\$ -	\$ -	\$ -
Total	\$ 15,282	\$ -	\$ -	\$ 1,101	\$ 7,527	\$ 6,654	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE Distribution Load Relief - Station 45

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006435	Charge Code: Electric Distribution	Project Sponsor: Gay, Ruben	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The RGE Distribution Load Relief (DLR) Program was established to identify and address thermal constraints in substation transformers and distribution feeders. This initiative aims to propose cost-effective solutions that mitigate these existing system needs, ensuring full N-0 "all-lines-in" operability across the RGE distribution system. The DLR Program will reduce the risk of utility equipment damage and/or failure which would negatively impact our customers. DLR projects are prioritized based on the consideration of weighted factors including, but not limited to, historic/forecasted thermal loading with respect to equipment ratings, asset health, and potential customer impacts.

Background: Station 45 is a 34.5/4.16 kV substation located in the Town of Webster. The 4.16kV is fed by a 7MVA transformer. There are three 4.16kV distribution feeders serving approximately 2,500 customers and 6.59 MVA of load.

Needs: Station 45 Transformer Bank #1 is heavily loaded nearing its thermal limits during peak conditions within the last three years (96% observed in 2023, 3-year average peak loading at 94%).

Project Scope:

The selected proposal involves substation upgrades only which are necessary to address the immediate system needs. The expected project in-service date is Q4 2028.

- Replace Transformer Bank #1 with a 14MVA transformer
- Replace Transformer Bank #1 Foundation to accommodate new transformer installation
- Replace two (2) dedicated transformer breakers
- Use of Mobile Substation required for project duration

Project Benefits:

The primary driver of the project is to address current capacity-driven needs. The project will also create capacity to support future load growth on the Station 45 Transformer Bank #1.

Capacity: The project will relieve emergent thermal needs on the transformer bank #1, which has been nearing overload within the last three years by reducing the transformer bank #1 loading to approximately 47% (50% thermal loading reduction). Resolving this thermal loading need will provide immediate benefits to customers by limiting risks associated with equipment-related outages.

Reliability: The project will enhance system reliability by solving existing N-0 thermal violations.

Project Risks and Mitigation Plan:

Risks exist in project execution, particularly regarding engineering and material procurement. To ensure materials are received on time, we will proactively order long lead materials.

Weather delays pose a risk in distribution construction as our resources frequently support storm restoration efforts. We mitigate these weather-related delays by incorporating contingency into our construction schedules.

The health and safety of our workers are a primary concern. Risks associated with traffic control, working with energized equipment, slips, and trips are common on most projects. We mitigate these risks with project-specific health and safety plans.

Many projects involve de-energizing existing substation equipment to facilitate replacements or upgrades. This process inherently carries risks, such as potential power outages and the safety of personnel working on de-energized equipment. To mitigate these risks, we coordinate and utilize mobile substations in applicable scenarios. Mobile substations allow for the temporary transfer of load, ensuring continuous power supply and minimizing disruptions to customers. Additionally, detailed planning and coordination are essential to ensure the safe and efficient use of mobile substations. This includes thorough risk assessments, clear communication with all stakeholders, and adherence to strict safety protocols. By implementing these measures, we can effectively manage the risks associated with de-energizing substation equipment and ensure the successful completion of our projects.

Financial risks are inherent in project execution as new information emerges. We mitigate these risks by utilizing scheduling and forecasting tools, such as Primavera, for project management. We continuously forecast project-specific activities using these tools and update the project progress monthly. This approach allows us to accurately predict project completion and estimate costs at completion.

If no action is taken, several risks could arise:

Taking proactive measures through programs like the Distribution Load Relief Program helps mitigate these risks and ensures a more reliable and efficient power supply.

Alternative 2 was not selected based on total cost and construction timeline.

Estimates are prepared using historical estimating tools and are benchmarked against actual investments in similar projects to establish a basis for project initiation. These estimates are revised throughout the project as new information becomes available.

[illegible]

RGE Distribution Load Relief - Station 205

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006436	Charge Code: Electric Distribution	Project Sponsor: Gay, Ruben	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2031

Project description:

The RGE Distribution Load Relief (DLR) Program was established to identify and address thermal constraints in substation transformers and distribution feeders. This initiative aims to propose cost-effective solutions that mitigate these existing system needs, ensuring full N-0 "all-lines-in" operability across the RGE distribution system. The DLR Program will reduce the risk of utility equipment damage and/or failure which would negatively impact our customers. DLR projects are prioritized based on the consideration of weighted factors including, but not limited to, historic/forecasted thermal loading with respect to equipment ratings, asset health, and potential customer impacts.

Background: Station 205 is a 34.5/12.47 kV substation located in Wayne County. The 12.47kV is fed by a 7MVA transformer. There are two 12.47kV distribution feeders serving approximately 2,800 customers and 6.00 MVA of load.

Needs: Station 205 Transformer Bank #2 is heavily loaded nearing its thermal limits during peak conditions within the last three years (93% observed in 2022, 3-year average peak loading at 86%).

Project Scope:

The selected proposal involves distribution and substation upgrades only which are necessary to address the immediate system needs. The expected project in-service date is Q4 2029.

Substation Upgrades:

- Replace Substation Transformer #2 on Station 205 (5.25MVA) with a new 12.47kV transformer (22.4MVA).

Distribution Upgrades:

- Load Transfer from circuit 0230RO5162 to circuit 0205LS0237
- Load Transfer from circuit 0202LS5194 to circuit 0205LS5202
- Load Transfer from circuit 0205RO5162 to circuit 0202LS5194
- Replace overloaded fuses with reclosers

Project Benefits:

The primary driver of the project is to address current capacity-driven needs. The project will also create capacity to support future load growth on the Station 205 Transformer Bank #2.

Capacity: The project will relieve emergent thermal needs on the Station 205 Transformer Bank #2, which has been nearing overload within the last three years by reducing the transformer bank #2 loading to approximately 39% (54% thermal loading reduction). This project will also resolve the thermal needs at Station 202 by reducing the load on circuit #5194 from 98% to 89%. Resolving these thermal loadings need will provide immediate benefits to customers by limiting risks associated with equipment-related outages.

Reliability: The project will enhance system reliability by solving existing N-0 and N-1 thermal violations. By installing a SCADA-operable reclosers, the project will improve system performance under outage conditions and will also provide additional operational flexibility, including for maintenance activities and future tie considerations.

Project Risks and Mitigation Plan:

Risks exist in project execution, particularly regarding engineering and material procurement. To ensure materials are received on time, we will proactively order long lead materials.

Weather delays pose a risk in distribution construction as our resources frequently support storm restoration efforts. We mitigate these weather-related delays by incorporating contingency into our construction schedules.

The health and safety of our workers are a primary concern. Risks associated with traffic control, working with energized equipment, slips, and trips are common on most projects. We mitigate these risks with project-specific health and safety plans.

Many projects involve de-energizing existing substation equipment to facilitate replacements or upgrades. This process inherently carries risks, such as potential power outages and the safety of personnel working on de-energized equipment. To mitigate these risks, we coordinate and utilize mobile substations in applicable scenarios. Mobile substations allow for the temporary transfer of load, ensuring continuous power supply and minimizing disruptions to customers. Additionally, detailed planning and coordination are essential to ensure the safe and efficient use of mobile substations. This includes thorough risk assessments, clear communication with all stakeholders, and adherence to strict safety protocols. By implementing these measures, we can effectively manage the risks associated with de-energizing substation equipment and ensure the successful completion of our projects.

Financial risks are inherent in project execution as new information emerges. These risks are mitigated by utilizing scheduling and forecasting tools, such as Primavera, for project management. Continuously forecasting project-specific activities using these tools and updating the project progress is done monthly. This approach allows us to accurately predict project completion and estimate costs at completion.

Risk of No Action:

If no action is taken, several risks could arise:

Equipment Damage: Operating substation transformers and other major equipment near or over capacity can lead to overheating and accelerated wear and tear, ultimately causing equipment failure.

Power Outages: The reliability of the power supply could be compromised, leading to more frequent and prolonged power outages for customers.

Safety Hazards: Overloaded equipment can pose safety risks, including the potential for fires or other hazardous conditions.

Increased Costs: The cost of emergency repairs and replacing damaged equipment can be significantly higher than the cost of proactive maintenance and upgrades.

Customer Dissatisfaction: Frequent power outages and unreliable service can lead to customer dissatisfaction and potential loss of trust in the utility provider.

Regulatory Non-Compliance: Failing to maintain equipment and ensure reliable service could result in non-compliance with regulatory standards, leading to fines and other penalties.

Limited Capacity for Growth: Without load reduction and system improvements, there may be limited capacity to accommodate new customer connections, hindering growth and development.

Taking proactive measures through programs like the Distribution Load Relief Program helps mitigate these risks and ensures a more reliable and efficient power supply.

Project Alternatives:

Alternative 1 - Replace Station 205 T1 Transformer & Load Relief- \$6.2M (Preferred), ISD Q4 2029

Alternative 2 - Station 205 Rebuild - \$16.2M, ISD Q4 2030

Alternative 2 was not selected based on total cost and construction timeline.

Basis for Project Estimates

Estimates are prepared using historical estimating tools and are benchmarked against actual investments in similar projects to establish a basis for project initiation. These estimates are revised throughout the project as new information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 62	\$ -	\$ -	\$ 12	\$ 40	\$ 3	\$ 5	\$ 1
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,310	\$ -	\$ -	\$ 661	\$ 2,140	\$ 183	\$ 252	\$ 75
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 176	\$ -	\$ -	\$ 149	\$ 11	\$ 13	\$ 4	\$ -
# Materials	\$ 2,061	\$ -	\$ -	\$ 412	\$ 1,332	\$ 114	\$ 157	\$ 47
# Overheads - External	\$ 376	\$ -	\$ -	\$ 317	\$ 24	\$ 28	\$ 8	\$ -
Total	\$ 5,986	\$ -	\$ -	\$ 1,550	\$ 3,547	\$ 341	\$ 425	\$ 124

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE Transmission Reinforcement Program - Line 759

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006550	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2027

Project description:

This project is a low cost, high benefit project to improve reliability for over 2,300 RG&E customers supplied by Stations 85 and 58 through sectionalizing 34.5 kV Lines 747 and 759 with reclosers capable of implementing an automatic throw-over scheme.

This project will install a new recloser on Line 747 and install a second new recloser on a tie point to Line 759. The reclosers will be programmed to coordinate to automatically restore power to Station 58 load in the event of an outage on Line 759. For a Line 759 fault, the existing load throwover scheme on the Station 85 2T transformer should be maintained and is expected to be operated prior to the restoration of Station 58.

Transmission Planning's Local Area Study (LAS) identified areas of high customer interruption exposure ("Loss of Load" criteria). Loss of Load needs are prioritized based on impact (MW affected, circuit length, customer count) and solution complexity/cost. Transmission Planning developed metrics based on these risks to determine needs with the highest "Risk score" to prioritize solutions to those needs.

Reliability Concern:

A transmission system loss of load sectionalization criteria violation exists for a fault on 34.5 kV Line 759 (~11 MW and ~3,684 customers). RG&E transmission planning criteria limits the load loss exposure between automated sectionalizing devices to 10 MW. This project mitigates this violation and makes the system more reliable.

Project Scope:

This project includes the following scope:

1. Install new recloser on Line 747.
2. Install second new recloser on tie point to Line 759.
3. Set reclosers to coordinate to automatically restore Station 58 load in the N-1 event.

For a Line 759 fault, the existing load throwover scheme on Station 85 2T transformer should be maintained and is expected to be executed prior to the restoration of Station 58.

Project Benefits:

This project will resolve a loss of load violation where the amount of load loss under N-1 contingency conditions will be significantly reduced making the transmission network more reliable. The load loss during an N-1 contingency event will reduce from ~11 MW to ~5.2 MW (~53% reduction) and the number of customers without service will be reduced from ~3,684 customers to ~1,350 customers (63% reduction).

Project Risks and Mitigation Plan:

1. Delays in Project Implementation: Project delays could lead to an increase in frequency and/or duration customer outages, resulting in worsening reliability performance. Weather delays are also a risk in construction due to personnel safety concerns. These risks will be addressed by incorporating contingency into our construction schedules. To mitigate this risk, the project team conducts thorough field scouting and feasibility assessments before finalizing device locations. Long lead-time equipment delays can also adversely impact project schedules. Equipment sourcing risks will be mitigated by identifying proposed equipment subject to long lead times and ordering such equipment proactively, as appropriate, to minimize the risk of project delays.

2. Budget Risks: Another risk is the possibility of budget overruns due to unexpected costs associated with device installation, reprogramming, or adding communications. To manage this risk, regular budget reviews and cost tracking are implemented to ensure the project remains within the allocated budget.

RGE Transmission Reinforcement Program

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-003858	Charge Code: Electric Distribution	Project Sponsor: Leghari, Noor	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The RG&E Transmission Reinforcement Program is crucial to the long-term viability of the RG&E transmission system and its ability to serve customer load growth conditions projected due in part to state clean energy goals. The program identified several system upgrades that are necessary to address current and forecasted system constraints within the RG&E Transmission system. This program covers all projects identified in the RG&E Transmission Local Area Study (LAS). The RG&E Transmission LAS is a comprehensive study designed to demonstrate that the portion of the non-Bulk Electric System (non-BES) transmission system owned by RG&E is compliant with the applicable Local Transmission Planning Criteria.

To achieve this objective, RG&E performed a comprehensive planning assessment of the non-BES transmission system to determine if any potential current or future system violations ("Needs") exist. For those instances where Needs were identified, long-term solutions were developed. All long-term solutions were tested against and comply with the Bulk Electric System (BES) and non-BES Planning Criteria.

Based on external projections of load growth through 2040, RG&E will need to upgrade 46 miles of transmission line, 8 transformers, 2 capacitors, and 1 substation. Asset Condition will be assessed on a project-specific basis.

Project Scope:

There are 46 miles of transmission line (16 miles of 115 kV and 30 miles of 34.5 kV) that need to be upgraded. 8 transformers require replacement, predominantly at the 115/34 kV voltage levels class. To minimize cost and defer more extensive transmission upgrades, 2 capacitors need to be added to the system at the 115 kV, and 34 kV, voltage levels. 1 substation will require significant upgrades which range from expanding the existing footprint with the new transformers and capacitors previously discussed to performing a full rebuild when the existing site is no longer practical for supporting expansion.

Substation-based Projects

Station 182 - Expand 34.5 kV station to include 115 kV ring bus off the nearby Line 934. Two new 115/34.5 kV transformers and 34.5 kV reconfiguration.

Station 246 - Install 34.5 kV capacitor bank + 34.5 kV breaker.

Station 109 - uprate Lines 745 and 747 unless a Non-Wires Alternative can be identified to peak-shave.

Station 124 - install 2nd 115/12 kV transformer.

Station 115 - new 34.5 kV circuit (7.4 miles) between Station 56 and Station 115 with terminal upgrades and local 34.5 kV network reconfiguration.

Station 125 - terminal upgrades to add auto-sectionalizing capabilities with distribution system power factor corrections.

Station 127 - install 34.5 kV breakers and reconfigure local 34.5 kV network.

Station 216 - new 115 kV line 15.5 miles between Station 216 and Slight Road substation, terminal upgrades at both stations, 2nd 115/34.5 kV transformer at Station 216.

Station 104 - expand to include new 34.5/12 kV transformer. Replace existing Station 67 2T with larger transformer. Reconfigure Line 718.

Line Projects (Primarily Overhead Lines)

Line 737 - uprate 6.4 miles of 34.5 kV line.

Line 739 - uprate 0.9 miles of 34.5 kV cable.

Line 764 - uprate 2.4 miles of 34.5 kV cable. Terminal upgrades at Station 100.

Circuit Projects (Primarily Underground Circuits)

Circuit 762 - uprate 1.0 miles of 34.5 kV cable near Station 41 terminal.

Circuits 567 and 680 - Reconductor 3.8 miles of 34.5 kV circuit, anticipated to be a full rebuild.

Circuit 769 - uprate 7.9 miles of 34.5 kV cable and reconfigure Station 112 terminal.

Circuit 766 - uprate 0.8 miles of 34.5 kV cable.

Sectionalizing/Reclosing Project Sites - Lines 753, 756, 737, 740, and 747. Stations 100, 125, 158, 202, 142, 64, 136, 114, and 89.

Project Benefits:

These projects combined resolve Thermal, Voltage, and Loss of Load violations across RGE's non-BES transmission system. Resolving these Needs improves customer reliability, reduces risk of equipment damage, replaces aging infrastructure, and creates capacity for local load growth. SAIFI and SAIDI are expected to improve, protection equipment will be modernized, and non-BES transmission resiliency will improve.

The Transmission Reinforcement projects identify the most immediate system reliability Needs on the non-BES transmission system. These projects form the backbone on top of which the Comprehensive Area Studies are performed. The combination of these two study efforts leads to resolving immediate Needs that exist on the network today, while "right-sizing" projects to support long-term load growth when applicable.

Specific quantifiable benefits (SAIFI improvement, SAIFI avoidance, capacity gained, etc.) are calculated on a per-project basis prior to final internal budget approval.

Project Risks and Mitigation Plan:

(1) Inability to support load growth while the project is in development. Delays in addressing load growth could lead to capacity constraints, resulting in worsening voltage violations and reliability issues. Mitigation measures to minimize these risks include monitoring load growth closely and to develop operational contingency plans and/or implement short-term system modifications if reliability criteria violations are forecasted to occur prior to project completion.

(2) Actual load growth may not align with forecasted values. If actual load growth is materially lower/slower or higher/faster than NYSEG's forecast indicated, there may be risks related to overbuilding or underbuilding, respectively. Mitigation measures of minimize the risk of overbuilding include prioritizing the projects based on urgency and severity, and implementing projects in phases, allowing for adjustment based on the actual load growth. To mitigate the risk of underbuilding, NYSEG designs infrastructure with scalability in mind, allowing for future expansions without significant additional costs.

(3) Further assessment of project-specific risks is performed during the comprehensive solution assessment, which is required as part of the internal budget approval process. Typical project risks that are evaluated include (but are not limited to) ground water monitoring, soil contamination, traffic control, energized equipment, and working in confined spaces.

Risk of No Action:

The Transmission Reinforcement projects address system Needs that exist today. As long as these risks continue unmitigated, there is abnormal risk to customer reliability and equipment security. Additionally, until these Needs are resolved, they are restricting the capacity that is available for load growth in the relevant areas. Delaying these projects may suppress economic growth in the affected region.

Taking no action could also impact the accomplishment of the State's CLCPA goals since there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth. Deferring action on these projects can constrain the ability to operate the system effectively during periods of high load.

Project Alternatives:

Individual projects within this program have specific alternative considerations. A pre-requisite to assigning any funding to a project is the System Review Group to review the alternative approaches to each specific project and reach agreement on the selected alternative. This judgement is made based on cost and total benefits (reliability, capacity gain, maintenance and construction risk, etc.) and documented with the project-specific files.

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at RG&E. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 257,325	\$ 3,000	\$ 10,164	\$ 11,011	\$ 24,217	\$ 36,187	\$ 76,822	\$ 95,924
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 5,076	\$ -	\$ 549	\$ 594	\$ 794	\$ 1,006	\$ 934	\$ 1,199
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 12,126	\$ -	\$ 1,288	\$ 1,395	\$ 1,907	\$ 2,416	\$ 2,243	\$ 2,878
Total	\$ 274,527	\$ 3,000	\$ 12,000	\$ 13,000	\$ 26,919	\$ 39,609	\$ 80,000	\$ 100,000

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE CAS Greece

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-001246	Charge Code: Electric Distribution	Project Sponsor: Gay, Ruben	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The purpose of the Comprehensive Area Study (CAS) projects is to plan for upgrades that will be needed in the region using 5, 10, and 20 year load growth forecasts.

The RGE Greece CAS identified a number of system upgrades that are necessary to address current and forecasted system constraints within the electric system region consisting of ten substations: Station 46, Station 65, Station 69, Station 70, Station 71, Station 72, Station 93, Station 112, Station 126, and Station 421; all located around the Greece Area in Monroe County. The Study utilized an integrated system evaluation approach wherein a targeted transmission planning assessment of relevant facilities was performed to determine how the solutions developed to address the distribution system needs should be optimized to respect, or incorporate, necessary upgrades to nearby transmission or substation facilities.

Area Overview

The electric system within the Greece Area serves approximately 53,000 customers with a peak load of 200 MVA, observed in 2023. The Area includes 48 distribution feeders with voltage classes of 4.16 kV and 12.47 kV. Six of the ten stations are fed from 34.5kV primary, one of ten are fed from 11.5 kV primary, and the remaining three are currently fed via 115 kV.

In addition to distribution circuits, Rochester is served by four 345 kV sources, and five 115kV sources all of which is networked to serve customers on the sub transmission 34.5 kV network. Transmission Planning 's Local Area Study has identified several needs/constraints on the 34.5 kV network throughout Rochester. Without upgrades the risk associated with these constraints will be worsened by Rochester's projected load growth.

The area is forecasted to undergo significant load growth, necessitating proactive grid expansion to address capacity constraints and support electrification and economic development. Forecasted load growth based on the NYISO Gold Book and internal forecasting indicates the following:

Winter Peak Load Growth: 12.6% by 2029, 41.4% by 2034, 100.3% by 2044.
Summer Peak Load Growth: -2.1% by 2029, 3.1% by 2034, 17.0% by 2044.

Needs Assessment

Capacity: The Greece Area is forecasted to experience significant reliability (e.g., voltage and/or thermal) violations within the 20 year planning horizon.

11 out of 18 transformers are projected to be overloaded: STA 65 T2, STA 69 T1, STA 70 T1 & T2, STA 71 T1 & T2, STA 72 T1, STA 93 T2, STA 112 T1 & T2, and STA 126 T1 will be overloaded by 2044.

Capacity constraints are already existing in Summer 2023 for 8 major grid assets. STA 69 T1, STA 71 T1, STA 72 T1, STA 112 T1 & T2, and STA 126 T1 are all over 80% peak loading, while STA 65 T2 and STA 70 T1 peak loading is over 100%

Additionally, over 2.84 mile of underground cable and 4.88 mile of overhead wire are projected to be overloaded by 2044.

Reliability: Based on the load forecast, there will be not be sufficient N-1 capacity at both the distribution and substation levels due to the high demand and the lack of tie points. This means that the system may lack the necessary redundancy to handle contingencies, potentially leading to criteria violations during peak load conditions.

Asset Condition:

STATIONS:

- o Two of the stations are rated as poor (Station 72 and Station 112).
- o There are seven transformers rated as poor or very poor in the stations under analysis.(STA 65 T2, STA 71 T1, STA 72 T1 & T2, STA 93 T1, and STA 421 T3 & T4)
- o There are 3 breakers out of 92 (3%) rated as very poor and 17 out of 92 (18%) rated as poor.

DISTRIBUTION:

- o 5993 out of 20106 distribution poles (29.8%) in the area are greater than 60 years old.
- o 58.8 miles out of 865 miles (6.8%) of underground cable in the area are greater than 50 years old.

Project Scope:

The conceptual project developed as part of the study includes distribution, substation, and transmission upgrades needed to address all identified system needs. Below is a summary of the planned actions.

Substation upgrades:**Retire Substations:**

- 1 - Decommission Station 72. Transfer all load to adjacent Station 93 and Station 112.

Rebuild of Substations:

- 1 - Replace Station 46 T4 & T5, existing 22.4 MVA 34.5/12.47 kV TXs, with new 22.4 MVA 115/12.47 kV TXs.
- 2 - Upgrade Station 65 with dual 50 MVA 115/12.47 kV TXs, 5 feeder breakers, and 1 mobile breaker positions per low-side 12.47 kV bus.
- 3 - Upgrade Station 69 with dual 37 MVA 115/12.47 kV TXs, 4 feeder breakers, and 1 mobile breaker positions per low-side 12.47 kV bus.
- 4 - Upgrade Station 70 with dual 50 MVA 115/12.47 kV TXs, 5 feeder breakers, and 1 mobile breaker positions per low-side 12.47 kV bus.
- 5 - Replace Station 71 T1 with a 22.4 MVA 115/12.47 kV TX to match existing T2. Reconfigure existing buswork to allow for an additional feeder breaker.
- 6 - Build newly proposed HILTON SUB south of the town of Hilton (to support overloaded STA 71) with dual 22.4 MVA 115/12.47 kV TXs allowing for 3 feeder breaker and 1 mobile breaker positions per low-side 12.47 kV bus.
- 7 - Upgrade Station 93 with dual 37 MVA 115/12.47 kV TXs, 4 feeder breakers, and 1 mobile breaker positions per low-side 12.47 kV bus.
- 8 - Upgrade Station 112 with dual 37 MVA 34.5/12.47 kV TXs, 4 feeder breakers, and 1 mobile breaker positions per low-side 12.47 kV bus.
- 9 - Upgrade Station 126 with dual 37 MVA 34.5/12.47 kV TXs, 4 feeder breakers, and 1 mobile breaker positions per low-side 12.47 kV bus.
- 10 - Decommission Station 421 transformers T3 and T4. Limit load to mall only; transfer non-mall load to adjacent Stations 65, 70, and 126. Refeed the low side 12.47 kV buses from nearby Station 65 via two express feeders.

Distribution upgrades:

- 1 - Upgrade all overhead and underground mainlines and equipment to hold 600A continuous loading from feeder breaker to all tie-points. Approximately 26 miles of underground cable and 34 miles of overhead wire require replacement.
- 2 - Convert all existing STA 65, 72, 93, and 112 feeders from 4.16 kV to 12.47 kV.
- 3 - Install four (4) new circuits at Station 65, three (3) at Station 69, one (1) at Station 70, four (4) at proposed HILTON SUB, one (1) at Station 93, and two (2) at Station 126.
- 4 - Perform multiple load transfers and reconfigure circuits to redistribute the load effectively.
- 5 - Install multiple reclosers in main line and tie points on the distribution feeders.

Transmission upgrades:**Station 46 Scope:**

- 1- Decommission 34.5 kV at Station 46. (Loads are transferred to NEW 115/12 kV station).
- 2- Add new 2.75 Mile 115 kV line from Station 65 to Station 46.
- 3- Bring Line 927 running past the station in and out of it.

Station 65 Scope:

- 1- Add new 3.25 Mile 115 kV line from Station 70 to Station 65.
- 2- Decommission Station 421. (Mall Loads will be fed by two express 12.47 kV feeds from Station 65).

Station 93 Scope:

- 1- Reconductor Line 917 between Station 7 and Station 93 (1.65 Miles). The conductor type recommended is 1192.5 54/19 ACSR GRACKLE.
- 2 - Decommission 34.5 kV at Station 93. (Loads are transferred to 115/12 kV station).

Station 112 Scope:

- 1- Reconductor Line 733 between Station 112 and PT 75 (2 Miles). The line should have minimum LTE rating of 36 MVA.
- 2- Reconductor Low rating sections of Line 763 between Station 112 and Station 48. These sections are cables. Total Line Length is 4 Miles. The line should have minimum LTE rating of 36 MVA.
- 3- Install two 4.8 MVAR step Capacitor Bank (Total 9.6 MVAR) at Station 112-L733 Bus.

Station 126 Scope:

- 1- Decommission 34.5 kV at Station 126. (Loads are transferred to NEW 115/12 kV station).
- 2- Add new 2.25 Mile 115 kV line from Station 65 to Station 126.

Project Benefits:

The primary driver of this project is to address emergent capacity constraints within the Area. In addition to resolving these capacity constraints, the project will also address reliability and asset condition needs within the Greece Area.

Voltage Conversion

One goal of the project is the conversion of all 4.16 kV circuits to 12.47 kV to create a universal voltage across the Greece Area. This will have major benefits to system reliability, particularly in N-1 contingency situations. Existing low-side 4.16 kV distribution stations include Stations 65, 72, 93, and 112. The co-primary goal of the project is to increase system capacity to allow for intense future load growth while also upgrading all mainlines to hold 600 amps continuous from feeder breaker to all tie-points. This will improve the voltage across the system and allow for greater N-1 pickup capacity during contingency events (reduced outages for customers).

Capacity

The project will relieve significant voltage and thermal constraints on the distribution system. It will also provide benefit by offloading a sizeable amount of load from the 34.5 kV to the 115 kV transmission system serving the Greece Area. The project will result in additional capacity at all Greece Area substations, providing sufficient capacity to support intense residential and economic load growth while also providing a network of back up sources for extensive N-1 restoration.

Reliability

The project will enhance system reliability and operability by providing N-1 backup capabilities for all 48 distribution feeders in the Greece Area. By standardizing circuit voltage at 12.47 kV and enhancing system capacity, the project will improve system performance under outage conditions and will also provide additional operational flexibility, including for maintenance activities.

Asset Condition

The project will address asset condition needs by replacing or retiring equipment that has exceeded its useful life, thereby limiting the risk of equipment-related outages.

Project Risks and Mitigation Plan:**Inability to Support Load Growth**

Delays in addressing load growth could lead to capacity constraints, resulting in worsening voltage violations and reliability issues. Mitigation measures include monitoring load growth closely and developing operational contingency plans.

Actual Load Growth Variance

If actual load growth deviates from forecasts, there may be risks related to overbuilding or underbuilding. Mitigation measures include designing scalable and right-sized project components to accommodate future growth.

The primary concern with the risk of underbuilding is that the cost-efficiency of projects can be severely impacted if a relatively new project must be re-worked in a way that results in redundancies or an overhaul of prior developed scope. To minimize underbuilding risk, RGE designed the project such that project components were either right-sized, or were scalable, to be sufficient to satisfy expected system needs for at least 20 years (i.e., 2044). Right-sizing solutions for future load growth is an effective method for mitigating underbuilding risk in instances where there is both limited space for adding additional facilities and the incremental cost of installing higher-capacity equipment does not materially increase total project costs.

Risk of No Action:

Opting to take no action on the proposed distribution and transmission upgrades would significantly limit the region's ability to support electrification driven by substantial customer load growth, which may result in longer and more frequent customer outages. This area is already facing voltage, thermal, asset, and reliability challenges. Without the necessary system capacity upgrades, the Area will be unable to accommodate the load growth driven by electrification and economic development. The majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. In general, RGE does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth causing significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's CLCPA goals because there is likely insufficient capacity to support the electrification of large loads such as school buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

The scope of work presented is the preferred scope, and alternative analysis is being performed as the next stage of the study. In general, the alternatives will be focused on attempting to consolidate the number of locations where it will be necessary to perform work.. An in-kind replacement in this area is not feasible because the existing 4.16 kV and 12.47kV system have very limited capacity to accommodate the forecasted load growth.

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at RGE. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE CAS Downtown

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006665	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The purpose of the Comprehensive Area Study (CAS) projects is to plan for upgrades that will be needed in the region using 5, 10, and 20 year load growth forecasts.

The Downtown Comprehensive Area Study (CAS) identified several systems upgrades necessary to address current and forecasted system constraints within the electric system region consisting of twelve substations: Station 1, Station 15, Station 16, Station 19, Station 29, Station 34, Station 40, Station 43, Station 49, Station 81, Station 96, and Station 103. All Stations are located within the towns of Rochester and Irondequoit in Monroe County. The Study utilized an integrated system evaluation approach, performing a targeted transmission planning assessment to determine how solutions developed to address distribution system needs should be optimized to incorporate necessary upgrades to nearby transmission and/or substation facilities.

Area Overview:

The electric system within the Downtown area serves approximately 50,484 customers with a combined total peak 3-year average load of 168.51 MVA and a 2023 summer peak load of 151.7 MVA. The area includes 89 distribution circuits with voltage classes of 4.16 kV and 11.5 kV. Four of the twelve stations are fed from 11.5kV primary and the remaining eight are currently fed via 34.5 kV and have no access to high-voltage 115 kV lines.

In addition to distribution circuits, Rochester is served by four 345 kV sources, and five 115kV sources all of which is networked to serve customers on the sub transmission 34.5 kV network. Transmission Planning 's Local Area Study has identified several needs/constraints on the 34.5 kV network throughout Rochester. Without upgrades the risk associated with these constraints will be worsened by Rochester's projected load growth.

The area is forecasted to undergo significant load growth, necessitating proactive grid expansion to address capacity constraints and support electrification and economic development. Forecasted load growth based on the NYISO Gold Book and internal forecasting indicates the following:

Winter Peak Load Growth: 12.6% by 2029, 41.4% by 2034, 100.3% by 2044.

Summer Peak Load Growth: -2.1% by 2029, 3.1% by 2034, 17.0% by 2044.

Needs Assessment:

Capacity:

The Downtown area is forecasted to experience significant thermal violations within the 20 year planning horizon:

12 out of 23 transformers are projected to be overloaded: STA 1 T2, STA 15 T1, STA 16 T1&T2, STA 19 T2, STA 34 T2, STA 40 T3, STA 43 T1&T2, STA 49 T1, STA 81 T1, STA 96 T1,

Capacity constraints are already existing in Summer 2023 for 5 major grid assets. STA 16 T2, STA 43 T1 are all over 80% peak loading, while STA 16 T1, STA 43 T2 peak loading is over 100%.

Additionally, over 25 miles of underground cable and 5 miles of overhead cable are projected to be overloaded by 2044.

Reliability:

N-1 Backup Capabilities: None of the stations will have N-1 capabilities due to the inability of one transformer to carry the entire load of the station. At the circuit level, no N-1 backup capabilities are available in the downtown area due to the lack of capacity in 4.16 kV underground circuits and the lack of tie points.

Asset Condition:

o Eight of the stations are rated as poor (Station 1, Station 15, Station 16, Station 19, Station 34, Station 81, Station 96, and Station 103), and four are rated as fair (Station 29, Station 40, Station 43, and Station 49). Station 43 has already been upgraded and is included in the study only to help and support adjacent stations.

o There are no transformers rated as poor or very poor in the stations under analysis.

o There are 21 breakers out of 208 (10%) rated as very poor and 48 out of 208 (23%) rated as poor.

o 6593 out of 17140 distribution poles (38.5%) in the area are greater than 60 years old.

o 151 miles out of 636 miles (24%) of underground cable in the area are greater than 50 years old.

Project Scope:

The conceptual project developed as part of the study includes distribution, substation, and transmission upgrades needed to address all identified system needs. Below is a summary of the planned actions:

Substation upgrades:**Retire Substations:**

- 1 - Decommission Station 15. Transfer all load to adjacent Station 19.
- 2 - Decommission Station 16. Transfer all load to adjacent Station 19 and 103.
- 3 - Decommission Station 34. Transfer all load to adjacent Station 29.
- 4 - Decommission Station 40. Transfer all load to adjacent Station 81.
- 5 - Decommission Station 96. Transfer all load to adjacent Station 49.

Rebuild of Substations:

- 1 - Upgrade Station 1 with dual 37 MVA 34.5/12.47 kV TXs.
 - 2 - Upgrade Station 19 with dual 22.4 MVA 115/12.47 kV TXs.
 - 3 - Upgrade Station 29 with dual 37 MVA 115/12.47 kV TXs.
 - 4 - Upgrade Station 49 with dual 37 MVA 115/12.47 kV TXs.
 - 5 - Upgrade Station 81 with dual 37 MVA 115/12.47 kV TXs.
 - 6 - Upgrade Station 103 with dual 37 MVA 115/12.47 kV TXs.
- Station 43 is already built with dual 22.4 MVA 115/12.47 kV TXs but the circuits conversion to 12.5 kV is still pending at the time of this study. This Station is not included in the upgrades of this CAS.

Distribution upgrades:

- 1 - Upgrade all overhead and underground mainlines and equipment to hold 600A continuous loading from feeder breaker to all tie-points. Approximately 46 miles of underground cable and 12 miles of overhead cable require replacement.
- 2 - Voltage Conversion: Convert all circuits from 4.16 kV to 12.47 kV.
- 3 - Perform multiple load transfers and reconfigure circuits to redistribute the load effectively.
- 4 - Install a Switching Station at the location of existing Station 16.

Transmission upgrades:**Station 19 Transmission Source:**

- 1 - Tap 115 kV line 920 (approximately halfway ~2 mi) and loop in and out of NEW station 19.
- 2 - 0.6 mi of NEW line section.

Station 23 Transmission Source:

- 1 - Expand Station 23 to add new 1.1 mi 115 kV line to New 115 kV Station 29.

Station 29 Transmission Source:

- 1 - Add new 2 mi 115 kV line to New 115 kV Station 48.
- 2 - Add new 3 mi 115 kV line to New 115 kV Station 103.

Station 48 Transmission Source:

- 1 - Expand Station 48 to add new 2 mi 115 kV line to New Station 29.

Station 49 Transmission Source:

- 1 - Add new 1.1 mi 115 kV line to New 115 kV Station 19.

Station 81 Transmission Source:

- 1 - Add new 1.5 mi 115 kV line to New 115 kV Station 49.

Station 103 Transmission Source:

- 1 - Add new 3 mi 115 kV line to Station 29.
- 2 - Add new 1.5 mi 115 kV line to New 115 kV Station 81.

Project Benefits:**Capacity:**

The project will relieve significant thermal constraints on both the distribution and transmission systems, providing sufficient capacity to support significant load growth and provide backup sources for feeders.

Reliability:

The project will enhance system reliability and operability by providing N-1 backup capabilities for all distribution feeders. By standardizing circuit voltage at 12.47 kV and enhancing system capacity, the project will improve system performance under outage conditions and provide additional operational flexibility, including for maintenance activities.

Asset Condition:

The project will address asset condition needs by replacing or retiring equipment that has exceeded its useful life, thereby limiting the risk of equipment-related outages.

Project Risks and Mitigation Plan:**Inability to Support Load Growth**

Delays in addressing load growth could lead to capacity constraints, resulting in worsening voltage violations and reliability issues. Mitigation measures include monitoring load growth closely and developing operational contingency plans.

Actual Load Growth Variance

If actual load growth deviates from forecasts, there may be risks related to overbuilding or underbuilding. Mitigation measures include designing scalable and right-sized project components to accommodate future growth.

The primary concern with the risk of underbuilding is that the cost-efficiency of projects can be severely impacted if a relatively new project must be re-worked in a way that results in redundancies or an overhaul of prior developed scope. To minimize underbuilding risk, RGE designed the project such that project components were either right-sized, or were scalable, to be sufficient to satisfy expected system needs for at least 20 years (i.e., 2044). Right-sizing solutions for future load growth is an effective method for mitigating underbuilding risk in instances where there is both limited space for adding additional facilities and the incremental cost of installing higher-capacity equipment does not materially increase total project costs.

Risk of No Action:

Opting to take no action on the proposed distribution and transmission upgrades would significantly limit the Area's ability to support electrification driven by substantial customer load growth. This area is already facing voltage, thermal, asset, and reliability challenges. Without the necessary system capacity upgrades, the Area will be unable to accommodate the load growth driven by electrification and economic development. The majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. In general, RGE does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth causing significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's CLCPA goals because there is likely insufficient capacity to support the electrification of large loads such as School Buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

Project Alternatives:

The scope of work presented is the preferred scope, and alternative analysis is being performed as the next stage of the study. In general, the alternatives will be focused on attempting to consolidate the number of locations where it will be necessary to perform work. An in-kind replacement in this area is not feasible because the existing 4.16 kV and 12.47kV systems have very limited capacity to accommodate the forecasted load growth.

Additionally, the majority of the area is served by 34.5 kV which cannot support the anticipated load increases and requires additional support from the 115kV transmission systems. Another alternative consideration was to focus on expanding 115 kV infrastructure. However, due to the challenges of citing, permitting, and public support for new transmission infrastructure, the preferred scope was selected to minimize the amount of new transmission infrastructure required.

Basis for Project Estimates

The basis for the cost estimate is an order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at RGE. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 381,466	\$ -	\$ -	\$ 20,565	\$ 38,796	\$ 65,263	\$ 114,387	\$ 142,455
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 152,586	\$ -	\$ -	\$ 8,226	\$ 15,518	\$ 26,105	\$ 45,755	\$ 56,982
# Internal, Overheads	\$ 24,366	\$ -	\$ -	\$ 1,766	\$ 2,901	\$ 4,138	\$ 6,822	\$ 8,738
# Materials	\$ 118,678	\$ -	\$ -	\$ 6,398	\$ 12,070	\$ 20,304	\$ 35,587	\$ 44,319
# Overheads - External	\$ 62,628	\$ -	\$ -	\$ 4,540	\$ 7,457	\$ 10,636	\$ 17,536	\$ 22,459
Total	\$ 739,725	\$ -	\$ -	\$ 41,495	\$ 76,743	\$ 126,446	\$ 220,087	\$ 274,953

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE CAS Victor

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006667	Charge Code: Electric Distribution	Project Sponsor: Gay, Ruben	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

The RGE Victor Comprehensive Area Study identified a number of system upgrades that are necessary to address current and forecasted system constraints within the electric system region consisting of seven substations: Station 120, Station 125, Station 127, Station 149, Station 154, Station 156, and Station 168 all located around the Victor/Canandaigua are in Monroe County. The Study utilized an integrated system evaluation approach where in a targeted transmission planning assessment of relevant facilities was performed to determine how the solutions developed to address the distribution system needs should be optimized to respect, or incorporate, necessary upgrades to nearby transmission or substation facilities.

Area Overview: The electric system within the Area serves approximately 18,500 customers with a peak load of 90 MVA, observed in 2023. The Area includes twenty-two distribution feeders with voltage classes of 4.16 kV and 12.47 kV. Six of the seven stations are fed from 34.5kV primary and station 168 is fed via 115kV. From a transmission perspective, this region is split into two load pockets. The northern pocket is a loop where load is shared between Station 120 and Station 127. The southern pocket is a radial load pocket sourced solely from Station 168. From Station 168, long radial 34.5 kV circuits extend primarily to the south.

The area currently has very limited available capacity and is forecasted to undergo significant winter and summer peak load growth, primarily due to building and transportation electrification. The high forecasted load growth necessitates proactive grid expansion to address capacity constraints and support electrification and economic development. Forecasted load growth based on the NYISO Gold Book and internal forecasting indicates the following:

Winter Peak Load Growth: 12.6% by 2029, 41.4% by 2034, and 100.3% by 2044

Summer Peak Load Growth: -2.1% by 2029, 3.1% by 2034, and 17% by 2044

Needs Assessment:

Capacity:

The Victor Area is forecasted to experience significant thermal violations within the 20 year planning horizon.

8 out of 11 transformers are projected to be overloaded: STA 120 T2, STA 125 T2, STA 127 T1, STA 149 T1, STA 154 T1, STA 156 T1 & T2, and STA 168 T3 by 2044.

Capacity constraints are already existing in Summer 2023 for 4 major grid assets. STA 125 T2, STA 149 T1, and STA 154 T1 are all over 80% peak loading, while STA 156 T1 peak loading at 100%.

Reliability:

Based on the load forecast, N-1 capabilities at both the distribution and substation levels will be very limited due to the high demand and the lack of tie points. This means that our system will lack the necessary redundancy to handle contingencies, potentially leading to reliability issues during peak load conditions. A primary goal of the project is the conversion of all 4.16 kV circuits to 12.47 kV to create a universal voltage across the Victor Area.

Asset Condition:

- Two of the stations are rated as poor; STA 149 and 156 (There is currently an on going project for STA 156 conversion from 4.16kV to 12.47kV)
- There are four transformers (STA 120 T1, STA 149 T1, STA 154 T2, and STA 156 T2) are rated in poor condition or have no asset condition score.
- There are 4 breakers out of 61 rated at very poor (6.56%), 5 breakers out of 61 at poor (8.2%) condition across STA 149, 156 and 168.
- Across the 7 Substation Network there are 852 out of 9487 Distribution Poles that are older than 60 years old (9%).
- 28.48 miles out of 469.25 miles (6.1%) of underground cable in the area are greater than 50 years old.

Project Scope:

The conceptual project developed as part of the study includes distribution, substation, and transmission upgrades needed to address all identified system needs. Below is a summary of the planned actions:

Substation Upgrades:

New Substation:

Build a new Distribution Station 122 with dual 50 MVA 115/12.47 kV TXs. This new Distribution Station 122 would be fed from the existing Transmission Station 122.

Retire Substations:

1 - Decommission Station 149. Transfer all load to adjacent Station 127 and 154

Rebuild of Substations:

1 - Upgrade Station 127 by adding an additional 22.4 MVA 34.5/12.47 kV TX.
2 - Upgrade Station 154 with dual 22.4 MVA 34.5/12.47 kV TXs. And converting any feeders from 4.16 kV to 12.47 kV.
Station 156 is already built with a new 14 MVA 34.5/12.47 kV TX but the circuits conversion to 12.47 kV is still pending at the time of this study. This Station is not included in the upgrades of this CAS.

Distribution upgrades:

1 - Upgrade all overhead and underground mainlines and equipment to hold 600A continuous loading from feeder breaker to all tie-points. Approximately 7.2 miles of underground cable and 26.6 miles of overhead cable require replacement.
2 - Voltage Conversion: Convert all circuits from Station 120, 149, 154 and 156 from 4.16 kV to 12.47 kV.
3 - Perform multiple load transfers and reconfigure circuits to redistribute the load effectively.
4 - Install several new circuit at the new Distribution Station 122.
5 - Install multiple reclosers in main line and tie points on the distribution feeders.

Transmission upgrades:

The constraints in the load pocket shared between Station 121 and Station 127 can most efficiently be resolved by leveraging the nearby 345 kV infrastructure. The closest point to access this infrastructure is at RG&E's Station 122. Station 122 would be expanded with 1-2 115/12 kV transformers, and distribution load would be pulled off of the nearby 34.5 kV network.

The constraints at Station 168 can be resolved by extending a 115 kV line further to the south. The 34.5 kV lines historically were able to extend so far due to the relatively low amount of load they served, but as that load has grown, the 34.5 kV voltage class is inadequate for carrying so much load over so long of a distance.

Project Benefits:

The primary driver of this project is to address emergent capacity constraints within the Area. In addition to resolving these capacity constraints, the project will also address reliability and asset condition needs within the Victor Area.

A primary goal of the project is the conversion of all 4.16 kV circuits to 12.47 kV to create a universal voltage across the Victor Area. This will have major benefits to system reliability, particularly in N-1 contingency situations. Existing low-side 4.16 kV distribution stations include STA 120, 149, 154, and 156. The co-primary goal of the project is to increase system capacity to allow for intense future load growth while also upgrading all mainlines to hold 600 amps continuous from feeder breaker to all tie-points. This will improve the voltage across the system and allow for greater N-1 pickup capacity during contingency events.

Capacity:

The project will relieve significant thermal constraints on the distribution system. It will also provide benefit by offloading a sizeable amount of load from the 34.5 kV to the 115 kV transmission system serving the Victor Area. The project will result in additional capacity at all Victor Area substations, providing sufficient capacity to support intense residential and economic load growth while also providing a network of back up sources for extensive N-1 restoration.

Reliability:

The project will enhance system reliability and operability by providing N-1 backup capabilities for all 22 distribution feeders in the Victor Area. By standardizing circuit voltage at 12.47 kV and enhancing system capacity, the project will improve system performance under outage conditions and will also provide additional operational flexibility, including for maintenance activities.

Asset Condition:

The project will address asset condition needs by replacing or retiring equipment that has exceeded its useful life, thereby limiting the risk of equipment-related outages.

Project Risks and Mitigation Plan:

Inability to Support Load Growth: Delays in addressing load growth could lead to capacity constraints, resulting in worsening voltage violations and reliability issues. Mitigation measures include monitoring load growth closely and developing operational contingency plans.

Actual Load Growth Variance: If actual load growth deviates from forecasts, there may be risks related to overbuilding or underbuilding. Mitigation measures include designing scalable and right-sized project components to accommodate future growth.

With regard to underbuilding risk, the primary concern is that the cost-efficiency of projects can be severely impacted if a relatively new project must be re-worked in a way that results in redundancies or an overhaul of prior developed scope. To minimize underbuilding risk, RGE designed the project such that project components were either right-sized, or were scalable, to be sufficient to satisfy expected system needs for at least 20 years (i.e., 2044). Right-sizing solutions for future load growth is an effective method for mitigating underbuilding risk in instances where (1) there is limited space for adding additional facilities and (2) the incremental cost of installing higher-capacity equipment does not materially increase total project costs.

Opting to take no action on the proposed distribution and transmission upgrades would significantly limit the Area's ability to support electrification driven by substantial customer load growth. This area is already facing voltage, thermal, asset, and reliability challenges. Without the necessary system capacity upgrades, the Area will be unable to accommodate the load growth driven by electrification and economic development. The majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. In general, RGE does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth causing significant overload and undervoltage conditions with very limited operational mitigations available.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

Due to the complexity of the study, no alternative study has been conducted at this moment. An in-kind replacement in this area is not feasible because the existing 4.16 kV and 12.47kV system have very limited capacity to accommodate the forecasted load growth. Additionally, the entire area is served by 34.5 kV which cannot support the anticipated load increases and 115kV transmission systems.

The basis for the cost estimate is and order of magnitude cost that was determined based on the scope of the project. Estimates were unitized on a per-asset and per-mile basis based on multiple sources, including the analysis of historical costs for similar activities and projects at RGE. Project estimates will be updated and refined as the project progresses and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 212,200	\$ -	\$ -	\$ 8,132	\$ 41,697	\$ 52,301	\$ 77,615	\$ 32,455
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 3,425	\$ -	\$ -	\$ 418	\$ 1,339	\$ 1,061	\$ 591	\$ 16
# Materials	\$ 17,956	\$ -	\$ -	\$ 1,758	\$ 6,473	\$ 6,049	\$ 3,583	\$ 93
# Overheads - External	\$ 6,729	\$ -	\$ -	\$ 821	\$ 2,631	\$ 2,084	\$ 1,162	\$ 31
Total	\$ 240,311	\$ -	\$ -	\$ 11,129	\$ 52,141	\$ 61,495	\$ 82,952	\$ 32,594

[illegible]

RGE CAS Penfield

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006668	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2029

Project description:

The purpose of the Comprehensive Area Study (CAS) projects is to plan for upgrades that will be needed in the region using 5, 10, and 20 year load growth forecasts.

The Penfield Comprehensive Area Study (CAS) identified several system upgrades that are necessary to address current and forecasted system constraints within the electric system region consisting of thirteen substations: Station 45, Station 55, Station 58, Station 60, Station 62, Station 74, Station 109, Station 117, Station 124, Station 136, Station 230, Station 420, Station 424. All Stations are located within the towns of Webster, Penfield, East Rochester, and Walworth in Monroe and Wayne County. The Study utilized an integrated system evaluation approach where in a targeted transmission planning assessment of relevant facilities was performed to determine how the solutions developed to address the distribution system needs should be optimized to respect, or incorporate, necessary upgrades to nearby transmission or substation facilities.

Area Overview:

The electric system within the Area serves approximately 42,700 customers with a peak load of 227 MVA in 2023. The Area includes forty-five distribution feeders with voltage classes of 4.16 kV and 12.47 kV. Ten of the thirteen stations are fed from 34.5kV primary and the remaining three are fed via 115 kV. This region is primarily fed from one 115/34.5/12 kV substation, Station 42. This station has four 115/34 kV transformers that support the local network. There are ties between Station 42 and other parts of the transmission network, but these ties are generally low-capacity relative to the amount of load that Station 42 carries.

The area is forecasted to undergo significant load growth, necessitating proactive grid expansion to address capacity constraints and support electrification and economic development. Forecasted load growth based on the NYISO Gold Book and internal forecasting indicates the following:

Winter Peak Load Growth: 12.6% by 2029, 41.4% by 2034, 100.3% by 2044.

Summer Peak Load Growth: -2.1% by 2029, 3.1% by 2034, 17.0% by 2044.

Needs Assessment:

Capacity:

The Penfield Area is forecasted to experience significant thermal violations within the 20 year planning horizon.

12 out of 18 transformers are projected to be overloaded: STA 45 T1, STA 55 T2, STA 58 T1, STA 60 T1, STA 62 T3 and T4, STA 109 T2, STA 117 T1, STA 124 T1 and T2, STA 230 T1, STA 420 T1.

Capacity constraints are already existing in Summer 2023 for 5 major grid assets. STA 424 T3, STA 109 T2, STA 55 T2, STA 58 T1 are all over 80% peak loading, while STA 117 T1 peak loading is over 100%.

Over 6.89 mile of underground cable and 12.26 mile of overhead cable are projected to be overloaded by 2044.

Reliability:

Based on the load forecast, there will be not sufficient N-1 capabilities at both the distribution and substation levels due to the high demand and the lack of tie points. This means that the system will lack the necessary redundancy to handle contingencies, potentially leading to reliability issues during peak load conditions.

Asset Condition:

- o Three stations are rated as poor (Station 420, Station 109, Station 62).

- o Five transformers rated as poor or very poor in the stations under analysis.(STA 45 T1, STA 109 T1, STA 117 T1, STA 230 T1, and STA 420 T3)

- o 12 out of 54 (22.2%) breakers are rated as poor and 3 out of 54 (5.5%) rated as very poor.

- o 4,840 out of 19,255 distribution poles (25.1%) in the area are greater than 60 years old.

- o 64.68 miles out of 780 miles (8.29%) of underground cable in the area are greater than 50 years old.

Project Scope:

The conceptual project developed as part of the study includes distribution, substation, and transmission upgrades needed to address all identified system needs. Below is a summary of the planned actions.

Substation upgrades:**Retire Substations:**

- 1 - Decommission Station 45. Transfer all load to adjacent Station 124 and Station 424.
- 2 - Decommission Station 60. Transfer all load to adjacent Station 424, Station 136 and Station 124.
- 3 - Decommission Station 74. Transfer all load to adjacent Station 424.
- 4 - Decommission Station 420. Transfer all load to adjacent Station 62.

Rebuild of Substations:

- 1 - Upgrade Station 55 with dual 22.4 MVA 115/12.47 kV TXs.
- 2 - Upgrade Station 58 with a 22.4 MVA 34.5/12.47 kV TX.
- 3 - Upgrade Station 62 with dual 37 MVA 115/12.47 kV TXs, 4 feeder and 1 mobile breaker positions per 12.47 kV bus.
- 4 - Upgrade Station 109 with dual 22.4 MVA 115/12.47 kV TXs.
- 5 - Upgrade Station 230 with a 22.4 MVA 115/12.47 kV TX (match existing T1), 4 feeder and 1 mobile breaker positions per low-side 12.47 kV bus.
- 6 - Decommission Station 117 4.16kV bus and T1 5.25 MVA 34.5kV/4.16 kV.
- 7 - Upgrade Station 124 with dual 50 MVA 115/12.47 kV TXs, 5 feeder and 1 mobile breaker positions per 12.47 kV bus.
- 8 - Upgrade Station 424 with a 22.4 MVA 34.5/12.47 kV TX (match existing T3), 4 feeder and 1 mobile breaker positions per 12.47 kV bus.

Distribution upgrades:

- 1 - Upgrade all overhead and underground mainlines and equipment to hold 600A continuous loading from feeder breaker to all tie-points. Approximately 13 miles of underground cable and 50 miles of overhead cable require replacement.
- 2 - Convert all existing STA 45, 58, 60, 74, 117, 420 feeders from 4.16 kV to 12.47 kV.
- 3 - Install one (1) new circuit at Station 136, one (1) Station 55 and four (4) at Station 124.
- 4 - Perform multiple load transfers and reconfigure circuits to redistribute the load effectively.
- 5 - Install multiple reclosers in main line and tie points on the distribution feeders.

Transmission upgrades:**Station 55 Transmission Source:**

- 1 - Convert Station from 34.5 kV to 115 kV
- 2 - Add new 3.25 mi 115 kV line to New 115 kV Station 109.
- 3 - Add new 8 mi 115 kV line to 115 kV Station 424.

Station 58 Transmission Source:

- 1 - Reconnector 34.5 kV Cable between Station 204 to Station 58.
- 2 - Install 2 x 12 MVAr Cap Banks at Station 58.

Station 62 Transmission Source:

- 1 - Convert Station from 34.5 kV to 115 kV
- 2 - Add new 7.8 mi 115 kV line to 115 kV Station 124 + Decommission Line 938.
- 3 - Add new 3.85 mi 115 kV line to 115 kV Station 42.

Station 109 Transmission Source:

- 1 - Convert Station from 34 kV to 115 kV
- 2 - Add new 6.7 mi 115 kV line to 115 kV Station 42.
- 3 - Add new 3.25 mi 115 kV line to New 115 kV Station 55.

Station 124 Transmission Source:

- 1 - Add a third BAAH bay to the 115 kV side.

Station 230 Transmission Source:

- 1 - Rebuild substation with ring bus configuration.

Station 424 Transmission Source:

- 1 - Reconfigure the 115kV to 3-bay BAAH.

Project Benefits:

The primary driver of this project is the significant number of load requests we are experiencing at Station 124 in the Penfield area, including new developments and school bus electrification.

Voltage Conversion

The circuit voltage conversion from 4.16 kV to 12.47 kV will have major benefits in the Penfield area. Converting STA 74 distribution circuits to 12.47 kV will create N-1 capabilities between Station 424 and Station 136. It will also improve capacity in the Xerox area, which is currently experiencing significant load growth and numerous capacity and load requests. Converting Station 58 distribution circuits will allow us to achieve N-1 capabilities with Stations 124, 55, 109, and 62. This is crucial since Station 124 distribution circuits that feed the town of Penfield to the south are tie limited due to Fairport Electric. Converting circuit stations 420 and 62 will increase circuit capacity and tie capabilities.

Capacity:

The project will relieve significant thermal constraints on the distribution system. It will also provide benefits by offloading a sizeable amount of load from the 34.5 kV to the 115 kV transmission system serving the area. The project will result in additional capacity at all substations, providing sufficient capacity to support intense residential and economic load growth while also providing a network of backup sources for extensive N-1 restoration.

Reliability:

The project will enhance system reliability and operability by providing N-1 backup capabilities for all 45 distribution feeders in the area. By standardizing circuit voltage at 12.47 kV and enhancing system capacity, the project will improve system performance under outage conditions and provide additional operational flexibility, including for maintenance activities.

Asset Condition:

The project will address asset condition needs by replacing or retiring equipment that has exceeded its useful life, thereby limiting the risk of equipment-related outages.

Project Risks and Mitigation Plan:**Inability to Support Load Growth**

Delays in addressing load growth could lead to capacity constraints, resulting in worsening voltage violations and reliability issues. Mitigation measures include monitoring load growth closely and developing operational contingency plans.

Actual Load Growth Variance

If actual load growth deviates from forecasts, there may be risks related to overbuilding or underbuilding. Mitigation measures include designing scalable and right-sized project components to accommodate future growth.

The primary concern with the risk of underbuilding is that the cost-efficiency of projects can be severely impacted if a relatively new project must be re-worked in a way that results in redundancies or an overhaul of prior developed scope. To minimize underbuilding risk, RGE designed the project such that project components were either right-sized, or were scalable, to be sufficient to satisfy expected system needs for at least 20 years (i.e., 2044). Right-sizing solutions for future load growth is an effective method for mitigating underbuilding risk in instances where there is both limited space for adding additional facilities and the incremental cost of installing higher-capacity equipment does not materially increase total project costs.

Risk of No Action:

Opting to take no action on the proposed distribution and transmission upgrades would significantly limit the region's ability to support electrification driven by substantial customer load growth, which may result in longer and more frequent customer outages. This area is already facing voltage, thermal, asset, and reliability challenges. Without the necessary system capacity upgrades, the Area will be unable to accommodate the load growth driven by electrification and economic development. The majority of forecasted load growth in the Area is expected to come from the residential sector via heating and transportation electrification. In general, RGE does not have the ability to delay residential load expansions, even when load growth could lead to reliability issues. Therefore, taking no action on this project could result in unmitigated load growth causing significant overload and undervoltage conditions with very limited operational mitigations available.

Taking no action could also impact the accomplishment of the State's CLCPA goals because there is likely insufficient capacity to support the electrification of large loads such as school buses or fast-charging stations. This may result in more costs being borne by customers or electrification projects being delayed or abandoned.

The lack of action will also prevent the optimization of the distribution voltage class in the area, which is crucial for improving reliability under N-1 conditions and ensuring the system's expandability to support future load growth.

The scope of work presented is the preferred scope, and alternative analysis is being performed as the next stage of the study. In general, the alternatives will be focused on attempting to consolidate the number of locations where it will be necessary to perform work.. An in-kind replacement in this area is not feasible because the existing 4.16 kV and 12.47kV system have very limited capacity to accommodate the forecasted load growth.

Basis for Project Estimates

FINANCIAL INFORMATION

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 556,886	\$ -	\$ -	\$ -	\$ 46,655	\$ 111,890	\$ 156,543	\$ 241,798
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 24,037	\$ -	\$ -	\$ -	\$ 2,413	\$ 4,907	\$ 6,458	\$ 10,259
# Materials	\$ 139,222	\$ -	\$ -	\$ -	\$ 11,664	\$ 27,973	\$ 39,136	\$ 60,449
# Overheads - External	\$ 47,218	\$ -	\$ -	\$ -	\$ 4,741	\$ 9,639	\$ 12,686	\$ 20,152
Total	\$ 767,363	\$ -	\$ -	\$ -	\$ 65,472	\$ 154,409	\$ 214,823	\$ 332,657

[illegible]

Proactive Planning - Station 124

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006421	Charge Code: Electric	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Planning and Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

Overview: The Station 124 Project aims to address urgent capacity constraints and reliability issues at Station 124, located in the Town of Penfield, Monroe County. The project involves strengthening the station's 115/12.5 kV transformation to resolve the urgent capacity constraints while also allowing for future growth/hosting capacity. The total load requests studied amount to 10.8 MW, with 22% from residential buildings (heat pumps), 37% from transportation electrification, and 41% from economic development.

Current State Needs Assessment: Station 124, constructed in 1968, faces significant reliability issues due to equipment thermal overloading and system voltage reliability criteria violations. The station's 1T and 2T transformers will be overloaded to 118% and 123% of their Long-Term Emergency (LTE) rating under contingency conditions. When queued loads are included, these loadings jump to 176% and 180% respectively. Transmission voltages as low as 0.84 PU have been identified for a 2T fault. When queued loads are added voltage collapse occurs.

The proposed Station 124 Upgrade Project is designed to: (1) Mitigate existing voltage and thermal needs, (2) Accommodate current load requests, and (3) Incorporate additional capacity for future load growth. Two solution alternatives were developed and evaluated against several factors, including future expandability, ability to address immediate electrification needs, execution certainty, and capacity headroom benefits using known forecasting data.

Project Scope:

The selected project proposal includes expanding Station 124's 115 kV bus to a 3-bay breaker-and-a-half (BAAH) configuration. Two new 50 MVA 115/12 kV transformers will be installed, and the existing 1T (34.5/12.5 kV) and 2T (115/12.5 kV) transformers will be removed. The local network will be reconfigured to have all distribution load served from the 115 kV source at Station 124. Additionally, two new 12.5 kV bus sections with a normally open tie breaker will be installed. The project also involves re-terminating Line 911 into a new bay position and removing the 1T connection pending further discussion on its value for emergency operations. No immediate distribution load transfers are planned, but consideration will be given to shifting load to Station 124 as new customer load requests come in.

Project Benefits:

The proposed project will resolve the thermal and voltage constraints at Station 124, ensuring reliable power supply to the Town of Penfield. It will support the connection of new residential buildings and EV school bus charging stations, facilitating economic development and electrification efforts.

Reliability: The project will significantly enhance system reliability by addressing N-1 contingency violations at Station 124. These violations occur when a single component failure leads to system overloads, causing potential outages. By upgrading the infrastructure and adding redundancy, the project will ensure continuous service even during faults or maintenance activities. This is particularly important for the Town of Penfield, which is experiencing rapid growth and increased demand for reliable power supply.

Capacity Headroom: The project will relieve voltage and thermal constraints on the 34.5 kV transmission network by feeding load from Station 124's 115 kV bus. The maximum N-0 capacity gained on the distribution system is 58 MVA, and the maximum N-1 capacity gained on the transmission system is 47 MVA. This additional capacity is crucial to support future load growth from residential, commercial, and EV charging developments.

Expandability: The new infrastructure at Station 124 will allow for future expansions, including the addition of new 12.5 kV distribution circuits. This will ensure the system can adapt to increasing demand over time. The project includes the installation of two new 12.5 kV bus sections with a normally open tie breaker, facilitating the transfer of load between transformers. This will provide the necessary capacity to accommodate future load growth and ensure reliable power supply to the area.

Project Risks and Mitigation Plan:

This project's key risk is the need to expand the substation approximately 100' to the south into forested, regulated wetland areas and acquiring new property. This property is critical to the expansion of the substation as it is not feasible to expand to the north, though southward expansion into the wetland areas will result in mitigation needs. This risk can be mitigated by securing this property as soon as the project is started, engaging with the permitting teams, and doing project surveys. If this property cannot be secured additional alternatives will need to be considered.

Risk of No Action:

If no action is taken, the thermal and voltage constraints at Station 124 will persist, preventing the connection of new load requests. This will hinder economic development and electrification efforts in the area, particularly for residential buildings and EV school bus charging stations. The continued overloading of transformers and low transmission voltages will increase the risk of outages and reduce the reliability of the power supply to the Town of Penfield.

Project Alternatives:

The alternative solution consists of expanding the existing 6-breaker ring bus into 8-breaker ring bus configuration by utilizing a double breaker. This will include installations of two new 50 MVA, 115/12.5 kV transformers alongside the required new structures while decommissioning the existing 115/12.5 kV 2T and 34.5/12.5 kV 1T transformers and associated structures.

This option was less favorable due to construction complexity and physical constraint, less reliable configuration compared to preferred alternative.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects at RG&E. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 3,929		\$ 533	\$ 1,497	\$ 1,899			
# CIAC	\$ -							
# External Services	\$ 26,853		\$ 8,931	\$ 8,846	\$ 9,076			
# Internal - Non-AC	\$ -							
# Internal, Labor	\$ 1,305		\$ 374	\$ 431	\$ 500			
# Internal, Overheads	\$ 1,323		\$ 689	\$ 349	\$ 285			
# Materials	\$ 10,569		\$ 8,429	\$ 2,140				
# Overheads - External	\$ 3,645		\$ 1,600	\$ 1,030	\$ 1,015			
Total	\$ 47,624	\$ -	\$ 20,556	\$ 14,293	\$ 12,775	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE - Breaker Replacement Program

PROJECT INFORMATION

OpCo: RG&E	Project ID: UI-R0064-RGE-ED	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Annual Program
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for RGE customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 33.5% (1,317 units) of circuit breakers in New York Operating Companies (NY Opcos) are classified as High Risk (Risk Index (RI-4) and Very High Risk (RI-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2031 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the planned replacement units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

1) We are forecasting to install approximately 47 breakers in 2028, around 23 breakers in 2029, and approximately 48 breakers in 2030. The actual in-service completion dates will vary depending on the voltage class of each breaker.

2) Individual breaker replacement projects costing more than \$500,000 will have a unique project ID created under this Breaker Replacement Program funding. Any breaker replacement estimated to cost less than \$500,000 will be purchased directly under this program ID number.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at RGE involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, RGE can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk R14 and R15 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as R14 or R15. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of R14 and R15 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 1,525	\$ 143	\$ 185	\$ 245	\$ 383	\$ 570		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 5,589	\$ 800	\$ 850	\$ 877	\$ 708	\$ 2,354		
# Internal - Non-AC	\$ 116	\$ 0	\$ 0	\$ 0	\$ 34	\$ 81		
# Internal, Labor	\$ 752	\$ 51	\$ 158	\$ 102	\$ 65	\$ 376		
# Internal, Overheads	\$ 1,062	\$ 66	\$ 154	\$ 184	\$ 133	\$ 525		
# Materials	\$ 5,633	\$ 457	\$ 1,090	\$ 1,267	\$ 810	\$ 2,009		
# Overheads - External	\$ 2,773	\$ 153	\$ 341	\$ 460	\$ 403	\$ 1,416		
Total	\$ 17,451	\$ 1,671	\$ 2,778	\$ 3,134	\$ 2,535	\$ 7,333		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ 10	\$ -	\$ -	\$ 9	\$ -	\$ 0		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ 10	\$ -	\$ -	\$ 9	\$ -	\$ 0		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 5,541	\$ 1,054	\$ 55	\$ 23	\$ 542	\$ 1,280	\$ 1,293	\$ 1,293
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 29,539	\$ 1,391	\$ 4,273	\$ 2,115	\$ 2,677	\$ 6,320	\$ 6,382	\$ 6,382
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 4,134	\$ 159	\$ 49	\$ 21	\$ 481	\$ 1,134	\$ 1,145	\$ 1,145
# Internal, Overheads	\$ -350	\$ -1,758	\$ 32	\$ 12	\$ 246	\$ 493	\$ 305	\$ 320
# Materials	\$ 15,541	\$ 2,933	\$ 155	\$ 66	\$ 1,524	\$ 3,598	\$ 3,633	\$ 3,633
# Overheads - External	\$ 3,105	\$ -411	\$ 92	\$ 35	\$ 700	\$ 1,402	\$ 628	\$ 659
Total	\$ 57,511	\$ 3,368	\$ 4,657	\$ 2,272	\$ 6,171	\$ 14,227	\$ 13,385	\$ 13,431

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Station 112

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006589	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace nine (9) 4.16 kV breakers at Station 112 Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for RG&E customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of existing circuit breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of NYSEG and RG&E circuit breakers are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs or projects are excluded from this program to avoid duplication of effort and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery bank voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. In some cases breakers may be added to a substation if a bay is available and its addition will enhance the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection, reliability, and operability of the electrical system.

Engineering and project development for circuit breaker replacement includes evaluating the condition of switches, insulators, and foundations. Station topology is reviewed to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements (potentially including automation upgrades) are made to enhance control and reliability. The scope of work is determined through outreach to Substation Operations, Transmission and Distribution Planning, Digital Grid, and the Protection & Control groups. These types of upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, reducing disruptions to our customers, and optimizing operations.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing the following breakers at Station 112:

Nine (9) 4.16 kV breakers (1T11232, 1X11232, 252102, 252202, 252302, 253402, 253502, 253602, 2T11232).

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at RG&E involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, RG&E can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining legacy equipment (e.g., brown glass insulators and electromechanical relays) in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, compromising the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to the long-term sustainability of the system.

A more comprehensive and holistic solution is achieved by replacing the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers. This approach mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, in the long run this strategy is cost-effective. While the initial investment may be higher due to the expanded scope of ancillary equipment replacement, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to customers.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within RG&E. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 213	\$ -	\$ -	\$ 75	\$ 139	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,053	\$ -	\$ -	\$ 369	\$ 684	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 189	\$ -	\$ -	\$ 66	\$ 123	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 91	\$ -	\$ -	\$ 35	\$ 56	\$ -	\$ -	\$ -
# Materials	\$ 599	\$ -	\$ -	\$ 210	\$ 390	\$ -	\$ -	\$ -
# Overheads - External	\$ 194	\$ -	\$ -	\$ 74	\$ 120	\$ -	\$ -	\$ -
Total	\$ 2,340	\$ -	\$ -	\$ 828	\$ 1,512	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Station 89

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006596	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace eight (8) 4.16 kV and three (3) 12.5 kV breakers at Station 89 Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for RG&E customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of existing circuit breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of NYSEG and RG&E circuit breakers in are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs or projects are excluded from this program to avoid duplication of effort and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery bank voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. In some cases breakers may be added to a substation if a bay is available and its addition will enhance the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection, reliability, and operability of the electrical system.

Engineering and project development for circuit breaker replacement includes evaluating the condition of switches, insulators, and foundations. Station topology is reviewed to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements (potentially including automation upgrades) are made to enhance control and reliability. The scope of work is determined through outreach to Substation Operations, Transmission and Distribution Planning, Digital Grid, and the Protection & Control groups. These types of upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, reducing disruptions to our customers, and optimizing operations.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing the following breakers at Station 89:

Eight (8) 4.16 kV breakers (1T8932, 1X8932, 212102, 212202, 212302, 221502, 221602, 2T8932),
Three (3) 12.5 kV breaker (522002).

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at RG&E involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, RG&E can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk R14 and R15 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences that can include entire substation outages due to the failure of a circuit breaker. If this failure results in damage to adjacent equipment, the repair costs, outage duration, and outage scope can be significant.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as R14 or R15. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of R14 and R15 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining legacy equipment (e.g., brown glass insulators and electromechanical relays) in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, compromising the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to the long-term sustainability of the system.

A more comprehensive and holistic solution is achieved by replacing the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers. This approach mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, in the long run this strategy is cost-effective. While the initial investment may be higher due to the expanded scope of ancillary equipment replacement, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to customers.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within RG&E. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 261	\$ -	\$ -	\$ 104	\$ 156	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,287	\$ -	\$ -	\$ 515	\$ 772	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 231	\$ -	\$ -	\$ 92	\$ 139	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 91	\$ -	\$ -	\$ 35	\$ 56	\$ -	\$ -	\$ -
# Materials	\$ 733	\$ -	\$ -	\$ 293	\$ 440	\$ -	\$ -	\$ -
# Overheads - External	\$ 194	\$ -	\$ -	\$ 74	\$ 120	\$ -	\$ -	\$ -
Total	\$ 2,796	\$ -	\$ -	\$ 1,113	\$ 1,683	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Station 85

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006595	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace eight (8) 4.16 kV breakers at Station 85 Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for RG&E customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of existing circuit breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of NYSEG and RG&E circuit breakers are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs or projects are excluded from this program to avoid duplication of effort and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery bank voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. In some cases breakers may be added to a substation if a bay is available and its addition will enhance the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection, reliability, and operability of the electrical system.

Engineering and project development for circuit breaker replacement includes evaluating the condition of switches, insulators, and foundations. Station topology is reviewed to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements (potentially including automation upgrades) are made to enhance control and reliability. The scope of work is determined through outreach to Substation Operations, Transmission and Distribution Planning, Digital Grid, and the Protection & Control groups. These types of upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, reducing disruptions to our customers, and optimizing operations.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing the following breakers at Station 85:

Eight (8) 4.16 kV breakers (1T8532, 1X8532, 210902, 211002, 211102, 222802, 222902, 2T8532).

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at RG&E involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, RG&E can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences that can include entire substation outages due to the failure of a circuit breaker. If this failure results in damage to adjacent equipment, the repair costs, outage duration, and outage scope can be significant.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining legacy equipment (e.g., brown glass insulators and electromechanical relays) in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, compromising the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to the long-term sustainability of the system.

A more comprehensive and holistic solution is achieved by replacing the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers. This approach mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, in the long run this strategy is cost-effective. While the initial investment may be higher due to the expanded scope of ancillary equipment replacement, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to customers.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within RG&E. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 190	\$ -	\$ -	\$ 66	\$ 123	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 936	\$ -	\$ -	\$ 328	\$ 608	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 168	\$ -	\$ -	\$ 59	\$ 109	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 81	\$ -	\$ -	\$ 31	\$ 50	\$ -	\$ -	\$ -
# Materials	\$ 533	\$ -	\$ -	\$ 186	\$ 346	\$ -	\$ -	\$ -
# Overheads - External	\$ 172	\$ -	\$ -	\$ 66	\$ 107	\$ -	\$ -	\$ -
Total	\$ 2,080	\$ -	\$ -	\$ 736	\$ 1,344	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Station 33

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-007373	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

This project is to replace eight (8) 34 kV (71702, 72502, 73102, 74102, 74402, 1T3352, 2T3352 an 3T3352) breakers at 33 Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for RGE customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an “in-kind” replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing eight (8) 34 kV (71702, 72502, 73102, 74102, 74402, 1T3352, 2T3352 an 3T3352) breakers. The estimated ISD is 10/27/2026.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at RGE involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, RGE can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement.

Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within RGE. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 171	\$ 7	\$ 164	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,036	\$ 228	\$ 808	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 193	\$ 48	\$ 145	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 272	\$ 228	\$ 44	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 501	\$ 41	\$ 460	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 260	\$ 138	\$ 122	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,434	\$ 691	\$ 1,743	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Station 86

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-007294	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace eight (8) 4.16 kV (252402, 252502, 252602, 250902, 251002, 251102, 1X8632, 1T8632 and 2T8632) breakers at 86 Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing eight (8) 4.16 kV (252402, 252502, 252602, 250902, 251002, 251102, 1X8632, 1T8632 and 2T8632) breakers. The estimated ISD is 12/31/2028.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement.

Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 158	\$ -	\$ 16	\$ 142	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 780	\$ -	\$ 78	\$ 702	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 140	\$ -	\$ 14	\$ 126	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 38	\$ -	\$ 4	\$ 34	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 444	\$ -	\$ 44	\$ 400	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 106	\$ -	\$ 12	\$ 94	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,667	\$ -	\$ 168	\$ 1,498	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Station 418

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-007268	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace one (1) 115 kV (7X41872) breakers and twenty-three (23) 12.5 kV breakers at 418 Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing one (1) 115 kV (7X41872) breakers and twenty-three (23) 12.5 kV breakers.
The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 480	\$ 3	\$ 130	\$ 346	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,457	\$ 105	\$ 644	\$ 1,709	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 445	\$ 22	\$ 116	\$ 307	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 223	\$ 105	\$ 35	\$ 83	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,358	\$ 19	\$ 367	\$ 973	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 390	\$ 64	\$ 97	\$ 230	\$ -	\$ -	\$ -	\$ -
Total	\$ 5,353	\$ 318	\$ 1,389	\$ 3,647	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Station 67

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-007267	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace five (5) 115 kV (90302, 92102, 92212, 2T6772 and 7X6772) breakers, three (3) 34 kV (73012, 73212 & 2T6752) breakers, and one (1) 4.16 kV (515102) breaker at 67 Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for NYSEG customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing five (5) 115 kV (90302, 92102, 92212, 2T6772 and 7X6772) breakers, three (3) 34 kV (73012, 73212 & 2T6752) breakers, and one (1) 4.16 kV (515102) breaker.

The estimated ISD is 12/31/2027.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at NYSEG involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, NYSEG can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 301	\$ 9	\$ 131	\$ 161	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,739	\$ 300	\$ 646	\$ 794	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 322	\$ 64	\$ 116	\$ 142	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 383	\$ 300	\$ 39	\$ 44	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 874	\$ 55	\$ 368	\$ 452	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 410	\$ 182	\$ 107	\$ 122	\$ -	\$ -	\$ -	\$ -
Total	\$ 4,029	\$ 909	\$ 1,406	\$ 1,715	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Station 48

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-007263	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

This project is to replace one (1) 115 kV (7X4872) breaker, five (5) 34 kV (76312, 1T4852, 4T4852, 5X4852 and 6X4852) breakers, five (5) 11kV (51802, 8T4842, 2X4842, 3X4842 and 4X4842) breakers and eight (8) 4 kV (45602, 45702, 45802, 250102, 250202, 1T4832, 4T4832 and 1X483) breakers at 48 Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for RGE customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an “in-kind” replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program’s comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing one (1) 115 kV (7X4872) breaker, five (5) 34 kV (76312, 1T4852, 4T4852, 5X4852 and 6X4852) breakers, five (5) 11kV (51802, 8T4842, 2X4842, 3X4842 and 4X4842) breakers and eight (8) 4 kV (45602, 45702, 45802, 250102, 250202, 1T4832, 4T4832 and 1X483) breakers.

The estimated ISD is 12/31/2026.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at RGE involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, RGE can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement.

Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within RGE. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 250	\$ 24	\$ 226	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,921	\$ 805	\$ 1,116	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 371	\$ 171	\$ 200	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 866	\$ 805	\$ 61	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 782	\$ 146	\$ 635	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 656	\$ 488	\$ 168	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 4,846	\$ 2,440	\$ 2,406	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Circuit Breaker Replacement - Station 13A

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-007261	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Reliability	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

This project is to replace six (6) 115 kV (90812, 91102, 91202, 6T13A72, 7X13A72 and 8X13A72) breakers at Station 13A Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for RGE customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an “in-kind” replacement strategy, meaning a one-for-one replacement of the existing breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of circuit breakers in NY Opcos are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI)-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability.

Breakers planned for replacement under other programs and projects are excluded from this program to avoid redundancy and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery backup voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. New breakers are installed if a bay is available and it enhances the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection and reliability of the electrical system.

Engineering and program development include evaluating the condition of switches, insulators, and foundations, and reviewing topology to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements are made to enhance control and reliability. The added scope of work is determined through outreach to Substation Operations, T&D Planning, Digital Grid, and P&C Group, and includes automation upgrades. These upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Program projections indicate that 60% to 70% of the replacement program units are expected to be Poor and Very Poor. This high percentage underscores the critical need for the program. Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, ensuring minimal disruption to our customers, and optimizing operational efficiency.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing six (6) 115 kV (90812, 91102, 91202, 6T13A72, 7X13A72 and 8X13A72) breakers.
The estimated ISD is 12/31/2026.

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at RGE involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, RGE can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network. The following is a breakdown of the 2024 breaker replacements by voltage level, along with their associated RI scores.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement.

Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining the brown glass insulator switches and electromechanical relays in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, which could compromise the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to long-term system sustainability.

By opting to replace the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers, we can achieve a more comprehensive upgrade. This approach not only addresses the immediate concerns but also mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, this strategy is cost-effective in the long run. While the initial investment may be higher, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to all stakeholders.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within RGE. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 125	\$ 11	\$ 114	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 918	\$ 356	\$ 562	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 176	\$ 76	\$ 101	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 387	\$ 356	\$ 31	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 384	\$ 65	\$ 320	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 301	\$ 216	\$ 85	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,291	\$ 1,080	\$ 1,211	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE - Elec Better

PROJECT INFORMATION

OpCo: RG&E	Project ID: UI-R0010-RGE-ED	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Reliability	Project Stage: IP4 Change	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

Betterments are projects that will improve the grid by improving reliability, operability, and flexibility of the grid. Projects come from ideas in Operations and ECC based on their knowledge about the real issues and challenges being faced by the system beyond just SAIFI allowing us to address SAIDI, CAIDI, Operability, Flexibility, Voltage Regulation, Loading and Safety.

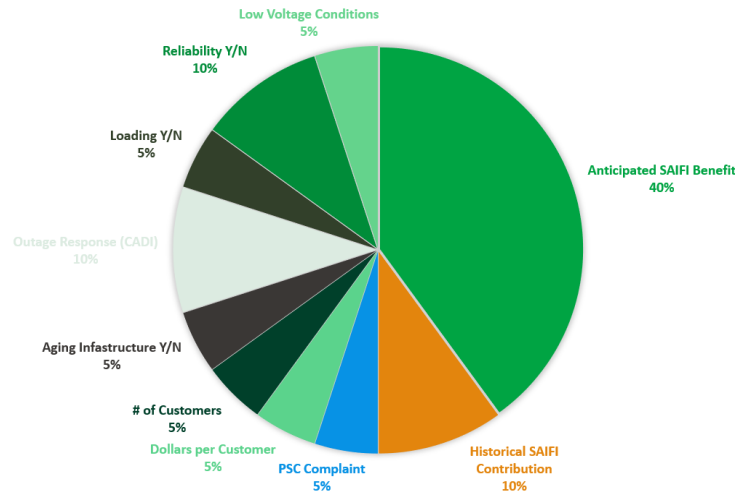
Project Scope:

Collection Method

Operations and ECC suggest projects based on their knowledge of system issues, such as those that appear in the weekly reliability tracker. Once the initial suggestion is given, then a detailed scope and cost estimate are developed.

Prioritization

Betterments is currently reevaluating all proposed projects using our updated prioritization methods. Project impacts, along with the historic SAIFI contribution, dollars per customer, and dollars per SAIFI benefit. These benefits are weighed and compared to competing projects to prioritize the projects with greatest impact. The prioritization breakdown is as follows; 60% Voltage, Loading, Reliability, Outage Response, Aging Infrastructure, Number of Customers, Dollars per Customer, and PSC Complaint, 10% Historical SAIFI Contribution, 40% Anticipated SAIFI Benefit. Conceptually the Betterments Program plans to break out 60% of the overall budget to named projects, with the remaining 40% being allocated for smaller division needs.



Project Benefits:

This approach offers significant benefits. The new prioritization method allows this program to refocus on both short- and long-term SAIFI benefits that will provide the NYSEG rate payers an improved customer experience. This method also enhances the Betterments program's project efficiency and ability to respond to division level and customer needs as they arise. This provides a clear methodology to choose the most impactful projects for both the customer and the company.

Project Risks and Mitigation Plan:

Distribution Planning and Engineering conduct circuit patrols, perform reliability analysis and develop alternatives where possible to select the most feasible designs. Any temporary repairs are sent to engineering for follow-up to ensure permanent repairs are made to current construction standards and adherence to industry codes.

Risk of No Action:

No action would result in leaving defective equipment in service or system in non-optimal configuration and accepting the reliability and safety risk of failure. Delayed or non-execution of the work could have negative impact on reliability, public safety, workforce safety and could result in penalties and/or reputation damage. If no action on this circuit the chances of improved reliability will be minimized.

Project Alternatives:

Alternative designs are considered on a case by case basis, in general this program provides like for like replacement of assets and small line relocations

Basis for Project Estimates

Real Estate; Surveying; Environmental, Licensing & Permitting; Materials; Material Sales Tax; Construction; Vegetation Management; Access Roads, Environmental Controls and Restoration; Removal Costs; Construction Sales Tax; Engineering; Program Management/Owner's Engineering; Construction Management; AFUDC; Escalation; Overheads; and Contingency

FINANCIAL INFORMATION**Actual Capital Spent, all amounts shown below in thousands (\$000's)**

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 506	\$ 80	\$ 45	\$ 193	\$ 128	\$ 59		
# CIAC	\$ -339	\$ -15	\$ -5	\$ -112	\$ -117	\$ -90		
# External Services	\$ 4,866	\$ 743	\$ 2,264	\$ 985	\$ 608	\$ 266		
# Internal - Non-AC	\$ 0	\$ 0	\$ 0	\$ 0	\$ -	\$ -		
# Internal, Labor	\$ 1,679	\$ 239	\$ 304	\$ 608	\$ 432	\$ 96		
# Internal, Overheads	\$ 650	\$ 98	\$ 193	\$ 163	\$ 136	\$ 60		
# Materials	\$ 1,711	\$ 293	\$ 159	\$ 431	\$ 608	\$ 220		
# Overheads - External	\$ 1,903	\$ 238	\$ 469	\$ 550	\$ 483	\$ 163		
Total	\$ 10,976	\$ 1,677	\$ 3,430	\$ 2,818	\$ 2,278	\$ 774		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ 234	\$ 41	\$ 32	\$ 111	\$ 17	\$ 34		
Materials	\$ 25	\$ 19	\$ 0	\$ 1	\$ 2	\$ 4		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ 259	\$ 60	\$ 32	\$ 111	\$ 18	\$ 38		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 553	\$ 31	\$ 78	\$ 84	\$ 86	\$ 89	\$ 91	\$ 94
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 23,158	\$ 1,310	\$ 3,378	\$ 3,479	\$ 3,583	\$ 3,691	\$ 3,802	\$ 3,916
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 7,427	\$ 424	\$ 1,093	\$ 1,126	\$ 1,159	\$ 1,194	\$ 1,198	\$ 1,234
# Internal, Overheads	\$ 1,650	\$ 138	\$ 309	\$ 284	\$ 255	\$ 222	\$ 214	\$ 227
# Materials	\$ 7,263	\$ 411	\$ 1,059	\$ 1,091	\$ 1,124	\$ 1,158	\$ 1,192	\$ 1,228
# Overheads - External	\$ 4,047	\$ 308	\$ 766	\$ 704	\$ 631	\$ 551	\$ 528	\$ 560
Total	\$ 44,099	\$ 2,623	\$ 6,683	\$ 6,767	\$ 6,838	\$ 6,905	\$ 7,025	\$ 7,258

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 265	\$ 35	\$ 36	\$ 37	\$ 38	\$ 39	\$ 40	\$ 40
Materials	\$ 28	\$ 4	\$ 4	\$ 4	\$ 4	\$ 4	\$ 4	\$ 4
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 294	\$ 38	\$ 40	\$ 41	\$ 42	\$ 43	\$ 44	\$ 45

RGE Animal Guards

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-003453	Charge Code: Electric Distribution	Project Sponsor: Shail, Joshua	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Animal Guard program was developed to increase reliability and reduce the number of interruptions caused by animal contact. These installations contribute to System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) improvements.

This program will target the worst performing circuits across RGE for animal guard installation with the goal of increasing service reliability through minimizing animal contact on distribution transformers. Guards are to be installed on distribution transformer bushings, arresters, and LA brackets, if applicable.

Project Scope:

This program focuses on installing animal guards on pole-mounted distribution transformers. The guards will be installed on transformer bushings, arresters, and LA brackets, where applicable.

The Animal Guard Program is prioritized by ranking circuits from highest number of customers affected by distribution animal contacts to lowest. This program has had over 72% reduction to customers affected by distribution animal contacts following remediation of a circuit. RGE interrupted an average of 11,400 customers annually from distribution animal contacts in the past 3 years.

The following units and average unit costs will be addressed between 2025-2031:

2025 - 1,200 (units) / \$731 (unit cost)
2026 - 921 (units) / \$753 (unit cost)
2027 - 939 (units) / \$775 (unit cost)
2028 - 957 (units) / \$799 (unit cost)
2029 - 976 (units) / \$823 (unit cost)
2030 - 995 (units) / \$847 (unit cost)
2031 - 1,014 (units) / \$873 (unit cost)

Project Benefits:

This project will increase circuit reliability and reduce O&M costs by minimizing the number of animal caused service interruptions.

Project Risks and Mitigation Plan:

The Animal Guard program employs data driven decision-making, proactive inspections and systematic maintenance, aiming to reduce outages and safety risks. The program ensures compliance with regulatory standards, efficient budget management and transparent stakeholder communication. By prioritizing safety and reliability, RGE seeks to provide a more dependable electricity supply and improved service quality to its customers in the region.

Animal guard installations are simple, can be executed quickly, and the benefits are immediate. Material costs are low, as well as the one-time cost of installation when compared to ongoing O&M costs to repair service interruptions from animal contact on an as needed basis. From this standpoint, fixing animal guards to existing distribution transformers is a more proactive approach to improving and ensuring continued service reliability.

Risk of No Action:

If this program is not pursued, service interruptions due to animal contact will continue to occur, leading to higher O&M costs for necessary restorations and adversely affecting SAIFI metrics.

Project Alternatives:

The animal guard program focuses on protecting transformer bushings, with alternatives evaluated on a case-by-case basis.

Basis for Project Estimates

The financial plan is based on the average cost per animal guard, which includes expenses for construction crews, internal labor, materials, and applicable overheads for standard installations.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 117	\$ -	\$ -	\$ 21	\$ 53	\$ 43		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 4,288	\$ -	\$ -	\$ 1,221	\$ 1,721	\$ 1,346		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ 381	\$ -	\$ -	\$ 77	\$ 158	\$ 146		
# Materials	\$ 495	\$ -	\$ -	\$ -	\$ 495	\$ -		
# Overheads - External	\$ 1,138	\$ -	\$ -	\$ 234	\$ 529	\$ 376		
Total	\$ 6,419	\$ -	\$ -	\$ 1,553	\$ 2,956	\$ 1,910		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:		Total	2020	2021	2022	2023	2024
	Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 5,393	\$ 676	\$ 693	\$ 728	\$ 765	\$ 803	\$ 843	\$ 885
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 310	\$ 54	\$ 48	\$ 46	\$ 43	\$ 38	\$ 39	\$ 42
# Materials	\$ 1,800	\$ 202	\$ 207	\$ 228	\$ 251	\$ 276	\$ 303	\$ 334
# Overheads - External	\$ 595	\$ 99	\$ 94	\$ 89	\$ 83	\$ 74	\$ 74	\$ 81
Total	\$ 8,099	\$ 1,031	\$ 1,043	\$ 1,091	\$ 1,140	\$ 1,191	\$ 1,259	\$ 1,342

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Replace DC Pilot Wire System

PROJECT INFORMATION

OpCo: RG&E	Project ID: UH-R0000142-RGE-ED	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP4 Change	Start Date: H1 2025	In-Service Date: H2 2025

Project description:

- "The copper Pilot Wire cables are old and deteriorating, this has caused several losses of communication that then resulted in misoperations
- The Pilot Wire electromechanical relays are obsolete, and replacements cannot be purchased
- The neutralizing transformers are old, deteriorating, and replacements are not stocked
- RG&E has lost its expertise with Pilot Wire, it's function, associated equipment, and required maintenance
- Projects like the Broad St Aqueduct require the relocation of Pilot Wire circuits.
- The Pilot Wire circuits take up many conduits in the RG&E Subway system that could be utilized for other circuits

- There is no active monitoring of the Pilot Wires
 - o When the Pilot Wire is shorted, the relay will fail to trip
 - o When the Pilot Wire is open circuited, the relay will overtrip during external faults (referred to as "sympathy tripping" by operations)
 - o Once a Pilot Wire becomes short or open circuit it won't be detected until the quarterly check or after a misoperation occurs

Project Scope:

The Purpose of this project is to replace the existing Pilot Wire (PW) cables located around the Rochester area (RG&E network) with Fiber Optic (FO) cables and upgrade terminal equipment and associated protective relays. The existing PW are still in service and all effected relay channels will have to be upgraded and moved to either the RG&E SONET network or to a direct fiber connection
 Phase 1 – Install New Fiber Optic Cables approximately 12 Miles total cost of \$12.5M (+50/-25%)
 Expand SONET Network
 Once done, all the fiber will be complete under the Pilot Wire Program.
 Phase 2 replace electromachanical relays

Project Benefits:

The Pilot Wire Replacement Program will improve the system reliability and will help to alleviate this condition and increase system reliability. Asset Condition – SP&C: A broad range of deficiencies such as obsolete or unsupported equipment at or near its end of life, poor operating or maintenance history, known operational issues or complexities, etc.

Project Risks and Mitigation Plan:

Department of Transportation permitting
 City of Rochester permitting
 Rochester and Southern Railroad Easement Agreement
 CSX Railroad Easement Agreement

Risk of No Action:

Obsolete equipment will continue to fail, causing outages to customers. Additionally, replacement equipment is not readily available and will cause delays in restoring the system to normal. Furthermore, there are communication limitations associated with the pilot wire system.

Project Alternatives:

Alternative 1 consists of replacing each pilot wire cable one for one with a direct fiber to maintain the existing communication infrastructure over a new medium. The total length of new fiber required for this alternative is estimated at 29 miles. All electromechanical pilot wire relays not already being replaced by another project will be replaced by the Pilot Wire project.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, project support costs, as well as associated overheads. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects. The estimated cost of this project was compiled by 3 major stakeholders, T&S Planning, P&T, OSG along in coordination with the project team. The estimates are routinely reviewed and adjusted as the project progresses, and more detailed information becomes available

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 1,199	\$ 197	\$ 152	\$ 188	\$ 263	\$ 399		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 6,428	\$ 2,706	\$ 1,648	\$ 623	\$ 1,089	\$ 362		
# Internal - Non-AC	\$ 34	\$ 17	\$ 12	\$ 5	\$ -	\$ -		
# Internal, Labor	\$ 306	\$ 137	\$ 37	\$ -	\$ 39	\$ 93		
# Internal, Overheads	\$ 407	\$ 104	\$ 88	\$ 53	\$ 67	\$ 94		
# Materials	\$ 695	\$ 93	\$ 27	\$ 172	\$ 10	\$ 394		
# Overheads - External	\$ 1,246	\$ 325	\$ 248	\$ 152	\$ 263	\$ 257		
Total	\$ 10,315	\$ 3,579	\$ 2,213	\$ 1,192	\$ 1,731	\$ 1,599		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 627	\$ 449	\$ 178	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 5,275	\$ 3,118	\$ 2,157	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 73	\$ 73	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 242	\$ 151	\$ 91	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 18	\$ 18	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 579	\$ 361	\$ 219	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 6,815	\$ 4,170	\$ 2,645	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

New TL 812 & DL 418

PROJECT INFORMATION

OpCo: RG&E	Project ID: UH-R0000703-RGE-ED	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP4 Change	Start Date: H1 2026	In-Service Date: H2 2028

Project description:

A comprehensive Transmission Planning Reliability Assessment (2019/2020) was performed in the Webster Region of RGE. This assessment resulted in the identification of numerous reliability violations requiring significant area-wide improvements and upgrades.

This is part of Webster Area Solution Project Definition UH-R0000703. The Line 812 project is the construction of a new 34.5kV Line between Station 424 and Station 73. This line must meet or exceed a 40 MVA Normal rating to support radial loading in the Webster Area and will follow a preliminary route along Klem Road. No specific LTE rating was required from Transmission Planning. Existing 4kV distribution Line 418 (0073RO0418) is located roadside along this route and new Line 812 will be located on that center line and rebuild the circuit as 12kV underbuild. The line will also follow new and existing ROW on the Xerox campus to reach Station 424. This line will be constructed with an associated OPGW to be used for protection and communication purposes between Station 424 and Station 73. The project will begin the construction in January 2028 and it is planned to end in June 2028.

Project Scope:

The Line 812 project is the construction of a new 34.5kV Line between Station 424 and Station 73. This line must meet or exceed a 40 MVA Normal rating to support radial loading in the Webster Area and will follow a preliminary route along Klem Road. No specific LTE rating was required from Transmission Planning. Existing 4kV distribution Line 418 (0073RO0418) is located roadside along this route and new Line 812 will be located on that center line and rebuild the circuit as 12kV underbuild. The line will also follow new and existing ROW on the Xerox campus to reach Station 424. This line will be constructed with an associated OPGW to be used for protection and communication purposes between Station 424 and Station 73. For L812, currently the scope of work is to build L812 with "Overhead 795 ACSR" conductor. The project will begin the construction in January 2028 and it is planned to end in June 2028. Please note that the cost of circuit 418 is captured in WBS Station 73 distribution upgrades but the construction of circuit 418 will be with TL812 as 418 will be the underbuilt and it will be cost effective.

Project Benefits:

Line 812 is a newly proposed 34.5 kV source between Station 424 and Station 73 and is solely driven by reliability. An all lines in (N-0) condition results in Line 778 exceeding its normal rating 108%. A single element N-1 contingency loss of line 778 (34.5 kV) results in 35.1 MW of consequential load loss exposure which violates Transmission Planning maximum criteria of 25 MW. Attempts to operationally restore load post-contingency causes area-wide voltage violations.

Project Risks and Mitigation Plan:

The top risks on this project are 1) Weather 2) Outage cancellation by system operator 3) City/County ROW

Mitigation Plan:

- 1) Weather: Schedule contingency has been considered. The project construction can be finished in three months. The project team has considered 25% of schedule contingency.
- 2) Outage cancellation by system operator: The project team has involved ECC and Operations already. The project team will schedule the outages with ECC months in advance before the construction.
- 3) City/County ROW: The project team will be working in City / County ROW. The team will be filing for the permit in January and provide them with the schedule of work and plans.

Risk of No Action:

If the project is not undertaken, it is a risk as explained below: An all lines in (N-0) condition results in Line 778 exceeding its normal rating 108% of Normal. A single element N-1 contingency loss of line 778 (34.5 kV) results in 35.1 MW of consequential load loss exposure which violates Transmission Planning maximum criteria of 25 MW. Attempts to operationally restore load post-contingency causes area-wide voltage violations.

Project Alternatives:

Below Solution alternative were considered:

WBS UH-R0000703 - For L812, currently the scope of work is to build L812 with "Overhead 795 ACSR" conductor where as the competitive alternative stated it to be built with "Two sets of 750 MCM" conductor which would have costed the project \$14M more. Therefore, the competitive alternative was deemed very costly and was not selected. Current alternative suffices the need.

Avangrid's Line Estimation tool was used to estimate the cost of the project.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Line 798 Uprate

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-001001	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP4 Change	Start Date: H1 2026	In-Service Date: H2 2027

Project description:

A comprehensive Transmission Planning Reliability Assessment (2019/2020) was performed in the Webster Region of RGE. This assessment resulted in the identification of numerous reliability violations requiring significant area-wide improvements/upgrades. Any proposed substation modifications included an asset condition assessment to address any known Asset Health and Risk Issues.

WBS UH-R0000742 Line 798 uprate is part of Webster Area Solution Project Definition UH-R0000703. The scope of work includes reconductoring approximately 4.5 miles of 34.5 kV underground cable from Station 42 to Station 49 by installation of a new parallel set of 500 MCM cable. A minimum LTE rating of 40 MVA is required. Currently, it is rated at 25.9 MVA. The existing 500 KCM cables will be reconducted using 750 KCM cable. The project will begin the construction in March 2027 and it is planned to end in June 2027.

Project Scope:

WBS UH-R0000742 - Line 798 uprate: The scope of work includes reconductoring approximately 4.5 miles of 34.5 kV underground cable from Station 42 to Station 49 by installation of a new parallel set of 500 MCM cable. A minimum LTE rating of 40 MVA is required. Currently, it is rated at 25.9 MVA. The existing 500 KCM cables will be reconducted using 750 KCM cable. The project will begin the construction in March 2027 and it is planned to end in June 2027.

Project Benefits:

Project Needs:

Need: A single element N-1 contingency loss of Line 726 (34.5 kV) results in an STE thermal overload on Line 798 and 799 (150% and 111% LTE respectively).

Project Benefits:

This line upgrade mitigates single element N-1 thermal overloads, and eliminates the need to shed load post-contingency.

Project Risks and Mitigation Plan:

The top risks on this project are 1) Weather 2) Outage cancellation by system operator 3) City/County ROW

Mitigation Plan:

- 1) Weather: Schedule contingency has been considered. The project construction can be finished in three months. The project team has considered 25% of schedule contingency.
- 2) Outage cancellation by system operator: The project team has involved ECC and Operations already. The project team will schedule the outages with ECC months in advance before the construction.
- 3) City/County ROW: The project team will be working in City / County ROW. The team will be filing for the permit in January and provide them with the schedule of work and plans.

Risk of No Action:

If the project is not undertaken, it is a risk as explained below: A single element N-1 contingency loss of Line 726 (34.5 kV) results in an STE thermal overload on Line 798 and 799 (150% and 111% LTE respectively). This line upgrade mitigates single element N-1 thermal overloads, and eliminates the need to shed load post-contingency. Webster Area Solution Program will help improve the whole infrastructure.

Two alternatives were considered for Line 798 in order to achieve a 40 MVA (LTE) rating.

Alternative 2:Rebuild "Two (2) New Sets of 500 MCM": Alternative 2 consists of the replacement of both sets of 500 MCM cable with new 500 MCM cable in new duct banks for the entire existing route. By inspection the installation of new duct bank systems would result in a significant cost increase.

Basis for Project Estimates

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 72	\$ -	\$ -	\$ 4	\$ 32	\$ 36		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 384	\$ -	\$ -	\$ 415	\$ -31	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ 22	\$ -	\$ -	\$ 23	\$ -2	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ 71	\$ -	\$ -	\$ 78	\$ -7	\$ -		
Total	\$ 549	\$ -	\$ -	\$ 521	\$ -7	\$ 36		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 184	\$ -	\$ 45	\$ 139	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 7,517	\$ -	\$ -	\$ 7,517	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 283	\$ -	\$ -	\$ 283	\$ -	\$ -	\$ -	\$ -
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 680	\$ -	\$ -	\$ 680	\$ -	\$ -	\$ -	\$ -
Total	\$ 8,663	\$ -	\$ 45	\$ 8,618	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Station 73 Distribution Upgrades

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-001005	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: H1 2026	In-Service Date: H2 2028

Project description:

A comprehensive Transmission Planning Reliability Assessment (2019/2020) was performed in the Webster Region of RGE. This assessment resulted in the identification of numerous reliability violations requiring significant area-wide improvements and upgrades. Any proposed substation modifications included an asset condition assessment to address any known Asset Health and Risk Issues.

This is part of Webster Area Solution Project Definition UH-R0000703. The WBS associated with Station 73 Distribution Upgrades is UH-R0000746. A full rebuild of Station 73 as a new MV GIS will occur adjacent to the existing station on the same parcel. The distribution lines will require upgrades to support the 4kV to 12kV conversion at this site. Existing Circuits 414 (New 5100), 418 (New 5111), and 419 (New 5147) will be converted to 12kV circuits and additional tie points will be installed in the network to feeders from other adjacent 4kV and 12kV stations. The project will begin the construction in June 2028 and it is planned to end in November 2028.

Project Scope:

This is part of Webster Area Solution Project Definition UH-R0000703. The WBS associated with Station 73 Distribution Upgrades is UH-R0000746. A full rebuild of Station 73 as a new MV GIS will occur adjacent to the existing station on the same parcel. The distribution lines will require upgrades to support the 4kV to 12kV conversion at this site. Existing Circuits 414 (New 5100), 418 (New 5111), and 419 (New 5147) will be converted to 12kV circuits and additional tie points will be installed in the network to feeders from other adjacent 4kV and 12kV stations. The project will begin the construction in June 2028 and it is planned to end in November 2028.

Project Benefits:

Station 73 has identified distribution reliability needs. The Circuit 422 is currently overloaded at (107%). Upon loss of the single 34.5/4.16 kV transformer, Station 73 is left without the ability to back up its 3.72 MVA of load. Station 73 also has inadequate 4.16 kV field tie switching capabilities and neighboring stations cannot support its load on the existing 4.16 kV network. Station 73's needs require the conversion of the existing 4.16 kV to 12.5 kV to allow for field tie capabilities and to address the overload and voltage concerns.

Distribution Reliability Needs:

- 1) Circuit 422 from Station 74, which ties with circuit 418 from Station 73 is overloaded at (107%). Substation 90 cannot pick up the 73 Substation load under N-1 contingency conditions (loss of the substation 73 transformer, 3.72MW).
- 2) Circuit 419 currently has voltage issues where the voltage profile drops below 114V for approximately half the circuit length.
- 3) Circuit 419 was flagged in 2017-2018 as a red circuit which means it was listed as among the worst 5% of circuits.
- 4) Circuits 419 and 418 are loaded at over 50% which limits their ability to provide field ties.

Project Risks and Mitigation Plan:

The top risks on this project are 1) Weather 2) Outage cancellation by system operator 3) City/County ROW

Mitigation Plan:

- 1) Weather: Schedule contingency has been considered. The project construction can be finished in three months. The project team has considered 25% of schedule contingency.
- 2) Outage cancellation by system operator: The project team has involved ECC and Operations already. The project team will schedule the outages with ECC months in advance before the construction.
- 3) City/County ROW: The project team will be working in City / County ROW. The team will be filing for the permit in January and provide them with the schedule of work and plans.

Risk of No Action:

If the project is not undertaken, it is a huge risk as explained below: Station 73 has identified distribution reliability needs. The Circuit 422 is currently overloaded at (107%). Upon loss of the single 34.5/4.16 kV transformer, Station 73 is left without the ability to back up its 3.72 MVA of load. Station 73 also has inadequate 4.16 kV field tie switching capabilities and neighboring stations cannot support its load on the existing 4.16 kV network. Station 73's needs require the conversion of the existing 4.16 kV to 12.5 kV to allow for field tie capabilities and to address the overload and voltage concerns.

Webster Project - Station 55

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-004012	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP4 Change	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

Webster Area substation project is a project which will attend the existing violations in terms of reliability and asset conditions that facilities on this areas is facing.

Station 55 is an existing 34.5/12.5 kV station with a single 34.5/12.5 (22.4 MVA) transformer built in 1989. The station's two (2) 34.5 kV line sources are Line 780 and Line 745 and are isolated by motor operated line disconnect switches. This station utilizes a metal-clad switchgear design for both the 34.5 kV transformer equipment and the 12.5 kV distribution line equipment.

Project Scope:

Station 55 A full rebuild of Station 55 as a 34.5 kV straight bus with 4 dedicated line breakers and a normally closed bus-tie breaker. Two (2) new 34.5/12.5 kV (22.4 MVA) distribution transformers will be installed to satisfy the distribution needs. The existing transformer will be relocated to Station 73. All lines and transformers will have dedicated breakers. Line terminals 778 (Station 43-Station 55) and 745 (Station 42 - Station 55) will be connected via new normally open breakers.

Project Benefits:

Station 55 will solve the need upon loss of the single 34.5/12.5 kV transformer, Station 55 is left without the ability to back up its 20 MVA of load. Station 55 has inadequate field tie switching capabilities and neighboring stations cannot support its load. A second transformer is required as part of this substation upgrade to address these needs

Project Risks and Mitigation Plan:

Risk: Construction Permits.

Mitigation Plan: Obtain a consultant early on in the design process and maintain their assistance throughout the Project. Maintain open communication with the entire project team throughout the Project. Work in conjunction with Avangrid Public Outreach, and work as a team with the Town/County/Municipality in order to understand the needs of the community and align the goals of the project accordingly.

Risk: Planned Outages

Mitigation Plan: Work actively in a predictive way in order to identify as earliest as possible the future issues that we can faced. We are going to maintain an active and frequent communication with all stakeholders involved in the outages in order to mitigate the risk of cancellation.

Risk: Material Supply

Mitigation Plan: Perform an early identification of those major materials which are delivered with a long lead time, all of them will be included into the project procurement plan as earliest as possible. also it is important to get wise agreements with suppliers in order to protect last minute delays.

Risk of No Action:

The no execution of this project will impact significantly the reliability of the Webster area, our facilities will continue in risk of violations which will impact negatively the quality of service that we bring to our customers.

Project Alternatives:

Station 55. upgrade on the existing site and requires the installation of a Line 778 normally open breaker at Station 55 as well as a normally open motor operated disconnect switch on Line 745 between 55 and 42. This alternative was dismissed due to space constraints making the solution infeasible.

Basis for Project Estimates

Engineering: Based off of historical cost, considering inflation. At this time actuals have been incurred as well.

Construction: Based off of estimated supplied by engineering firm that designed the project, and historical costs considering inflation. At this time actuals have been incurred as well.

Material: Based off of historical cost, considering inflation. At this time actuals have been incurred as well.

Labor: Rolling 6 months of actuals

Project Management: Rolling 6 months of actuals

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 562	\$ -	\$ -	\$ 0	\$ 117	\$ 444		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 4,794	\$ -	\$ -	\$ 76	\$ 1,396	\$ 3,322		
# Internal - Non-AC	\$ 24	\$ -	\$ -	\$ -	\$ 13	\$ 11		
# Internal, Labor	\$ 296	\$ -	\$ -	\$ -	\$ 93	\$ 203		
# Internal, Overheads	\$ 784	\$ -	\$ -	\$ 4	\$ 275	\$ 505		
# Materials	\$ 3,198	\$ -	\$ -	\$ -	\$ 1,794	\$ 1,404		
# Overheads - External	\$ 2,227	\$ -	\$ -	\$ 14	\$ 811	\$ 1,402		
Total	\$ 11,884	\$ -	\$ -	\$ 95	\$ 4,499	\$ 7,289		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,422	\$ 937	\$ 97	\$ 127	\$ 262	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 9,164	\$ 2,367	\$ 1,356	\$ 1,771	\$ 3,670	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 505	\$ 198	\$ 61	\$ 80	\$ 166	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 975	\$ 426	\$ 129	\$ 150	\$ 270	\$ -	\$ -	\$ -
# Materials	\$ 10,528	\$ 4,582	\$ 1,187	\$ 1,550	\$ 3,211	\$ -	\$ -	\$ -
# Overheads - External	\$ 2,006	\$ 823	\$ 277	\$ 323	\$ 583	\$ -	\$ -	\$ -
Total	\$ 24,601	\$ 9,333	\$ 3,107	\$ 4,000	\$ 8,161	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Line 778 Uprate - Station 42 to 43

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-001000	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP4 Change	Start Date: H1 2026	In-Service Date: H2 2026

Project description:

A comprehensive Transmission Planning Reliability Assessment (2019/2020) was performed in the Webster Region of RGE. This assessment resulted in the identification of numerous reliability violations requiring significant area-wide improvements and upgrades. Any proposed substation modifications included an asset condition assessment to address any known Asset Health and Risk Issues.

WBS UH-R0000741 Line 778 Uprate - Station 42 to 43 is part of Webster Area Solution Project Definition UH-R0000703. The scope of work includes the reconductoring of existing underground Circuit 778 between ST 42 and ST 43 to meet or exceed target ratings of 45 MVA Summer Normal and 57 MVA Summer LTE. The Existing Line 778 K&N mostly consists of one set of 500 KCM EPR cables in parallel with one set of 500 KCM XLP cables and they will each be replaced with 750 KCM cables. The project will begin the construction in March 2026 and it is planned to end in July 2026.

Project Scope:

UH-R0000741 Line 778 uprate - Station 42 to 43: The scope of work includes the reconductoring of existing underground Circuit 778 between ST 42 and ST 43 to meet or exceed target ratings of 45 MVA Summer Normal and 57 MVA Summer LTE. The Existing Line 778 K&N mostly consists of one set of 500 KCM EPR cables in parallel with one set of 500 KCM XLP cables and they will each be replaced with 750 KCM cables. The project will begin the construction in March 2026 and it is planned to end in July 2026.

Project Benefits:

Station 42 is located on the eastern side of the city of Rochester and supplies over 90 MW of power across ten 34.5 kV transmission circuits. Line 778 is the most heavily loaded of the circuits out of Station 42 and is poorly sectionalized, such that a fault on Line 778 can result in a loss of load greater than 35.1 MW. Lines 726 and 750 are subject to thermal overloads in excess of their Short Term Emergency ratings for single contingency conditions. Lines 735, 798, and 799 are subject to overloads in excess of their Long Term Emergency ratings for single contingency conditions. Additionally, there are multiple contingencies (five identified) that result in low voltages (less than .95 per-unit) on the transmission system. Webster Area Solution Program will help improve the whole infrastructure and L778 is part of this Webster Area Solution Program.

Project Risks and Mitigation Plan:

The top risks on this project are 1) Weather 2) Outage cancellation by system operator 3) City/County ROW

Mitigation Plan:

- 1) Weather: Schedule contingency has been considered. The project construction can be finished in three months. The project team has considered 25% of schedule contingency.
- 2) Outage cancellation by system operator: The project team has involved ECC and Operations already. The project team will schedule the outages with ECC months in advance before the construction.
- 3) City/County ROW: The project team will be working in City / County ROW. The team will be filing for the permit in January and provide them with the schedule of work and plans.

Risk of No Action:

If the project is not undertaken, it is a huge risk as explained below: Station 42 is located on the eastern side of the city of Rochester and supplies over 90 MW of power across ten 34.5 kV transmission circuits. Line 778 is the most heavily loaded of the circuits out of Station 42 and is poorly sectionalized, such that a fault on Line 778 can result in a loss of load greater than 35.1 MW. Lines 726 and 750 are subject to thermal overloads in excess of their Short Term Emergency ratings for single contingency conditions. Lines 735, 798, and 799 are subject to overloads in excess of their Long Term Emergency ratings for single contingency conditions. Additionally, there are multiple faults (five identified) that result in low voltages (less than .95 per-unit) on the transmission system. Webster Area Solution Program will help improve the whole infrastructure.

Below Solution alternative were considered:

Alternative 1 Reconductor "Two (2) Sets of 750 MCM": Alternative 1 consists of the replacement of both sets of 500 MCM cable with two (2) new sets of reduced diameter 750 MCM cable in the existing duct bank systems.

Alternative 2 Rebuild "Two (2) Sets of 750 MCM": Alternative 2 consists of the replacement of both sets of 500 MCM cable with two (2) new sets of reduced diameter 750 MCM cables in new duct bank systems for the entire length of the existing route. By inspection the installation of new duct bank system would result in a significant cost increase.

Selected Alternative 1 would cost us around \$8.6M less than Alternative 2.

Avangrid's Line Estimation tool was used to create the initial cost estimate of the project. Primavera is used to provide monthly updates to the schedule and final cost of the project.

FINANCIAL INFORMATION

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 15	\$ -	\$ -	\$ -	\$ -	\$ 15		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 154	\$ -	\$ -	\$ -	\$ -	\$ 154		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ 121	\$ -	\$ -	\$ -	\$ -	\$ 121		
# Materials	\$ 814	\$ -	\$ -	\$ -	\$ -	\$ 814		
# Overheads - External	\$ 269	\$ -	\$ -	\$ -	\$ -	\$ 269		
Total	\$ 1,374	\$ -	\$ -	\$ -	\$ -	\$ 1,374		

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 306	\$ -	\$ 306	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,943	\$ -	\$ 3,943	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 167	\$ -	\$ 167	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 400	\$ -	\$ 400	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 4,816	\$ -	\$ 4,816	\$ -	\$ -	\$ -	\$ -	\$ -

[illegible]

Line 799 Uprate

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-001002	Charge Code: Electric Transmission	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP4 Change	Start Date: H1 2027	In-Service Date: H2 2027

Project description:

A comprehensive Transmission Planning Reliability Assessment (2019/2020) was performed in the Webster Region of RGE. This assessment resulted in the identification of numerous reliability violations requiring significant area-wide improvements and upgrades. Any proposed substation modifications included an asset condition assessment to address any known Asset Health and Risk Issues.

WBS UH-R0000743 Line 799 uprate is part of Webster Area Solution Project Definition UH-R0000703. The scope of work includes reconductoring One set of 750 MCM cable for approximately 4.5 miles of 34.5 kV underground circuit from Station 42 to Station 49. A minimum LTE rating of 36 MVA is required. The project will begin the construction in July 2027 and it is planned to end in October 2027.

Project Scope:

WBS UH-R0000743 Line 799 uprate. The scope of work includes reconductoring One set of 750 MCM cable for approximately 4.5 miles of 34.5 kV underground circuit from Station 42 to Station 49. A minimum LTE rating of 36 MVA is required. The project will begin the construction in July 2027 and it is planned to end in October 2027.

Project Benefits:

Project Needs:

Need: A single element N-1 contingency loss of Line 726 (34.5 kV) results in an STE thermal overload on Line 799 (111% LTE).

Benefits:

This line upgrade mitigates single element N-1 thermal overloads, and eliminates the need to load shed post-contingency.

Project Risks and Mitigation Plan:

The top risks on this project are 1) Weather 2) Outage cancellation by system operator 3) City/County ROW

Mitigation Plan:

- 1) Weather: Schedule contingency has been considered. The project construction can be finished in three months. The project team has considered 25% of schedule contingency.
- 2) Outage cancellation by system operator: The project team has involved ECC and Operations already. The project team will schedule the outages with ECC months in advance before the construction.
- 3) City/County ROW: The project team will be working in City / County ROW. The team will be filing for the permit in January and provide them with the schedule of work and plans.

Risk of No Action:

If the project is not undertaken, it is a risk as explained below: A single element N-1 contingency loss of Line 726 (34.5 kV) results in an STE thermal overload on Line 799 (111% LTE). This line upgrade mitigates single element N-1 thermal overloads, and eliminates the need to shed load post-contingency. Webster Area Solution Program will help improve the whole infrastructure.

Two alternatives were considered for Line 799 in order to achieve a 36 MVA LTE rating.

Alternative 1 Reconductor "One (1) set of 750 MCM": Alternative 1 consists of the replacement of the existing 500 MCM cable with new reduced diameter 750 MCM cable in the existing duct bank systems.

Alternative 2 Rebuild "Two sets of 500 MCM": Alternative 2 consists of the replacement of the existing 500 MCM cable with two (2) new sets of reduced diameter 500 MCM cable in new duct banks for the entire existing route. By inspection the installation of new duct bank system would result in a significant cost increase.

Alternative 1 would cost us \$24M less than Alternative 2 and would also meet the need and thus Alternative 1 was selected.

Avangrid's Line Estimation tool was used to estimate the cost of the project.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Webster Project - Station 73

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-007378	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Reliability	Project Stage: 0	Start Date: H1 2026	In-Service Date: H2 2028

Project description:

Webster Area substation project is a project which will attend the existing violations in terms of reliability and asset conditions that facilities on this areas is facing.

Station 73 is an existing 34.5/4.16 kV station with a single 34.5/4.16 (7 MVA) transformer built in 1989. The station's one (1) 34.5 kV line source is Line 745 and it can be isolated by manual line disconnect switches. This station utilizes an AIS 34.5 kV box structure and a metal-clad switchgear design for the 4.16 kV distribution equipment. The current design doesn't allow for any future 34.5kV line positions.

Project Scope:

Station 73: a full rebuild of Station 73 as a 34.5 kV & 12.5 kV straight bus and all lines and transformers with dedicated breakers. The station will utilize the existing Station 55 34.5/12.5/4.16 kV (22.4 MVA) transformer, the existing line 745 will be sectionalized and its two sections will be re-designated as 820 (Station 73-Station 90) and 821 (Station 73 - Station 55). The Station 73 distribution bus will remain be converted to 12 kV, and all equipment will be sized for 15 kV. One spare cubical will be installed on the bus to allow for future needs. Included the 12.5 kV conversion of the existing 4.16 kV lines.

Project Benefits:

Station 73 will solve the following needs. The Circuit 422 is currently overloaded at (107%). Upon loss of the single 34.5/4.16 kV transformer, Station 73 is left without the ability to back up its 3.72 MVA of load. Station 73 also has inadequate 4.16 kV field tie switching capabilities and neighboring stations cannot support its load on the existing 4.16 kV network. Station 73's needs require the conversion of the existing 4.16 kV to 12.5 kV to allow for field tie capabilities and to address the overload and voltage concerns. The installation and reuse of the existing Station 55 transformer has many benefits. This allows for the two parallel transformers at Station 55 to be designed together and reduce the addition cost required in order to match impedances. This also allows for increased capacity at Station 73 for future load growth. Another benefit of the use of the existing Station 55 transformer is that the design of Station 73 can start immediately without requiring transformer vendor prints.

Project Risks and Mitigation Plan:

Risk: Construction Permits.

Mitigation Plan: Obtain a consultant early on in the design process and maintain their assistance throughout the Project. Maintain open communication with the entire project team throughout the Project. Work in conjunction with Avangrid Public Outreach, and work as a team with the Town/County/Municipality in order to understand the needs of the community and align the goals of the project accordingly.

Risk: Planned Outages

Mitigation Plan: Work actively in a predictive way in order to identify as earliest as possible the future issues that we can faced. We are going to maintain an active and frequent communication with all stakeholders involved in the outages in order to mitigate the risk of cancellation.

Risk: Material Supply

Mitigation Plan: Perform an early identification of those major materials which are delivered with a long lead time, all of them will be included into the project procurement plan as earliest as possible. also it is important to get wise agreements with suppliers in order to protect last minute delays.

Risk of No Action:

The no execution of this project will impact significantly the reliability of the Webster area, our facilities will continue in risk of violations which will impact negatively the quality of service that we bring to our customers.

Project Alternatives:

Station 73. Full Rebuild with Dual Secondary Transformer (dismissed due to complexity associated with transformer) and Full Rebuild with Stepdown Banks (dismissed as it does not resolve voltage issues on Circuit 413).

Project Management: Rolling 6 months of actuals

Webster Project - Station 62

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-007379	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Reliability	Project Stage: 0	Start Date: H1 2026	In-Service Date: H2 2026

Project description:

Webster Area substation project is a project which will attend the existing violations in terms of reliability and asset conditions that facilities on this areas is facing.

Station 62 is a 34.5/4 kV station built in 1951. The station consists of two (2) 34.5 kV lines (780 & 740), two (2) 34.5/4 kV (10.5 MVA) transformers and eight (8) 4 kV distribution circuits. The existing 34.5kV is configured in a non-standard configuration. The existing configuration has the 3T transformer normally fed by Line 740 on the 34.5 kV bus section 1. Both 740 and 780 have line breakers on the 34.5 kV bus section 1, but Line 780 is operated as normally open and is only used to back-up Line 740. The 4T transformer has no 34.5 kV bus and is normally fed via Line 780 with a single line side breaker. Line 780 is tapped in two positions at Station 62; one with a normally open Breaker, and the other with a normally closed breaker feeding the 4T transformer. The station is in Penfield, NY and is constrained by highways and adjacent property owners.

Project Scope:

Station 62: is a full rebuild of Station 62 as a 34.5 kV straight bus with 4 dedicated line breakers, a normally closed bus-tie breaker and two transformer high side breakers. All lines and transformers will have dedicated breakers. The existing Line 740 (Station 62-Station 117) will be connected via a new normally open breaker at Station 62. The Line 780 section from Station 62 to Station 85 will also have a dedicated breaker. Equipment ratings will consist of four (4) 2000A bus sections (34.5 kV & 12.5 kV) with 2000A rated tie breakers, 2000A rated high side and lows side transformer breakers. All line breakers for both 34.5 and 12.5 kV will be rated for 1200A.

Project Benefits:

Station 62 upgrades will solve the following issues. A single element N-1 contingency loss of Line 780 (34.5 kV) results in 21 MW of consequential load loss exposure which violates T-Planning's loss of load criteria for automated post-contingency restoration. This loss of load condition cannot be restored through existing back up sources. Attempts to restore load resulted in severe thermal violations.

Project Risks and Mitigation Plan:

Risk: Construction Permits.

Mitigation Plan: Obtain a consultant early on in the design process and maintain their assistance throughout the Project. Maintain open communication with the entire project team throughout the Project. Work in conjunction with Avangrid Public Outreach, and work as a team with the Town/County/Municipality in order to understand the needs of the community and align the goals of the project accordingly.

Risk: Planned Outages

Mitigation Plan: Work actively in a predictive way in order to identify as earliest as possible the future issues that we can faced. We are going to maintain an active and frequent communication with all stakeholders involved in the outages in order to mitigate the risk of cancellation.

Risk: Material Supply

Mitigation Plan: Perform an early identification of those major materials which are delivered with a long lead time, all of them will be included into the project procurement plan as earliest as possible. also it is important to get wise agreements with suppliers in order to protect last minute delays.

Risk of No Action:

The no execution of this project will impact significantly the reliability of the Webster area, our facilities will continue in risk of violations which will impact negatively the quality of service that we bring to our customers.

Project Alternatives:

Station 62. in-kind replacements to avoid the full rebuild of Station 62, terminate the new Line 813 in the existing Line 740 position, close the normally open Line 780 breaker, and terminate Line 740 at the existing Line 780 normally-closed position. This alternative was dismissed as it does not provide the desired amount of operational flexibility, and the fact that RG&E would not be able to restore Station 62 upon loss of the 780 Line.

Project Management: Rolling 6 months of actuals

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 152	\$ -	\$ 72	\$ 80	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,128	\$ -	\$ 1,013	\$ 1,114	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 96	\$ -	\$ 46	\$ 50	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 221	\$ -	\$ 112	\$ 110	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,862	\$ -	\$ 887	\$ 975	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 421	\$ -	\$ 213	\$ 209	\$ -	\$ -	\$ -	\$ -
Total	\$ 4,880	\$ -	\$ 2,343	\$ 2,537	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Webster Project - Station 42

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-007375	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Reliability	Project Stage: 0	Start Date: H1 2026	In-Service Date: H2 2026

Project description:

Project ID UH-R0000711 originally contains substation scope and lines scope, in order to perform a more efficient management, the company decided to create a new Project ID UH-R0005770 for managing Substation 42 scope and Project ID UH-R0000711 remains to be used for lines scope.

Webster Area substation project is a project which will attend the existing violations in terms of reliability and asset conditions that facilities on this areas is facing,

Station 42 is a 115/34.5/11.5/4.8 kV substation built in 1951 serving approximately 33 MW of net distribution load as well as providing a key source for roughly 170 MW of networked load fed from the 34.5 kV transmission system in and around the Northeast Rochester-Irondequoit Bay area. A total of ten different 34.5 kV circuits are fed from Station 42, three of which are normally operated radially, while the remaining seven are tied into 34.5 kV networks.

Project Scope:

Station 42: the replacement of two (2) existing oil filled circuit breakers along with all other associated equipment's e.g. (steel structure, bus work, switches etc.).

Project Benefits:

Station 42. Installing an additional 34.5 kV source from Station 42 - Station 62 eliminates all consequential load loss exposure for single element transmission faults and resolves T-Planning's loss of load criteria violations. Three oil filled circuit breakers rated in poor health are being replaced at Station 42.

Project Risks and Mitigation Plan:

Risk: Construction Permits for ST62

Mitigation Plan: Obtain a consultant early on in the design process and maintain their assistance throughout the Project. Maintain open communication with the entire project team throughout the Project. Work in conjunction with Avangrid Public Outreach, and work as a team with the Town/County/Municipality in order to understand the needs of the community and align the goals of the project accordingly.

Risk: Planned Outages

Mitigation Plan: Work actively in a predictive way in order to identify as earliest as possible the future issues that we can faced. We are going to maintain an active and frequent communication with all stakeholders involved in the outages in order to mitigate the risk of cancellation.

Risk: Material Supply

Mitigation Plan: Perform an early identification of those major materials which are delivered with a long lead time, all of them will be included into the project procurement plan as earliest as possible. also it is important to get wise agreements with suppliers in order to protect last minute delays.

Risk of No Action:

The no execution of this project will impact significantly the reliability of the Webster area, our facilities will continue in risk of violations which will impact negatively the quality of service that we bring to our customers.

Project Alternatives:

No alternatives specifically for ST42 were considered, however ST42 solution was part of the complete analysis of the entire Webster Area Solution Project

Engineering: Based off of historical cost, considering inflation. At this time actuals have been incurred as well.
Construction: Based off of estimated supplied by engineering firm that designed the project, and historical costs considering inflation. At this time actuals have been incurred as well.
Material: Based off of historical cost, considering inflation. At this time actuals have been incurred as well.
Labor: Rolling 6 months of actuals
Project Management: Rolling 6 months of actuals

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 91	\$ -	\$ 90	\$ 1	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,269	\$ -	\$ 1,262	\$ 7	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 57	\$ -	\$ 57	\$ 0	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 140	\$ -	\$ 139	\$ 1	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,110	\$ -	\$ 1,104	\$ 6	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 266	\$ -	\$ 265	\$ 1	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,933	\$ -	\$ 2,917	\$ 16	\$ -	\$ -	\$ -	\$ -

[illegible]

Webster Project - Station 424

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-007377	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: H1 2026	In-Service Date: H2 2028

Project description:

Project ID UH-R0000703 originally contains substation scope and lines scope, in order to perform a more efficient management, the company decided to create a new Project ID UH-R0005768 for managing Substation 424 scope and Project ID UH-R0000703 remains to be used for lines scope.

Webster Area substation project is a project which will attend the existing violations in terms of reliability and asset conditions that facilities on this areas is facing.

Station 424 is one of two main 34.5 kV network sources in the Webster East Sub-Area. The station is in the town of Webster and was constructed in 1973. It consists of two (2) 115 kV lines (Line 936 and Line 934), five (5) 34.5 kV lines, two 115/34.5 kV transformers (1T [74 MVA] and 2T [112 MVA]), a single 34.5/12.5 kV (22.4 MVA) distribution transformer and three (3) distribution feeders. The station has three future 34.5 kV line positions in the existing configuration

Project Scope:

Station 424: termination of the new 34.5 kV line 812 into the existing 34.5 kV future line position. This solution alternative includes the installation of all protection, control, automation, and integration required for the new line and line bay.

Project Benefits:

Station 424 will alleviate the following current needs. [REDACTED]

Project Risks and Mitigation Plan:

Risk: Material Supply

Mitigation Plan: Perform an early identification of those major materials which are delivered with a long lead time, all of them will be included into the project procurement plan as earliest as possible. Also it is important to get wise agreements with suppliers in order to protect last minute delays.

Risk of No Action:

The no execution of this project will impact significantly the reliability of the Webster area, our facilities will continue in risk of violations which will impact negatively the quality of service that we bring to our customers.

Project Alternatives:

Station 424. Termination of the new 34.5 kV line 812 into the existing 34.5 kV future line positions in the middle of the station yard. This alternative was dismissed due to the difficulty in performing the construction.

Engineering: Based off of historical cost, considering inflation. At this time actuals have been incurred as well.
Construction: Based off of estimated supplied by engineering firm that designed the project, and historical costs considering inflation. At this time actuals have been incurred as well.
Material: Based off of historical cost, considering inflation. At this time actuals have been incurred as well.
Labor: Rolling 6 months of actuals
Project Management: Rolling 6 months of actuals

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 67	\$ -	\$ 9	\$ 11	\$ 47	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 937	\$ -	\$ 125	\$ 153	\$ 659	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 42	\$ -	\$ 6	\$ 7	\$ 30	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 85	\$ -	\$ 14	\$ 15	\$ 56	\$ -	\$ -	\$ -
# Materials	\$ 820	\$ -	\$ 109	\$ 134	\$ 577	\$ -	\$ -	\$ -
# Overheads - External	\$ 162	\$ -	\$ 26	\$ 29	\$ 107	\$ -	\$ -	\$ -
Total	\$ 2,114	\$ -	\$ 289	\$ 348	\$ 1,477	\$ -	\$ -	\$ -

[illegible]

Webster Project - Station 420

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-007380	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Projects	Rate Case Category Reliability	Project Stage: 0	Start Date: H1 2026	In-Service Date: H2 2026

Project description:

Webster Area substation project is a project which will attend the existing violations in terms of reliability and asset conditions that facilities on this areas is facing.

Station 420 is a 34.5/4.8 kV station built in 1967. The station consists of straight bus with no tie breakers or line breakers, one 34.5/4.16 kV transformer and one 34.5 kV customer feed. The station currently has one 600 amp sectionalizing switch on the L780 section between Station 420 and Station 62. The station is in Penfield, NY on land leased from Saint John Fischer College and is constrained by I490 to the north and east.

Project Scope:

Station 420 is limited to only a brownfield upgrade at Station 420. The existing line 780 section from Station 420 to Station 42 will have a new sectionalizing MOD switch added

Project Benefits:

Station 420 will solve the following issue. A single element N-1 contingency loss of Line 780 (34.5 kV) results in 21 MW of consequential load loss exposure which violates T-Planning's loss of load criteria for automated post-contingency restoration. This loss of load condition cannot be restored through existing back up sources.

Project Risks and Mitigation Plan:

Risk: Material Supply

Mitigation Plan: Perform an early identification of those major materials which are delivered with a long lead time, all of them will be included into the project procurement plan as earliest as possible. also it is important to get wise agreements with suppliers in order to protect last minute delays.

Risk of No Action:

The no execution of this project will impact significantly the reliability of the Webster area.

Project Alternatives:

Station 420. partial rebuild of Station 62's 34.5 kV as a 34.5 kV straight bus with 4 dedicated line breakers, a normally closed bus-tie breaker and one transformer high side breaker. All 34.5 kV lines would have dedicated breakers. This alternative was dismissed as it was a far greater cost with little added benefit when compared with the preferred solution for the Webster Area Project.

Engineering: Based off of historical cost, considering inflation. At this time actuals have been incurred as well.
Construction: Based off of estimated supplied by engineering firm that designed the project, and historical costs considering inflation. At this time actuals have been incurred as well.
Material: Based off of historical cost, considering inflation. At this time actuals have been incurred as well.
Labor: Rolling 6 months of actuals
Project Management: Rolling 6 months of actuals

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 43	\$ -	\$ 39	\$ 5	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 606	\$ -	\$ 539	\$ 67	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 27	\$ -	\$ 24	\$ 3	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 66	\$ -	\$ 59	\$ 7	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 531	\$ -	\$ 472	\$ 59	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 126	\$ -	\$ 113	\$ 13	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,400	\$ -	\$ 1,246	\$ 153	\$ -	\$ -	\$ -	\$ -

[illegible]

Station 255 12 kV Yard Addition to Proactive Planning - Station 255

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-005048	Charge Code: Electric Distribution	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

Overview: The project aims to address the urgent N-1 constraints at Station 419 in Henrietta by expanding the 115 kV infrastructure and constructing a new 12 kV yard at Station 255. This initiative involves transferring load from Station 419 to Station 255 to accommodate new customer connections and support future load growth. The project is critical due to the significant economic and residential development in the area, which has led to increased load requests and exacerbated existing transmission violations. The total load requests studied amount to 10.2 MW, with 27% from residential/commercial buildings (heat pumps), 22% from transportation electrification, and the remaining 51% from economic development.

Current State Needs Assessment: Station 419's 115/12.47 kV transformers are currently overloaded to 123% of the summer Normal rating based on the peak historical 3-year average, and 176% if queued loads are included. The 12 kV bus at Station 419 is also thermally overloaded under contingency, and the transmission system has identified N-1 thermal needs on the 115 kV lines. The proposed Station 255 Upgrade Project is designed to: (1) Mitigate existing voltage and thermal needs, (2) Accommodate current load requests, and (3) Incorporate additional capacity for future load growth. Two solution alternatives were developed and evaluated against several factors, including future expandability, ability to address immediate electrification needs, execution certainty, and capacity headroom benefits using known forecasting data.

Project Scope:

The selected alternative is to expand the existing Station 255 to include a new 115/12.5 kV 50 MVA distribution transformer and the installation of a new 115 kV breaker and a half bay.

- (1) one 115/12.47 kV 50 MVA transformer
- (2) 12 kV GIS switchgear
- (3) two new distribution circuits that will pick up load from circuits 5164 and 5243 (currently served from Station 419)

Project Benefits:

The proposed project will mitigate identified reliability and capacity-driven needs within Disadvantaged Communities and Potential Environmental Justice Areas, allowing for additional load growth over time. Prospective customers will benefit from the immediate advancement of this project, which is the basis for it being considered as part of the urgent phase portion of the proactive planning proceeding. This project is in proximity to major highways and supports residential housing and commercial developments currently underway.

Reliability: The project will significantly enhance system reliability by addressing N-1 contingency violations at Station 419. These violations occur when a single component failure leads to system overloads, causing potential outages. By upgrading the infrastructure and adding redundancy, the project will ensure continuous service even during faults or maintenance activities. This is particularly important for the Town of Henrietta, which is experiencing rapid growth and increased demand for reliable power supply.

Capacity Headroom: The project will relieve voltage and thermal constraints on the 115 kV transmission system by feeding load directly from Station 255's 115 kV. Long-term benefits include reliability improvements (N-1) and capacity (headroom for electrification and business development). The maximum N-0 capacity gained on the distribution system is 52.5 MVA, and the maximum N-1 capacity gained on the transmission system is 57.5 MVA. Expanding Station 255 provides the most cost-effective solution to resolving the urgent transmission capacity constraints while allowing for future growth/hosting capacity in the Henrietta area.

Expandability: The new infrastructure at Station 255 will allow for future expansions, including the addition of new transformers and circuits. This will ensure the system can adapt to increasing demand over time. The project includes the installation of a new 12.5 kV bus section and enclosure, which will facilitate the transfer of load from Station 419 to Station 255. This will provide the necessary capacity to accommodate future load growth and ensure reliable power supply to the area.

Project Risks and Mitigation Plan:

There are State/Federal Wetlands on the property. The project team has already begun taking a deeper look at past, current, and near future requirements that Station 255 that could impact these Wetlands. Information from other projects with Wetland experience is being used to aid in these efforts.

Another key risk is the need to file an Article 7 Amendment application for the proposed work inside the substation as well as the construction of two new distribution circuits outside the substation. This permitting risk is mitigated by engaging with the permitting team as soon as the project is started and possibly having preliminary discussions with DPS Staff.

The decision to take no action means the substation will remain unable to support electrification driven by customer load interconnection requests in an area with existing voltage, thermal, and reliability needs. The existing 115 kV transmission system serving Station 419 is fully constrained under contingency, with an urgent need for system capacity upgrades to support existing load interconnection requests in the surrounding Henrietta area. The risk of no action is that residential housing development, EV chargers and commercial buildings with excessive load driven by electrification may be delayed or put on hold for several years. This inaction suppresses electrification initiatives and economic development in the area until major system upgrades are implemented.

An alternative solution considered was adding a third transformer and new switchgear at Station 419. This option involved installing a new 12.5 kV GIS bus section to accommodate four new 12.5 kV positions and one 115/12.5 kV transformer connection. The scope also included installing two new 12.5 kV 1200A normally open bus tie connections between the new 12.5 kV bus section and the two existing bus sections, relocating two circuits from Transformer 1 and Transformer 2 to the new 12.5 kV bus section, and installing a new 37 MVA 115/12.5 kV transformer connected through a high side breaker and low side breaker. This option required yard expansion to allow room for the new transformer and new positions, resulting in a non-standard 115 kV station topology. The estimated cost for this alternative was \$17.4 million, with a capacity gain of 39.3 MVA (N-0) in distribution and 53 MVA (N-1) in transmission.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects at RG&E. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$'000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Station 46 - Circuit 261

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-003971	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

Station 46 is a 34.5/4.16 kV and 34.5/11 kV substation constructed in 1957. The station is fed by 34.5kV transmission lines 743 and 768. It has two 4.16 kV distribution buses and one 11 kV distribution bus. Tranformer 1 (T1) is 4.16 kV and feeds lines 261, 297, and 2508 with 3542 customers and has a continuous nameplate rating (CNR) 6.6 MVA. Transformer 3 (T3) is also at 4.16 kV and feeds lines 262, 2507, and 2548 with 3609 customers and has a CNR of 6.25 MVA. T1 experienced its worst overload of 129% in 2024 at 8.52 MVA with a 5-year average loading at 126% at 8.33 MVA. T3 is estimated to be around 110% loading based on customer load data, however there is no head-end load data.

Station 95 has capacity on its 4.16 kV bank T1, which has a CNR of 14 MVA and has a 5-yr average loading of 4.8 MVA at 34%.

This project aims to run a new 4.16 kV circuit out of Station 95 to relieve the overload at Station 46.

Station 46 also has two unused 12.47kV banks, T4 and T5. The second phase of this project will convert the 4.16 kV circuits out of Station 46 and convert them to 12.47 kV and attach them to the new banks.

Project Scope:

In order to relieve load off the 4.16 kV bus at Station 46 a new 4.16 kV distribution circuit will be run out of Station 95 to transfer the load.

- 1.1 miles of new underground cable run from Station 95 up Lake Ave to manhole (MH) 48.38 to connect to both 261 and 262.
- A switch at MH 317.36 on W Ridge Rd (300550766) will be opened to transfer the load from 261 to station 95, about 2200 kVA.
- A switch at MH 317.21 on W Ridge Rd (300549829) will be opened to transfer the load from 262 to station 95, about 400 kVA.
- At MH 317.38 (300322608) a spur line will be transfered from circuit 262 to 261 to more evenly balance the loading on each bank, about 250 kVA.
- A new recloser installed at or around L-102702 P-92 (300322552).

For phase 2 of the project, all six (6) 4.16 kV circuit main lines will be converted to 12.47 kV. 12.47 kV transformers, relieving load on the 4.16 kV transformers. As a part of this conversion the Projects Team will need to ensure that there will be at least one (1) main line tie on each circuit to each other as this will be a 12.47 kV island. This second phase will require additional engineering and scoping.

Project Benefits:

This spare circuit out of station 95 will absorb 2600 kVA from station 46. After all load transfers, T1 will see a 2 MVA reduction in load, bringing it down to 5.9 MVA or 90% loading, and T3 will see an estimated 0.7 MVA reduction in load, bringing it down to an estimated 6.2 MVA or 98% loading. Station 95 T1 would be at 7.6 MVA or 54%.

After phase 2, the 12.47 kV transformers at Station 46 will create a hige amount of cpacity in the area and will be able to support future 12.47 kV conversions in the area.

Project Risks and Mitigation Plan:

Risks exist in project execution, particularly regarding engineering and material procurement. To ensure materials are received on time, we will proactively order long lead materials.

Weather delays pose a risk in distribution construction as our resources frequently support storm restoration efforts. We mitigate these weather-related delays by incorporating contingency into our construction schedules.

The health and safety of our workers are a primary concern. Risks associated with traffic control, working with energized equipment, slips, and trips are common on most projects. We mitigate these risks with project-specific health and safety plans.

Many projects involve de-energizing existing substation equipment to facilitate replacements or upgrades. This process inherently carries risks, such as potential power outages and the safety of personnel working on de-energized equipment. To mitigate these risks, we coordinate and utilize mobile substations in applicable scenarios. Mobile substations allow for the temporary transfer of load, ensuring continuous power supply and minimizing disruptions to customers. Additionally, detailed planning and coordination are essential to ensure the safe and efficient use of mobile substations. This includes thorough risk assessments, clear communication with all stakeholders, and adherence to strict safety protocols. By implementing these measures, we can effectively manage the risks associated with de-energizing substation equipment and ensure the successful completion of our projects.

Financial risks are inherent in project execution as new information emerges. We mitigate these risks by utilizing scheduling and forecasting tools, such as Primavera, for project management. We continuously forecast project-specific activities using these tools and update the project progress monthly. This approach allows us to accurately predict project completion and estimate costs at completion.

There may be issues with pad mount locations due to restrictions from the city of Rochester. We mitigate these issues by being careful in padmounted equipment selection, and keeping some areas at 4.16 kV to negate the need for new padmounted installations.

Risk of No Action:

If no action is taken, several risks could arise:

Equipment Damage: Operating substation transformers and other major equipment near or over capacity can lead to overheating and accelerated wear and tear, ultimately causing equipment failure.

Power Outages: The reliability of the power supply could be compromised, leading to more frequent and prolonged power outages for customers.

Safety Hazards: Overloaded equipment can pose safety risks, including the potential for fires or other hazardous conditions.

Increased Costs: The cost of emergency repairs and replacing damaged equipment can be significantly higher than the cost of proactive maintenance and upgrades.

Customer Dissatisfaction: Frequent power outages and unreliable service can lead to customer dissatisfaction and potential loss of trust in the utility provider.

Regulatory Non-Compliance: Failing to maintain equipment and ensure reliable service could result in non-compliance with regulatory standards, leading to fines and other penalties.

Limited Capacity for Growth: Without load reduction and system improvements, there may be limited capacity to accommodate new customer connections, hindering growth and development.

Project Alternatives:

Alternative 1 - Utilize the spare breaker out of station 95 and create a new circuit to offload station 46 T1 and T3. - \$1.78M, ISD Q3 2025

Alternative 2 - Convert 4.16 kV circuits to 12.47 kV to utilize unused banks T4 and T5 and offload T1 and T3. This project is infeasible as the cost and timeline exceeds project needs, so this will be phase 2 of the project. - 19.5M, ISD 2027

Basis for Project Estimates

Estimates are prepared utilizing historical estimating tools comparing against actual investments in similar projects as basis for project initiation and are revised through the project as new information is received.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 15	\$ -	\$ -	\$ 0	\$ 5	\$ 10		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 3	\$ -	\$ -	\$ -	\$ -	\$ 3		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 93	\$ -	\$ -	\$ 23	\$ 49	\$ 21		
# Internal, Overheads	\$ 8	\$ -	\$ -	\$ 2	\$ 4	\$ 2		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ 48	\$ -	\$ -	\$ 11	\$ 26	\$ 12		
Total	\$ 168	\$ -	\$ -	\$ 36	\$ 84	\$ 48		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,665	\$ 121	\$ 263	\$ 432	\$ 586	\$ 263	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 16,070	\$ 1,483	\$ 1,499	\$ 3,356	\$ 9,732	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 344	\$ 42	\$ 25	\$ 126	\$ 151	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 809	\$ 134	\$ 21	\$ 440	\$ 214	\$ -	\$ -	\$ -
# Materials	\$ 4,819	\$ 939	\$ -	\$ 1,740	\$ 2,140	\$ -	\$ -	\$ -
# Overheads - External	\$ 1,826	\$ 278	\$ 54	\$ 1,019	\$ 475	\$ -	\$ -	\$ -
Total	\$ 25,533	\$ 2,996	\$ 1,862	\$ 7,114	\$ 13,298	\$ 263	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Station 51

PROJECT INFORMATION

OpCo: RG&E	Project ID: UH-R0000705-RGE-ED	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP4 Change	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

Station 51 is an existing 11.5kV/4.16kV substation located at 40 Topper Drive, Rochester NY. Transformer T1 2015 summer peak loading exceeded it's normal rating (103.4% of capacity). Due to location of the substation and it's circuits, there are very limited options to relieve the transformer. The substation is surrounded on three fronts by Irondequoit Bay on the east, Lake Ontario & Sea breeze Amusement Park on the north and Durand Eastman Park on the west.

Station 51 has only two available tie points to provide load relief. In addition, neighboring circuits and their substation transformers have insufficient capacity or are not physically located in a position to relieve station 51's transformer.

Adjacent distribution circuits and substation do not have the capacity to pick up contingency load for the loss of Station 51's Transformer or circuits. Proposed upgrades will comply with SAIFI #64 requirement and increase network reliability in the surrounding area.

Project Scope:

Replace existing Station 51 transformer with a new 10 MVA 11/4 kV LTC type transformer and upgrade the existing facilities including transformer foundation, firewalls and oil containment. Installing of new control house with 11.5kV and 4.16kV switchgear and other support equipment that includes protection and control panels, battery systems, AC/DC Power equipments, fire alarm and security systems.

Project Benefits:

This project will increase station capacity and develop second source contingency. This is a reliability improvement project. The station is located in an isolated area of service. The station provides service to Seabreeze park. If the station transformer were lost the area distribution would not be able to support the load during the summer peak.

Project Risks and Mitigation Plan:

Risk#1:

Material delivery delay due to supply chain disruption can increase the project timeline as well as overall project costs

Mitigation Plan: Maintain an inventory list of long lead items, order them early in the project and follow up with the suppliers on a weekly basis to ensure progress.

Risk#2:

Not receiving demolition permit from the town for existing station demolition in the future years.

Mitigation Plan: Create a permits checklist required for demolition of the station and manage it with assistance of a permitting specialist to update it at least once every week. Work closely with Public Outreach in order to keep neighboring business updated on the demolition of the station.

Risk of No Action:

The existing transformer at Station 51 exceeded its normal rating in the summer of 2015. Not upgrading the substation and keeping it as is with overloaded equipment can present a risk of unplanned and long outages, or low voltage issues, that will directly affect customers given adjacent distribution circuits and substation do not have the capacity to pick up contingency load in case of Station 51's failure of transformer or circuits. Additionally, upgrading the substation will provide much safer equipment for personnel to utilize. Proposed upgrades will comply with SAIFI #64 requirement and increase network reliability in the surrounding area.

Project Alternatives:

There are no project alternatives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects at RG&E. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 1,113	\$ 56	\$ 121	\$ 208	\$ 312	\$ 417		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 2,059	\$ 217	\$ 409	\$ 556	\$ 613	\$ 264		
# Internal - Non-AC	\$ 1	\$ -	\$ -	\$ -	\$ 1	\$ 0		
# Internal, Labor	\$ 370	\$ 65	\$ 76	\$ 22	\$ 74	\$ 132		
# Internal, Overheads	\$ 305	\$ 30	\$ 98	\$ 60	\$ 74	\$ 43		
# Materials	\$ 1,617	\$ 226	\$ 784	\$ 272	\$ 297	\$ 38		
# Overheads - External	\$ 859	\$ 83	\$ 203	\$ 168	\$ 254	\$ 151		
Total	\$ 6,323	\$ 676	\$ 1,691	\$ 1,287	\$ 1,625	\$ 1,045		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,531	\$ 692	\$ 839	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 6,126	\$ 2,367	\$ 3,697	\$ 61	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 123	\$ 123	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 406	\$ 225	\$ 177	\$ 3	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 2,007	\$ 1,620	\$ 371	\$ 16	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 892	\$ 472	\$ 413	\$ 7	\$ -	\$ -	\$ -	\$ -
Total	\$ 11,085	\$ 5,500	\$ 5,498	\$ 87	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

RGE STA 001 4T Transformer Failure Solution

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-004274	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

Station 1 is a 34.5/11.5/4.16 kV substation in RGE's Central region, originally constructed in the 1920s. There are thirteen 4.16 kV distribution circuits supplying approximately 8,019 customers and one 11.5 kV distribution circuit supplying 6 customer-owned substations. Station 1 is connected to Stations 29 and 42 via 34.5 kV lines 718 and 770, respectively. The peak 5-year average load for the substation is 23.9 MVA. The 34.5 kV bus is connected to two (2) 34.5/4.16 kV transformers (2T and 5T) and one (1) 34.5/11.5 kV transformer (4T). The 4T transformer is a Westinghouse 3-phase 34.5/11.5 kV transformer manufactured in 1965 (58 years old). The nameplate rating is 10.0 MVA. The peak 5-year average load for the 4T is 4.19 MVA.

The 4T transformer has test results that make it unsuitable for return to service. 4T Transformer was found to have increases in dissolved gasses based on routine testing in March 2022. Maintenance performed an internal inspection of the transformer and discovered damage to the core via slag, carbon and burn marks. Probable cause is circulating current in the core due to loss of isolation from ground.

4T Transformer remains out of service and has been disconnected and removed from the existing foundation. The customers fed from line 540 are currently being fed by the back-up circuits from Station 23 and Station 42. In addition, some customers have lost their redundant emergency feeds as a result of the loss of line 540.

Project Scope:

Alternative 1: Replace transformer with a 34.5/11.5 kV 37MVA spare transformer (ISD 2029)
Replace the 4T transformer with the spare 34.5/11.5 kV 37 MVA transformer at Station 251.
Purchase replacement for spare transformer.
Requires addition of oil containment at Station 1.
Due to physical constraints in yard, location in the yard has not been finalized.
This alternative results in the shortest schedule to provide a new transformer to Station 1.

Project Benefits:

Returning the operating system to normal and once again providing customers redundant feeds.

Project Risks and Mitigation Plan:

Risks exist in project execution, particularly regarding engineering and material procurement. To ensure materials are received on time, we will proactively order long lead materials.

Weather delays pose a risk in distribution construction as our resources frequently support storm restoration efforts. We mitigate these weather-related delays by incorporating contingency into our construction schedules.

The health and safety of our workers are a primary concern. Risks associated with traffic control, working with energized equipment, slips, and trips are common on most projects. We mitigate these risks with project-specific health and safety plans.

Many projects involve de-energizing existing substation equipment to facilitate replacements or upgrades. This process inherently carries risks, such as potential power outages and the safety of personnel working on de-energized equipment. To mitigate these risks, we coordinate and utilize mobile substations in applicable scenarios. Mobile substations allow for the temporary transfer of load, ensuring continuous power supply and minimizing disruptions to customers. Additionally, detailed planning and coordination are essential to ensure the safe and efficient use of mobile substations. This includes thorough risk assessments, clear communication with all stakeholders, and adherence to strict safety protocols. By implementing these measures, we can effectively manage the risks associated with de-energizing substation equipment and ensure the successful completion of our projects.

Financial risks are inherent in project execution as new information emerges. We mitigate these risks by utilizing scheduling and forecasting tools, such as Primavera, for project management. We continuously forecast project-specific activities using these tools and update the project progress monthly. This approach allows us to accurately predict project completion and estimate costs at completion.

If no action is taken, customers do not have a redundant feed and will lose service upon loss of their primary feed.

Alternative 2: Load transfer from STA 1 11.5 kV (540 circuit) to Station 42
Eliminates 11.5 kV at Station 1.
Requires connecting the 6 customers to different circuits.
Two options under consideration:
Option 1 would be a new circuit to feed the Station 1 11.5 kV customers
Option 2 would feed the Station 1 11.5 kV customers from various existing circuits

Estimates are prepared using historical estimating tools and are benchmarked against actual investments in similar projects to establish a basis for project initiation. These estimates are revised throughout the project as new information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 258	\$ -	\$ -	\$ 38	\$ 74	\$ 101	\$ 45	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,612	\$ -	\$ -	\$ 527	\$ 1,036	\$ 1,420	\$ 628	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 163	\$ -	\$ -	\$ 24	\$ 47	\$ 64	\$ 28	\$ -
# Internal, Overheads	\$ 247	\$ -	\$ -	\$ 45	\$ 76	\$ 89	\$ 37	\$ -
# Materials	\$ 3,161	\$ -	\$ -	\$ 462	\$ 907	\$ 1,243	\$ 550	\$ -
# Overheads - External	\$ 532	\$ -	\$ -	\$ 96	\$ 165	\$ 191	\$ 80	\$ -
Total	\$ 7,972	\$ -	\$ -	\$ 1,191	\$ 2,304	\$ 3,108	\$ 1,368	\$ -

[illegible]

Hosting Capacity Automation

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-006717	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The company seeks to develop and implement a highly automated and comprehensive end-to-end solution to integrate and streamline different existing and future tools and processes to run Hosting Capacity (HC) analyses and update HC maps for Load and Distributed Generation (DG) on a bi-weekly basis. The existing process to run the HC analysis and publish the maps requires a significant amount of manual intervention and effort, and is currently not sustainable to support an increase in frequency of updates.

This project would be to identify a System Integrator to develop a solution and process leveraging existing tools and identifying new ones that would support an automated HC refresh at the company.

Project Scope:

Integration and Automation: Develop and implement a solution to integrate existing and proposed new tools (as well as define necessary processes to automate as much as possible the hosting capacity analysis and map creation and publishing). Proposed solutions must leverage existing CYME and CYME Gateway platforms.

Data Quality and Validation: Implement new and/or propose improvements to existing processes to correct data in source systems and maintain accurate data.

Quality Assurance: Solution must include tools or components to enable Planners to perform expedited data validation.

Hourly Analysis: Solution should enable implementation of 576 to 8760 hourly hosting capacity analyses for load and generation.

Trigger-Based Updates: Use Rules and thresholds to limit the scope of each refresh to distribution circuits that have experienced a significant change.

Training, Documentation & Change Management: Provide detailed documentation for new and improved processes and integrations as well as provide training to Avangrid personnel and develop change management strategies.

Hardware and Software: Hardware, software and network requirements to support the integration and automation of the different systems.

Project Benefits:

The project will significantly reduced the time duration for refreshing HC maps and alleviate the resource demands for the planning teams of performing these analyses. An automated HC process will deliver value to customers and developers within the service territory by enabling access to more frequent updates to system capacity. It is expected that any model clean up and validation steps could be leveraged when performing other CYME analyses, expediting analysis results across the suite of CYME analysis modules.

Project Risks and Mitigation Plan:

Risks related to this project include vendor resource availability, internal resource availability and data availability.

With thorough communication with the selected vendor and clear expectations set from the onset of the project, it is expected that the risk related to vendor resource availability would be mitigated.

With clear expectations of internal resource requirements set from the onset of the project, it is expected that the risk related to internal resource availability would be mitigated.

Data availability is a common issue when performing this analysis. This risk could be mitigated by engaging the necessary groups and building the data pathways and integration. Setting a clear expectation to the vendor and including improvements in the data process at the company, it is expected that the system integrator take on these challenges and propose solutions when data availability is a challenge.

Risk of No Action:

As a result of No Action in regard to this project, the company will be limited in its ability to meet the increasing expectations related to frequency of update to public facing hosting capacity maps. The company would be unable to deliver updates to these maps in a reasonable time frame and continue to experience resource constraints whenever updating these analyses.

There are no reasonable project alternatives to the proposed project.

The project estimate is informed by conversations with vendors during an RFI process and experience pursuing a similar project solution at The United Illuminating Company, an Avangrid sister company. The estimate reflects approximate hardware and licensing costs and software development services provided by the vendor, with allocation for training included.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 13	\$ -	\$ -	\$ -	\$ 13	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 560	\$ -	\$ -	\$ -	\$ 560	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 130	\$ -	\$ -	\$ -	\$ 130	\$ -	\$ -	\$ -
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 430	\$ -	\$ -	\$ -	\$ 430	\$ -	\$ -	\$ -
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,132	\$ -	\$ -	\$ -	\$ 1,132	\$ -	\$ -	\$ -

[illegible]

Circuit Breaker Replacement - Station 114

PROJECT INFORMATION

OpCo: RG&E	Project ID: PRJ-007269	Charge Code: Electric Distribution	Project Sponsor: Tiongco, Dindo	Project Type: Project
Business Area: Planning & Coordination	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This project is to replace four (4) 4.16 kV breakers at Station 114 Substation.

The NY Substation Circuit Breaker Replacement Program is a critical initiative designed to ensure the reliability and safety of the electrical infrastructure for RG&E customers. This program targets the replacement of Transmission and Distribution circuit breakers that have been assessed as Poor (Health Index (HI)-4) and Very Poor (HI-5). These breakers are nearing or have surpassed their end-of-life, posing a higher risk of failure, which could lead to significant disruptions and negatively impact customers.

The program primarily follows an annual prioritization process, focusing on an "in-kind" replacement strategy, meaning a one-for-one replacement of existing circuit breakers. This approach ensures that the replacements are straightforward and efficient. However, the program is also flexible enough to accommodate emergency replacements for unplanned breaker failures throughout the year. This flexibility is crucial for maintaining system reliability and minimizing downtime.

In addition to the standard replacements, the program evaluates compact or alternative solutions on a case-by-case basis. Compact substations, or Compact Secondary Substations (CSS), are prefabricated assemblies that include medium voltage switchgear, low voltage switchboards, and auxiliary equipment. These compact solutions are designed for efficient use of space, making them ideal for urban areas or locations with limited space. They also ensure safety through rigorous type-testing and arc-testing, providing a reliable and secure solution for substation needs.

The annual prioritization process is driven by asset health and risk criticality scoring, alongside an evaluation of SAIFI (System Average Interruption Frequency Index) Impact Avoidance. This comprehensive approach ensures that the most critical and high-risk breakers are prioritized for replacement. Notably, 32.2% (1,257 units) of NYSEG and RG&E circuit breakers are classified as High Risk (Risk Index (RI)-4) and Very High Risk (RI-5). These high-risk breakers are given top priority to mitigate potential failures and ensure system reliability. Breakers planned for replacement under other programs or projects are excluded from this program to avoid duplication of effort and ensure efficient use of resources. Additionally, substations with planned breaker replacements, a project ISD (In-Service Date) of 2029 or sooner, line uprating potential, or requiring a new control house are also excluded from this program. This strategic exclusion helps streamline the replacement process and focus efforts on the most critical areas.

The base scope of work involves the one-for-one replacement of circuit breakers, utilizing existing relays in control houses and existing battery bank voltages (24V, 48V, 125V, etc.). This approach ensures compatibility and minimizes the need for extensive modifications. In some cases breakers may be added to a substation if a bay is available and its addition will enhance the protection scheme, typically replacing fuses or switches. This strategic installation improves the overall protection, reliability, and operability of the electrical system.

Engineering and project development for circuit breaker replacement includes evaluating the condition of switches, insulators, and foundations. Station topology is reviewed to assess the need and opportunity for new breaker installations. This thorough evaluation ensures that all aspects of the substation are considered, and any necessary improvements (potentially including automation upgrades) are made to enhance control and reliability. The scope of work is determined through outreach to Substation Operations, Transmission and Distribution Planning, Digital Grid, and the Protection & Control groups. These types of upgrades are essential for modernizing the infrastructure and improving operational efficiency.

Procured program breakers can be used for unplanned emergency replacements, ensuring that the system remains reliable even in unexpected situations. However, major capital substation projects and emergency replacements alone will not suffice to address the Poor and Very Poor population. This program is crucial for maintaining the reliability and safety of our electrical infrastructure, reducing disruptions to our customers, and optimizing operations.

By proactively replacing high-risk circuit breakers and modernizing the infrastructure, the Substation Circuit Breaker Replacement Program plays a vital role in ensuring the continued reliability and safety of the electrical system. This proactive approach helps prevent failures, reduces the risk of outages, and ensures that customers receive consistent and reliable service. The program's comprehensive and strategic approach ensures that resources are used efficiently and effectively, providing long-term benefits for both the utility and its customers.

Project Scope:

The project involves replacing the following breakers at Station 114:

Four (4) 4.16 kV breakers (1T11432, 251802, 251902, 252002).

Project Benefits:

1) SAIFI Improvement - Improving SAIFI through the replacement of old, high-risk substation circuit breakers at RG&E involves a detailed and technical approach to enhance the reliability of their systems. These older circuit breakers, often nearing the end of their operational life, are susceptible to mechanical failures and operational inefficiencies, which can lead to frequent and prolonged power interruptions.

Modern circuit breakers, which replace the outdated ones, are equipped with advanced fault detection and isolation capabilities. These breakers can quickly identify and isolate faults, thereby reducing the duration and frequency of power interruptions. Additionally, they often feature enhanced communication capabilities, allowing for real-time monitoring and remote operation, which further improves response times and operational efficiency.

By systematically replacing these high-risk circuit breakers, RG&E can significantly reduce the incidence of equipment-related outages. This not only improves the SAIFI score but also enhances the overall reliability and stability of the system, ensuring a more consistent and dependable service for their customers.

2) Replace aging and obsolete infrastructure - The current population of circuit breakers within the New York Operating Companies (NY Opcos) reveals a significant portion assessed as Reliability Index (RI) categories RI4 and RI 5. Specifically, 32.2% of the total circuit breakers, amounting to 1,257 units, fall into these categories. Breaking this down further, the RI-5 category comprises 192 distribution circuit breakers operating at voltages below 15kV and 90 transmission circuit breakers operating at voltages above 34kV. Meanwhile, the RI-4 category includes 574 distribution circuit breakers and 401 transmission circuit breakers within the same voltage ranges.

When considering the population of circuit breakers excluding those replaced by other programs and projects, the percentage assessed as RI-4 and RI-5 slightly decreases to 27.8%, which corresponds to 892 units. Within this subset, the RI-5 category consists of 140 distribution circuit breakers and 42 transmission circuit breakers. The RI-4 category, on the other hand, includes 430 distribution circuit breakers and 280 transmission circuit breakers.

This refined population of circuit breakers, excluding those already addressed by other initiatives, forms the candidate list for replacement as specified in the preceding section. This detailed assessment and categorization are crucial for prioritizing maintenance and replacement efforts, ensuring the reliability and safety of the electrical infrastructure within the NY Opcos. By focusing on the RI-4 and RI-5 categories, the aim is to mitigate potential risks associated with aging or underperforming circuit breakers, thereby enhancing the overall stability and efficiency of the power distribution and transmission network.

Project Risks and Mitigation Plan:

Throughout the duration of this program, there is a potential for sudden failures to occur, which could significantly impact its progress. In the event of an unplanned failure, it becomes imperative to re-evaluate the program to prioritize addressing the emergency condition. This is particularly critical in scenarios where a suitable spare part is unavailable, necessitating the use of the program to mitigate the emergency breaker replacement. Depending on the timing of such a failure, it may be necessary to advance a substation into the current program, while deferring another substation or multiple substations to a subsequent year's plan. This flexible approach ensures that emergency conditions are managed effectively, minimizing disruptions and maintaining the overall integrity of the program.

The program's success hinges on its ability to adapt to unforeseen challenges. Sudden failures, while unpredictable, are an inherent risk in any complex system. When such failures occur, the immediate focus shifts to resolving the emergency to prevent further complications. This often involves a thorough assessment of the situation to determine the best course of action. If a suitable spare part is not readily available, the program must pivot to address the most pressing needs, such as replacing a critical breaker.

The timing of these failures plays a crucial role in the decision-making process. For instance, if a failure occurs early in the program, there may be more flexibility to adjust the schedule and resources. Conversely, a failure later in the program might require more drastic measures, such as advancing a substation's maintenance or upgrade to the current year. This could mean postponing other planned activities to the following year, ensuring that the most critical issues are addressed promptly.

This proactive and dynamic approach is essential for maintaining the program's overall effectiveness. By prioritizing emergency conditions and adjusting plans as needed, the program can continue to operate smoothly, even in the face of unexpected challenges. This strategy not only helps in managing immediate risks but also contributes to the long-term success and reliability of the infrastructure.

Risk of No Action:

The decision to take 'no action' regarding the replacement of the high-risk RI4 and RI5 circuit breakers is effectively a 'run-to-failure' strategy. This approach is laden with significant risks and is particularly unwise in the absence of reserve or surplus units. Circuit breakers are critical components in electrical systems, designed to protect circuits from damage caused by overloads or short circuits. When these breakers are known to be high-risk, their failure can lead to severe consequences that can include entire substation outages due to the failure of a circuit breaker. If this failure results in damage to adjacent equipment, the repair costs, outage duration, and outage scope can be significant.

Consider an example where a breaker fails on a radial circuit with no suitable circuit tie back-ups. In such a scenario, the entire circuit would be left without power, leading to an unplanned outage. This would be an unacceptable situation, especially if the breaker was identified as RI4 or RI5. The lack of backup options would exacerbate the impact, causing significant operational disruptions and potentially high costs associated with downtime.

Additionally, the safety hazards posed by failing circuit breakers cannot be overstated. Electrical faults can lead to fires, equipment damage, and even pose risks to personnel safety. Proactively replacing these high-risk breakers would mitigate these risks. It would ensure the reliability and continuity of operations, safeguarding both the infrastructure and the people working within it.

Investing in the replacement of RI4 and RI5 breakers is a strategic move that prioritizes long-term stability and safety over short-term cost savings. By doing so, the organization can avoid the potentially catastrophic consequences of a 'run-to-failure' scenario and maintain a robust and resilient electrical system.

Project Alternatives:

An alternative solution involves focusing on the replacement of only the poor health breakers, while retaining legacy equipment (e.g., brown glass insulators and electromechanical relays) in service. While the primary objective is to address the poor health breakers due to their immediate risk, it's crucial to consider the broader implications of leaving the other components unchanged.

Brown glass insulators, although currently functional, have a relatively higher failure rate compared to modern alternatives. This increased likelihood of failure can lead to unexpected outages and maintenance challenges, compromising the overall reliability of the system. Additionally, electromechanical relays, while still operational, are becoming increasingly obsolete. As technology advances, the availability of parts and expertise to maintain these relays diminishes, posing a significant risk to the long-term sustainability of the system .

A more comprehensive and holistic solution is achieved by replacing the brown glass insulator switches and electromechanical relays concurrently with the poor health breakers. This approach mitigates future risks associated with component failures and obsolescence. The integration of modern, more reliable components will enhance the overall reliability and resiliency of the system, reducing the likelihood of unplanned outages and maintenance interventions.

Moreover, in the long run this strategy is cost-effective. While the initial investment may be higher due to the expanded scope of ancillary equipment replacement, the reduction in maintenance costs, improved system performance, and extended lifespan of the infrastructure will provide significant savings over time. This holistic upgrade ensures that the system is better equipped to handle future demands and challenges, providing a more stable and reliable service to customers.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within RG&E. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 134	\$ -	\$ -	\$ 134	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 663	\$ -	\$ -	\$ 663	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 119	\$ -	\$ -	\$ 119	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 19	\$ -	\$ -	\$ 19	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 377	\$ -	\$ -	\$ 377	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 52	\$ -	\$ -	\$ 52	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,365	\$ -	\$ -	\$ 1,365	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Station 55 34.5/12kV Rebuild

PROJECT INFORMATION

OpCo: Rochester Gas & Electric	Project ID: PRJ-001004	Charge Code: Electric Distribution	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP4 Change	Start Date: 1/1/2026	In-Service Date: 12/31/2034

Project description:

A comprehensive T-Planning (LTP) Reliability Assessment (2019/2020) was performed in the Webster Region of RGE. This assessment resulted in the identification of numerous reliability violations requiring significant area-wide improvements/upgrades. Any proposed substation modifications included an asset condition assessment to address any known Asset Health and Risk Issues.

Station 55 34.5/12kV Rebuild - is part of Webster Area Solution Proj. Def. UH-R0000703

Project Scope:

Rebuild Station 55 as a 34.5 kV straight bus with 4 dedicated line breakers and a Normally Closed bus-tie breaker. In addition, 1- new 34.5/12.5 kV distribution transformer will be installed and the existing transformer will be relocated to the new site.

Existing Line 778 (Station 92-Station 55) will be connected via a normally closed breaker at Station 55.

Existing Line 778 (Station 55 to 42) will be connected via a normally open breaker at Station 55.

Line terminal 745 (Station 42 - Station 55) will be connected via a normally open breaker at Station 55.

Line terminal 745 (Station 73- Station 55) will be connected via a normally closed breaker at Station 55.

Project Benefits:

Project Needs:

Need (EL-1): A single element N-1 contingency loss of Line 778 (34.5 kV) results in 31.9 MW of consequential load loss exposure which violates T-Planning maximum criteria of 25 MW.

Project Benefits

Station 55 Rebuild eliminates post-contingency (consequential) load loss and provides full load restoration against single element contingencies.

Project Risks and Mitigation Plan:

The selected scope relies on partial reuse of the existing Station 55 infrastructure, including the existing transformer and portions of the 34.5 kV and 12.5 kV equipment that are documented as being in generally good health; however, the retained 34.5 kV metal-clad equipment remains limited to a 1200 A rating and Line 778 will not have a dedicated breaker under the preferred configuration.

Project execution risk is mitigated by constructing a new combined 34.5/12.5 kV GIS enclosure on the adjacent parcel, installing one new 34.5/12.5 kV 22.4 MVA transformer, replacing the existing electromechanical relays, and expanding JMUX Ring 8 to include Station 55.

Operational risk is mitigated by configuring the station so that Line 821 is normally closed, Line 745 is normally open, Line 778 is transferred through the existing metal-clad with new CTs and line relays, and the 34.5 kV tie utilizes the existing 745 switch, preserving the required Webster North load pocket operating configuration during contingency conditions.

Future capacity risk is partially mitigated by the adjacent parcel size, which is of a sufficient size to support an additional future transformer if needed.

Risk of No Action:

If no action is taken, Station 55 remains served by a single 34.5/12.5 kV transformer and, as of June 2025, carries a peak load of 24.9 MVA, or approximately 106% of station capacity, making it a candidate for distribution load relief. Under existing conditions, loss of the transformer leaves approximately 22 MVA of load without adequate backup because nearby stations and existing field ties cannot absorb the station load, including limited or no support capability for Circuits 5212, 5239, and 5240. From a transmission reliability standpoint, a single-element N-1 loss of Line 778 results in 31.9 MW of consequential load-loss exposure, exceeding the stated T-Planning criterion of 25 MW. Accordingly, deferral of the project would leave both the station loading and contingency performance issues unresolved.

Project Alternatives:

The preferred alternative is a transformer addition with a single new GIS building on the adjacent parcel. This scope installs one new 34.5/12.5 kV 22.4 MVA transformer, reuses the existing Station 55 transformer and portions of the existing station equipment, adds the required 34.5 kV line connections and tie arrangement, replaces electromechanical relays, and includes approximately 2,300 feet of new 34.5 kV cable for Line 820. The documented project cost is \$20.72 million with an approximate in-service date of 2027.

The primary alternative considered in the updated review was a full rebuild on the adjacent parcel. That option would install two new 22.4 MVA transformers and provide dedicated breakers for all lines and transformers in a full 34.5 kV straight-bus arrangement. While this option is electrically straightforward and simplifies protection and construction, it carries a significantly higher documented cost of \$32.28 million and a later in-service date of 2028.

An earlier brownfield upgrade on the existing site was also evaluated and dismissed because the existing 34.5 kV metal-clad switchgear could not be expanded to accommodate both a new line breaker and the required second transformer, and because the associated protection and control scheme was considered abnormally complex and carried increased risk of improper operation. Based on the documented evaluation, the preferred alternative was selected because it satisfies the identified reliability and load relief needs at the lowest cost while leveraging existing infrastructure that remains in acceptable condition.

Basis for Project Estimates

The project estimate is based on the selected transformer-addition scope, including one new 34.5/12.5 kV 22.4 MVA transformer, one new combined 34.5/12.5 kV GIS enclosure, new 34.5 kV breaker and tie connections, approximately 2,300 feet of new 34.5 kV cable, relay replacement work, and communications expansion to include Station 55 on JMUX Ring 8. The estimate reflects the updated project configuration developed during the scope re-evaluation and incorporates documented cost escalation in major components, including transformer pricing, land acquisition, and medium-voltage GIS equipment. Specifically, transformer cost growth from approximately \$432k to \$1.5 million, land acquisition growth from approximately \$75k to \$2 million, and MV GIS growth from approximately \$3 million to \$7 million.

Planning estimates for the selected alternative is \$20.72 million, with cost estimating presented at a planning accuracy range of +50% / -25%. The associated cash flow shown in the supporting material consists of \$7.0 million in actuals and forecast annual spend of \$3.89 million in 2025, \$5.77 million in 2026, and \$4.06 million in 2027.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2021	2022	2023	2024	2025		
# AFUDC	\$ 67	\$ 2	\$ 12	\$ 16	\$ 18	\$ 20		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 114	\$ 89	\$ 25	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ 0	\$ 0	\$ 0	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 50	\$ 20	\$ 30	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ 10	\$ 6	\$ 4	\$ -	\$ -	\$ -		
# Materials	\$ 7	\$ 7	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ 40	\$ 21	\$ 19	\$ -	\$ -	\$ -		
Total	\$ 289	\$ 145	\$ 90	\$ 16	\$ 18	\$ 20		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2021	2022	2023	2024	2025		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$'000's)

Capital Details:	Total	2026	2027	2028	2029	2030		
# AFUDC	\$ 60	\$ 22	\$ 24	\$ 15	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 2,000	\$ -	\$ -	\$ 2,000	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ 66	\$ -	\$ -	\$ 66	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ 157	\$ -	\$ -	\$ 157	\$ -	\$ -		
Total	\$ 2,283	\$ 22	\$ 24	\$ 2,238	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2026	2027	2028	2029	2030
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Station 89 Upgrades

PROJECT INFORMATION

OpCo: Rochester Gas & Electric	Project ID: PRJ-004278	Charge Code: Electric Distribution	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Integrated System Planning	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: 1/0/1900	In-Service Date: 1/0/1900

Project description:

Transformer upgrade at station 89 is required in order to accommodate Winfield Park Customer.

Project Scope:

To install additional 37MVA ,115kV/12.47kV transformer.
Install 12.5kV AIS Bus to accommodate a 12kV circuit and transformer connection.
Install a 12.47kV direct feed circuit to customer facility.
Install a N/O Tie breaker to establish N-1 redundancy.

Project Benefits:

This will add an additional 30MVA capacity at Station 89 in addition to the proposed customer load to accommodate any future load growth.

Project Risks and Mitigation Plan:

This project's key risk is the ability to rebuild the substation in the existing parcel. The site is constrained to the north by the 115 kV transmission right of way and to the east by Highway 98. The substation has enough space to execute the proposed scope but will need to be phased to ensure the substation remains in service throughout the project. This can be mitigated by a detailed outage and construction sequence plan.

Risk of No Action:

If this project is not undertaken, the current electrical system will not be able to support electrification driven by customer load interconnections in an area with existing voltage, thermal, asset, and reliability needs. The existing 34 kV transmission system that serves part of Station 89 (1T and 2T) is fully constrained, creating an urgent need for system capacity upgrades to support existing load interconnection requests. The risk of no action is that proposed developments may be delayed or put on hold for several years. This could hinder economic growth and lead to increased outages and customer dissatisfaction. The N-1 violations will also continue to exist at Station 89 if this work is not performed, leaving the 12kV system vulnerable to outages.

Project Alternatives:

One alternative proposed included the following scope of work:

- Install a new 12.5 kV AIS bus to accommodate a new 12.5 kV circuit and 115/12.5 kV transformer connection.
- Install a new 14 MVA 115/12.5 kV transformer connected through two dedicated high/low side breakers.
- Install a new 12.5 kV feeder (direct feed) to the Winfield Customer site. The approximate circuit length would be two miles.
- This alternative is what Planning considers the "minimum" solution. This solution alternative does not provide station transformer redundancy (N-1 capabilities)

This alternative is what Planning considers the "minimum" solution to accommodate only Winfield Park Development's interconnection and would be 100% customer funded. It requires the least amount of work to bring in additional capacity for Winfield Park Customer, but it will only add approximately 7 MVA of extra capacity for future load growth in this area. This alternative also does not provide station transformer redundancy (N-1 capabilities) to existing customers. This alternative was not selected because of the limited capacity gains and exclusion of N-1 redundancy.

Another alternative proposed included the following scope of work:

- Install a new 12.5 kV GIS bus (normally open bus-tie) with a new 12.5 kV circuit and 115/12.5 kV transformer.
- Install a new 37 MVA 115/12.5 kV transformer connected through two dedicated high/low side breakers.
- Install a new 12.5 kV feeder (direct feed) to the Winfield Customer site. The approximate length of this circuit is two miles.
- Install a normally open 12.5 kV bus-tie breaker to establish N-1 redundancy capabilities.

This third alternative was not selective because it only added 3.7 MVA of N-1 capacity on the transmission system.

Basis for Project Estimates

This project's cost estimate was prepared using a tool that forecasts amounts based on historical spend and the expected project timeline. Estimates are benchmarked against actual investments in similar projects to establish a basis for project initiation, and revised throughout the project as new information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2021	2022	2023	2024	2025		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-	

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2021	2022	2023	2024	2025		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$'000's)

Capital Details:	Total	2026	2027	2028	2029	2030		
# AFUDC	\$ 48	\$ -	\$ -	\$ -	\$ -	\$ 48		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 2,527	\$ -	\$ -	\$ -	\$ -	\$ 2,527		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ 502	\$ -	\$ -	\$ -	\$ -	\$ 502		
# Materials	\$ 1,573	\$ -	\$ -	\$ -	\$ -	\$ 1,573		
# Overheads - External	\$ 1,070	\$ -	\$ -	\$ -	\$ -	\$ 1,070		
Total	\$ 5,720	\$ -	\$ -	\$ -	\$ -	\$ 5,720	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2026	2027	2028	2029	2030
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Station 117 Circuit Upgrades

PROJECT INFORMATION

OpCo: Rochester Gas & Electric	Project ID: PRJ-005980	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Project
Business Area: Projects	Rate Case Category Reliability	Project Stage: IP3 Financial Execute	Start Date: 12/31/2026	In-Service Date: 12/31/2026

Project description:

Overview: The Station 117 project began in 2011 to address reliability issues caused by thermal constraints on the existing 34.5/4.16kV transformer at Station 117, which was thermally overloaded during N-0 peak conditions.

Current State Needs Assessment: The 34.5/4.16 kV transformer bank #1 at Station 117 is loaded to 102% of its summer normal rating based on the peak historical 5-year average. The 4.16 kV system lacks adequate N-1 capabilities and cannot be fully backed up through neighboring circuit field tie switching without causing new voltage or thermal violations at peak, or phase angle issues.

The project aims to: 1) Mitigate voltage and thermal needs, and 2) Add capacity for future load growth.

Project Scope:

Transfer the existing 12.5kV load on Circuit 5187 to Circuit 5186 and a 1-mile section of 12.5kV load on Circuit 5188 to Circuit 5187 to facilitate the load transfer from Circuit 2156.

Convert and transfer the 4.16kV load on Circuit 2156 to 12.5kV on Circuit 5187, fed by the 34.5/12.5kV transformer bank #2 at Station 117, except for 1.28MVA downstream with new 3-500kVA step-down transformers.

Partially convert and transfer a 0.8-mile section of Station 420's 4.16kV load on Circuit 2181 to 12.5kV on Circuit 5187 with new 3-500kVA step-down transformers.

Install two new 3-500kVA step-down transformers near existing tie points to maintain N-1 support.

Install seven new SCADA reclosers for remote switching and automatic switching schemes on the 12.5kV circuit.

Project Benefits:

This project will resolve the thermal overloads on the T1 Transformer at Station 117 and to enhance system reliability with N-0 and N-1 contingency headroom, ensuring continuous service during faults or maintenance and relieve voltage and thermal constraints, allowing for future load growth in the East Rochester area.

Project Risks and Mitigation Plan:

This project carries execution, schedule, and system integration risk because it requires a phased voltage conversion and load transfer across multiple circuits, including Circuit 2156, a section of 0420RO2181, portions of Circuit 5188, and the transfer of existing Circuit 5187 load to Circuit 5186. The scope also requires installation of new step-down transformers, seven SCADA reclosers, new tie points, conductor/fuse/capacitor bank modifications, and coordination with other local resiliency work on Circuits 5187 and 5188.

Risks

Funding / Schedule risks: The project schedule is contingent on receiving financial approval.

Construction / outage coordination risk: The work requires multiple field cutovers, voltage conversions, service can replacements, and tie reconfiguration, which increases the need for careful outage planning and customer transition sequencing.

System Performance / Load Transfer risks: The selected solution depends on Circuit 5186 absorbing Circuit 5187 load and Transformer 2T accepting additional transferred load while maintaining acceptable loading and operability. The presentation indicates this is feasible and expected to remain acceptable for approximately 15 years assuming 2% annual load growth.

Scope Limitation risk: The selected alternative addresses the immediate reliability and overload needs and supports the long-term 4.16 kV to 12.5 kV conversion strategy, but it does not resolve all identified asset condition issues at Station 117.

Inter-project dependency risk: The selected alternative assumes the already procured 34.5/12.5 kV 22.4 MVA transformer will be transferred to the Station 127 project, so execution depends on that material reassignment being completed as planned.

Mitigation Plan:

Execute the work in phases, consistent with the presentation's alternative scope, to reduce cutover complexity and better manage system risk during construction.

Coordinate early with Distribution Operations, Line Projects, and the Resiliency team to align outage planning, SCADA device installation, and related circuit work on 5187 and 5188.

Validate field conditions and final design assumptions before construction, including tie point configuration, service conversions, and any conductor/structural requirements identified during detailed engineering.

Continue to monitor Transformer 1T and Transformer 2T loading after implementation and use the project as a near-term bridge while preserving the long-term strategy to further modernize the Station 117 system.

Risk of No Action:

If no action is taken, Station 117 will continue to operate with an overloaded 34.5/4.16 kV Transformer 1T. Transformer 1T has a 5.25 MVA normal rating, a historical 5-year peak average loading of approximately 102%, a maximum recent peak of 106.5%, and an estimated future 5-year peak loading of 113% assuming 2% annual load growth.

No action would leave approximately 1,715 customers served by Transformer 1T exposed to continued overload risk and would maintain the existing inability to provide effective N-1 or emergency backup through the five existing tie points because of voltage, thermal, and/or phase angle limitations.

In addition, the station would continue to rely on aging and deteriorated assets, including a 61-year-old Transformer 1T with poor LTC health and DGA results, four HI-4 breakers in the 4.16 kV metal-clad switchgear, obsolete electromechanical relays / limited SCADA capability, and deteriorated 34.5 kV dead-end structure foundations requiring repair or replacement.

Deferring action also postpones the long-term transition of the 4.16 kV system to 12.5 kV, limits system resiliency in the East Rochester area, and misses the opportunity to relieve overload on Station 420 Circuit 2181 that is also addressed by the selected alternative.

Project Alternatives:**Alternative 1 – Original Legacy Scope / Full Station Rebuild and Conversion**

The original project scope, initiated in 2011, proposed replacing the existing 5.25 MVA Transformer 1T with a new 34.5/12.5 kV 12/16/20 (22.4) MVA LTC transformer, constructing a new powerhouse, installing new 34.5 kV and 12.5 kV GIS switchgear, and converting the 4.16 kV circuits to 12.5 kV over time. This alternative addressed both capacity and broader asset condition needs, but at an estimated cost of approximately \$35.0M, making it significantly more capital intensive than the targeted near-term alternatives.

Alternative 2 – Circuit 2131 Voltage Conversion and Load Transfer to Circuit 5187

This option would transfer all existing 12.5 kV load on Circuit 5187 to Circuit 5186 and use the 5187 breaker position to convert and transfer Circuit 2131 load from Transformer 1T to Transformer 2T. It also includes step-down transformers and six new SCADA reclosers to preserve contingency support and improve switching capability. This alternative would reduce Transformer 1T loading to approximately 73% and increase Transformer 2T loading to approximately 60%, with an estimated project cost of \$3.89M and a total project cost of \$6.33M including prior CWIP.

Alternative 3 – Circuit 2156, Section of 0420RO2181 Voltage Conversion and Load Transfer to Circuit 5187

This selected option transfers Circuit 5187 load to Circuit 5186, converts and transfers most of Circuit 2156 to Circuit 5187, transfers a section of Station 420 Circuit 2181 to the modified Circuit 5187, transfers a section of Circuit 5188, and installs step-down transformers plus seven new SCADA reclosers. This alternative reduces Transformer 1T loading to approximately 67%, increases Transformer 2T loading to approximately 65%, and additionally resolves the Station 420 Circuit 2181 overload from 103.4% to 62% at peak. The estimated project cost is \$4.13M, with a total cost of \$6.57M including prior CWIP.

Non-Wires Alternative (NWA)

NWA screening was completed on 08/17/2023, and the project is not suitable for an NWA solution due to time of need.

Alternative 3 was selected because it provides the best balance of reliability improvement, overload relief, system resiliency, and capital efficiency while supporting the long-term strategy of converting the remaining 4.16 kV system to 12.5 kV. It also produces substantial savings relative to the original legacy scope.

Basis for Project Estimates

The estimate for the selected project is based on the detailed scope of work developed for Alternative 2. The project cost estimate for the selected alternative is \$4.13M with an estimate accuracy range of +50% / -25%. The total project cost reflected in the cost comparison is \$6.57M, which includes: \$4.13M for the selected alternative scope and \$2.44M of prior CWIP / actuals applied to the new solution, including prior engineering, internal labor, overheads, and AFUDC.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2021	2022	2023	2024	2025		
# AFUDC	\$ 14	\$ -	\$ -	\$ -	\$ -	\$ 14		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 517	\$ -	\$ -	\$ -	\$ -	\$ 517		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 25	\$ -	\$ -	\$ -	\$ -	\$ 25		
# Internal, Overheads	\$ 49	\$ -	\$ -	\$ -	\$ -	\$ 49		
# Materials	\$ 37	\$ -	\$ -	\$ -	\$ -	\$ 37		
# Overheads - External	\$ 110	\$ -	\$ -	\$ -	\$ -	\$ 110		
Total	\$ 751	\$ -	\$ -	\$ -	\$ -	\$ 751		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2021	2022	2023	2024	2025		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$'000's)

Capital Details:	Total	2026	2027	2028	2029	2030		
# AFUDC	\$ 36	\$ 29	\$ 7	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 1,913	\$ 1,521	\$ 392	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ 170	\$ 138	\$ 32	\$ -	\$ -	\$ -		
# Materials	\$ 1,191	\$ 947	\$ 244	\$ -	\$ -	\$ -		
# Overheads - External	\$ 319	\$ 259	\$ 60	\$ -	\$ -	\$ -		
Total	\$ 3,630	\$ 2,895	\$ 735	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Network Protectors				
PROJECT INFORMATION				
OpCo: RG&E	Project ID: PRJ-009235	Charge Code: Electric Distribution	Project Sponsor: Paul Iannuzzelli	Project Type: asset betterments
Business Area: Process & Technology	Rate Case Category Reliability	Project Stage: IP1 Originate	Start Date: H1 2026	In-Service Date: H2 2030
Project description: The Rochester Network System supplies a major portion of the electric load for the downtown area of Rochester. The system is made up of (2) independent east and west AC secondary networks. The east is fed by (10) circuits from substation 38 and the west is fed by (7) circuits from substations 6 and 26. These AC 120/240 volt networks consist of a grid of low voltage interconnected cables which are fed from (161) network protectors located in underground network manholes and vaults throughout the two network areas. (21) of the (161) protectors are 277/480 volt spot networks consisting of two or more transformers with their secondary cables connected to maintain a constant source of supply. RG&E's current (161) network protectors are 'live front' units that were manufactured based on 1930's technologies. These 'live front' units expose technicians to energized components when performing routine maintainance and testing when working within the confined space of a network vault. This program will replace all 'live front' network style protectors with new state of the art solid state 'dead front' units.				
Project Scope: The objective of this program is to replace all 'live front' style network protectors with new solid state 'dead front' units. This program will address (161) 'live front' units and replace them with new 'dead front' style protectors, add the ability to communicate system details (voltage, current, equipment/space details, etc), and arc flash protection on the 480V spots.				
Project Benefits: The existing 'live front' protectors expose technicians to energized components when performing routine maintainance and testing when working within the confined space of a network vault. The 'live front' protectors also use a breaker closing motor that are known to malfunction causing the protector to close catastrophically with deadly results known in other utilities. 1. New 'dead front' protectors are solid state style units that were first introduced in 2000 and have a proven in-service track record with other utilities. 2. The 'dead front' units require less maintainance and testing when fitted with the Vault Gard Arms self diagnostic tool and the Arc Flash Reduction tool. 3. The on-board diagnostics indicators included with the Vault Gard Arms system requires less technician time working in the confined space of a network vault reducing maintainance and testing costs. 4. The Arc Flash Reduction Mitigation System when installed on 277/480 volts spot network locations can react to an arc flash within 4ms reducing technicians arc flash exposure. 5. The dead front units can be operated, tested and remotely racked out with protector door bolted shut outside of the network vault or manhole eliminating the technicians exposure to energized components or failure.				
Project Risks and Mitigation Plan: 1. The project is designed to eliminate the maintainance technicians exposure to energized components or electrical equipment failures. 2. The Vault Gard Arms and Arc Flash Reduction Mitigation System will minimize arc flash exposure when working within the confined space of a network vault or manhole. 3. Dead front units require less maintenance and will reduce the overall O&M maintainance costs and will promote a safer working environment.				

Risk of No Action:

Operations personnel work in a more hazardous environment due to the current live front protectors and no arc flash protection.

Project Alternatives:

There are no other acceptable programs or upgrades available for the current style of 'live front' network protectors. Developing a replacement program and using the state of the art, solid state 'dead front' style units eliminates technicians current exposure to energized components and will minimize arc flash exposure when working within an underground network vault or manhole. The dead front protectors will also reduce the O&M maintainace costs.

Basis for Project Estimates

Actual historic costs with + inflation.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 15,788	\$ 3,026	\$ 3,092	\$ 3,157	\$ 3,223	\$ 3,291	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 26	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5	\$ -	\$ -
# Internal, Overheads	\$ 1,898	\$ 364	\$ 372	\$ 379	\$ 387	\$ 396	\$ -	\$ -
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 4,744	\$ 909	\$ 929	\$ 949	\$ 969	\$ 989	\$ -	\$ -
Total	\$ 22,457	\$ 4,304	\$ 4,398	\$ 4,490	\$ 4,584	\$ 4,681	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]



NYSEG Electric Resiliency

NYSEG - SCADA/Automation

PROJECT INFORMATION

OpCo: NYSEG	Project ID: UI-N0062-NYSEG-ED	Charge Code: Electric Distribution	Project Sponsor: Malone, Chris	Project Type: Annual Program
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The primary objective of this program is to enhance the operational efficiency and reliability of our substations by installing remote terminal units (RTUs) in all substations that currently lack them. For substations already equipped with RTUs, the program aims to integrate all the bays into our master supervisory control and data acquisition (SCADA) system. This integration will ensure seamless communication and control across the network, facilitating better management and monitoring of the substations. By having a unified SCADA system, we can streamline operations and improve the overall performance of our power distribution network.

In addition to the installation of RTUs, the program includes the replacement of outdated electromechanical relays with modern digital relays. This upgrade is crucial for the digitalization of the bays, enabling more precise and reliable system protection. Digital relays offer advanced features such as self-diagnostics, event recording, and remote configuration, which are not available in electromechanical relays. By transitioning to digital relays, we can significantly enhance the protection and control capabilities of our substations, ensuring they are equipped to handle modern power distribution demands.

The integration of SCADA with digital relays will provide improved visibility and remote control of the substations. This enhanced visibility allows for real-time monitoring and quick identification of issues, leading to faster response times and better outage management. Proper system protection coordination and outage assessment will result in improved Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Frequency Index (SAIFI) performance over the long term. These improvements are essential for maintaining a reliable power supply and minimizing the impact of outages on customers, thereby enhancing customer satisfaction and trust in our services.

Furthermore, providing remote control capabilities will greatly enhance the safety of our workers. By allowing operators to control the switchgear remotely, we can reduce the need for manual intervention, which can be hazardous. This not only increases the safety of our personnel but also ensures more efficient and accurate operation of the substations. Remote control capabilities also mean that our response teams can address issues more swiftly and effectively, reducing downtime and improving the overall reliability of the power supply.

The program also emphasizes the importance of proper system protection coordination and outage assessment. By integrating SCADA with digital relays, we can achieve better coordination and quicker identification of faults, leading to faster restoration times. This will result in improved CAIDI and SAIFI performance, which are critical metrics for evaluating the reliability of our power distribution network. Enhanced performance in these areas will contribute to a more stable and dependable power supply for our customers.

Project Scope:

The primary objective of this program is to enhance the operational efficiency and reliability of our substations by installing remote terminal units (RTUs) in all substations that currently lack them. For substations already equipped with RTUs, the program aims to integrate all the bays into our master supervisory control and data acquisition (SCADA) system. This integration will ensure seamless communication and control across the network, facilitating better management and monitoring of the substations. By having a unified SCADA system, we can streamline operations and improve the overall performance of our power distribution network.

RTU Installation and Integration:

Identify Substations Lacking RTUs: Conduct a comprehensive survey to identify all substations that currently do not have RTUs installed.

Procure RTUs: Source and procure the necessary RTUs that meet the technical specifications required for our network.

Install RTUs: Deploy and install RTUs in the identified substations, ensuring proper configuration and integration with existing systems.

Integrate Existing RTUs: For substations already equipped with RTUs, integrate all the bays into the master SCADA system to ensure unified control and monitoring.

Digital Relay Upgrades:

Assess Current Relay Systems: Evaluate the existing electromechanical relays in all substations to determine the scope of replacement needed.

Procure Digital Relays: Source and procure modern digital relays that offer advanced features such as self-diagnostics, event recording, and remote configuration.

Replace Electromechanical Relays: Systematically replace outdated electromechanical relays with digital relays, ensuring minimal disruption to operations.

Configure Digital Relays: Configure the new digital relays to integrate seamlessly with the SCADA system and ensure proper system protection coordination.

Enhanced Visibility and Control:

SCADA Integration: Integrate the newly installed RTUs and digital relays with the SCADA system to provide real-time monitoring and control capabilities.

Develop Monitoring Protocols: Establish protocols for continuous monitoring of substation equipment, including status changes, alarms, and fault detection.

Implement Remote Control Capabilities: Enable remote control functionalities for all integrated substations, allowing operators to manage equipment from a central location.

It is estimated that approximately 15 to 20 projects will be completed annually, contingent on funding level approval of approximately \$7.5 to \$8 million per year.

Project Benefits:

By enabling remote restoration, the program ensures that power outages are addressed more swiftly and efficiently. This not only minimizes the downtime experienced by customers but also enhances their overall satisfaction. The ability to restore services remotely means that technicians can quickly identify and resolve issues without the need for on-site visits, which can be time-consuming and costly. This improvement in response time is crucial for maintaining customer trust and reliability in the power supply.

Another significant advantage is the digitalization of substation equipment. Transitioning from analog to digital systems allows for more precise monitoring and control of electrical infrastructure. Digital systems are generally more reliable and easier to maintain, reducing the likelihood of equipment failures. Additionally, digitalization facilitates better data collection and analysis, enabling more informed decision-making and proactive maintenance strategies. This shift not only improves operational efficiency but also supports the integration of advanced technologies such as smart grids, which are essential for modernizing the power grid and enhancing its resilience.

The program also contributes to the reduction of Operations and Maintenance (O&M) costs, particularly in the testing of electromechanical relays that require periodic adjustments. Digital relays, in contrast, are more stable and require less frequent testing and calibration. This reduction in maintenance needs translates to lower labor costs and fewer disruptions to the power supply. Moreover, the increased reliability of digital relays enhances the overall safety and stability of the electrical system, providing a more consistent and dependable service to customers. This cost-saving aspect is particularly important for utility companies looking to optimize their budgets and allocate resources more effectively.

Safety during operation activities is another critical benefit of this program. By implementing advanced monitoring and control systems, the risk of accidents and equipment malfunctions is significantly reduced. Proper system protection coordination ensures that any faults or issues are quickly detected and isolated, preventing them from escalating into more serious problems. Additionally, the program's focus on data collection for planning purposes allows for better outage assessment and future infrastructure improvements. This proactive approach to system management not only enhances safety but also ensures a more resilient and reliable power supply for all users. The emphasis on safety is paramount, as it protects both the workforce and the general public from potential hazards.

Furthermore, the program's ability to provide proper system protection coordination and outage assessment is invaluable. By ensuring that the electrical system is well-coordinated and protected, the program minimizes the risk of widespread outages and ensures that any disruptions are quickly contained. This level of coordination is essential for maintaining the integrity of the power grid and preventing cascading failures that could lead to extensive blackouts. The ability to assess outages accurately also helps in identifying the root causes of issues and implementing effective solutions, thereby improving the overall reliability of the power supply.

Lastly, the data collection aspect of the program plays a crucial role in planning and future development. By gathering detailed information on the performance and condition of the electrical infrastructure, utility companies can make more informed decisions about upgrades, maintenance, and expansions. This data-driven approach allows for better resource allocation and prioritization of projects, ensuring that investments are made where they are most needed. Additionally, the insights gained from data analysis can help in predicting future trends and challenges, enabling proactive measures to be taken to address potential issues before they become critical. This forward-thinking strategy is essential for building a robust and adaptable power grid that can meet the demands of the future.

Project Risks and Mitigation Plan:

Delays in the installation of Remote Terminal Units (RTUs) and digital relays could disrupt the project timeline, leading to extended downtime and increased costs. To mitigate this risk, we will develop a comprehensive project schedule with clear milestones and deadlines. Establishing strong communication channels with vendors will ensure the timely delivery of equipment. Additionally, we will allocate buffer time in the schedule to accommodate potential delays.

Integrating new RTUs and digital relays with the existing SCADA system may encounter technical difficulties, leading to compatibility issues and operational disruptions. To address this, we will conduct a thorough technical assessment of the existing SCADA system to identify potential integration challenges. Implementing pilot testing for the integration process will help identify and resolve issues before full-scale deployment. We will also engage with SCADA and relay integration experts to provide guidance and support during the integration process.

The transition to new RTUs and digital relays may cause temporary system downtime, affecting the reliability of the network. To minimize this impact, we will implement the upgrades in phases. Backup systems will be in place to maintain power supply during the transition. Additionally, we will develop a communication plan to inform stakeholders and customers about potential downtime and mitigation measures.

Unexpected costs related to equipment, labor, or technical issues could lead to budget overruns. To manage this risk, we will implement regular budget monitoring and reporting to track expenses. Identifying and implementing cost control measures will help manage and reduce expenses. We will also allocate a contingency fund to cover unexpected costs.

Risk of No Action:

If this program is not pursued, our SCADA (Supervisory Control and Data Acquisition) system will lack the necessary visibility and remote-control capabilities over the substation equipment. This deficiency will have several critical impacts. Without visibility, NYSEG will be unable to monitor the status changes of substation equipment, including being unaware of equipment alarms and the positions of various components. Such a lack of awareness can lead to undetected substation failures, which may negatively impact the System Average Interruption Frequency Index (SAIFI). SAIFI is a key performance indicator that measures the average number of interruptions a customer experiences. Therefore, undetected issues could result in more frequent and prolonged outages.

The absence of remote-control capabilities will necessitate manual operations by RGE crews. This means that any adjustments or repairs will require physical presence at the substation, significantly increasing the time required to restore service to customers. Consequently, this will lead to longer restoration times and decreased customer satisfaction. The ability to remotely control substation equipment is crucial for timely interventions and efficient management of the power grid.

Without digital relays, there will be a miscoordination within the protection system. Digital relays are crucial for the accurate detection and isolation of faults. Their absence can lead to improper fault isolation, causing wider outages and further impacting SAIFI. Additionally, NYSEG engineers will be unable to perform effective fault assessments, hindering their ability to diagnose and resolve issues promptly. This lack of coordination can result in more extensive damage to the electrical infrastructure and longer recovery times.

Furthermore, the lack of visibility and remote-control capabilities will prevent RGE from implementing proactive maintenance strategies. Proactive maintenance relies on real-time data and alerts to identify potential issues before they escalate into major problems. Without this capability, NYSEG will be forced to rely on reactive maintenance, which is less efficient and more costly. This reactive approach can lead to increased wear and tear on equipment, reducing its lifespan and increasing the likelihood of unexpected failures.

The inability to monitor and control substation equipment remotely also poses significant safety risks. Manual operations require personnel to be physically present at the substation, exposing them to potential hazards. Remote control capabilities allow for safer operations by minimizing the need for on-site interventions. Ensuring the safety of RGE personnel is paramount, and the implementation of this program is essential to achieving that goal.

Not pursuing this program will severely compromise the efficiency and reliability of our substation operations. It will lead to increased outage frequencies and durations, negatively impacting customer satisfaction and operational performance. The lack of visibility, remote control capabilities, and digital relays will hinder RGE's ability to manage the power grid effectively, resulting in higher costs, safety risks, and reduced service quality. Therefore, it is imperative to move forward with this program to ensure the continued reliability and safety of our electrical infrastructure.

Project Alternatives:

One alternative could be to continue using the existing electromechanical relays and manually operated systems. While this approach would avoid the initial costs associated with upgrading to Remote Terminal Units (RTUs) and digital relays, it would not address the long-term inefficiencies and reliability issues inherent in the current system. The lack of advanced features such as self-diagnostics, event recording, and remote configuration would mean continued reliance on manual intervention, which is both time-consuming and prone to human error. This could lead to prolonged downtimes and increased operational costs, ultimately affecting the reliability of our power distribution network.

Another alternative could be to implement a partial upgrade, where only the most critical substations receive RTUs and digital relays, while others remain unchanged. This approach would reduce the overall cost of the program but would result in an inconsistent level of operational efficiency and reliability across the network. The substations without upgrades would continue to face the same challenges, potentially leading to uneven performance and increased maintenance costs over time. This inconsistency could also complicate the management and monitoring of the network, making it difficult to achieve the desired improvements in operational efficiency and reliability.

A third alternative might involve outsourcing the monitoring and control of substations to a third-party service provider. While this could potentially reduce the burden on internal resources and provide access to specialized expertise, it would also introduce new risks related to data security, control, and dependency on external vendors. Additionally, the long-term costs of outsourcing could outweigh the benefits, especially if the service provider's fees increase over time. There is also the risk of losing critical in-house knowledge and expertise, which could be detrimental in the event of an emergency or if the service provider fails to meet expectations.

A fourth alternative to the proposed program could involve installing line sensors or Shark meters instead of RTUs. Line sensors and Shark meters are designed to monitor electrical parameters such as voltage, current, and power quality. While these devices can provide valuable data for monitoring the performance of the power distribution network, they do not offer the same level of control and integration as RTUs. Line sensors are primarily used for detecting faults and monitoring line conditions, but they lack the capability to control and automate the operation of substations. Similarly, Shark meters provide detailed measurements and analytics but are not designed to interface with SCADA systems for remote control and automation. The main limitation of using line sensors or Shark meters as an alternative is that they do not facilitate seamless communication and control across the network. RTUs, on the other hand, are specifically designed to interface with SCADA systems, enabling real-time monitoring, control, and automation of substations. This integration is crucial for achieving the program's objective of enhancing operational efficiency and reliability. Additionally, line sensors and Shark meters do not offer the advanced features of digital relays, such as self-diagnostics, event recording, and remote configuration. These features are essential for precise and reliable system protection, which is a key component of the proposed program. Without these capabilities, the network would continue to rely on manual intervention and face challenges in achieving consistent performance and reliability.

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within RGE. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 3,578	\$ 695	\$ 948	\$ 696	\$ 680	\$ 559		
# CIAC	\$ -2	\$ -	\$ -	\$ -1	\$ -1	\$ -		
# External Services	\$ 15,868	\$ 3,714	\$ 5,376	\$ 4,785	\$ 699	\$ 1,293		
# Internal - Non-AC	\$ 447	\$ 4	\$ 69	\$ 62	\$ 66	\$ 245		
# Internal, Labor	\$ 3,908	\$ 1,160	\$ 674	\$ 658	\$ 864	\$ 552		
# Internal, Overheads	\$ 4,070	\$ 1,093	\$ 1,244	\$ 1,098	\$ 304	\$ 330		
# Materials	\$ 7,544	\$ 2,709	\$ 1,536	\$ 2,589	\$ 551	\$ 159		
# Overheads - External	\$ 6,486	\$ 1,701	\$ 1,749	\$ 1,678	\$ 745	\$ 613		
Total	\$ 41,897	\$ 11,076	\$ 11,596	\$ 11,566	\$ 3,908	\$ 3,752		

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ 16	\$ 8	\$ 7	\$ 1	\$ -	\$ -		
Materials	\$ 5	\$ 4	\$ 1	\$ -	\$ -	\$ -		
Other O&M	\$ 14	\$ 7	\$ 5	\$ 2	\$ -	\$ 1		
Total	\$ 35	\$ 19	\$ 13	\$ 2	\$ -	\$ 1		

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 3,463	\$ 586	\$ 573	\$ 654	\$ -	\$ 550	\$ 550	\$ 550
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 30,797	\$ 2,885	\$ 5,189	\$ 6,007	\$ 4,216	\$ 4,000	\$ 4,200	\$ 4,300
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 11,762	\$ 824	\$ 838	\$ 621	\$ 1,229	\$ 2,750	\$ 2,750	\$ 2,750
# Internal, Overheads	\$ 4,164	\$ 510	\$ 748	\$ 666	\$ 507	\$ 496	\$ 554	\$ 682
# Materials	\$ 6,721	\$ 1,725	\$ 1,584	\$ 2,003	\$ 1,409	\$ -	\$ -	\$ -
# Overheads - External	\$ 6,364	\$ 627	\$ 938	\$ 776	\$ 712	\$ 958	\$ 1,058	\$ 1,295
Total	\$ 63,270	\$ 7,158	\$ 9,869	\$ 10,727	\$ 8,073	\$ 8,754	\$ 9,111	\$ 9,577

[illegible]

Resiliency

PROJECT INFORMATION

OpCo: NYSEG	Project ID: UH-N0005682-NYSEG-ED	Charge Code: Electric Distribution	Project Sponsor: Fairchild, Jon	Project Type: Annual Program
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: IP2 Technical	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

Background: NYSEG implemented the Resiliency Program to enhance its distribution system's ability to withstand severe weather and major storms, thereby reducing the frequency and impact of outages. This initiative is vital for ensuring safe, reliable electricity service amid increasing climate change risks. The NYSEG service area is particularly susceptible to intense windstorms, heavy thunderstorms with lightning, occasional tornadic activity, ice storms, and heavy snowstorms, all of which can severely damage the overhead transmission and distribution system. By targeting the worst-performing circuits, the Resiliency Program aims to significantly improve service quality through strategies designed to prevent and limit outages and expedite power restoration after significant disruptions.

The Resiliency Plan focuses on three components to limit outages resulting from severe storms on worst-performing circuits:

1. Circuit Ties and Automation: Create connections between adjacent circuits ("circuit ties") to provide an N-1 backup power source during outages and use automation technology to operate these circuit ties without sending electrical workers into the field.
2. Infrastructure Hardening: Utilize Avangrid's Distribution Resiliency Guide to apply stronger designs and infrastructure standards to damage-susceptible circuits, reducing the frequency and impact of outages.
3. Enhanced Vegetation Management (EVM): Implement Enhanced Vegetation Management techniques, such as ground-to-sky clearing, to reduce the probability of tree-related outages along targeted line sections.

Project Justification: NYSEG prioritizes resiliency investments based on the most recent three-year average System Average Interruption Frequency Index (SAIFI) with storm data above 2.2 and an individual SAIFI contribution lower than 0.14%. The SAIFI contribution of each circuit to the total system SAIFI is ranked, with priority 1 assigned to the circuit with the highest SAIFI score.

NYSEG 2026 Distribution Resiliency Plan IP2 is being provided as supporting documentation on annual resiliency plans that will be developed annually from 2027-2031.

Project Scope:

NYSEG has estimated a preliminary annual budget of \$6-8 million per circuit, depending on system needs, which could extend into adjacent circuits to support creating or improving N-1 circuit ties and substation upgrades. The 2027-2031 Resiliency Project Description and Scope of Work will be evaluated annually by Distribution Planning Management to ensure alignment with the most recent three-year average SAIFI with storm data when selecting appropriate circuits. Circuits selected each year will be evaluated for system needs, providing justification, benefits, and solution alternatives. Solutions may include enhanced vegetation management (including hazard tree removal), application of animal guards, establishment of more robust design standards for poles and other utility infrastructure, and distribution automation and topology changes that enable circuit reconfiguration and power rerouting. The expected project in-service date for each annual resiliency plan will be in the fourth quarter for from 2026 to 2031.

Project Benefits:

The Resiliency Program is a key part of NYSEG's approach to enhancing the reliability and robustness of our distribution system. With the increasing frequency and severity of extreme weather events due to climate change, investments in resiliency are crucial to prevent and mitigate outages, ensuring continuous and safe electricity service for our customers and communities.

Specific needs and alternative solutions will be identified in each project scope annually from 2026-2031. These solutions will aim to improve pole health, operating circuit voltage, power quality, and decrease outage duration and frequency. Increasing the equipment rating for circuits approaching overload conditions and/or right-sizing for potential topography changes and load transfers will allow for increased flexibility in circuit restoration. Installing tree wire and performing enhanced "ground-to-sky" clearance of vegetation will mitigate tree-related outages. Among the most notable benefits are the following:

1. Improved Reliability: The project will mitigate the risk of weather and tree-related customer outages in the area. Avoiding or limiting the scope of outages will improve system SAIFI as well as overall customer experience.
2. Operational Cost Savings: Implementing circuit ties and automation reduces the need to dispatch field crews for switching operations, leading to savings on operational expenses. Infrastructure hardening will decrease the frequency of outages, reducing repair and maintenance expenses.
3. Asset Longevity: Infrastructure designed to withstand severe weather conditions is less likely to be damaged during storms and other weather events, thus avoiding early replacement of assets.

Project Risks and Mitigation Plan:

1. Execution Challenges: The project schedule could be impacted by field conditions, particularly in heavily wooded or environmentally sensitive areas, where it can be difficult to access infrastructure with heavy equipment. Weather delays are also a risk in distribution construction because of worker safety concerns. These risks will be addressed by incorporating contingency into our construction schedules.

2. Material Availability: Difficulty in sourcing long lead-time and/or scarce equipment can adversely impact project schedules and costs. Equipment sourcing risks will be mitigated by identifying proposed equipment which is subject to long lead times and ordering such equipment proactively, as appropriate, to minimize the risk of project delays.

3. Re-Prioritization: The Resiliency Program is periodically re-evaluated based on updated customer outage data. It is possible that this project may be deferred to a future year if it is deemed to have a lower priority based on a future re-evaluation of the Resiliency Program. This risk is mitigated by the fact, in the event of a deferral due to reprioritization, funding would be redirected to a higher-priority resiliency project.

4. Property Owner Opposition: Customers with property abutting electric infrastructure may oppose aspects of the project such as infrastructure relocation or vegetation trimming/clearing. In certain circumstances, failure to perform proposed work that is opposed by property owners can negatively affect the efficacy of resiliency projects. To mitigate this risk, NYSEG will proactively engage in outreach to abutting property owners to notify them of the proposed work. If concerns are raised, NYSEG will engage in a dialog to determine what accommodations can reasonably be made and to emphasize the benefits of the project to the community. If work cannot proceed as planned due to opposition from a property owner, the scope of work will be re-evaluated.

Risk of No Action:

The main risks to NYSEG and their customers from taking no action include infrastructure damage from more frequent and intense storms accompanied by heavy snow, ice, and high winds, leading to power outages that could last multiple days. Inaction on circuits with a history of major outages would allow existing equipment to fail and miss the potential benefits of Circuit Automation schemes, reducing flexibility in circuit restoration. This would result in longer, more frequent customer outages, which are more costly for the utility to restore. Additionally, financial impacts could involve increased costs due to inefficient fault management and manual operations.

Failure to take action to improve system reliability also threatens NYSEG's ability to meet customer expectations as well as to satisfy regulatory performance targets for metrics such as SAIFI and CAIDI.

Project Alternatives:

Project alternatives will be evaluated annually by Distribution Planning, focusing on immediate circuit needs based on outage data and identifying voltage, thermal, and N-1 constraints. While the primary objective is to create a more resilient circuit, resolving under/over voltages and thermal overloading is the minimum requirement. It is crucial to consider the broader implications of foregoing additional resiliency strategies to improve circuit SAIFI.

Basis for Project Estimates

Project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 4,531	\$ 765	\$ 779	\$ 998	\$ 1,047	\$ 941		
# CIAC	\$ -1,072	\$ -6	\$ -92	\$ -11	\$ -237	\$ -726		
# External Services	\$ 63,811	\$ 9,336	\$ 19,789	\$ 17,596	\$ 10,925	\$ 6,165		
# Internal - Non-AC	\$ -8	\$ -8	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ 1,427	\$ 244	\$ 28	\$ 55	\$ 15	\$ 1,084		
# Internal, Overheads	\$ 13,457	\$ 2,208	\$ 3,913	\$ 3,151	\$ 2,687	\$ 1,498		
# Materials	\$ 26,103	\$ 5,001	\$ 4,695	\$ 6,180	\$ 7,700	\$ 2,526		
# Overheads - External	\$ 19,353	\$ 2,879	\$ 5,111	\$ 4,747	\$ 4,270	\$ 2,346		
Total	\$ 127,601	\$ 20,420	\$ 34,223	\$ 32,716	\$ 26,407	\$ 13,836		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 928	\$ 925	\$ 2	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 61,400	\$ 9,572	\$ 78	\$ -	\$ 3,026	\$ 3,743	\$ 19,483	\$ 25,498
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -2,426	\$ -2,426	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 3,864	\$ -193	\$ 8	\$ -	\$ 202	\$ 245	\$ 1,390	\$ 2,212
# Materials	\$ -7,889	\$ -7,897	\$ 8	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 4,248	\$ 20	\$ 8	\$ -	\$ 211	\$ 256	\$ 1,449	\$ 2,305
Total	\$ 60,125	\$ 1	\$ 104	\$ -	\$ 3,440	\$ 4,245	\$ 22,322	\$ 30,014

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 787	\$ 90	\$ 95	\$ -	\$ 146	\$ 149	\$ 152	\$ 155
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 787	\$ 90	\$ 95	\$ -	\$ 146	\$ 149	\$ 152	\$ 155

Lancaster Project - Losson Road Substation 34.5/12.5 kV GIS Upgrade

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007398	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

The Losson Road Substation 34.5-12.5 kV GIS Upgrade project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Division Grid Modernization Pilot is a comprehensive initiative aimed at addressing critical needs related to system reliability, aging infrastructure, electrification readiness, and network resilience. The project aligns with state energy policy objectives and utility planning standards, providing a forward-looking framework to modernize both the distribution and sub-transmission networks.

This project also represents a shift in planning philosophy. It introduces a differentiated approach not only in execution, but in how system needs are identified and addressed. Rather than applying traditional asset-by-asset solutions, NYSEG has adopted a zonal planning model, grounded in an in-depth analysis of local network performance, asset condition, and long-term demand forecasts. The result is a holistic solution tailored to the specific needs of the Lancaster area—improving reliability, optimizing capacity, reducing operational costs, and enabling future growth in a coordinated and scalable way.

Project Justification

- **Reliability:** Between 2020 and 2022, the Lancaster Division accounted for approximately 19% of NYSEG's total SAIFI (System Average Interruption Frequency Index) impact. Three substations—Losson Rd, Blossom Rd, and Walden Ave—were among the poorest performers system-wide.
- **Asset Condition:** Multiple substations were identified with outdated transformers, electromechanical relays, deteriorated switchgear, and poor structural conditions, many lacking SCADA visibility or control.
- **Resiliency & Redundancy:** The area lacks sufficient N-1 contingency support, making it vulnerable to prolonged outages and limiting the ability to automatically isolate and restore faults.
- **Load Growth:** Forecasts project a 30% increase in peak demand by 2037, driven by building electrification and electric vehicle (EV) adoption.

Project Scope:

The Losson Road Substation 34.5-12.5 kV GIS Upgrade is a subproject of the Lancaster Grid Modernization Project. The Lancaster Grid Modernization Pilot proposes a comprehensive reconfiguration of the electric distribution and sub-transmission network in one of NYSEG's highest-impact service areas. The initiative targets a region that serves approximately 177,000 customers and carries roughly 690 MW of system load, representing a substantial portion of NYSEG's reliability performance metrics. The scope includes infrastructure upgrades, voltage conversions, substation retirements, and implementation of advanced system automation, all designed to improve reliability, resilience, and operational efficiency.

Main Infrastructure Components

1. Rebuild of Key Substations

- Losson Road (34.5/12.5 kV GIS): Full rebuild with 9 feeders and 2×50 MVA transformers
- Blossom Road (34.5/12.5 kV GIS): Full rebuild with 6 feeders and 2×37.3 MVA transformers
- Walden Avenue (115/12.5 kV AIS): Upgrade with 9 feeders, 2×50 MVA transformers, new breakers, and control house

2. Substation Retirements - Aging infrastructure with poor condition ratings, obsolete equipment, and limited operational visibility

- Five legacy substations to be retired: Sloan, Ellicott, Ebenezer, Indian Church, and Depew

3. Construction of two new 12.5 kV distribution centers to serve as centralized and automated feeder hubs strategically located at Sloan and Losson to enable rapid fault isolation, load transfer, and network reconfiguration

4. North Broadway Substation Expansion and Depew Line Replacement

- Installation of three new 115 kV breakers and expansion of the 34.5 kV yard with three new breakers
- Addition of a new 50 MVA 115/34.5 kV transformer
- Construction of a new 34.5 kV line to reroute Line 532 into North Broadway, enabling the full retirement of Depew substation

5. Distribution upgrades (Blossom Rd, Losson Rd and Walden Ave & Sloan)

- Conversion of approximately 75 miles of distribution circuits from legacy 4.8 kV to standard 12.5 kV
- Upgrades to conductor sizes (up to 477 AL) to increase thermal capacity and reduce voltage drop

6. Installation of multiple 12.5 kV express feeders between substations and distribution centers (~10 miles total).

Additional Technical Elements

- Integration of SCADA control and visibility across all new and upgraded facilities
- Enhanced remote operation capabilities and automated restoration (self-healing features)
- System-wide reconfiguration to ensure all 12.5 kV feeders operate in phase
- Elimination of backlot lines and inaccessible equipment to improve maintenance and safety

Project Benefits:**1. Enhanced System Reliability**

The project directly addresses chronic reliability issues in one of NYSEG's most outage-prone areas. By replacing obsolete substations and reconfiguring the network, the initiative is expected to reduce SAIFI across the NYSEG system by an estimated 2.15%. This translates into fewer and shorter outages for nearly 177,000 customers, aligning with state reliability standards and improving service equity across the grid.

2. Improved Resilience and Contingency Support

Through the construction of new distribution centers and the expansion of strategic substations like North Broadway, the project introduces much-needed N-1 contingency capability to the area. This ensures that the system can withstand the failure of a single major component without causing widespread outages, significantly strengthening grid resilience in the face of storms and equipment failures.

3. Optimization of System Capacity and Load Transfer Flexibility

The conversion of legacy 4.8 kV circuits to 12.5 kV and the installation of express feeders improve the system's ability to transfer load between feeders and substations efficiently. This expanded tie capability allows for faster restoration and real-time operational flexibility, which is especially important as demand increases and load patterns shift due to electrification.

4. Long-Term Cost Efficiency

By retiring five aging substations and consolidating infrastructure, the project eliminates high-maintenance assets and reduces operational expenditures. NYSEG estimates annual O&M savings of approximately \$815,000, providing financial relief over the long term while maintaining or improving service levels. These savings also help moderate future rate impacts for customers.

5. Grid Readiness for Electrification and Future Growth

The upgraded network will support up to 52 MVA of additional load, preparing the system for forecasted growth in electric vehicles, electric heating, and distributed energy resources (DERs). With capacity in place, NYSEG can accommodate customer transitions to cleaner energy without compromising reliability or triggering reactive investment.

6. Modernized Operational Capabilities

All rebuilt and new facilities will be integrated into NYSEG's SCADA system, enabling full remote visibility and control. Combined with automated switching and advanced protection schemes, this will shorten restoration times, enable predictive maintenance, and improve outage response across the service area.

7. Risk Mitigation and Safety Improvements

The project eliminates numerous backlot lines and inaccessible infrastructure, reducing risk for field crews and enhancing public safety. Retired substations and upgraded sites also reduce the likelihood of equipment-related environmental incidents, aligning with modern utility safety and compliance standards.

Project Risks and Mitigation Plan:**1. Construction and Execution Risk**

Due to the scale and complexity of the project, there is a risk of delays related to permitting, material lead times, contractor mobilization, and construction sequencing. To mitigate this, NYSEG will adopt a phased execution strategy, prioritize early design finalization, and initiate procurement of long-lead equipment such as transformers and breakers well in advance. A detailed construction schedule will be developed and closely monitored to manage critical path activities.

2. Cost Escalation and Budget Risk

Material price volatility, labor cost increases, and potential supply chain disruptions could impact the project budget. NYSEG will include contingency allowances in the financial planning and will implement cost tracking systems to monitor expenditures. Regular budget reviews and a formal process for identifying and responding to cost deviations will be established to maintain financial discipline.

3. System Integration and Operational Transition Risk

Transitioning from legacy infrastructure to the new network configuration—especially during substation retirements and feeder reconfigurations—could pose operational risks, including service interruptions. NYSEG will prepare detailed transition and cutover plans, including temporary configurations and backup solutions such as mobile substations, to minimize impacts to customers during system switchover periods.

4. Stakeholder and Community Impact Risk

Construction activities may temporarily affect local communities through traffic disruptions, noise, or access limitations. To address this, NYSEG will engage proactively with municipalities and stakeholders, provide advance notice of planned work, and coordinate closely to minimize disruptions. Communication plans will be put in place to keep the public informed throughout the project.

5. Environmental and Regulatory Compliance Risk

Project components involving civil works or equipment installation may require environmental permitting and regulatory reviews. NYSEG will conduct thorough pre-construction environmental assessments and will work with regulatory agencies to secure all necessary approvals. Compliance will be monitored throughout the project by internal teams and external environmental consultants.

6. Technology Integration and Cybersecurity Risk

The integration of SCADA systems, protection relays, and remote switching technologies introduces risks related to system compatibility and cybersecurity. NYSEG will perform comprehensive factory and site acceptance testing, follow standard protocols for equipment integration, and implement cybersecurity reviews in line with internal policies and industry best practices.

Risk of No Action:

In addition to the project execution risks, it is important to highlight the significant consequences of inaction—should the Lancaster Grid Modernization Project be delayed, deferred, or not implemented. These risks would affect both operational performance and long-term strategic objectives:

1. Continued System Reliability Degradation

Several of the substations in the project scope are among the worst performers in NYSEG's service territory in terms of SAIFI and SAIDI. Without modernization, customers in the region would continue to experience frequent and prolonged outages. Aging infrastructure increases the likelihood of unplanned failures, which could further degrade service quality and lead to regulatory penalties.

2. Inability to Support Load Growth and Electrification

The existing 4.8 kV infrastructure and current system configuration cannot accommodate forecasted demand growth driven by electrification (EVs, heat pumps, DERs). Delaying the project would constrain NYSEG's ability to connect new load and meet statewide decarbonization and electrification goals. It may also lead to more reactive, less efficient capital spending in the future.

3. Escalating Maintenance and Operational Costs

Aging substations and equipment require increasingly frequent maintenance and emergency repairs. Without proactive investment, O&M costs will continue to rise, driven by unplanned interventions and inefficient asset management. This also ties up workforce resources that could otherwise support strategic initiatives.

4. Increased Risk of Equipment Failure and Safety Incidents

Legacy equipment poses not only reliability risks but also safety and environmental risks. Continued operation of deteriorated assets increases the chance of equipment failure, potential fire hazards, oil spills, and unsafe working conditions for field personnel.

5. Missed Opportunity for Operational Modernization

Postponing the project would delay the deployment of advanced grid functionalities such as SCADA, remote switching, and self-healing networks. This limits NYSEG's ability to improve outage response times, reduce truck rolls, and integrate data-driven system operations.

6. Reduced Long-Term Cost Efficiency

Failure to act now could result in higher future capital expenditures. Delaying coordinated modernization may force NYSEG to invest in piecemeal upgrades under time and reliability pressures, which are typically less cost-effective than comprehensive, planned reinforcements.

Project Alternatives:

As part of the planning process, NYSEG evaluated multiple alternatives to address the reliability, capacity, and asset condition issues in the Lancaster Division. Each alternative was assessed based on technical feasibility, cost-effectiveness, reliability benefits, future readiness, and constructability. The alternatives ranged from minimal intervention to full system reconfiguration.

Alternative 0 – Do Nothing

This baseline alternative would involve no proactive investment and would rely on continued operation and maintenance of the existing infrastructure.

- Pros: No upfront capital cost
- Cons: No improvement in reliability or capacity, continued deterioration of assets, increasing O&M costs, and high risk of equipment failure
- Conclusion: Not viable. This alternative fails to meet basic planning criteria and leaves the system vulnerable.

Alternative 1 – Limited Substation Replacement

This alternative proposed rebuilding only one or two of the most critical substations (e.g., Walden Avenue and Blossom Road), while keeping the rest of the network intact.

- Pros: Moderate capital cost, localized improvement at high-impact substations
- Cons: Minimal impact on broader network reliability and redundancy; does not address 4.8 kV conversion or N-1 contingency gaps; limited long-term scalability
- Conclusion: Provides partial benefit but does not support a comprehensive modernization strategy.

Alternative 2 – Comprehensive Grid Modernization (Selected)

This alternative includes the full rebuild of three major substations, retirement of five legacy substations, conversion of 4.8 kV to 12.5 kV, construction of two new distribution centers, and expansion of North Broadway.

- Pros: Maximizes reliability improvement (2.15% SAIFI reduction), fully resolves N-1 contingency deficiencies, supports long-term electrification, enables flexible load transfer, and reduces O&M costs
- Cons: Higher initial capital investment
- Additional Note: Within this alternative, multiple grid modernization configurations were evaluated, varying in substation design, feeder layout, and sequencing strategy. The selected configuration was found to be the most cost-effective while meeting all technical and operational objectives.
- Conclusion: Selected as the preferred solution due to its comprehensive, long-term value and alignment with utility and regulatory objectives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 2,865	\$ 262	\$ 987	\$ 1,218	\$ 398	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 7,021	\$ 642	\$ 2,419	\$ 2,984	\$ 977	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 713	\$ 65	\$ 245	\$ 303	\$ 99	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 2,470	\$ 218	\$ 991	\$ 964	\$ 296	\$ -	\$ -	\$ -
# Materials	\$ 18,956	\$ 1,732	\$ 6,530	\$ 8,056	\$ 2,637	\$ -	\$ -	\$ -
# Overheads - External	\$ 2,505	\$ 289	\$ 976	\$ 949	\$ 291	\$ -	\$ -	\$ -
Total	\$ 34,528	\$ 3,208	\$ 12,148	\$ 14,474	\$ 4,698	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Lancaster Project - Blossom Road Substation 34.5/12.5 kV GIS Upgrade

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007397	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2025

Project description:

The Blossom Road Substation 34.5-12.5 kV GIS Upgrade project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Division Grid Modernization Pilot is a comprehensive initiative aimed at addressing critical needs related to system reliability, aging infrastructure, electrification readiness, and network resilience. The project aligns with state energy policy objectives and utility planning standards, providing a forward-looking framework to modernize both the distribution and sub-transmission networks.

This project also represents a shift in planning philosophy. It introduces a differentiated approach not only in execution, but in how system needs are identified and addressed. Rather than applying traditional asset-by-asset solutions, NYSEG has adopted a zonal planning model, grounded in an in-depth analysis of local network performance, asset condition, and long-term demand forecasts. The result is a holistic solution tailored to the specific needs of the Lancaster area—improving reliability, optimizing capacity, reducing operational costs, and enabling future growth in a coordinated and scalable way.

Project Justification

- **Reliability:** Between 2020 and 2022, the Lancaster Division accounted for approximately 19% of NYSEG's total SAIFI (System Average Interruption Frequency Index) impact. Three substations—Losson Rd, Blossom Rd, and Walden Ave—were among the poorest performers system-wide.
- **Asset Condition:** Multiple substations were identified with outdated transformers, electromechanical relays, deteriorated switchgear, and poor structural conditions, many lacking SCADA visibility or control.
- **Resiliency & Redundancy:** The area lacks sufficient N-1 contingency support, making it vulnerable to prolonged outages and limiting the ability to automatically isolate and restore faults.
- **Load Growth:** Forecasts project a 30% increase in peak demand by 2037, driven by building electrification and electric vehicle (EV) adoption.

Project Scope:

The Blossom Road Substation 34.5-12.5 kV GIS Upgrade is a subproject of the Lancaster Grid Modernization Project. The Lancaster Grid Modernization Pilot proposes a comprehensive reconfiguration of the electric distribution and sub-transmission network in one of NYSEG's highest-impact service areas. The initiative targets a region that serves approximately 177,000 customers and carries roughly 690 MW of system load, representing a substantial portion of NYSEG's reliability performance metrics. The scope includes infrastructure upgrades, voltage conversions, substation retirements, and implementation of advanced system automation, all designed to improve reliability, resilience, and operational efficiency.

Main Infrastructure Components

1. Rebuild of Key Substations

- Losson Road (34.5/12.5 kV GIS): Full rebuild with 9 feeders and 2×50 MVA transformers
- Blossom Road (34.5/12.5 kV GIS): Full rebuild with 6 feeders and 2×37.3 MVA transformers
- Walden Avenue (115/12.5 kV AIS): Upgrade with 9 feeders, 2×50 MVA transformers, new breakers, and control house

2. Substation Retirements - Aging infrastructure with poor condition ratings, obsolete equipment, and limited operational visibility

- Five legacy substations to be retired: Sloan, Ellicott, Ebenezer, Indian Church, and Depew

3. Construction of two new 12.5 kV distribution centers to serve as centralized and automated feeder hubs strategically located at Sloan and Losson to enable rapid fault isolation, load transfer, and network reconfiguration

4. North Broadway Substation Expansion and Depew Line Replacement

- Installation of three new 115 kV breakers and expansion of the 34.5 kV yard with three new breakers
- Addition of a new 50 MVA 115/34.5 kV transformer
- Construction of a new 34.5 kV line to reroute Line 532 into North Broadway, enabling the full retirement of Depew substation

5. Distribution upgrades (Blossom Rd, Losson Rd and Walden Ave & Sloan)

- Conversion of approximately 75 miles of distribution circuits from legacy 4.8 kV to standard 12.5 kV
- Upgrades to conductor sizes (up to 477 AL) to increase thermal capacity and reduce voltage drop

6. Installation of multiple 12.5 kV express feeders between substations and distribution centers (~10 miles total).

Additional Technical Elements

- Integration of SCADA control and visibility across all new and upgraded facilities
- Enhanced remote operation capabilities and automated restoration (self-healing features)
- System-wide reconfiguration to ensure all 12.5 kV feeders operate in phase
- Elimination of backlot lines and inaccessible equipment to improve maintenance and safety

Project Benefits:**1. Enhanced System Reliability**

The project directly addresses chronic reliability issues in one of NYSEG's most outage-prone areas. By replacing obsolete substations and reconfiguring the network, the initiative is expected to reduce SAIFI across the NYSEG system by an estimated 2.15%. This translates into fewer and shorter outages for nearly 177,000 customers, aligning with state reliability standards and improving service equity across the grid.

2. Improved Resilience and Contingency Support

Through the construction of new distribution centers and the expansion of strategic substations like North Broadway, the project introduces much-needed N-1 contingency capability to the area. This ensures that the system can withstand the failure of a single major component without causing widespread outages, significantly strengthening grid resilience in the face of storms and equipment failures.

3. Optimization of System Capacity and Load Transfer Flexibility

The conversion of legacy 4.8 kV circuits to 12.5 kV and the installation of express feeders improve the system's ability to transfer load between feeders and substations efficiently. This expanded tie capability allows for faster restoration and real-time operational flexibility, which is especially important as demand increases and load patterns shift due to electrification.

4. Long-Term Cost Efficiency

By retiring five aging substations and consolidating infrastructure, the project eliminates high-maintenance assets and reduces operational expenditures. NYSEG estimates annual O&M savings of approximately \$815,000, providing financial relief over the long term while maintaining or improving service levels. These savings also help moderate future rate impacts for customers.

5. Grid Readiness for Electrification and Future Growth

The upgraded network will support up to 52 MVA of additional load, preparing the system for forecasted growth in electric vehicles, electric heating, and distributed energy resources (DERs). With capacity in place, NYSEG can accommodate customer transitions to cleaner energy without compromising reliability or triggering reactive investment.

6. Modernized Operational Capabilities

All rebuilt and new facilities will be integrated into NYSEG's SCADA system, enabling full remote visibility and control. Combined with automated switching and advanced protection schemes, this will shorten restoration times, enable predictive maintenance, and improve outage response across the service area.

7. Risk Mitigation and Safety Improvements

The project eliminates numerous backlot lines and inaccessible infrastructure, reducing risk for field crews and enhancing public safety. Retired substations and upgraded sites also reduce the likelihood of equipment-related environmental incidents, aligning with modern utility safety and compliance standards.

Project Risks and Mitigation Plan:**1. Construction and Execution Risk**

Due to the scale and complexity of the project, there is a risk of delays related to permitting, material lead times, contractor mobilization, and construction sequencing. To mitigate this, NYSEG will adopt a phased execution strategy, prioritize early design finalization, and initiate procurement of long-lead equipment such as transformers and breakers well in advance. A detailed construction schedule will be developed and closely monitored to manage critical path activities.

2. Cost Escalation and Budget Risk

Material price volatility, labor cost increases, and potential supply chain disruptions could impact the project budget. NYSEG will include contingency allowances in the financial planning and will implement cost tracking systems to monitor expenditures. Regular budget reviews and a formal process for identifying and responding to cost deviations will be established to maintain financial discipline.

3. System Integration and Operational Transition Risk

Transitioning from legacy infrastructure to the new network configuration—especially during substation retirements and feeder reconfigurations—could pose operational risks, including service interruptions. NYSEG will prepare detailed transition and cutover plans, including temporary configurations and backup solutions such as mobile substations, to minimize impacts to customers during system switchover periods.

4. Stakeholder and Community Impact Risk

Construction activities may temporarily affect local communities through traffic disruptions, noise, or access limitations. To address this, NYSEG will engage proactively with municipalities and stakeholders, provide advance notice of planned work, and coordinate closely to minimize disruptions. Communication plans will be put in place to keep the public informed throughout the project.

5. Environmental and Regulatory Compliance Risk

Project components involving civil works or equipment installation may require environmental permitting and regulatory reviews. NYSEG will conduct thorough pre-construction environmental assessments and will work with regulatory agencies to secure all necessary approvals. Compliance will be monitored throughout the project by internal teams and external environmental consultants.

6. Technology Integration and Cybersecurity Risk

The integration of SCADA systems, protection relays, and remote switching technologies introduces risks related to system compatibility and cybersecurity. NYSEG will perform comprehensive factory and site acceptance testing, follow standard protocols for equipment integration, and implement cybersecurity reviews in line with internal policies and industry best practices.

Risk of No Action:

In addition to the project execution risks, it is important to highlight the significant consequences of inaction—should the Lancaster Grid Modernization Project be delayed, deferred, or not implemented. These risks would affect both operational performance and long-term strategic objectives:

1. Continued System Reliability Degradation

Several of the substations in the project scope are among the worst performers in NYSEG's service territory in terms of SAIFI and SAIDI. Without modernization, customers in the region would continue to experience frequent and prolonged outages. Aging infrastructure increases the likelihood of unplanned failures, which could further degrade service quality and lead to regulatory penalties.

2. Inability to Support Load Growth and Electrification

The existing 4.8 kV infrastructure and current system configuration cannot accommodate forecasted demand growth driven by electrification (EVs, heat pumps, DERs). Delaying the project would constrain NYSEG's ability to connect new load and meet statewide decarbonization and electrification goals. It may also lead to more reactive, less efficient capital spending in the future.

3. Escalating Maintenance and Operational Costs

Aging substations and equipment require increasingly frequent maintenance and emergency repairs. Without proactive investment, O&M costs will continue to rise, driven by unplanned interventions and inefficient asset management. This also ties up workforce resources that could otherwise support strategic initiatives.

4. Increased Risk of Equipment Failure and Safety Incidents

Legacy equipment poses not only reliability risks but also safety and environmental risks. Continued operation of deteriorated assets increases the chance of equipment failure, potential fire hazards, oil spills, and unsafe working conditions for field personnel.

5. Missed Opportunity for Operational Modernization

Postponing the project would delay the deployment of advanced grid functionalities such as SCADA, remote switching, and self-healing networks. This limits NYSEG's ability to improve outage response times, reduce truck rolls, and integrate data-driven system operations.

6. Reduced Long-Term Cost Efficiency

Failure to act now could result in higher future capital expenditures. Delaying coordinated modernization may force NYSEG to invest in piecemeal upgrades under time and reliability pressures, which are typically less cost-effective than comprehensive, planned reinforcements.

Project Alternatives:

As part of the planning process, NYSEG evaluated multiple alternatives to address the reliability, capacity, and asset condition issues in the Lancaster Division. Each alternative was assessed based on technical feasibility, cost-effectiveness, reliability benefits, future readiness, and constructability. The alternatives ranged from minimal intervention to full system reconfiguration.

Alternative 0 – Do Nothing

This baseline alternative would involve no proactive investment and would rely on continued operation and maintenance of the existing infrastructure.

- Pros: No upfront capital cost
- Cons: No improvement in reliability or capacity, continued deterioration of assets, increasing O&M costs, and high risk of equipment failure
- Conclusion: Not viable. This alternative fails to meet basic planning criteria and leaves the system vulnerable.

Alternative 1 – Limited Substation Replacement

This alternative proposed rebuilding only one or two of the most critical substations (e.g., Walden Avenue and Blossom Road), while keeping the rest of the network intact.

- Pros: Moderate capital cost, localized improvement at high-impact substations
- Cons: Minimal impact on broader network reliability and redundancy; does not address 4.8 kV conversion or N-1 contingency gaps; limited long-term scalability
- Conclusion: Provides partial benefit but does not support a comprehensive modernization strategy.

Alternative 2 – Comprehensive Grid Modernization (Selected)

This alternative includes the full rebuild of three major substations, retirement of five legacy substations, conversion of 4.8 kV to 12.5 kV, construction of two new distribution centers, and expansion of North Broadway.

- Pros: Maximizes reliability improvement (2.15% SAIFI reduction), fully resolves N-1 contingency deficiencies, supports long-term electrification, enables flexible load transfer, and reduces O&M costs
- Cons: Higher initial capital investment
- Additional Note: Within this alternative, multiple grid modernization configurations were evaluated, varying in substation design, feeder layout, and sequencing strategy. The selected configuration was found to be the most cost-effective while meeting all technical and operational objectives.
- Conclusion: Selected as the preferred solution due to its comprehensive, long-term value and alignment with utility and regulatory objectives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 2,765	\$ 309	\$ 999	\$ 1,273	\$ 183	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 6,776	\$ 757	\$ 2,450	\$ 3,120	\$ 449	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 688	\$ 77	\$ 249	\$ 317	\$ 46	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 2,406	\$ 258	\$ 1,004	\$ 1,008	\$ 136	\$ -	\$ -	\$ -
# Materials	\$ 18,294	\$ 2,045	\$ 6,614	\$ 8,424	\$ 1,211	\$ -	\$ -	\$ -
# Overheads - External	\$ 2,455	\$ 341	\$ 988	\$ 992	\$ 134	\$ -	\$ -	\$ -
Total	\$ 33,383	\$ 3,786	\$ 12,303	\$ 15,135	\$ 2,159	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Lancaster Project - Sloan - Distribution Center

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007396	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

The Sloan - Distribution Center project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Division Grid Modernization Pilot is a comprehensive initiative aimed at addressing critical needs related to system reliability, aging infrastructure, electrification readiness, and network resilience. The project aligns with state energy policy objectives and utility planning standards, providing a forward-looking framework to modernize both the distribution and sub-transmission networks.

This project also represents a shift in planning philosophy. It introduces a differentiated approach not only in execution, but in how system needs are identified and addressed. Rather than applying traditional asset-by-asset solutions, NYSEG has adopted a zonal planning model, grounded in an in-depth analysis of local network performance, asset condition, and long-term demand forecasts. The result is a holistic solution tailored to the specific needs of the Lancaster area—improving reliability, optimizing capacity, reducing operational costs, and enabling future growth in a coordinated and scalable way.

Project Justification

- **Reliability:** Between 2020 and 2022, the Lancaster Division accounted for approximately 19% of NYSEG's total SAIFI (System Average Interruption Frequency Index) impact. Three substations—Losson Rd, Blossom Rd, and Walden Ave—were among the poorest performers system-wide.
- **Asset Condition:** Multiple substations were identified with outdated transformers, electromechanical relays, deteriorated switchgear, and poor structural conditions, many lacking SCADA visibility or control.
- **Resiliency & Redundancy:** The area lacks sufficient N-1 contingency support, making it vulnerable to prolonged outages and limiting the ability to automatically isolate and restore faults.
- **Load Growth:** Forecasts project a 30% increase in peak demand by 2037, driven by building electrification and electric vehicle (EV) adoption.

Project Scope:

The Sloan - Distribution Center is a subproject of the Lancaster Grid Modernization Project. The Lancaster Grid Modernization Pilot proposes a comprehensive reconfiguration of the electric distribution and sub-transmission network in one of NYSEG's highest-impact service areas. The initiative targets a region that serves approximately 177,000 customers and carries roughly 690 MW of system load, representing a substantial portion of NYSEG's reliability performance metrics. The scope includes infrastructure upgrades, voltage conversions, substation retirements, and implementation of advanced system automation, all designed to improve reliability, resilience, and operational efficiency.

Main Infrastructure Components

1. Rebuild of Key Substations
 - Losson Road (34.5/12.5 kV GIS): Full rebuild with 9 feeders and 2×50 MVA transformers
 - Blossom Road (34.5/12.5 kV GIS): Full rebuild with 6 feeders and 2×37.3 MVA transformers
 - Walden Avenue (115/12.5 kV AIS): Upgrade with 9 feeders, 2×50 MVA transformers, new breakers, and control house
2. Substation Retirements - Aging infrastructure with poor condition ratings, obsolete equipment, and limited operational visibility
 - Five legacy substations to be retired: Sloan, Ellicott, Ebenezer, Indian Church, and Depew
3. Construction of two new 12.5 kV distribution centers to serve as centralized and automated feeder hubs strategically located at Sloan and Losson to enable rapid fault isolation, load transfer, and network reconfiguration
4. North Broadway Substation Expansion and Depew Line Replacement
 - Installation of three new 115 kV breakers and expansion of the 34.5 kV yard with three new breakers
 - Addition of a new 50 MVA 115/34.5 kV transformer
 - Construction of a new 34.5 kV line to reroute Line 532 into North Broadway, enabling the full retirement of Depew substation
5. Distribution upgrades (Blossom Rd, Losson Rd and Walden Ave & Sloan)
 - Conversion of approximately 75 miles of distribution circuits from legacy 4.8 kV to standard 12.5 kV
 - Upgrades to conductor sizes (up to 477 AL) to increase thermal capacity and reduce voltage drop
6. Installation of multiple 12.5 kV express feeders between substations and distribution centers (~10 miles total).

Additional Technical Elements

- Integration of SCADA control and visibility across all new and upgraded facilities
- Enhanced remote operation capabilities and automated restoration (self-healing features)
- System-wide reconfiguration to ensure all 12.5 kV feeders operate in phase
- Elimination of backlot lines and inaccessible equipment to improve maintenance and safety

Project Benefits:**1. Enhanced System Reliability**

The project directly addresses chronic reliability issues in one of NYSEG's most outage-prone areas. By replacing obsolete substations and reconfiguring the network, the initiative is expected to reduce SAIFI across the NYSEG system by an estimated 2.15%. This translates into fewer and shorter outages for nearly 177,000 customers, aligning with state reliability standards and improving service equity across the grid.

2. Improved Resilience and Contingency Support

Through the construction of new distribution centers and the expansion of strategic substations like North Broadway, the project introduces much-needed N-1 contingency capability to the area. This ensures that the system can withstand the failure of a single major component without causing widespread outages, significantly strengthening grid resilience in the face of storms and equipment failures.

3. Optimization of System Capacity and Load Transfer Flexibility

The conversion of legacy 4.8 kV circuits to 12.5 kV and the installation of express feeders improve the system's ability to transfer load between feeders and substations efficiently. This expanded tie capability allows for faster restoration and real-time operational flexibility, which is especially important as demand increases and load patterns shift due to electrification.

4. Long-Term Cost Efficiency

By retiring five aging substations and consolidating infrastructure, the project eliminates high-maintenance assets and reduces operational expenditures. NYSEG estimates annual O&M savings of approximately \$815,000, providing financial relief over the long term while maintaining or improving service levels. These savings also help moderate future rate impacts for customers.

5. Grid Readiness for Electrification and Future Growth

The upgraded network will support up to 52 MVA of additional load, preparing the system for forecasted growth in electric vehicles, electric heating, and distributed energy resources (DERs). With capacity in place, NYSEG can accommodate customer transitions to cleaner energy without compromising reliability or triggering reactive investment.

6. Modernized Operational Capabilities

All rebuilt and new facilities will be integrated into NYSEG's SCADA system, enabling full remote visibility and control. Combined with automated switching and advanced protection schemes, this will shorten restoration times, enable predictive maintenance, and improve outage response across the service area.

7. Risk Mitigation and Safety Improvements

The project eliminates numerous backlot lines and inaccessible infrastructure, reducing risk for field crews and enhancing public safety. Retired substations and upgraded sites also reduce the likelihood of equipment-related environmental incidents, aligning with modern utility safety and compliance standards.

Project Risks and Mitigation Plan:**1. Construction and Execution Risk**

Due to the scale and complexity of the project, there is a risk of delays related to permitting, material lead times, contractor mobilization, and construction sequencing. To mitigate this, NYSEG will adopt a phased execution strategy, prioritize early design finalization, and initiate procurement of long-lead equipment such as transformers and breakers well in advance. A detailed construction schedule will be developed and closely monitored to manage critical path activities.

2. Cost Escalation and Budget Risk

Material price volatility, labor cost increases, and potential supply chain disruptions could impact the project budget. NYSEG will include contingency allowances in the financial planning and will implement cost tracking systems to monitor expenditures. Regular budget reviews and a formal process for identifying and responding to cost deviations will be established to maintain financial discipline.

3. System Integration and Operational Transition Risk

Transitioning from legacy infrastructure to the new network configuration—especially during substation retirements and feeder reconfigurations—could pose operational risks, including service interruptions. NYSEG will prepare detailed transition and cutover plans, including temporary configurations and backup solutions such as mobile substations, to minimize impacts to customers during system switchover periods.

4. Stakeholder and Community Impact Risk

Construction activities may temporarily affect local communities through traffic disruptions, noise, or access limitations. To address this, NYSEG will engage proactively with municipalities and stakeholders, provide advance notice of planned work, and coordinate closely to minimize disruptions. Communication plans will be put in place to keep the public informed throughout the project.

5. Environmental and Regulatory Compliance Risk

Project components involving civil works or equipment installation may require environmental permitting and regulatory reviews. NYSEG will conduct thorough pre-construction environmental assessments and will work with regulatory agencies to secure all necessary approvals. Compliance will be monitored throughout the project by internal teams and external environmental consultants.

6. Technology Integration and Cybersecurity Risk

The integration of SCADA systems, protection relays, and remote switching technologies introduces risks related to system compatibility and cybersecurity. NYSEG will perform comprehensive factory and site acceptance testing, follow standard protocols for equipment integration, and implement cybersecurity reviews in line with internal policies and industry best practices.

Risk of No Action:

In addition to the project execution risks, it is important to highlight the significant consequences of inaction—should the Lancaster Grid Modernization Project be delayed, deferred, or not implemented. These risks would affect both operational performance and long-term strategic objectives:

1. Continued System Reliability Degradation

Several of the substations in the project scope are among the worst performers in NYSEG's service territory in terms of SAIFI and SAIDI. Without modernization, customers in the region would continue to experience frequent and prolonged outages. Aging infrastructure increases the likelihood of unplanned failures, which could further degrade service quality and lead to regulatory penalties.

2. Inability to Support Load Growth and Electrification

The existing 4.8 kV infrastructure and current system configuration cannot accommodate forecasted demand growth driven by electrification (EVs, heat pumps, DERs). Delaying the project would constrain NYSEG's ability to connect new load and meet statewide decarbonization and electrification goals. It may also lead to more reactive, less efficient capital spending in the future.

3. Escalating Maintenance and Operational Costs

Aging substations and equipment require increasingly frequent maintenance and emergency repairs. Without proactive investment, O&M costs will continue to rise, driven by unplanned interventions and inefficient asset management. This also ties up workforce resources that could otherwise support strategic initiatives.

4. Increased Risk of Equipment Failure and Safety Incidents

Legacy equipment poses not only reliability risks but also safety and environmental risks. Continued operation of deteriorated assets increases the chance of equipment failure, potential fire hazards, oil spills, and unsafe working conditions for field personnel.

5. Missed Opportunity for Operational Modernization

Postponing the project would delay the deployment of advanced grid functionalities such as SCADA, remote switching, and self-healing networks. This limits NYSEG's ability to improve outage response times, reduce truck rolls, and integrate data-driven system operations.

6. Reduced Long-Term Cost Efficiency

Failure to act now could result in higher future capital expenditures. Delaying coordinated modernization may force NYSEG to invest in piecemeal upgrades under time and reliability pressures, which are typically less cost-effective than comprehensive, planned reinforcements.

Project Alternatives:

As part of the planning process, NYSEG evaluated multiple alternatives to address the reliability, capacity, and asset condition issues in the Lancaster Division. Each alternative was assessed based on technical feasibility, cost-effectiveness, reliability benefits, future readiness, and constructability. The alternatives ranged from minimal intervention to full system reconfiguration.

Alternative 0 – Do Nothing

This baseline alternative would involve no proactive investment and would rely on continued operation and maintenance of the existing infrastructure.

- Pros: No upfront capital cost
- Cons: No improvement in reliability or capacity, continued deterioration of assets, increasing O&M costs, and high risk of equipment failure
- Conclusion: Not viable. This alternative fails to meet basic planning criteria and leaves the system vulnerable.

Alternative 1 – Limited Substation Replacement

This alternative proposed rebuilding only one or two of the most critical substations (e.g., Walden Avenue and Blossom Road), while keeping the rest of the network intact.

- Pros: Moderate capital cost, localized improvement at high-impact substations
- Cons: Minimal impact on broader network reliability and redundancy; does not address 4.8 kV conversion or N-1 contingency gaps; limited long-term scalability
- Conclusion: Provides partial benefit but does not support a comprehensive modernization strategy.

Alternative 2 – Comprehensive Grid Modernization (Selected)

This alternative includes the full rebuild of three major substations, retirement of five legacy substations, conversion of 4.8 kV to 12.5 kV, construction of two new distribution centers, and expansion of North Broadway.

- Pros: Maximizes reliability improvement (2.15% SAIFI reduction), fully resolves N-1 contingency deficiencies, supports long-term electrification, enables flexible load transfer, and reduces O&M costs
- Cons: Higher initial capital investment
- Additional Note: Within this alternative, multiple grid modernization configurations were evaluated, varying in substation design, feeder layout, and sequencing strategy. The selected configuration was found to be the most cost-effective while meeting all technical and operational objectives.
- Conclusion: Selected as the preferred solution due to its comprehensive, long-term value and alignment with utility and regulatory objectives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 751	\$ 113	\$ 271	\$ 234	\$ 133	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,840	\$ 277	\$ 665	\$ 574	\$ 325	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 187	\$ 28	\$ 67	\$ 58	\$ 33	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 651	\$ 94	\$ 272	\$ 185	\$ 99	\$ -	\$ -	\$ -
# Materials	\$ 4,968	\$ 747	\$ 1,794	\$ 1,549	\$ 879	\$ -	\$ -	\$ -
# Overheads - External	\$ 672	\$ 124	\$ 268	\$ 182	\$ 97	\$ -	\$ -	\$ -
Total	\$ 9,069	\$ 1,383	\$ 3,338	\$ 2,783	\$ 1,565	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Lancaster Project - Losson Road - Distribution Center

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007395	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

The Losson Road - Distribution Center project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Division Grid Modernization Pilot is a comprehensive initiative aimed at addressing critical needs related to system reliability, aging infrastructure, electrification readiness, and network resilience. The project aligns with state energy policy objectives and utility planning standards, providing a forward-looking framework to modernize both the distribution and sub-transmission networks.

This project also represents a shift in planning philosophy. It introduces a differentiated approach not only in execution, but in how system needs are identified and addressed. Rather than applying traditional asset-by-asset solutions, NYSEG has adopted a zonal planning model, grounded in an in-depth analysis of local network performance, asset condition, and long-term demand forecasts. The result is a holistic solution tailored to the specific needs of the Lancaster area—improving reliability, optimizing capacity, reducing operational costs, and enabling future growth in a coordinated and scalable way.

Project Justification

- **Reliability:** Between 2020 and 2022, the Lancaster Division accounted for approximately 19% of NYSEG's total SAIFI (System Average Interruption Frequency Index) impact. Three substations—Losson Rd, Blossom Rd, and Walden Ave—were among the poorest performers system-wide.
- **Asset Condition:** Multiple substations were identified with outdated transformers, electromechanical relays, deteriorated switchgear, and poor structural conditions, many lacking SCADA visibility or control.
- **Resiliency & Redundancy:** The area lacks sufficient N-1 contingency support, making it vulnerable to prolonged outages and limiting the ability to automatically isolate and restore faults.
- **Load Growth:** Forecasts project a 30% increase in peak demand by 2037, driven by building electrification and electric vehicle (EV) adoption.

Project Scope:

The Losson Road - Distribution Center is a subproject of the Lancaster Grid Modernization Project. The Lancaster Grid Modernization Pilot proposes a comprehensive reconfiguration of the electric distribution and sub-transmission network in one of NYSEG's highest-impact service areas. The initiative targets a region that serves approximately 177,000 customers and carries roughly 690 MW of system load, representing a substantial portion of NYSEG's reliability performance metrics. The scope includes infrastructure upgrades, voltage conversions, substation retirements, and implementation of advanced system automation, all designed to improve reliability, resilience, and operational efficiency.

Main Infrastructure Components

1. Rebuild of Key Substations
 - Losson Road (34.5/12.5 kV GIS): Full rebuild with 9 feeders and 2×50 MVA transformers
 - Blossom Road (34.5/12.5 kV GIS): Full rebuild with 6 feeders and 2×37.3 MVA transformers
 - Walden Avenue (115/12.5 kV AIS): Upgrade with 9 feeders, 2×50 MVA transformers, new breakers, and control house
2. Substation Retirements - Aging infrastructure with poor condition ratings, obsolete equipment, and limited operational visibility
 - Five legacy substations to be retired: Sloan, Ellicott, Ebenezer, Indian Church, and Depew
3. Construction of two new 12.5 kV distribution centers to serve as centralized and automated feeder hubs strategically located at Sloan and Losson to enable rapid fault isolation, load transfer, and network reconfiguration
4. North Broadway Substation Expansion and Depew Line Replacement
 - Installation of three new 115 kV breakers and expansion of the 34.5 kV yard with three new breakers
 - Addition of a new 50 MVA 115/34.5 kV transformer
 - Construction of a new 34.5 kV line to reroute Line 532 into North Broadway, enabling the full retirement of Depew substation
5. Distribution upgrades (Blossom Rd, Losson Rd and Walden Ave & Sloan)
 - Conversion of approximately 75 miles of distribution circuits from legacy 4.8 kV to standard 12.5 kV
 - Upgrades to conductor sizes (up to 477 AL) to increase thermal capacity and reduce voltage drop
6. Installation of multiple 12.5 kV express feeders between substations and distribution centers (~10 miles total).

Additional Technical Elements

- Integration of SCADA control and visibility across all new and upgraded facilities
- Enhanced remote operation capabilities and automated restoration (self-healing features)
- System-wide reconfiguration to ensure all 12.5 kV feeders operate in phase
- Elimination of backlot lines and inaccessible equipment to improve maintenance and safety

Project Benefits:**1. Enhanced System Reliability**

The project directly addresses chronic reliability issues in one of NYSEG's most outage-prone areas. By replacing obsolete substations and reconfiguring the network, the initiative is expected to reduce SAIFI across the NYSEG system by an estimated 2.15%. This translates into fewer and shorter outages for nearly 177,000 customers, aligning with state reliability standards and improving service equity across the grid.

2. Improved Resilience and Contingency Support

Through the construction of new distribution centers and the expansion of strategic substations like North Broadway, the project introduces much-needed N-1 contingency capability to the area. This ensures that the system can withstand the failure of a single major component without causing widespread outages, significantly strengthening grid resilience in the face of storms and equipment failures.

3. Optimization of System Capacity and Load Transfer Flexibility

The conversion of legacy 4.8 kV circuits to 12.5 kV and the installation of express feeders improve the system's ability to transfer load between feeders and substations efficiently. This expanded tie capability allows for faster restoration and real-time operational flexibility, which is especially important as demand increases and load patterns shift due to electrification.

4. Long-Term Cost Efficiency

By retiring five aging substations and consolidating infrastructure, the project eliminates high-maintenance assets and reduces operational expenditures. NYSEG estimates annual O&M savings of approximately \$815,000, providing financial relief over the long term while maintaining or improving service levels. These savings also help moderate future rate impacts for customers.

5. Grid Readiness for Electrification and Future Growth

The upgraded network will support up to 52 MVA of additional load, preparing the system for forecasted growth in electric vehicles, electric heating, and distributed energy resources (DERs). With capacity in place, NYSEG can accommodate customer transitions to cleaner energy without compromising reliability or triggering reactive investment.

6. Modernized Operational Capabilities

All rebuilt and new facilities will be integrated into NYSEG's SCADA system, enabling full remote visibility and control. Combined with automated switching and advanced protection schemes, this will shorten restoration times, enable predictive maintenance, and improve outage response across the service area.

7. Risk Mitigation and Safety Improvements

The project eliminates numerous backlot lines and inaccessible infrastructure, reducing risk for field crews and enhancing public safety. Retired substations and upgraded sites also reduce the likelihood of equipment-related environmental incidents, aligning with modern utility safety and compliance standards.

Project Risks and Mitigation Plan:**1. Construction and Execution Risk**

Due to the scale and complexity of the project, there is a risk of delays related to permitting, material lead times, contractor mobilization, and construction sequencing. To mitigate this, NYSEG will adopt a phased execution strategy, prioritize early design finalization, and initiate procurement of long-lead equipment such as transformers and breakers well in advance. A detailed construction schedule will be developed and closely monitored to manage critical path activities.

2. Cost Escalation and Budget Risk

Material price volatility, labor cost increases, and potential supply chain disruptions could impact the project budget. NYSEG will include contingency allowances in the financial planning and will implement cost tracking systems to monitor expenditures. Regular budget reviews and a formal process for identifying and responding to cost deviations will be established to maintain financial discipline.

3. System Integration and Operational Transition Risk

Transitioning from legacy infrastructure to the new network configuration—especially during substation retirements and feeder reconfigurations—could pose operational risks, including service interruptions. NYSEG will prepare detailed transition and cutover plans, including temporary configurations and backup solutions such as mobile substations, to minimize impacts to customers during system switchover periods.

4. Stakeholder and Community Impact Risk

Construction activities may temporarily affect local communities through traffic disruptions, noise, or access limitations. To address this, NYSEG will engage proactively with municipalities and stakeholders, provide advance notice of planned work, and coordinate closely to minimize disruptions. Communication plans will be put in place to keep the public informed throughout the project.

5. Environmental and Regulatory Compliance Risk

Project components involving civil works or equipment installation may require environmental permitting and regulatory reviews. NYSEG will conduct thorough pre-construction environmental assessments and will work with regulatory agencies to secure all necessary approvals. Compliance will be monitored throughout the project by internal teams and external environmental consultants.

6. Technology Integration and Cybersecurity Risk

The integration of SCADA systems, protection relays, and remote switching technologies introduces risks related to system compatibility and cybersecurity. NYSEG will perform comprehensive factory and site acceptance testing, follow standard protocols for equipment integration, and implement cybersecurity reviews in line with internal policies and industry best practices.

Risk of No Action:

In addition to the project execution risks, it is important to highlight the significant consequences of inaction—should the Lancaster Grid Modernization Project be delayed, deferred, or not implemented. These risks would affect both operational performance and long-term strategic objectives:

1. Continued System Reliability Degradation

Several of the substations in the project scope are among the worst performers in NYSEG's service territory in terms of SAIFI and SAIDI. Without modernization, customers in the region would continue to experience frequent and prolonged outages. Aging infrastructure increases the likelihood of unplanned failures, which could further degrade service quality and lead to regulatory penalties.

2. Inability to Support Load Growth and Electrification

The existing 4.8 kV infrastructure and current system configuration cannot accommodate forecasted demand growth driven by electrification (EVs, heat pumps, DERs). Delaying the project would constrain NYSEG's ability to connect new load and meet statewide decarbonization and electrification goals. It may also lead to more reactive, less efficient capital spending in the future.

3. Escalating Maintenance and Operational Costs

Aging substations and equipment require increasingly frequent maintenance and emergency repairs. Without proactive investment, O&M costs will continue to rise, driven by unplanned interventions and inefficient asset management. This also ties up workforce resources that could otherwise support strategic initiatives.

4. Increased Risk of Equipment Failure and Safety Incidents

Legacy equipment poses not only reliability risks but also safety and environmental risks. Continued operation of deteriorated assets increases the chance of equipment failure, potential fire hazards, oil spills, and unsafe working conditions for field personnel.

5. Missed Opportunity for Operational Modernization

Postponing the project would delay the deployment of advanced grid functionalities such as SCADA, remote switching, and self-healing networks. This limits NYSEG's ability to improve outage response times, reduce truck rolls, and integrate data-driven system operations.

6. Reduced Long-Term Cost Efficiency

Failure to act now could result in higher future capital expenditures. Delaying coordinated modernization may force NYSEG to invest in piecemeal upgrades under time and reliability pressures, which are typically less cost-effective than comprehensive, planned reinforcements.

Project Alternatives:

As part of the planning process, NYSEG evaluated multiple alternatives to address the reliability, capacity, and asset condition issues in the Lancaster Division. Each alternative was assessed based on technical feasibility, cost-effectiveness, reliability benefits, future readiness, and constructability. The alternatives ranged from minimal intervention to full system reconfiguration.

Alternative 0 – Do Nothing

This baseline alternative would involve no proactive investment and would rely on continued operation and maintenance of the existing infrastructure.

- Pros: No upfront capital cost
- Cons: No improvement in reliability or capacity, continued deterioration of assets, increasing O&M costs, and high risk of equipment failure
- Conclusion: Not viable. This alternative fails to meet basic planning criteria and leaves the system vulnerable.

Alternative 1 – Limited Substation Replacement

This alternative proposed rebuilding only one or two of the most critical substations (e.g., Walden Avenue and Blossom Road), while keeping the rest of the network intact.

- Pros: Moderate capital cost, localized improvement at high-impact substations
- Cons: Minimal impact on broader network reliability and redundancy; does not address 4.8 kV conversion or N-1 contingency gaps; limited long-term scalability
- Conclusion: Provides partial benefit but does not support a comprehensive modernization strategy.

Alternative 2 – Comprehensive Grid Modernization (Selected)

This alternative includes the full rebuild of three major substations, retirement of five legacy substations, conversion of 4.8 kV to 12.5 kV, construction of two new distribution centers, and expansion of North Broadway.

- Pros: Maximizes reliability improvement (2.15% SAIFI reduction), fully resolves N-1 contingency deficiencies, supports long-term electrification, enables flexible load transfer, and reduces O&M costs
- Cons: Higher initial capital investment
- Additional Note: Within this alternative, multiple grid modernization configurations were evaluated, varying in substation design, feeder layout, and sequencing strategy. The selected configuration was found to be the most cost-effective while meeting all technical and operational objectives.
- Conclusion: Selected as the preferred solution due to its comprehensive, long-term value and alignment with utility and regulatory objectives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 795	\$ 136	\$ 280	\$ 241	\$ 138	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,949	\$ 334	\$ 686	\$ 590	\$ 339	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 198	\$ 34	\$ 70	\$ 60	\$ 34	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 688	\$ 114	\$ 281	\$ 191	\$ 103	\$ -	\$ -	\$ -
# Materials	\$ 5,263	\$ 903	\$ 1,851	\$ 1,594	\$ 916	\$ -	\$ -	\$ -
# Overheads - External	\$ 716	\$ 150	\$ 277	\$ 188	\$ 101	\$ -	\$ -	\$ -
Total	\$ 9,610	\$ 1,672	\$ 3,443	\$ 2,863	\$ 1,632	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Lancaster Project - Walden Ave to Sloan - Distribution Express feeder

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007390	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

The Walden Ave to Sloan - Distribution Express feeder project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Division Grid Modernization Pilot is a comprehensive initiative aimed at addressing critical needs related to system reliability, aging infrastructure, electrification readiness, and network resilience. The project aligns with state energy policy objectives and utility planning standards, providing a forward-looking framework to modernize both the distribution and sub-transmission networks.

This project also represents a shift in planning philosophy. It introduces a differentiated approach not only in execution, but in how system needs are identified and addressed. Rather than applying traditional asset-by-asset solutions, NYSEG has adopted a zonal planning model, grounded in an in-depth analysis of local network performance, asset condition, and long-term demand forecasts. The result is a holistic solution tailored to the specific needs of the Lancaster area—improving reliability, optimizing capacity, reducing operational costs, and enabling future growth in a coordinated and scalable way.

Project Justification

- **Reliability:** Between 2020 and 2022, the Lancaster Division accounted for approximately 19% of NYSEG's total SAIFI (System Average Interruption Frequency Index) impact. Three substations—Losson Rd, Blossom Rd, and Walden Ave—were among the poorest performers system-wide.
- **Asset Condition:** Multiple substations were identified with outdated transformers, electromechanical relays, deteriorated switchgear, and poor structural conditions, many lacking SCADA visibility or control.
- **Resiliency & Redundancy:** The area lacks sufficient N-1 contingency support, making it vulnerable to prolonged outages and limiting the ability to automatically isolate and restore faults.
- **Load Growth:** Forecasts project a 30% increase in peak demand by 2037, driven by building electrification and electric vehicle (EV) adoption.

Project Scope:

The Walden Ave to Sloan - Distribution Express feeder project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Grid Modernization Pilot proposes a comprehensive reconfiguration of the electric distribution and sub-transmission network in one of NYSEG's highest-impact service areas. The initiative targets a region that serves approximately 177,000 customers and carries roughly 690 MW of system load, representing a substantial portion of NYSEG's reliability performance metrics. The scope includes infrastructure upgrades, voltage conversions, substation retirements, and implementation of advanced system automation, all designed to improve reliability, resilience, and operational efficiency.

Main Infrastructure Components

1. Rebuild of Key Substations
 - Losson Road (34.5/12.5 kV GIS): Full rebuild with 9 feeders and 2×50 MVA transformers
 - Blossom Road (34.5/12.5 kV GIS): Full rebuild with 6 feeders and 2×37.3 MVA transformers
 - Walden Avenue (115/12.5 kV AIS): Upgrade with 9 feeders, 2×50 MVA transformers, new breakers, and control house
2. Substation Retirements - Aging infrastructure with poor condition ratings, obsolete equipment, and limited operational visibility
 - Five legacy substations to be retired: Sloan, Ellicott, Ebenezer, Indian Church, and Depew
3. Construction of two new 12.5 kV distribution centers to serve as centralized and automated feeder hubs strategically located at Sloan and Losson to enable rapid fault isolation, load transfer, and network reconfiguration
4. North Broadway Substation Expansion and Depew Line Replacement
 - Installation of three new 115 kV breakers and expansion of the 34.5 kV yard with three new breakers
 - Addition of a new 50 MVA 115/34.5 kV transformer
 - Construction of a new 34.5 kV line to reroute Line 532 into North Broadway, enabling the full retirement of Depew substation
5. Distribution upgrades (Blossom Rd, Losson Rd and Walden Ave & Sloan)
 - Conversion of approximately 75 miles of distribution circuits from legacy 4.8 kV to standard 12.5 kV
 - Upgrades to conductor sizes (up to 477 AL) to increase thermal capacity and reduce voltage drop
6. Installation of multiple 12.5 kV express feeders between substations and distribution centers (~10 miles total).

Additional Technical Elements

- Integration of SCADA control and visibility across all new and upgraded facilities
- Enhanced remote operation capabilities and automated restoration (self-healing features)
- System-wide reconfiguration to ensure all 12.5 kV feeders operate in phase
- Elimination of backlot lines and inaccessible equipment to improve maintenance and safety

Project Benefits:**1. Enhanced System Reliability**

The project directly addresses chronic reliability issues in one of NYSEG's most outage-prone areas. By replacing obsolete substations and reconfiguring the network, the initiative is expected to reduce SAIFI across the NYSEG system by an estimated 2.15%. This translates into fewer and shorter outages for nearly 177,000 customers, aligning with state reliability standards and improving service equity across the grid.

2. Improved Resilience and Contingency Support

Through the construction of new distribution centers and the expansion of strategic substations like North Broadway, the project introduces much-needed N-1 contingency capability to the area. This ensures that the system can withstand the failure of a single major component without causing widespread outages, significantly strengthening grid resilience in the face of storms and equipment failures.

3. Optimization of System Capacity and Load Transfer Flexibility

The conversion of legacy 4.8 kV circuits to 12.5 kV and the installation of express feeders improve the system's ability to transfer load between feeders and substations efficiently. This expanded tie capability allows for faster restoration and real-time operational flexibility, which is especially important as demand increases and load patterns shift due to electrification.

4. Long-Term Cost Efficiency

By retiring five aging substations and consolidating infrastructure, the project eliminates high-maintenance assets and reduces operational expenditures. NYSEG estimates annual O&M savings of approximately \$815,000, providing financial relief over the long term while maintaining or improving service levels. These savings also help moderate future rate impacts for customers.

5. Grid Readiness for Electrification and Future Growth

The upgraded network will support up to 52 MVA of additional load, preparing the system for forecasted growth in electric vehicles, electric heating, and distributed energy resources (DERs). With capacity in place, NYSEG can accommodate customer transitions to cleaner energy without compromising reliability or triggering reactive investment.

6. Modernized Operational Capabilities

All rebuilt and new facilities will be integrated into NYSEG's SCADA system, enabling full remote visibility and control. Combined with automated switching and advanced protection schemes, this will shorten restoration times, enable predictive maintenance, and improve outage response across the service area.

7. Risk Mitigation and Safety Improvements

The project eliminates numerous backlot lines and inaccessible infrastructure, reducing risk for field crews and enhancing public safety. Retired substations and upgraded sites also reduce the likelihood of equipment-related environmental incidents, aligning with modern utility safety and compliance standards.

Project Risks and Mitigation Plan:**1. Construction and Execution Risk**

Due to the scale and complexity of the project, there is a risk of delays related to permitting, material lead times, contractor mobilization, and construction sequencing. To mitigate this, NYSEG will adopt a phased execution strategy, prioritize early design finalization, and initiate procurement of long-lead equipment such as transformers and breakers well in advance. A detailed construction schedule will be developed and closely monitored to manage critical path activities.

2. Cost Escalation and Budget Risk

Material price volatility, labor cost increases, and potential supply chain disruptions could impact the project budget. NYSEG will include contingency allowances in the financial planning and will implement cost tracking systems to monitor expenditures. Regular budget reviews and a formal process for identifying and responding to cost deviations will be established to maintain financial discipline.

3. System Integration and Operational Transition Risk

Transitioning from legacy infrastructure to the new network configuration—especially during substation retirements and feeder reconfigurations—could pose operational risks, including service interruptions. NYSEG will prepare detailed transition and cutover plans, including temporary configurations and backup solutions such as mobile substations, to minimize impacts to customers during system switchover periods.

4. Stakeholder and Community Impact Risk

Construction activities may temporarily affect local communities through traffic disruptions, noise, or access limitations. To address this, NYSEG will engage proactively with municipalities and stakeholders, provide advance notice of planned work, and coordinate closely to minimize disruptions. Communication plans will be put in place to keep the public informed throughout the project.

5. Environmental and Regulatory Compliance Risk

Project components involving civil works or equipment installation may require environmental permitting and regulatory reviews. NYSEG will conduct thorough pre-construction environmental assessments and will work with regulatory agencies to secure all necessary approvals. Compliance will be monitored throughout the project by internal teams and external environmental consultants.

6. Technology Integration and Cybersecurity Risk

The integration of SCADA systems, protection relays, and remote switching technologies introduces risks related to system compatibility and cybersecurity. NYSEG will perform comprehensive factory and site acceptance testing, follow standard protocols for equipment integration, and implement cybersecurity reviews in line with internal policies and industry best practices.

Risk of No Action:

In addition to the project execution risks, it is important to highlight the significant consequences of inaction—should the Lancaster Grid Modernization Project be delayed, deferred, or not implemented. These risks would affect both operational performance and long-term strategic objectives:

1. Continued System Reliability Degradation

Several of the substations in the project scope are among the worst performers in NYSEG's service territory in terms of SAIFI and SAIDI. Without modernization, customers in the region would continue to experience frequent and prolonged outages. Aging infrastructure increases the likelihood of unplanned failures, which could further degrade service quality and lead to regulatory penalties.

2. Inability to Support Load Growth and Electrification

The existing 4.8 kV infrastructure and current system configuration cannot accommodate forecasted demand growth driven by electrification (EVs, heat pumps, DERs). Delaying the project would constrain NYSEG's ability to connect new load and meet statewide decarbonization and electrification goals. It may also lead to more reactive, less efficient capital spending in the future.

3. Escalating Maintenance and Operational Costs

Aging substations and equipment require increasingly frequent maintenance and emergency repairs. Without proactive investment, O&M costs will continue to rise, driven by unplanned interventions and inefficient asset management. This also ties up workforce resources that could otherwise support strategic initiatives.

4. Increased Risk of Equipment Failure and Safety Incidents

Legacy equipment poses not only reliability risks but also safety and environmental risks. Continued operation of deteriorated assets increases the chance of equipment failure, potential fire hazards, oil spills, and unsafe working conditions for field personnel.

5. Missed Opportunity for Operational Modernization

Postponing the project would delay the deployment of advanced grid functionalities such as SCADA, remote switching, and self-healing networks. This limits NYSEG's ability to improve outage response times, reduce truck rolls, and integrate data-driven system operations.

6. Reduced Long-Term Cost Efficiency

Failure to act now could result in higher future capital expenditures. Delaying coordinated modernization may force NYSEG to invest in piecemeal upgrades under time and reliability pressures, which are typically less cost-effective than comprehensive, planned reinforcements.

Project Alternatives:

As part of the planning process, NYSEG evaluated multiple alternatives to address the reliability, capacity, and asset condition issues in the Lancaster Division. Each alternative was assessed based on technical feasibility, cost-effectiveness, reliability benefits, future readiness, and constructability. The alternatives ranged from minimal intervention to full system reconfiguration.

Alternative 0 – Do Nothing

This baseline alternative would involve no proactive investment and would rely on continued operation and maintenance of the existing infrastructure.

- Pros: No upfront capital cost
- Cons: No improvement in reliability or capacity, continued deterioration of assets, increasing O&M costs, and high risk of equipment failure
- Conclusion: Not viable. This alternative fails to meet basic planning criteria and leaves the system vulnerable.

Alternative 1 – Limited Substation Replacement

This alternative proposed rebuilding only one or two of the most critical substations (e.g., Walden Avenue and Blossom Road), while keeping the rest of the network intact.

- Pros: Moderate capital cost, localized improvement at high-impact substations
- Cons: Minimal impact on broader network reliability and redundancy; does not address 4.8 kV conversion or N-1 contingency gaps; limited long-term scalability
- Conclusion: Provides partial benefit but does not support a comprehensive modernization strategy.

Alternative 2 – Comprehensive Grid Modernization (Selected)

This alternative includes the full rebuild of three major substations, retirement of five legacy substations, conversion of 4.8 kV to 12.5 kV, construction of two new distribution centers, and expansion of North Broadway.

- Pros: Maximizes reliability improvement (2.15% SAIFI reduction), fully resolves N-1 contingency deficiencies, supports long-term electrification, enables flexible load transfer, and reduces O&M costs
- Cons: Higher initial capital investment
- Additional Note: Within this alternative, multiple grid modernization configurations were evaluated, varying in substation design, feeder layout, and sequencing strategy. The selected configuration was found to be the most cost-effective while meeting all technical and operational objectives.
- Conclusion: Selected as the preferred solution due to its comprehensive, long-term value and alignment with utility and regulatory objectives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 607	\$ 73	\$ 97	\$ 213	\$ 213	\$ 12	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,488	\$ 179	\$ 238	\$ 521	\$ 521	\$ 30	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 151	\$ 18	\$ 24	\$ 53	\$ 53	\$ 3	\$ -	\$ -
# Internal, Overheads	\$ 493	\$ 61	\$ 98	\$ 168	\$ 158	\$ 9	\$ -	\$ -
# Materials	\$ 4,018	\$ 482	\$ 643	\$ 1,406	\$ 1,406	\$ 80	\$ -	\$ -
# Overheads - External	\$ 506	\$ 80	\$ 96	\$ 166	\$ 155	\$ 9	\$ -	\$ -
Total	\$ 7,264	\$ 893	\$ 1,196	\$ 2,527	\$ 2,506	\$ 143	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Lancaster Project - Sloan to Losson - Distribution Express feeder

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007389	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

The Sloan to Losson - Distribution Express feeder project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Division Grid Modernization Pilot is a comprehensive initiative aimed at addressing critical needs related to system reliability, aging infrastructure, electrification readiness, and network resilience. The project aligns with state energy policy objectives and utility planning standards, providing a forward-looking framework to modernize both the distribution and sub-transmission networks.

This project also represents a shift in planning philosophy. It introduces a differentiated approach not only in execution, but in how system needs are identified and addressed. Rather than applying traditional asset-by-asset solutions, NYSEG has adopted a zonal planning model, grounded in an in-depth analysis of local network performance, asset condition, and long-term demand forecasts. The result is a holistic solution tailored to the specific needs of the Lancaster area—improving reliability, optimizing capacity, reducing operational costs, and enabling future growth in a coordinated and scalable way.

Project Justification

- **Reliability:** Between 2020 and 2022, the Lancaster Division accounted for approximately 19% of NYSEG's total SAIFI (System Average Interruption Frequency Index) impact. Three substations—Losson Rd, Blossom Rd, and Walden Ave—were among the poorest performers system-wide.
- **Asset Condition:** Multiple substations were identified with outdated transformers, electromechanical relays, deteriorated switchgear, and poor structural conditions, many lacking SCADA visibility or control.
- **Resiliency & Redundancy:** The area lacks sufficient N-1 contingency support, making it vulnerable to prolonged outages and limiting the ability to automatically isolate and restore faults.
- **Load Growth:** Forecasts project a 30% increase in peak demand by 2037, driven by building electrification and electric vehicle (EV) adoption.

Project Scope:

The Sloan to Losson - Distribution Express feeder project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Grid Modernization Pilot proposes a comprehensive reconfiguration of the electric distribution and sub-transmission network in one of NYSEG's highest-impact service areas. The initiative targets a region that serves approximately 177,000 customers and carries roughly 690 MW of system load, representing a substantial portion of NYSEG's reliability performance metrics. The scope includes infrastructure upgrades, voltage conversions, substation retirements, and implementation of advanced system automation, all designed to improve reliability, resilience, and operational efficiency.

Main Infrastructure Components

1. Rebuild of Key Substations

- Losson Road (34.5/12.5 kV GIS): Full rebuild with 9 feeders and 2×50 MVA transformers
- Blossom Road (34.5/12.5 kV GIS): Full rebuild with 6 feeders and 2×37.3 MVA transformers
- Walden Avenue (115/12.5 kV AIS): Upgrade with 9 feeders, 2×50 MVA transformers, new breakers, and control house

2. Substation Retirements - Aging infrastructure with poor condition ratings, obsolete equipment, and limited operational visibility

- Five legacy substations to be retired: Sloan, Ellicott, Ebenezer, Indian Church, and Depew

3. Construction of two new 12.5 kV distribution centers to serve as centralized and automated feeder hubs strategically located at Sloan and Losson to enable rapid fault isolation, load transfer, and network reconfiguration

4. North Broadway Substation Expansion and Depew Line Replacement

- Installation of three new 115 kV breakers and expansion of the 34.5 kV yard with three new breakers
- Addition of a new 50 MVA 115/34.5 kV transformer
- Construction of a new 34.5 kV line to reroute Line 532 into North Broadway, enabling the full retirement of Depew substation

5. Distribution upgrades (Blossom Rd, Losson Rd and Walden Ave & Sloan)

- Conversion of approximately 75 miles of distribution circuits from legacy 4.8 kV to standard 12.5 kV
- Upgrades to conductor sizes (up to 477 AL) to increase thermal capacity and reduce voltage drop

6. Installation of multiple 12.5 kV express feeders between substations and distribution centers (~10 miles total).

Additional Technical Elements

- Integration of SCADA control and visibility across all new and upgraded facilities
- Enhanced remote operation capabilities and automated restoration (self-healing features)
- System-wide reconfiguration to ensure all 12.5 kV feeders operate in phase
- Elimination of backlot lines and inaccessible equipment to improve maintenance and safety

Project Benefits:**1. Enhanced System Reliability**

The project directly addresses chronic reliability issues in one of NYSEG's most outage-prone areas. By replacing obsolete substations and reconfiguring the network, the initiative is expected to reduce SAIFI across the NYSEG system by an estimated 2.15%. This translates into fewer and shorter outages for nearly 177,000 customers, aligning with state reliability standards and improving service equity across the grid.

2. Improved Resilience and Contingency Support

Through the construction of new distribution centers and the expansion of strategic substations like North Broadway, the project introduces much-needed N-1 contingency capability to the area. This ensures that the system can withstand the failure of a single major component without causing widespread outages, significantly strengthening grid resilience in the face of storms and equipment failures.

3. Optimization of System Capacity and Load Transfer Flexibility

The conversion of legacy 4.8 kV circuits to 12.5 kV and the installation of express feeders improve the system's ability to transfer load between feeders and substations efficiently. This expanded tie capability allows for faster restoration and real-time operational flexibility, which is especially important as demand increases and load patterns shift due to electrification.

4. Long-Term Cost Efficiency

By retiring five aging substations and consolidating infrastructure, the project eliminates high-maintenance assets and reduces operational expenditures. NYSEG estimates annual O&M savings of approximately \$815,000, providing financial relief over the long term while maintaining or improving service levels. These savings also help moderate future rate impacts for customers.

5. Grid Readiness for Electrification and Future Growth

The upgraded network will support up to 52 MVA of additional load, preparing the system for forecasted growth in electric vehicles, electric heating, and distributed energy resources (DERs). With capacity in place, NYSEG can accommodate customer transitions to cleaner energy without compromising reliability or triggering reactive investment.

6. Modernized Operational Capabilities

All rebuilt and new facilities will be integrated into NYSEG's SCADA system, enabling full remote visibility and control. Combined with automated switching and advanced protection schemes, this will shorten restoration times, enable predictive maintenance, and improve outage response across the service area.

7. Risk Mitigation and Safety Improvements

The project eliminates numerous backlot lines and inaccessible infrastructure, reducing risk for field crews and enhancing public safety. Retired substations and upgraded sites also reduce the likelihood of equipment-related environmental incidents, aligning with modern utility safety and compliance standards.

Project Risks and Mitigation Plan:**1. Construction and Execution Risk**

Due to the scale and complexity of the project, there is a risk of delays related to permitting, material lead times, contractor mobilization, and construction sequencing. To mitigate this, NYSEG will adopt a phased execution strategy, prioritize early design finalization, and initiate procurement of long-lead equipment such as transformers and breakers well in advance. A detailed construction schedule will be developed and closely monitored to manage critical path activities.

2. Cost Escalation and Budget Risk

Material price volatility, labor cost increases, and potential supply chain disruptions could impact the project budget. NYSEG will include contingency allowances in the financial planning and will implement cost tracking systems to monitor expenditures. Regular budget reviews and a formal process for identifying and responding to cost deviations will be established to maintain financial discipline.

3. System Integration and Operational Transition Risk

Transitioning from legacy infrastructure to the new network configuration—especially during substation retirements and feeder reconfigurations—could pose operational risks, including service interruptions. NYSEG will prepare detailed transition and cutover plans, including temporary configurations and backup solutions such as mobile substations, to minimize impacts to customers during system switchover periods.

4. Stakeholder and Community Impact Risk

Construction activities may temporarily affect local communities through traffic disruptions, noise, or access limitations. To address this, NYSEG will engage proactively with municipalities and stakeholders, provide advance notice of planned work, and coordinate closely to minimize disruptions. Communication plans will be put in place to keep the public informed throughout the project.

5. Environmental and Regulatory Compliance Risk

Project components involving civil works or equipment installation may require environmental permitting and regulatory reviews. NYSEG will conduct thorough pre-construction environmental assessments and will work with regulatory agencies to secure all necessary approvals. Compliance will be monitored throughout the project by internal teams and external environmental consultants.

6. Technology Integration and Cybersecurity Risk

The integration of SCADA systems, protection relays, and remote switching technologies introduces risks related to system compatibility and cybersecurity. NYSEG will perform comprehensive factory and site acceptance testing, follow standard protocols for equipment integration, and implement cybersecurity reviews in line with internal policies and industry best practices.

Risk of No Action:

In addition to the project execution risks, it is important to highlight the significant consequences of inaction—should the Lancaster Grid Modernization Project be delayed, deferred, or not implemented. These risks would affect both operational performance and long-term strategic objectives:

1. Continued System Reliability Degradation

Several of the substations in the project scope are among the worst performers in NYSEG's service territory in terms of SAIFI and SAIDI. Without modernization, customers in the region would continue to experience frequent and prolonged outages. Aging infrastructure increases the likelihood of unplanned failures, which could further degrade service quality and lead to regulatory penalties.

2. Inability to Support Load Growth and Electrification

The existing 4.8 kV infrastructure and current system configuration cannot accommodate forecasted demand growth driven by electrification (EVs, heat pumps, DERs). Delaying the project would constrain NYSEG's ability to connect new load and meet statewide decarbonization and electrification goals. It may also lead to more reactive, less efficient capital spending in the future.

3. Escalating Maintenance and Operational Costs

Aging substations and equipment require increasingly frequent maintenance and emergency repairs. Without proactive investment, O&M costs will continue to rise, driven by unplanned interventions and inefficient asset management. This also ties up workforce resources that could otherwise support strategic initiatives.

4. Increased Risk of Equipment Failure and Safety Incidents

Legacy equipment poses not only reliability risks but also safety and environmental risks. Continued operation of deteriorated assets increases the chance of equipment failure, potential fire hazards, oil spills, and unsafe working conditions for field personnel.

5. Missed Opportunity for Operational Modernization

Postponing the project would delay the deployment of advanced grid functionalities such as SCADA, remote switching, and self-healing networks. This limits NYSEG's ability to improve outage response times, reduce truck rolls, and integrate data-driven system operations.

6. Reduced Long-Term Cost Efficiency

Failure to act now could result in higher future capital expenditures. Delaying coordinated modernization may force NYSEG to invest in piecemeal upgrades under time and reliability pressures, which are typically less cost-effective than comprehensive, planned reinforcements.

Project Alternatives:

As part of the planning process, NYSEG evaluated multiple alternatives to address the reliability, capacity, and asset condition issues in the Lancaster Division. Each alternative was assessed based on technical feasibility, cost-effectiveness, reliability benefits, future readiness, and constructability. The alternatives ranged from minimal intervention to full system reconfiguration.

Alternative 0 – Do Nothing

This baseline alternative would involve no proactive investment and would rely on continued operation and maintenance of the existing infrastructure.

- Pros: No upfront capital cost
- Cons: No improvement in reliability or capacity, continued deterioration of assets, increasing O&M costs, and high risk of equipment failure
- Conclusion: Not viable. This alternative fails to meet basic planning criteria and leaves the system vulnerable.

Alternative 1 – Limited Substation Replacement

This alternative proposed rebuilding only one or two of the most critical substations (e.g., Walden Avenue and Blossom Road), while keeping the rest of the network intact.

- Pros: Moderate capital cost, localized improvement at high-impact substations
- Cons: Minimal impact on broader network reliability and redundancy; does not address 4.8 kV conversion or N-1 contingency gaps; limited long-term scalability
- Conclusion: Provides partial benefit but does not support a comprehensive modernization strategy.

Alternative 2 – Comprehensive Grid Modernization (Selected)

This alternative includes the full rebuild of three major substations, retirement of five legacy substations, conversion of 4.8 kV to 12.5 kV, construction of two new distribution centers, and expansion of North Broadway.

- Pros: Maximizes reliability improvement (2.15% SAIFI reduction), fully resolves N-1 contingency deficiencies, supports long-term electrification, enables flexible load transfer, and reduces O&M costs
- Cons: Higher initial capital investment
- Additional Note: Within this alternative, multiple grid modernization configurations were evaluated, varying in substation design, feeder layout, and sequencing strategy. The selected configuration was found to be the most cost-effective while meeting all technical and operational objectives.
- Conclusion: Selected as the preferred solution due to its comprehensive, long-term value and alignment with utility and regulatory objectives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 633	\$ 76	\$ 101	\$ 221	\$ 221	\$ 13	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,004	\$ 186	\$ 248	\$ 543	\$ 996	\$ 31	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 154	\$ 19	\$ 25	\$ 55	\$ 52	\$ 3	\$ -	\$ -
# Internal, Overheads	\$ 505	\$ 63	\$ 102	\$ 175	\$ 155	\$ 9	\$ -	\$ -
# Materials	\$ 3,718	\$ 502	\$ 670	\$ 1,465	\$ 997	\$ 84	\$ -	\$ -
# Overheads - External	\$ 523	\$ 84	\$ 100	\$ 173	\$ 157	\$ 9	\$ -	\$ -
Total	\$ 7,535	\$ 930	\$ 1,246	\$ 2,632	\$ 2,579	\$ 149	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Lancaster Project - Losson - Distribution Express feeder

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007388	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

The Losson - Distribution Express feeder project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Division Grid Modernization Pilot is a comprehensive initiative aimed at addressing critical needs related to system reliability, aging infrastructure, electrification readiness, and network resilience. The project aligns with state energy policy objectives and utility planning standards, providing a forward-looking framework to modernize both the distribution and sub-transmission networks.

This project also represents a shift in planning philosophy. It introduces a differentiated approach not only in execution, but in how system needs are identified and addressed. Rather than applying traditional asset-by-asset solutions, NYSEG has adopted a zonal planning model, grounded in an in-depth analysis of local network performance, asset condition, and long-term demand forecasts. The result is a holistic solution tailored to the specific needs of the Lancaster area—improving reliability, optimizing capacity, reducing operational costs, and enabling future growth in a coordinated and scalable way.

Project Justification

- **Reliability:** Between 2020 and 2022, the Lancaster Division accounted for approximately 19% of NYSEG's total SAIFI (System Average Interruption Frequency Index) impact. Three substations—Losson Rd, Blossom Rd, and Walden Ave—were among the poorest performers system-wide.
- **Asset Condition:** Multiple substations were identified with outdated transformers, electromechanical relays, deteriorated switchgear, and poor structural conditions, many lacking SCADA visibility or control.
- **Resiliency & Redundancy:** The area lacks sufficient N-1 contingency support, making it vulnerable to prolonged outages and limiting the ability to automatically isolate and restore faults.
- **Load Growth:** Forecasts project a 30% increase in peak demand by 2037, driven by building electrification and electric vehicle (EV) adoption.

Project Scope:

The Losson - Distribution Express feeder project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Grid Modernization Pilot proposes a comprehensive reconfiguration of the electric distribution and sub-transmission network in one of NYSEG's highest-impact service areas. The initiative targets a region that serves approximately 177,000 customers and carries roughly 690 MW of system load, representing a substantial portion of NYSEG's reliability performance metrics. The scope includes infrastructure upgrades, voltage conversions, substation retirements, and implementation of advanced system automation, all designed to improve reliability, resilience, and operational efficiency.

Main Infrastructure Components

1. Rebuild of Key Substations

- Losson Road (34.5/12.5 kV GIS): Full rebuild with 9 feeders and 2×50 MVA transformers
- Blossom Road (34.5/12.5 kV GIS): Full rebuild with 6 feeders and 2×37.3 MVA transformers
- Walden Avenue (115/12.5 kV AIS): Upgrade with 9 feeders, 2×50 MVA transformers, new breakers, and control house

2. Substation Retirements - Aging infrastructure with poor condition ratings, obsolete equipment, and limited operational visibility

- Five legacy substations to be retired: Sloan, Ellicott, Ebenezer, Indian Church, and Depew

3. Construction of two new 12.5 kV distribution centers to serve as centralized and automated feeder hubs strategically located at Sloan and Losson to enable rapid fault isolation, load transfer, and network reconfiguration

4. North Broadway Substation Expansion and Depew Line Replacement

- Installation of three new 115 kV breakers and expansion of the 34.5 kV yard with three new breakers
- Addition of a new 50 MVA 115/34.5 kV transformer
- Construction of a new 34.5 kV line to reroute Line 532 into North Broadway, enabling the full retirement of Depew substation

5. Distribution upgrades (Blossom Rd, Losson Rd and Walden Ave & Sloan)

- Conversion of approximately 75 miles of distribution circuits from legacy 4.8 kV to standard 12.5 kV
- Upgrades to conductor sizes (up to 477 AL) to increase thermal capacity and reduce voltage drop

6. Installation of multiple 12.5 kV express feeders between substations and distribution centers (~10 miles total).

Additional Technical Elements

- Integration of SCADA control and visibility across all new and upgraded facilities
- Enhanced remote operation capabilities and automated restoration (self-healing features)
- System-wide reconfiguration to ensure all 12.5 kV feeders operate in phase
- Elimination of backlot lines and inaccessible equipment to improve maintenance and safety

Project Benefits:**1. Enhanced System Reliability**

The project directly addresses chronic reliability issues in one of NYSEG's most outage-prone areas. By replacing obsolete substations and reconfiguring the network, the initiative is expected to reduce SAIFI across the NYSEG system by an estimated 2.15%. This translates into fewer and shorter outages for nearly 177,000 customers, aligning with state reliability standards and improving service equity across the grid.

2. Improved Resilience and Contingency Support

Through the construction of new distribution centers and the expansion of strategic substations like North Broadway, the project introduces much-needed N-1 contingency capability to the area. This ensures that the system can withstand the failure of a single major component without causing widespread outages, significantly strengthening grid resilience in the face of storms and equipment failures.

3. Optimization of System Capacity and Load Transfer Flexibility

The conversion of legacy 4.8 kV circuits to 12.5 kV and the installation of express feeders improve the system's ability to transfer load between feeders and substations efficiently. This expanded tie capability allows for faster restoration and real-time operational flexibility, which is especially important as demand increases and load patterns shift due to electrification.

4. Long-Term Cost Efficiency

By retiring five aging substations and consolidating infrastructure, the project eliminates high-maintenance assets and reduces operational expenditures. NYSEG estimates annual O&M savings of approximately \$815,000, providing financial relief over the long term while maintaining or improving service levels. These savings also help moderate future rate impacts for customers.

5. Grid Readiness for Electrification and Future Growth

The upgraded network will support up to 52 MVA of additional load, preparing the system for forecasted growth in electric vehicles, electric heating, and distributed energy resources (DERs). With capacity in place, NYSEG can accommodate customer transitions to cleaner energy without compromising reliability or triggering reactive investment.

6. Modernized Operational Capabilities

All rebuilt and new facilities will be integrated into NYSEG's SCADA system, enabling full remote visibility and control. Combined with automated switching and advanced protection schemes, this will shorten restoration times, enable predictive maintenance, and improve outage response across the service area.

7. Risk Mitigation and Safety Improvements

The project eliminates numerous backlot lines and inaccessible infrastructure, reducing risk for field crews and enhancing public safety. Retired substations and upgraded sites also reduce the likelihood of equipment-related environmental incidents, aligning with modern utility safety and compliance standards.

Project Risks and Mitigation Plan:**1. Construction and Execution Risk**

Due to the scale and complexity of the project, there is a risk of delays related to permitting, material lead times, contractor mobilization, and construction sequencing. To mitigate this, NYSEG will adopt a phased execution strategy, prioritize early design finalization, and initiate procurement of long-lead equipment such as transformers and breakers well in advance. A detailed construction schedule will be developed and closely monitored to manage critical path activities.

2. Cost Escalation and Budget Risk

Material price volatility, labor cost increases, and potential supply chain disruptions could impact the project budget. NYSEG will include contingency allowances in the financial planning and will implement cost tracking systems to monitor expenditures. Regular budget reviews and a formal process for identifying and responding to cost deviations will be established to maintain financial discipline.

3. System Integration and Operational Transition Risk

Transitioning from legacy infrastructure to the new network configuration—especially during substation retirements and feeder reconfigurations—could pose operational risks, including service interruptions. NYSEG will prepare detailed transition and cutover plans, including temporary configurations and backup solutions such as mobile substations, to minimize impacts to customers during system switchover periods.

4. Stakeholder and Community Impact Risk

Construction activities may temporarily affect local communities through traffic disruptions, noise, or access limitations. To address this, NYSEG will engage proactively with municipalities and stakeholders, provide advance notice of planned work, and coordinate closely to minimize disruptions. Communication plans will be put in place to keep the public informed throughout the project.

5. Environmental and Regulatory Compliance Risk

Project components involving civil works or equipment installation may require environmental permitting and regulatory reviews. NYSEG will conduct thorough pre-construction environmental assessments and will work with regulatory agencies to secure all necessary approvals. Compliance will be monitored throughout the project by internal teams and external environmental consultants.

6. Technology Integration and Cybersecurity Risk

The integration of SCADA systems, protection relays, and remote switching technologies introduces risks related to system compatibility and cybersecurity. NYSEG will perform comprehensive factory and site acceptance testing, follow standard protocols for equipment integration, and implement cybersecurity reviews in line with internal policies and industry best practices.

Risk of No Action:

In addition to the project execution risks, it is important to highlight the significant consequences of inaction—should the Lancaster Grid Modernization Project be delayed, deferred, or not implemented. These risks would affect both operational performance and long-term strategic objectives:

1. Continued System Reliability Degradation

Several of the substations in the project scope are among the worst performers in NYSEG's service territory in terms of SAIFI and SAIDI. Without modernization, customers in the region would continue to experience frequent and prolonged outages. Aging infrastructure increases the likelihood of unplanned failures, which could further degrade service quality and lead to regulatory penalties.

2. Inability to Support Load Growth and Electrification

The existing 4.8 kV infrastructure and current system configuration cannot accommodate forecasted demand growth driven by electrification (EVs, heat pumps, DERs). Delaying the project would constrain NYSEG's ability to connect new load and meet statewide decarbonization and electrification goals. It may also lead to more reactive, less efficient capital spending in the future.

3. Escalating Maintenance and Operational Costs

Aging substations and equipment require increasingly frequent maintenance and emergency repairs. Without proactive investment, O&M costs will continue to rise, driven by unplanned interventions and inefficient asset management. This also ties up workforce resources that could otherwise support strategic initiatives.

4. Increased Risk of Equipment Failure and Safety Incidents

Legacy equipment poses not only reliability risks but also safety and environmental risks. Continued operation of deteriorated assets increases the chance of equipment failure, potential fire hazards, oil spills, and unsafe working conditions for field personnel.

5. Missed Opportunity for Operational Modernization

Postponing the project would delay the deployment of advanced grid functionalities such as SCADA, remote switching, and self-healing networks. This limits NYSEG's ability to improve outage response times, reduce truck rolls, and integrate data-driven system operations.

6. Reduced Long-Term Cost Efficiency

Failure to act now could result in higher future capital expenditures. Delaying coordinated modernization may force NYSEG to invest in piecemeal upgrades under time and reliability pressures, which are typically less cost-effective than comprehensive, planned reinforcements.

Project Alternatives:

As part of the planning process, NYSEG evaluated multiple alternatives to address the reliability, capacity, and asset condition issues in the Lancaster Division. Each alternative was assessed based on technical feasibility, cost-effectiveness, reliability benefits, future readiness, and constructability. The alternatives ranged from minimal intervention to full system reconfiguration.

Alternative 0 – Do Nothing

This baseline alternative would involve no proactive investment and would rely on continued operation and maintenance of the existing infrastructure.

- Pros: No upfront capital cost
- Cons: No improvement in reliability or capacity, continued deterioration of assets, increasing O&M costs, and high risk of equipment failure
- Conclusion: Not viable. This alternative fails to meet basic planning criteria and leaves the system vulnerable.

Alternative 1 – Limited Substation Replacement

This alternative proposed rebuilding only one or two of the most critical substations (e.g., Walden Avenue and Blossom Road), while keeping the rest of the network intact.

- Pros: Moderate capital cost, localized improvement at high-impact substations
- Cons: Minimal impact on broader network reliability and redundancy; does not address 4.8 kV conversion or N-1 contingency gaps; limited long-term scalability
- Conclusion: Provides partial benefit but does not support a comprehensive modernization strategy.

Alternative 2 – Comprehensive Grid Modernization (Selected)

This alternative includes the full rebuild of three major substations, retirement of five legacy substations, conversion of 4.8 kV to 12.5 kV, construction of two new distribution centers, and expansion of North Broadway.

- Pros: Maximizes reliability improvement (2.15% SAIFI reduction), fully resolves N-1 contingency deficiencies, supports long-term electrification, enables flexible load transfer, and reduces O&M costs
- Cons: Higher initial capital investment
- Additional Note: Within this alternative, multiple grid modernization configurations were evaluated, varying in substation design, feeder layout, and sequencing strategy. The selected configuration was found to be the most cost-effective while meeting all technical and operational objectives.
- Conclusion: Selected as the preferred solution due to its comprehensive, long-term value and alignment with utility and regulatory objectives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 810	\$ 97	\$ 130	\$ 283	\$ 283	\$ 16	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,984	\$ 238	\$ 317	\$ 695	\$ 695	\$ 40	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 201	\$ 24	\$ 32	\$ 70	\$ 70	\$ 4	\$ -	\$ -
# Internal, Overheads	\$ 658	\$ 81	\$ 130	\$ 224	\$ 210	\$ 12	\$ -	\$ -
# Materials	\$ 5,358	\$ 643	\$ 857	\$ 1,875	\$ 1,875	\$ 107	\$ -	\$ -
# Overheads - External	\$ 675	\$ 107	\$ 128	\$ 221	\$ 207	\$ 12	\$ -	\$ -
Total	\$ 9,686	\$ 1,191	\$ 1,595	\$ 3,369	\$ 3,341	\$ 190	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Lancaster Project - Blossom to Losson - Distribution Express feeder

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007387	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

The Blossom to Losson - Distribution Express feeder project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Division Grid Modernization Pilot is a comprehensive initiative aimed at addressing critical needs related to system reliability, aging infrastructure, electrification readiness, and network resilience. The project aligns with state energy policy objectives and utility planning standards, providing a forward-looking framework to modernize both the distribution and sub-transmission networks.

This project also represents a shift in planning philosophy. It introduces a differentiated approach not only in execution, but in how system needs are identified and addressed. Rather than applying traditional asset-by-asset solutions, NYSEG has adopted a zonal planning model, grounded in an in-depth analysis of local network performance, asset condition, and long-term demand forecasts. The result is a holistic solution tailored to the specific needs of the Lancaster area—improving reliability, optimizing capacity, reducing operational costs, and enabling future growth in a coordinated and scalable way.

Project Justification

- **Reliability:** Between 2020 and 2022, the Lancaster Division accounted for approximately 19% of NYSEG's total SAIFI (System Average Interruption Frequency Index) impact. Three substations—Losson Rd, Blossom Rd, and Walden Ave—were among the poorest performers system-wide.
- **Asset Condition:** Multiple substations were identified with outdated transformers, electromechanical relays, deteriorated switchgear, and poor structural conditions, many lacking SCADA visibility or control.
- **Resiliency & Redundancy:** The area lacks sufficient N-1 contingency support, making it vulnerable to prolonged outages and limiting the ability to automatically isolate and restore faults.
- **Load Growth:** Forecasts project a 30% increase in peak demand by 2037, driven by building electrification and electric vehicle (EV) adoption.

Project Scope:

The Blossom to Losson - Distribution Express feeder project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Grid Modernization Pilot proposes a comprehensive reconfiguration of the electric distribution and sub-transmission network in one of NYSEG's highest-impact service areas. The initiative targets a region that serves approximately 177,000 customers and carries roughly 690 MW of system load, representing a substantial portion of NYSEG's reliability performance metrics. The scope includes infrastructure upgrades, voltage conversions, substation retirements, and implementation of advanced system automation, all designed to improve reliability, resilience, and operational efficiency.

Main Infrastructure Components

1. Rebuild of Key Substations

- Losson Road (34.5/12.5 kV GIS): Full rebuild with 9 feeders and 2×50 MVA transformers
- Blossom Road (34.5/12.5 kV GIS): Full rebuild with 6 feeders and 2×37.3 MVA transformers
- Walden Avenue (115/12.5 kV AIS): Upgrade with 9 feeders, 2×50 MVA transformers, new breakers, and control house

2. Substation Retirements - Aging infrastructure with poor condition ratings, obsolete equipment, and limited operational visibility

- Five legacy substations to be retired: Sloan, Ellicott, Ebenezer, Indian Church, and Depew

3. Construction of two new 12.5 kV distribution centers to serve as centralized and automated feeder hubs strategically located at Sloan and Losson to enable rapid fault isolation, load transfer, and network reconfiguration

4. North Broadway Substation Expansion and Depew Line Replacement

- Installation of three new 115 kV breakers and expansion of the 34.5 kV yard with three new breakers
- Addition of a new 50 MVA 115/34.5 kV transformer
- Construction of a new 34.5 kV line to reroute Line 532 into North Broadway, enabling the full retirement of Depew substation

5. Distribution upgrades (Blossom Rd, Losson Rd and Walden Ave & Sloan)

- Conversion of approximately 75 miles of distribution circuits from legacy 4.8 kV to standard 12.5 kV
- Upgrades to conductor sizes (up to 477 AL) to increase thermal capacity and reduce voltage drop

6. Installation of multiple 12.5 kV express feeders between substations and distribution centers (~10 miles total).

Additional Technical Elements

- Integration of SCADA control and visibility across all new and upgraded facilities
- Enhanced remote operation capabilities and automated restoration (self-healing features)
- System-wide reconfiguration to ensure all 12.5 kV feeders operate in phase
- Elimination of backlot lines and inaccessible equipment to improve maintenance and safety

Project Benefits:**1. Enhanced System Reliability**

The project directly addresses chronic reliability issues in one of NYSEG's most outage-prone areas. By replacing obsolete substations and reconfiguring the network, the initiative is expected to reduce SAIFI across the NYSEG system by an estimated 2.15%. This translates into fewer and shorter outages for nearly 177,000 customers, aligning with state reliability standards and improving service equity across the grid.

2. Improved Resilience and Contingency Support

Through the construction of new distribution centers and the expansion of strategic substations like North Broadway, the project introduces much-needed N-1 contingency capability to the area. This ensures that the system can withstand the failure of a single major component without causing widespread outages, significantly strengthening grid resilience in the face of storms and equipment failures.

3. Optimization of System Capacity and Load Transfer Flexibility

The conversion of legacy 4.8 kV circuits to 12.5 kV and the installation of express feeders improve the system's ability to transfer load between feeders and substations efficiently. This expanded tie capability allows for faster restoration and real-time operational flexibility, which is especially important as demand increases and load patterns shift due to electrification.

4. Long-Term Cost Efficiency

By retiring five aging substations and consolidating infrastructure, the project eliminates high-maintenance assets and reduces operational expenditures. NYSEG estimates annual O&M savings of approximately \$815,000, providing financial relief over the long term while maintaining or improving service levels. These savings also help moderate future rate impacts for customers.

5. Grid Readiness for Electrification and Future Growth

The upgraded network will support up to 52 MVA of additional load, preparing the system for forecasted growth in electric vehicles, electric heating, and distributed energy resources (DERs). With capacity in place, NYSEG can accommodate customer transitions to cleaner energy without compromising reliability or triggering reactive investment.

6. Modernized Operational Capabilities

All rebuilt and new facilities will be integrated into NYSEG's SCADA system, enabling full remote visibility and control. Combined with automated switching and advanced protection schemes, this will shorten restoration times, enable predictive maintenance, and improve outage response across the service area.

7. Risk Mitigation and Safety Improvements

The project eliminates numerous backlot lines and inaccessible infrastructure, reducing risk for field crews and enhancing public safety. Retired substations and upgraded sites also reduce the likelihood of equipment-related environmental incidents, aligning with modern utility safety and compliance standards.

Project Risks and Mitigation Plan:**1. Construction and Execution Risk**

Due to the scale and complexity of the project, there is a risk of delays related to permitting, material lead times, contractor mobilization, and construction sequencing. To mitigate this, NYSEG will adopt a phased execution strategy, prioritize early design finalization, and initiate procurement of long-lead equipment such as transformers and breakers well in advance. A detailed construction schedule will be developed and closely monitored to manage critical path activities.

2. Cost Escalation and Budget Risk

Material price volatility, labor cost increases, and potential supply chain disruptions could impact the project budget. NYSEG will include contingency allowances in the financial planning and will implement cost tracking systems to monitor expenditures. Regular budget reviews and a formal process for identifying and responding to cost deviations will be established to maintain financial discipline.

3. System Integration and Operational Transition Risk

Transitioning from legacy infrastructure to the new network configuration—especially during substation retirements and feeder reconfigurations—could pose operational risks, including service interruptions. NYSEG will prepare detailed transition and cutover plans, including temporary configurations and backup solutions such as mobile substations, to minimize impacts to customers during system switchover periods.

4. Stakeholder and Community Impact Risk

Construction activities may temporarily affect local communities through traffic disruptions, noise, or access limitations. To address this, NYSEG will engage proactively with municipalities and stakeholders, provide advance notice of planned work, and coordinate closely to minimize disruptions. Communication plans will be put in place to keep the public informed throughout the project.

5. Environmental and Regulatory Compliance Risk

Project components involving civil works or equipment installation may require environmental permitting and regulatory reviews. NYSEG will conduct thorough pre-construction environmental assessments and will work with regulatory agencies to secure all necessary approvals. Compliance will be monitored throughout the project by internal teams and external environmental consultants.

6. Technology Integration and Cybersecurity Risk

The integration of SCADA systems, protection relays, and remote switching technologies introduces risks related to system compatibility and cybersecurity. NYSEG will perform comprehensive factory and site acceptance testing, follow standard protocols for equipment integration, and implement cybersecurity reviews in line with internal policies and industry best practices.

Risk of No Action:

In addition to the project execution risks, it is important to highlight the significant consequences of inaction—should the Lancaster Grid Modernization Project be delayed, deferred, or not implemented. These risks would affect both operational performance and long-term strategic objectives:

1. Continued System Reliability Degradation

Several of the substations in the project scope are among the worst performers in NYSEG's service territory in terms of SAIFI and SAIDI. Without modernization, customers in the region would continue to experience frequent and prolonged outages. Aging infrastructure increases the likelihood of unplanned failures, which could further degrade service quality and lead to regulatory penalties.

2. Inability to Support Load Growth and Electrification

The existing 4.8 kV infrastructure and current system configuration cannot accommodate forecasted demand growth driven by electrification (EVs, heat pumps, DERs). Delaying the project would constrain NYSEG's ability to connect new load and meet statewide decarbonization and electrification goals. It may also lead to more reactive, less efficient capital spending in the future.

3. Escalating Maintenance and Operational Costs

Aging substations and equipment require increasingly frequent maintenance and emergency repairs. Without proactive investment, O&M costs will continue to rise, driven by unplanned interventions and inefficient asset management. This also ties up workforce resources that could otherwise support strategic initiatives.

4. Increased Risk of Equipment Failure and Safety Incidents

Legacy equipment poses not only reliability risks but also safety and environmental risks. Continued operation of deteriorated assets increases the chance of equipment failure, potential fire hazards, oil spills, and unsafe working conditions for field personnel.

5. Missed Opportunity for Operational Modernization

Postponing the project would delay the deployment of advanced grid functionalities such as SCADA, remote switching, and self-healing networks. This limits NYSEG's ability to improve outage response times, reduce truck rolls, and integrate data-driven system operations.

6. Reduced Long-Term Cost Efficiency

Failure to act now could result in higher future capital expenditures. Delaying coordinated modernization may force NYSEG to invest in piecemeal upgrades under time and reliability pressures, which are typically less cost-effective than comprehensive, planned reinforcements.

Project Alternatives:

As part of the planning process, NYSEG evaluated multiple alternatives to address the reliability, capacity, and asset condition issues in the Lancaster Division. Each alternative was assessed based on technical feasibility, cost-effectiveness, reliability benefits, future readiness, and constructability. The alternatives ranged from minimal intervention to full system reconfiguration.

Alternative 0 – Do Nothing

This baseline alternative would involve no proactive investment and would rely on continued operation and maintenance of the existing infrastructure.

- Pros: No upfront capital cost
- Cons: No improvement in reliability or capacity, continued deterioration of assets, increasing O&M costs, and high risk of equipment failure
- Conclusion: Not viable. This alternative fails to meet basic planning criteria and leaves the system vulnerable.

Alternative 1 – Limited Substation Replacement

This alternative proposed rebuilding only one or two of the most critical substations (e.g., Walden Avenue and Blossom Road), while keeping the rest of the network intact.

- Pros: Moderate capital cost, localized improvement at high-impact substations
- Cons: Minimal impact on broader network reliability and redundancy; does not address 4.8 kV conversion or N-1 contingency gaps; limited long-term scalability
- Conclusion: Provides partial benefit but does not support a comprehensive modernization strategy.

Alternative 2 – Comprehensive Grid Modernization (Selected)

This alternative includes the full rebuild of three major substations, retirement of five legacy substations, conversion of 4.8 kV to 12.5 kV, construction of two new distribution centers, and expansion of North Broadway.

- Pros: Maximizes reliability improvement (2.15% SAIFI reduction), fully resolves N-1 contingency deficiencies, supports long-term electrification, enables flexible load transfer, and reduces O&M costs
- Cons: Higher initial capital investment
- Additional Note: Within this alternative, multiple grid modernization configurations were evaluated, varying in substation design, feeder layout, and sequencing strategy. The selected configuration was found to be the most cost-effective while meeting all technical and operational objectives.
- Conclusion: Selected as the preferred solution due to its comprehensive, long-term value and alignment with utility and regulatory objectives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 810	\$ 97	\$ 130	\$ 283	\$ 283	\$ 16	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,984	\$ 238	\$ 317	\$ 695	\$ 695	\$ 40	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 201	\$ 24	\$ 32	\$ 70	\$ 70	\$ 4	\$ -	\$ -
# Internal, Overheads	\$ 658	\$ 81	\$ 130	\$ 224	\$ 210	\$ 12	\$ -	\$ -
# Materials	\$ 5,358	\$ 643	\$ 857	\$ 1,875	\$ 1,875	\$ 107	\$ -	\$ -
# Overheads - External	\$ 675	\$ 107	\$ 128	\$ 221	\$ 207	\$ 12	\$ -	\$ -
Total	\$ 9,686	\$ 1,191	\$ 1,595	\$ 3,369	\$ 3,341	\$ 190	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Lancaster Project - Line 532 - Reroute

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007386	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

The Line 532 - Reroute project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Division Grid Modernization Pilot is a comprehensive initiative aimed at addressing critical needs related to system reliability, aging infrastructure, electrification readiness, and network resilience. The project aligns with state energy policy objectives and utility planning standards, providing a forward-looking framework to modernize both the distribution and sub-transmission networks.

This project also represents a shift in planning philosophy. It introduces a differentiated approach not only in execution, but in how system needs are identified and addressed. Rather than applying traditional asset-by-asset solutions, NYSEG has adopted a zonal planning model, grounded in an in-depth analysis of local network performance, asset condition, and long-term demand forecasts. The result is a holistic solution tailored to the specific needs of the Lancaster area—improving reliability, optimizing capacity, reducing operational costs, and enabling future growth in a coordinated and scalable way.

Project Justification

- **Reliability:** Between 2020 and 2022, the Lancaster Division accounted for approximately 19% of NYSEG's total SAIFI (System Average Interruption Frequency Index) impact. Three substations—Losson Rd, Blossom Rd, and Walden Ave—were among the poorest performers system-wide.
- **Asset Condition:** Multiple substations were identified with outdated transformers, electromechanical relays, deteriorated switchgear, and poor structural conditions, many lacking SCADA visibility or control.
- **Resiliency & Redundancy:** The area lacks sufficient N-1 contingency support, making it vulnerable to prolonged outages and limiting the ability to automatically isolate and restore faults.
- **Load Growth:** Forecasts project a 30% increase in peak demand by 2037, driven by building electrification and electric vehicle (EV) adoption.

Project Scope:

The Line 532 - Reroute project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Grid Modernization Pilot proposes a comprehensive reconfiguration of the electric distribution and sub-transmission network in one of NYSEG's highest-impact service areas. The initiative targets a region that serves approximately 177,000 customers and carries roughly 690 MW of system load, representing a substantial portion of NYSEG's reliability performance metrics. The scope includes infrastructure upgrades, voltage conversions, substation retirements, and implementation of advanced system automation, all designed to improve reliability, resilience, and operational efficiency.

Main Infrastructure Components

1. Rebuild of Key Substations

- Losson Road (34.5/12.5 kV GIS): Full rebuild with 9 feeders and 2×50 MVA transformers
- Blossom Road (34.5/12.5 kV GIS): Full rebuild with 6 feeders and 2×37.3 MVA transformers
- Walden Avenue (115/12.5 kV AIS): Upgrade with 9 feeders, 2×50 MVA transformers, new breakers, and control house

2. Substation Retirements - Aging infrastructure with poor condition ratings, obsolete equipment, and limited operational visibility

- Five legacy substations to be retired: Sloan, Ellicott, Ebenezer, Indian Church, and Depew

3. Construction of two new 12.5 kV distribution centers to serve as centralized and automated feeder hubs strategically located at Sloan and Losson to enable rapid fault isolation, load transfer, and network reconfiguration

4. North Broadway Substation Expansion and Depew Line Replacement

- Installation of three new 115 kV breakers and expansion of the 34.5 kV yard with three new breakers
- Addition of a new 50 MVA 115/34.5 kV transformer
- Construction of a new 34.5 kV line to reroute Line 532 into North Broadway, enabling the full retirement of Depew substation

5. Distribution upgrades (Blossom Rd, Losson Rd and Walden Ave & Sloan)

- Conversion of approximately 75 miles of distribution circuits from legacy 4.8 kV to standard 12.5 kV
- Upgrades to conductor sizes (up to 477 AL) to increase thermal capacity and reduce voltage drop

6. Installation of multiple 12.5 kV express feeders between substations and distribution centers (~10 miles total).

Additional Technical Elements

- Integration of SCADA control and visibility across all new and upgraded facilities
- Enhanced remote operation capabilities and automated restoration (self-healing features)
- System-wide reconfiguration to ensure all 12.5 kV feeders operate in phase
- Elimination of backlot lines and inaccessible equipment to improve maintenance and safety

Project Benefits:**1. Enhanced System Reliability**

The project directly addresses chronic reliability issues in one of NYSEG's most outage-prone areas. By replacing obsolete substations and reconfiguring the network, the initiative is expected to reduce SAIFI across the NYSEG system by an estimated 2.15%. This translates into fewer and shorter outages for nearly 177,000 customers, aligning with state reliability standards and improving service equity across the grid.

2. Improved Resilience and Contingency Support

Through the construction of new distribution centers and the expansion of strategic substations like North Broadway, the project introduces much-needed N-1 contingency capability to the area. This ensures that the system can withstand the failure of a single major component without causing widespread outages, significantly strengthening grid resilience in the face of storms and equipment failures.

3. Optimization of System Capacity and Load Transfer Flexibility

The conversion of legacy 4.8 kV circuits to 12.5 kV and the installation of express feeders improve the system's ability to transfer load between feeders and substations efficiently. This expanded tie capability allows for faster restoration and real-time operational flexibility, which is especially important as demand increases and load patterns shift due to electrification.

4. Long-Term Cost Efficiency

By retiring five aging substations and consolidating infrastructure, the project eliminates high-maintenance assets and reduces operational expenditures. NYSEG estimates annual O&M savings of approximately \$815,000, providing financial relief over the long term while maintaining or improving service levels. These savings also help moderate future rate impacts for customers.

5. Grid Readiness for Electrification and Future Growth

The upgraded network will support up to 52 MVA of additional load, preparing the system for forecasted growth in electric vehicles, electric heating, and distributed energy resources (DERs). With capacity in place, NYSEG can accommodate customer transitions to cleaner energy without compromising reliability or triggering reactive investment.

6. Modernized Operational Capabilities

All rebuilt and new facilities will be integrated into NYSEG's SCADA system, enabling full remote visibility and control. Combined with automated switching and advanced protection schemes, this will shorten restoration times, enable predictive maintenance, and improve outage response across the service area.

7. Risk Mitigation and Safety Improvements

The project eliminates numerous backlot lines and inaccessible infrastructure, reducing risk for field crews and enhancing public safety. Retired substations and upgraded sites also reduce the likelihood of equipment-related environmental incidents, aligning with modern utility safety and compliance standards.

Project Risks and Mitigation Plan:**1. Construction and Execution Risk**

Due to the scale and complexity of the project, there is a risk of delays related to permitting, material lead times, contractor mobilization, and construction sequencing. To mitigate this, NYSEG will adopt a phased execution strategy, prioritize early design finalization, and initiate procurement of long-lead equipment such as transformers and breakers well in advance. A detailed construction schedule will be developed and closely monitored to manage critical path activities.

2. Cost Escalation and Budget Risk

Material price volatility, labor cost increases, and potential supply chain disruptions could impact the project budget. NYSEG will include contingency allowances in the financial planning and will implement cost tracking systems to monitor expenditures. Regular budget reviews and a formal process for identifying and responding to cost deviations will be established to maintain financial discipline.

3. System Integration and Operational Transition Risk

Transitioning from legacy infrastructure to the new network configuration—especially during substation retirements and feeder reconfigurations—could pose operational risks, including service interruptions. NYSEG will prepare detailed transition and cutover plans, including temporary configurations and backup solutions such as mobile substations, to minimize impacts to customers during system switchover periods.

4. Stakeholder and Community Impact Risk

Construction activities may temporarily affect local communities through traffic disruptions, noise, or access limitations. To address this, NYSEG will engage proactively with municipalities and stakeholders, provide advance notice of planned work, and coordinate closely to minimize disruptions. Communication plans will be put in place to keep the public informed throughout the project.

5. Environmental and Regulatory Compliance Risk

Project components involving civil works or equipment installation may require environmental permitting and regulatory reviews. NYSEG will conduct thorough pre-construction environmental assessments and will work with regulatory agencies to secure all necessary approvals. Compliance will be monitored throughout the project by internal teams and external environmental consultants.

6. Technology Integration and Cybersecurity Risk

The integration of SCADA systems, protection relays, and remote switching technologies introduces risks related to system compatibility and cybersecurity. NYSEG will perform comprehensive factory and site acceptance testing, follow standard protocols for equipment integration, and implement cybersecurity reviews in line with internal policies and industry best practices.

Risk of No Action:

In addition to the project execution risks, it is important to highlight the significant consequences of inaction—should the Lancaster Grid Modernization Project be delayed, deferred, or not implemented. These risks would affect both operational performance and long-term strategic objectives:

1. Continued System Reliability Degradation

Several of the substations in the project scope are among the worst performers in NYSEG's service territory in terms of SAIFI and SAIDI. Without modernization, customers in the region would continue to experience frequent and prolonged outages. Aging infrastructure increases the likelihood of unplanned failures, which could further degrade service quality and lead to regulatory penalties.

2. Inability to Support Load Growth and Electrification

The existing 4.8 kV infrastructure and current system configuration cannot accommodate forecasted demand growth driven by electrification (EVs, heat pumps, DERs). Delaying the project would constrain NYSEG's ability to connect new load and meet statewide decarbonization and electrification goals. It may also lead to more reactive, less efficient capital spending in the future.

3. Escalating Maintenance and Operational Costs

Aging substations and equipment require increasingly frequent maintenance and emergency repairs. Without proactive investment, O&M costs will continue to rise, driven by unplanned interventions and inefficient asset management. This also ties up workforce resources that could otherwise support strategic initiatives.

4. Increased Risk of Equipment Failure and Safety Incidents

Legacy equipment poses not only reliability risks but also safety and environmental risks. Continued operation of deteriorated assets increases the chance of equipment failure, potential fire hazards, oil spills, and unsafe working conditions for field personnel.

5. Missed Opportunity for Operational Modernization

Postponing the project would delay the deployment of advanced grid functionalities such as SCADA, remote switching, and self-healing networks. This limits NYSEG's ability to improve outage response times, reduce truck rolls, and integrate data-driven system operations.

6. Reduced Long-Term Cost Efficiency

Failure to act now could result in higher future capital expenditures. Delaying coordinated modernization may force NYSEG to invest in piecemeal upgrades under time and reliability pressures, which are typically less cost-effective than comprehensive, planned reinforcements.

Project Alternatives:

As part of the planning process, NYSEG evaluated multiple alternatives to address the reliability, capacity, and asset condition issues in the Lancaster Division. Each alternative was assessed based on technical feasibility, cost-effectiveness, reliability benefits, future readiness, and constructability. The alternatives ranged from minimal intervention to full system reconfiguration.

Alternative 0 – Do Nothing

This baseline alternative would involve no proactive investment and would rely on continued operation and maintenance of the existing infrastructure.

- Pros: No upfront capital cost
- Cons: No improvement in reliability or capacity, continued deterioration of assets, increasing O&M costs, and high risk of equipment failure
- Conclusion: Not viable. This alternative fails to meet basic planning criteria and leaves the system vulnerable.

Alternative 1 – Limited Substation Replacement

This alternative proposed rebuilding only one or two of the most critical substations (e.g., Walden Avenue and Blossom Road), while keeping the rest of the network intact.

- Pros: Moderate capital cost, localized improvement at high-impact substations
- Cons: Minimal impact on broader network reliability and redundancy; does not address 4.8 kV conversion or N-1 contingency gaps; limited long-term scalability
- Conclusion: Provides partial benefit but does not support a comprehensive modernization strategy.

Alternative 2 – Comprehensive Grid Modernization (Selected)

This alternative includes the full rebuild of three major substations, retirement of five legacy substations, conversion of 4.8 kV to 12.5 kV, construction of two new distribution centers, and expansion of North Broadway.

- Pros: Maximizes reliability improvement (2.15% SAIFI reduction), fully resolves N-1 contingency deficiencies, supports long-term electrification, enables flexible load transfer, and reduces O&M costs
- Cons: Higher initial capital investment
- Additional Note: Within this alternative, multiple grid modernization configurations were evaluated, varying in substation design, feeder layout, and sequencing strategy. The selected configuration was found to be the most cost-effective while meeting all technical and operational objectives.
- Conclusion: Selected as the preferred solution due to its comprehensive, long-term value and alignment with utility and regulatory objectives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,208	\$ 28	\$ 365	\$ 572	\$ 243	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,960	\$ 69	\$ 894	\$ 1,401	\$ 596	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 300	\$ 7	\$ 91	\$ 142	\$ 60	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 1,023	\$ 23	\$ 366	\$ 453	\$ 181	\$ -	\$ -	\$ -
# Materials	\$ 7,992	\$ 186	\$ 2,414	\$ 3,783	\$ 1,609	\$ -	\$ -	\$ -
# Overheads - External	\$ 1,015	\$ 31	\$ 361	\$ 446	\$ 178	\$ -	\$ -	\$ -
Total	\$ 14,499	\$ 345	\$ 4,490	\$ 6,796	\$ 2,867	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Lancaster Project - Walden Ave & Sloan - Distribution upgrades

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007385	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

The Walden Ave & Sloan - Distribution upgrades project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Division Grid Modernization Pilot is a comprehensive initiative aimed at addressing critical needs related to system reliability, aging infrastructure, electrification readiness, and network resilience. The project aligns with state energy policy objectives and utility planning standards, providing a forward-looking framework to modernize both the distribution and sub-transmission networks.

This project also represents a shift in planning philosophy. It introduces a differentiated approach not only in execution, but in how system needs are identified and addressed. Rather than applying traditional asset-by-asset solutions, NYSEG has adopted a zonal planning model, grounded in an in-depth analysis of local network performance, asset condition, and long-term demand forecasts. The result is a holistic solution tailored to the specific needs of the Lancaster area—improving reliability, optimizing capacity, reducing operational costs, and enabling future growth in a coordinated and scalable way.

Project Justification

- **Reliability:** Between 2020 and 2022, the Lancaster Division accounted for approximately 19% of NYSEG's total SAIFI (System Average Interruption Frequency Index) impact. Three substations—Losson Rd, Blossom Rd, and Walden Ave—were among the poorest performers system-wide.
- **Asset Condition:** Multiple substations were identified with outdated transformers, electromechanical relays, deteriorated switchgear, and poor structural conditions, many lacking SCADA visibility or control.
- **Resiliency & Redundancy:** The area lacks sufficient N-1 contingency support, making it vulnerable to prolonged outages and limiting the ability to automatically isolate and restore faults.
- **Load Growth:** Forecasts project a 30% increase in peak demand by 2037, driven by building electrification and electric vehicle (EV) adoption.

Project Scope:

The Walden Ave & Sloan - Distribution upgrades project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Grid Modernization Pilot proposes a comprehensive reconfiguration of the electric distribution and sub-transmission network in one of NYSEG's highest-impact service areas. The initiative targets a region that serves approximately 177,000 customers and carries roughly 690 MW of system load, representing a substantial portion of NYSEG's reliability performance metrics. The scope includes infrastructure upgrades, voltage conversions, substation retirements, and implementation of advanced system automation, all designed to improve reliability, resilience, and operational efficiency.

Main Infrastructure Components

1. Rebuild of Key Substations

- Losson Road (34.5/12.5 kV GIS): Full rebuild with 9 feeders and 2×50 MVA transformers
- Blossom Road (34.5/12.5 kV GIS): Full rebuild with 6 feeders and 2×37.3 MVA transformers
- Walden Avenue (115/12.5 kV AIS): Upgrade with 9 feeders, 2×50 MVA transformers, new breakers, and control house

2. Substation Retirements - Aging infrastructure with poor condition ratings, obsolete equipment, and limited operational visibility

- Five legacy substations to be retired: Sloan, Ellicott, Ebenezer, Indian Church, and Depew

3. Construction of two new 12.5 kV distribution centers to serve as centralized and automated feeder hubs strategically located at Sloan and Losson to enable rapid fault isolation, load transfer, and network reconfiguration

4. North Broadway Substation Expansion and Depew Line Replacement

- Installation of three new 115 kV breakers and expansion of the 34.5 kV yard with three new breakers
- Addition of a new 50 MVA 115/34.5 kV transformer
- Construction of a new 34.5 kV line to reroute Line 532 into North Broadway, enabling the full retirement of Depew substation

5. Distribution upgrades (Blossom Rd, Losson Rd and Walden Ave & Sloan)

- Conversion of approximately 75 miles of distribution circuits from legacy 4.8 kV to standard 12.5 kV
- Upgrades to conductor sizes (up to 477 AL) to increase thermal capacity and reduce voltage drop

6. Installation of multiple 12.5 kV express feeders between substations and distribution centers (~10 miles total).

Additional Technical Elements

- Integration of SCADA control and visibility across all new and upgraded facilities
- Enhanced remote operation capabilities and automated restoration (self-healing features)
- System-wide reconfiguration to ensure all 12.5 kV feeders operate in phase
- Elimination of backlot lines and inaccessible equipment to improve maintenance and safety

Project Benefits:**1. Enhanced System Reliability**

The project directly addresses chronic reliability issues in one of NYSEG's most outage-prone areas. By replacing obsolete substations and reconfiguring the network, the initiative is expected to reduce SAIFI across the NYSEG system by an estimated 2.15%. This translates into fewer and shorter outages for nearly 177,000 customers, aligning with state reliability standards and improving service equity across the grid.

2. Improved Resilience and Contingency Support

Through the construction of new distribution centers and the expansion of strategic substations like North Broadway, the project introduces much-needed N-1 contingency capability to the area. This ensures that the system can withstand the failure of a single major component without causing widespread outages, significantly strengthening grid resilience in the face of storms and equipment failures.

3. Optimization of System Capacity and Load Transfer Flexibility

The conversion of legacy 4.8 kV circuits to 12.5 kV and the installation of express feeders improve the system's ability to transfer load between feeders and substations efficiently. This expanded tie capability allows for faster restoration and real-time operational flexibility, which is especially important as demand increases and load patterns shift due to electrification.

4. Long-Term Cost Efficiency

By retiring five aging substations and consolidating infrastructure, the project eliminates high-maintenance assets and reduces operational expenditures. NYSEG estimates annual O&M savings of approximately \$815,000, providing financial relief over the long term while maintaining or improving service levels. These savings also help moderate future rate impacts for customers.

5. Grid Readiness for Electrification and Future Growth

The upgraded network will support up to 52 MVA of additional load, preparing the system for forecasted growth in electric vehicles, electric heating, and distributed energy resources (DERs). With capacity in place, NYSEG can accommodate customer transitions to cleaner energy without compromising reliability or triggering reactive investment.

6. Modernized Operational Capabilities

All rebuilt and new facilities will be integrated into NYSEG's SCADA system, enabling full remote visibility and control. Combined with automated switching and advanced protection schemes, this will shorten restoration times, enable predictive maintenance, and improve outage response across the service area.

7. Risk Mitigation and Safety Improvements

The project eliminates numerous backlot lines and inaccessible infrastructure, reducing risk for field crews and enhancing public safety. Retired substations and upgraded sites also reduce the likelihood of equipment-related environmental incidents, aligning with modern utility safety and compliance standards.

Project Risks and Mitigation Plan:**1. Construction and Execution Risk**

Due to the scale and complexity of the project, there is a risk of delays related to permitting, material lead times, contractor mobilization, and construction sequencing. To mitigate this, NYSEG will adopt a phased execution strategy, prioritize early design finalization, and initiate procurement of long-lead equipment such as transformers and breakers well in advance. A detailed construction schedule will be developed and closely monitored to manage critical path activities.

2. Cost Escalation and Budget Risk

Material price volatility, labor cost increases, and potential supply chain disruptions could impact the project budget. NYSEG will include contingency allowances in the financial planning and will implement cost tracking systems to monitor expenditures. Regular budget reviews and a formal process for identifying and responding to cost deviations will be established to maintain financial discipline.

3. System Integration and Operational Transition Risk

Transitioning from legacy infrastructure to the new network configuration—especially during substation retirements and feeder reconfigurations—could pose operational risks, including service interruptions. NYSEG will prepare detailed transition and cutover plans, including temporary configurations and backup solutions such as mobile substations, to minimize impacts to customers during system switchover periods.

4. Stakeholder and Community Impact Risk

Construction activities may temporarily affect local communities through traffic disruptions, noise, or access limitations. To address this, NYSEG will engage proactively with municipalities and stakeholders, provide advance notice of planned work, and coordinate closely to minimize disruptions. Communication plans will be put in place to keep the public informed throughout the project.

5. Environmental and Regulatory Compliance Risk

Project components involving civil works or equipment installation may require environmental permitting and regulatory reviews. NYSEG will conduct thorough pre-construction environmental assessments and will work with regulatory agencies to secure all necessary approvals. Compliance will be monitored throughout the project by internal teams and external environmental consultants.

6. Technology Integration and Cybersecurity Risk

The integration of SCADA systems, protection relays, and remote switching technologies introduces risks related to system compatibility and cybersecurity. NYSEG will perform comprehensive factory and site acceptance testing, follow standard protocols for equipment integration, and implement cybersecurity reviews in line with internal policies and industry best practices.

Risk of No Action:

In addition to the project execution risks, it is important to highlight the significant consequences of inaction—should the Lancaster Grid Modernization Project be delayed, deferred, or not implemented. These risks would affect both operational performance and long-term strategic objectives:

1. Continued System Reliability Degradation

Several of the substations in the project scope are among the worst performers in NYSEG's service territory in terms of SAIFI and SAIDI. Without modernization, customers in the region would continue to experience frequent and prolonged outages. Aging infrastructure increases the likelihood of unplanned failures, which could further degrade service quality and lead to regulatory penalties.

2. Inability to Support Load Growth and Electrification

The existing 4.8 kV infrastructure and current system configuration cannot accommodate forecasted demand growth driven by electrification (EVs, heat pumps, DERs). Delaying the project would constrain NYSEG's ability to connect new load and meet statewide decarbonization and electrification goals. It may also lead to more reactive, less efficient capital spending in the future.

3. Escalating Maintenance and Operational Costs

Aging substations and equipment require increasingly frequent maintenance and emergency repairs. Without proactive investment, O&M costs will continue to rise, driven by unplanned interventions and inefficient asset management. This also ties up workforce resources that could otherwise support strategic initiatives.

4. Increased Risk of Equipment Failure and Safety Incidents

Legacy equipment poses not only reliability risks but also safety and environmental risks. Continued operation of deteriorated assets increases the chance of equipment failure, potential fire hazards, oil spills, and unsafe working conditions for field personnel.

5. Missed Opportunity for Operational Modernization

Postponing the project would delay the deployment of advanced grid functionalities such as SCADA, remote switching, and self-healing networks. This limits NYSEG's ability to improve outage response times, reduce truck rolls, and integrate data-driven system operations.

6. Reduced Long-Term Cost Efficiency

Failure to act now could result in higher future capital expenditures. Delaying coordinated modernization may force NYSEG to invest in piecemeal upgrades under time and reliability pressures, which are typically less cost-effective than comprehensive, planned reinforcements.

Project Alternatives:

As part of the planning process, NYSEG evaluated multiple alternatives to address the reliability, capacity, and asset condition issues in the Lancaster Division. Each alternative was assessed based on technical feasibility, cost-effectiveness, reliability benefits, future readiness, and constructability. The alternatives ranged from minimal intervention to full system reconfiguration.

Alternative 0 – Do Nothing

This baseline alternative would involve no proactive investment and would rely on continued operation and maintenance of the existing infrastructure.

- Pros: No upfront capital cost
- Cons: No improvement in reliability or capacity, continued deterioration of assets, increasing O&M costs, and high risk of equipment failure
- Conclusion: Not viable. This alternative fails to meet basic planning criteria and leaves the system vulnerable.

Alternative 1 – Limited Substation Replacement

This alternative proposed rebuilding only one or two of the most critical substations (e.g., Walden Avenue and Blossom Road), while keeping the rest of the network intact.

- Pros: Moderate capital cost, localized improvement at high-impact substations
- Cons: Minimal impact on broader network reliability and redundancy; does not address 4.8 kV conversion or N-1 contingency gaps; limited long-term scalability
- Conclusion: Provides partial benefit but does not support a comprehensive modernization strategy.

Alternative 2 – Comprehensive Grid Modernization (Selected)

This alternative includes the full rebuild of three major substations, retirement of five legacy substations, conversion of 4.8 kV to 12.5 kV, construction of two new distribution centers, and expansion of North Broadway.

- Pros: Maximizes reliability improvement (2.15% SAIFI reduction), fully resolves N-1 contingency deficiencies, supports long-term electrification, enables flexible load transfer, and reduces O&M costs
- Cons: Higher initial capital investment
- Additional Note: Within this alternative, multiple grid modernization configurations were evaluated, varying in substation design, feeder layout, and sequencing strategy. The selected configuration was found to be the most cost-effective while meeting all technical and operational objectives.
- Conclusion: Selected as the preferred solution due to its comprehensive, long-term value and alignment with utility and regulatory objectives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 2,782	\$ 28	\$ 419	\$ 921	\$ 1,396	\$ 19	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 6,998	\$ 68	\$ 1,026	\$ 2,257	\$ 3,420	\$ 226	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 782	\$ 7	\$ 104	\$ 229	\$ 347	\$ 94	\$ -	\$ -
# Internal, Overheads	\$ 2,233	\$ 23	\$ 421	\$ 730	\$ 1,036	\$ 23	\$ -	\$ -
# Materials	\$ 18,284	\$ 185	\$ 2,770	\$ 6,095	\$ 9,234	\$ -	\$ -	\$ -
# Overheads - External	\$ 2,222	\$ 31	\$ 414	\$ 718	\$ 1,020	\$ 39	\$ -	\$ -
Total	\$ 33,300	\$ 342	\$ 5,154	\$ 10,950	\$ 16,454	\$ 401	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Lancaster Project - Losson Road - Distribution upgrades

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007384	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

The Losson Road - Distribution upgrades project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Division Grid Modernization Pilot is a comprehensive initiative aimed at addressing critical needs related to system reliability, aging infrastructure, electrification readiness, and network resilience. The project aligns with state energy policy objectives and utility planning standards, providing a forward-looking framework to modernize both the distribution and sub-transmission networks.

This project also represents a shift in planning philosophy. It introduces a differentiated approach not only in execution, but in how system needs are identified and addressed. Rather than applying traditional asset-by-asset solutions, NYSEG has adopted a zonal planning model, grounded in an in-depth analysis of local network performance, asset condition, and long-term demand forecasts. The result is a holistic solution tailored to the specific needs of the Lancaster area—improving reliability, optimizing capacity, reducing operational costs, and enabling future growth in a coordinated and scalable way.

Project Justification

- **Reliability:** Between 2020 and 2022, the Lancaster Division accounted for approximately 19% of NYSEG's total SAIFI (System Average Interruption Frequency Index) impact. Three substations—Losson Rd, Blossom Rd, and Walden Ave—were among the poorest performers system-wide.
- **Asset Condition:** Multiple substations were identified with outdated transformers, electromechanical relays, deteriorated switchgear, and poor structural conditions, many lacking SCADA visibility or control.
- **Resiliency & Redundancy:** The area lacks sufficient N-1 contingency support, making it vulnerable to prolonged outages and limiting the ability to automatically isolate and restore faults.
- **Load Growth:** Forecasts project a 30% increase in peak demand by 2037, driven by building electrification and electric vehicle (EV) adoption.

Project Scope:

The Losson Road - Distribution upgrades project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Grid Modernization Pilot proposes a comprehensive reconfiguration of the electric distribution and sub-transmission network in one of NYSEG's highest-impact service areas. The initiative targets a region that serves approximately 177,000 customers and carries roughly 690 MW of system load, representing a substantial portion of NYSEG's reliability performance metrics. The scope includes infrastructure upgrades, voltage conversions, substation retirements, and implementation of advanced system automation, all designed to improve reliability, resilience, and operational efficiency.

Main Infrastructure Components

1. Rebuild of Key Substations
 - Losson Road (34.5/12.5 kV GIS): Full rebuild with 9 feeders and 2×50 MVA transformers
 - Blossom Road (34.5/12.5 kV GIS): Full rebuild with 6 feeders and 2×37.3 MVA transformers
 - Walden Avenue (115/12.5 kV AIS): Upgrade with 9 feeders, 2×50 MVA transformers, new breakers, and control house
2. Substation Retirements - Aging infrastructure with poor condition ratings, obsolete equipment, and limited operational visibility
 - Five legacy substations to be retired: Sloan, Ellicott, Ebenezer, Indian Church, and Depew
3. Construction of two new 12.5 kV distribution centers to serve as centralized and automated feeder hubs strategically located at Sloan and Losson to enable rapid fault isolation, load transfer, and network reconfiguration
4. North Broadway Substation Expansion and Depew Line Replacement
 - Installation of three new 115 kV breakers and expansion of the 34.5 kV yard with three new breakers
 - Addition of a new 50 MVA 115/34.5 kV transformer
 - Construction of a new 34.5 kV line to reroute Line 532 into North Broadway, enabling the full retirement of Depew substation
5. Distribution upgrades (Blossom Rd, Losson Rd and Walden Ave & Sloan)
 - Conversion of approximately 75 miles of distribution circuits from legacy 4.8 kV to standard 12.5 kV
 - Upgrades to conductor sizes (up to 477 AL) to increase thermal capacity and reduce voltage drop
6. Installation of multiple 12.5 kV express feeders between substations and distribution centers (~10 miles total).

Additional Technical Elements

- Integration of SCADA control and visibility across all new and upgraded facilities
- Enhanced remote operation capabilities and automated restoration (self-healing features)
- System-wide reconfiguration to ensure all 12.5 kV feeders operate in phase
- Elimination of backlot lines and inaccessible equipment to improve maintenance and safety

Project Benefits:**1. Enhanced System Reliability**

The project directly addresses chronic reliability issues in one of NYSEG's most outage-prone areas. By replacing obsolete substations and reconfiguring the network, the initiative is expected to reduce SAIFI across the NYSEG system by an estimated 2.15%. This translates into fewer and shorter outages for nearly 177,000 customers, aligning with state reliability standards and improving service equity across the grid.

2. Improved Resilience and Contingency Support

Through the construction of new distribution centers and the expansion of strategic substations like North Broadway, the project introduces much-needed N-1 contingency capability to the area. This ensures that the system can withstand the failure of a single major component without causing widespread outages, significantly strengthening grid resilience in the face of storms and equipment failures.

3. Optimization of System Capacity and Load Transfer Flexibility

The conversion of legacy 4.8 kV circuits to 12.5 kV and the installation of express feeders improve the system's ability to transfer load between feeders and substations efficiently. This expanded tie capability allows for faster restoration and real-time operational flexibility, which is especially important as demand increases and load patterns shift due to electrification.

4. Long-Term Cost Efficiency

By retiring five aging substations and consolidating infrastructure, the project eliminates high-maintenance assets and reduces operational expenditures. NYSEG estimates annual O&M savings of approximately \$815,000, providing financial relief over the long term while maintaining or improving service levels. These savings also help moderate future rate impacts for customers.

5. Grid Readiness for Electrification and Future Growth

The upgraded network will support up to 52 MVA of additional load, preparing the system for forecasted growth in electric vehicles, electric heating, and distributed energy resources (DERs). With capacity in place, NYSEG can accommodate customer transitions to cleaner energy without compromising reliability or triggering reactive investment.

6. Modernized Operational Capabilities

All rebuilt and new facilities will be integrated into NYSEG's SCADA system, enabling full remote visibility and control. Combined with automated switching and advanced protection schemes, this will shorten restoration times, enable predictive maintenance, and improve outage response across the service area.

7. Risk Mitigation and Safety Improvements

The project eliminates numerous backlot lines and inaccessible infrastructure, reducing risk for field crews and enhancing public safety. Retired substations and upgraded sites also reduce the likelihood of equipment-related environmental incidents, aligning with modern utility safety and compliance standards.

Project Risks and Mitigation Plan:**1. Construction and Execution Risk**

Due to the scale and complexity of the project, there is a risk of delays related to permitting, material lead times, contractor mobilization, and construction sequencing. To mitigate this, NYSEG will adopt a phased execution strategy, prioritize early design finalization, and initiate procurement of long-lead equipment such as transformers and breakers well in advance. A detailed construction schedule will be developed and closely monitored to manage critical path activities.

2. Cost Escalation and Budget Risk

Material price volatility, labor cost increases, and potential supply chain disruptions could impact the project budget. NYSEG will include contingency allowances in the financial planning and will implement cost tracking systems to monitor expenditures. Regular budget reviews and a formal process for identifying and responding to cost deviations will be established to maintain financial discipline.

3. System Integration and Operational Transition Risk

Transitioning from legacy infrastructure to the new network configuration—especially during substation retirements and feeder reconfigurations—could pose operational risks, including service interruptions. NYSEG will prepare detailed transition and cutover plans, including temporary configurations and backup solutions such as mobile substations, to minimize impacts to customers during system switchover periods.

4. Stakeholder and Community Impact Risk

Construction activities may temporarily affect local communities through traffic disruptions, noise, or access limitations. To address this, NYSEG will engage proactively with municipalities and stakeholders, provide advance notice of planned work, and coordinate closely to minimize disruptions. Communication plans will be put in place to keep the public informed throughout the project.

5. Environmental and Regulatory Compliance Risk

Project components involving civil works or equipment installation may require environmental permitting and regulatory reviews. NYSEG will conduct thorough pre-construction environmental assessments and will work with regulatory agencies to secure all necessary approvals. Compliance will be monitored throughout the project by internal teams and external environmental consultants.

6. Technology Integration and Cybersecurity Risk

The integration of SCADA systems, protection relays, and remote switching technologies introduces risks related to system compatibility and cybersecurity. NYSEG will perform comprehensive factory and site acceptance testing, follow standard protocols for equipment integration, and implement cybersecurity reviews in line with internal policies and industry best practices.

Risk of No Action:

In addition to the project execution risks, it is important to highlight the significant consequences of inaction—should the Lancaster Grid Modernization Project be delayed, deferred, or not implemented. These risks would affect both operational performance and long-term strategic objectives:

1. Continued System Reliability Degradation

Several of the substations in the project scope are among the worst performers in NYSEG's service territory in terms of SAIFI and SAIDI. Without modernization, customers in the region would continue to experience frequent and prolonged outages. Aging infrastructure increases the likelihood of unplanned failures, which could further degrade service quality and lead to regulatory penalties.

2. Inability to Support Load Growth and Electrification

The existing 4.8 kV infrastructure and current system configuration cannot accommodate forecasted demand growth driven by electrification (EVs, heat pumps, DERs). Delaying the project would constrain NYSEG's ability to connect new load and meet statewide decarbonization and electrification goals. It may also lead to more reactive, less efficient capital spending in the future.

3. Escalating Maintenance and Operational Costs

Aging substations and equipment require increasingly frequent maintenance and emergency repairs. Without proactive investment, O&M costs will continue to rise, driven by unplanned interventions and inefficient asset management. This also ties up workforce resources that could otherwise support strategic initiatives.

4. Increased Risk of Equipment Failure and Safety Incidents

Legacy equipment poses not only reliability risks but also safety and environmental risks. Continued operation of deteriorated assets increases the chance of equipment failure, potential fire hazards, oil spills, and unsafe working conditions for field personnel.

5. Missed Opportunity for Operational Modernization

Postponing the project would delay the deployment of advanced grid functionalities such as SCADA, remote switching, and self-healing networks. This limits NYSEG's ability to improve outage response times, reduce truck rolls, and integrate data-driven system operations.

6. Reduced Long-Term Cost Efficiency

Failure to act now could result in higher future capital expenditures. Delaying coordinated modernization may force NYSEG to invest in piecemeal upgrades under time and reliability pressures, which are typically less cost-effective than comprehensive, planned reinforcements.

Project Alternatives:

As part of the planning process, NYSEG evaluated multiple alternatives to address the reliability, capacity, and asset condition issues in the Lancaster Division. Each alternative was assessed based on technical feasibility, cost-effectiveness, reliability benefits, future readiness, and constructability. The alternatives ranged from minimal intervention to full system reconfiguration.

Alternative 0 – Do Nothing

This baseline alternative would involve no proactive investment and would rely on continued operation and maintenance of the existing infrastructure.

- Pros: No upfront capital cost
- Cons: No improvement in reliability or capacity, continued deterioration of assets, increasing O&M costs, and high risk of equipment failure
- Conclusion: Not viable. This alternative fails to meet basic planning criteria and leaves the system vulnerable.

Alternative 1 – Limited Substation Replacement

This alternative proposed rebuilding only one or two of the most critical substations (e.g., Walden Avenue and Blossom Road), while keeping the rest of the network intact.

- Pros: Moderate capital cost, localized improvement at high-impact substations
- Cons: Minimal impact on broader network reliability and redundancy; does not address 4.8 kV conversion or N-1 contingency gaps; limited long-term scalability
- Conclusion: Provides partial benefit but does not support a comprehensive modernization strategy.

Alternative 2 – Comprehensive Grid Modernization (Selected)

This alternative includes the full rebuild of three major substations, retirement of five legacy substations, conversion of 4.8 kV to 12.5 kV, construction of two new distribution centers, and expansion of North Broadway.

- Pros: Maximizes reliability improvement (2.15% SAIFI reduction), fully resolves N-1 contingency deficiencies, supports long-term electrification, enables flexible load transfer, and reduces O&M costs
- Cons: Higher initial capital investment
- Additional Note: Within this alternative, multiple grid modernization configurations were evaluated, varying in substation design, feeder layout, and sequencing strategy. The selected configuration was found to be the most cost-effective while meeting all technical and operational objectives.
- Conclusion: Selected as the preferred solution due to its comprehensive, long-term value and alignment with utility and regulatory objectives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,731	\$ 17	\$ 261	\$ 573	\$ 868	\$ 12	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 4,354	\$ 43	\$ 638	\$ 1,405	\$ 2,128	\$ 141	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 486	\$ 4	\$ 65	\$ 143	\$ 216	\$ 59	\$ -	\$ -
# Internal, Overheads	\$ 1,389	\$ 14	\$ 262	\$ 454	\$ 645	\$ 14	\$ -	\$ -
# Materials	\$ 11,377	\$ 115	\$ 1,724	\$ 3,792	\$ 5,746	\$ -	\$ -	\$ -
# Overheads - External	\$ 1,382	\$ 19	\$ 258	\$ 447	\$ 635	\$ 24	\$ -	\$ -
Total	\$ 20,721	\$ 213	\$ 3,207	\$ 6,814	\$ 10,238	\$ 249	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Kline Kill 630 - 631

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006735	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2026	In-Service Date: H2 2026

Project description:

Klinekill 630/631 is a 2026 Resiliency Project selected based on a weighted average ranking including all NYSEG Circuits.

The ranking includes major storms SAIFI contribution and excludes circuits with individual SAIFI below 2.2 for NYSEG. The objective of this project is to improve this circuits SAIFI.

Resiliency focuses on, preventing and limiting the scope and impact of outages when they occur. The ability to expediently restore power after a significant outage.

This is Achieved through Topology with Automation (Circuit Ties) - Circuit reconfiguration and sectionalizing with switching device automation Infrastructure

Hardening - Tree-wire (where applicable), pole replacement, and relocate lines closer to roads (where applicable).

Enhanced Vegetation Management - Ground-to-sky clearance

Project Scope:

- 1.1. Improve the Existing Tie between Kline Kill 631 and Craryville 610 to support N-1
- 1.2. Reconductor ~0.05 miles Exit Conductor 3P_2ALURD_2AL(N) to 500CU
- 1.3. Reconductor ~0.29 miles 3P_2ALURD_2AL(N) to 3P 500CU with Neutral Wire from L175 P4941 to L175 P4950
- 1.4. Replace existing 3-167A Feeder Regulator bank with 3- 335A Regulator Bank
- 1.5. Install 3-200A Regulator at L269 P195
- 2.1. Replace Existing Overloaded transformers on Kline Kill 630 at:
 - o L150 P5785 from 1-250KVA to 500_19.9YG/4.8D
 - o L140 P9993 from 1-333KVA to 500_19.9YG/4.8D.
- 2.2. Replace Existing Overloaded transformers on Kline Kill 631 at:
 - o L95 P48 from 167KVA to 1-333_19.9YG/4.8D,
 - o L95 P66 from 1-333KVA to 500_19.9YG/4.8D
 - o L175 P4997 from 1-100KVA to 250KVA_19.9YG/4.8D
 - o L106 P4 from 3-167KVA to 3-333_19.9YG/4.8D
 - o L109 P5 from 1-167KVA to 333_19.9YG/4.8D.
- 3.1. Install N/O SCADA switch at L150 P5701
- 3.2. Install N/C SCADA recloser at L-175 P5025
- 3.3. Install N/C SCADA recloser at L109 P1367
- 3.4. Install N/C SCADA recloser at L189 P6186
4. Relocate 0.23miles 4/0AC on Kline Kill 630 off road to roadway from L1113 P55 to L1113 P62.

Project Benefits:

Completing this project will improve system SAIFI (System Average Interruption Frequency Index) by 0.404

Project Risks and Mitigation Plan:

Risks exist in project execution particularly as it relates to engineering and material procurement. In order to ensure materials are received on time, we will order long lead materials in advance to ensure they are received within 1 year of ordering (Poles, devices, wire, etc.).

Weather delays are a risk in distribution construction because our resources often support storm restoration efforts. We address these types of weather delay risks by incorporating contingency into our construction schedules.

Health and Safety of our workers are of a primary concern. Risks related to traffic control, working with energized equipment, slips and trips, etc. are a concern on most projects, we mitigate these risks with project specific health and safety plans.

Financial risks are always present with new information learned during project execution, financial risks are mitigated utilizing available scheduling and forecasting tools for project management (ie. Primavera), we forecast project specific activities in the living tool as the project progress and update monthly project progress to accurately forecast project completion including estimate at completion.

Risk of No Action:

CAIDI and SAIFI metrics will continue to be an issue for the circuits and the customers in the region will have more frequent prolonged outages. In the event of an outage these improvements will help to reduce outage frequency and facilitate restoration of power to a greater number of customers in a shorter timeframe

Project Alternatives:

Projects are developed using the following criteria and therefore alternatives are not provided.

Rank and Prioritize Worst Performing Circuits:

Based on SAIFI data (3 Year Weighted Average)* including major storms

Prioritize circuits with SAIFI above 2.2 and individual SAIFI contribution lower than 0.14%

Consider feedback from Operations and Field Evaluations

*Weighted values taken from reliability calculator

Resiliency focuses on:

Preventing and limiting the scope and impact of outages when they occur

The ability to expediently restore power after a significant outage

Achieved through:

Topology with Automation (Circuit Ties) - Circuit reconfiguration and sectionalizing with switching device automation

Infrastructure Hardening - Tree-wire (where applicable), pole replacement, and relocate lines closer to roads (where applicable).

Enhanced Vegetation Management - Ground-to-sky clearance

Basis for Project Estimates

Estimates are prepared utilizing historical estimating tools comparing against actual investments in similar projects as basis for project initiation and are revised through the project as new information is received.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 23	\$ -	\$ 23	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 973	\$ -	\$ 973	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 226	\$ -	\$ 226	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 200	\$ -	\$ 200	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 747	\$ -	\$ 747	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 245	\$ -	\$ 245	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,414	\$ -	\$ 2,414	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 45	\$ -	\$ 45	\$ -	\$ -	\$ -	\$ -	\$ -
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 45	\$ -	\$ 45	\$ -	\$ -	\$ -	\$ -	\$ -

NYSEG Resiliency - Shandaken 501

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006733	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

Shandaken 501 is a 2026 Resiliency Project selected based on a weighted average ranking including all NYSEG Circuits. The ranking includes major storms SAIFI contribution and excludes circuits with individual SAIFI below 2.2 for NYSEG. The objective of this project is to improve this circuits SAIFI.

Resiliency focuses on, preventing and limiting the scope and impact of outages when they occur. The ability to expediently restore power after a significant outage.

This is Achieved through Topology with Automation (Circuit Ties) - Circuit reconfiguration and sectionalizing with switching device automation Infrastructure

Hardening - Tree-wire (where applicable), pole replacement, and relocate lines closer to roads (where applicable).

Enhanced Vegetation Management - Ground-to-sky clearance

Project Scope:

1.1. Relocate 0.34 miles of line with 3 Phase 477ALTW with neutral wire to road from L321 P25 to L321 P34

1.2. Reconductor 0.12 miles of line with 3 Phase 477ALTW with neutral wire from L321 P41 to L321 P45

1.3. Relocate 0.19 miles of line with 3 Phase 477ALTW with neutral wire to road from L321 P51 to L321 P55

1.4. Relocate 0.33 miles of line with 3 Phase 477ALTW with neutral wire to road from L321 P79 to L321 P89

1.5. Relocate 1.26 miles of line with 3 Phase 477ALTW with neutral wire to road from L321 P104 to L321 P141

1.6. Reconductor 0.2 miles of line with 3 Phase 477ALTW with neutral wire from L321 P166 to L321 P175

2.1. Relocate 3-500kVA Overhead Step Bank downstream and convert section from 8.32kV to 34.5kV and relocate Recloser to be after the step bank from L330 P1 to L330 P32

3.7. Remove over-water step banks and create a 2 phase 4.16kV line to absorb the stranded single-phase sections

Project Benefits:

Completing this project will improve system SAIFI (System Average Interruption Frequency Index)

0.005% (Including Storm)

0.005% (Excluding Storm)

Project Risks and Mitigation Plan:

Risks exist in project execution particularly as it relates to engineering and material procurement. In order to ensure materials are received on time, we will order long lead materials in advance to ensure they are received within 1 year of ordering (Poles, devices, wire, etc.).

Weather delays are a risk in distribution construction because our resources often support storm restoration efforts. We address these types of weather delay risks by incorporating contingency into our construction schedules.

Health and Safety of our workers are of a primary concern. Risks related to traffic control, working with energized equipment, slips and trips, etc. are a concern on most projects, we mitigate these risks with project specific health and safety plans.

Financial risks are always present with new information learned during project execution, financial risks are mitigated utilizing available scheduling and forecasting tools for project management (ie. Primavera), we forecast project specific activities in the living tool as the project progress and update monthly project progress to accurately forecast project completion including estimate at completion.

Risk of No Action:

CAIDI and SAIFI metrics will continue to be an issue for the circuits and the customers in the region will have more frequent prolonged outages. In the event of an outage these improvements will help to reduce outage frequency and facilitate restoration of power to a greater number of customers in a shorter timeframe

Project Alternatives:

Projects are developed using the following criteria and therefore alternatives are not provided.

Rank and Prioritize Worst Performing Circuits:

Based on SAIFI data (3 Year Weighted Average)* including major storms

Prioritize circuits with SAIFI above 2.2 and individual SAIFI contribution lower than 0.14%

Consider feedback from Operations and Field Evaluations

*Weighted values taken from reliability calculator

Resiliency focuses on:

Preventing and limiting the scope and impact of outages when they occur

The ability to expediently restore power after a significant outage

Achieved through:

Topology with Automation (Circuit Ties) - Circuit reconfiguration and sectionalizing with switching device automation

Infrastructure Hardening - Tree-wire (where applicable), pole replacement, and relocate lines closer to roads (where applicable).

Enhanced Vegetation Management - Ground-to-sky clearance

Basis for Project Estimates

Estimates are prepared utilizing historical estimating tools comparing against actual investments in similar projects as basis for project initiation and are revised through the project as new information is received.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 37	\$ 2	\$ 35	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,594	\$ 86	\$ 1,508	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 371	\$ 20	\$ 351	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 323	\$ 14	\$ 309	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,224	\$ 66	\$ 1,158	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 392	\$ 12	\$ 380	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 3,942	\$ 200	\$ 3,742	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 70	\$ -	\$ 70	\$ -	\$ -	\$ -	\$ -	\$ -
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 70	\$ -	\$ 70	\$ -	\$ -	\$ -	\$ -	\$ -

NYSEG Automation - Liberty

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-005871	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2025

Project description:

NYSEG Automation - Liberty is a 2025 Distribution Automation Project, focusing on Automated Recloser deployment of sequential reclosing schemes on circuits in the Liberty Division. Circuits are selected from substations where the circuits contribute more than 0.29% of System SAIFI (11,200 Customer Count), using 2021-2023 SAIFI data (3 Year Average Data), prioritizing worst performing service territories. Circuits are analyzed holistically to maximize reliability improvement (approximately 500 customers and/or 10 miles).

The objective of this program is to improve circuit SAIFI by enabling automatic fault clearing or SCADA controlled device operation to minimize customer outage impact. Device deployment Provides better quality data for Distribution Planning analyses (ability to gather data remotely) and System Operators with an increased level of visibility enabling more informed decision making in real-time operations

Project Scope:

This project will deploy 17 New Devices across 9 Circuits in the Division utilizing the sequential reclosing mode of operation.

These circuits include:

Grossinger 210&211

Kiamesha 263

Liberty 142&144&145

Maplewood 127&229

White Lake 151

*These totals are pending the coordination review as part of the engineering process. Additional Scope may be added to include fuse downsizing, tripsavers, and/or additional reprogramming on existing devices.

Project Benefits:

Fundamental objective is to improve system SAIFI by enabling automatic fault clearing or SCADA controlled device operation to minimize customer outage impact.

Provides better quality data for Distribution Planning analyses (ability to gather data remotely) and System Operators with an increased level of visibility enabling more informed decision making in real-time operations.

Remotely controlled and communicating devices.

Improves reliability in a safe, efficient, and cost-effective way.

Reclosers.

Sequential Reclosing: All devices installed will be reclosers, including tie points (more than 3 reclosers in series).

Distribution Engineering (DE) / Projects to conduct a feasibility/field assessment, propose settings for reclosers, and develop refined cost estimates (+50/-25%) in support of annual IP2 activities.

Supervisory Control and Data Acquisition (SCADA) Devices.

Circuit tie points to receive new SCADA reclosers, or become SCADA enabled, which are programmed as switches.

Completing this project will improve system SAIFI (System Average Interruption Frequency Index) by 0.457

Project Risks and Mitigation Plan:

Risks exist in project execution particularly as it relates to engineering and material procurement. In order to ensure materials are received on time, we will order long lead materials in advance to ensure they are received within 1 year of ordering (Poles, devices, wire, etc.).

Weather delays are a risk in distribution construction because our resources often support storm restoration efforts. We address these types of weather delay risks by incorporating contingency into our construction schedules.

Health and Safety of our workers are of a primary concern. Risks related to traffic control, working with energized equipment, slips and trips, etc. are a concern on most projects, we mitigate these risks with project specific health and safety plans.

Financial risks are always present with new information learned during project execution, financial risks are mitigated utilizing available scheduling and forecasting tools for project management (ie. Primavera), we forecast project specific activities in the living tool as the project progress and update monthly project progress to accurately forecast project completion including estimate at completion.

Risk of No Action:

Circuits will continue to contribute significantly to company wide SAIFI metrics.

Project Alternatives:

Distribution Automation Ranking

Used 2021-2023 SAIFI data (3 Year Average Data) to identify worst performing circuits

Selection of device locations using the following criteria:

Every circuit is analyzed holistically to maximize reliability improvement

500 customers and/or 10 miles

Prioritized by Worst Performing Service Territory

Circuits selected from Stations where the circuits contribute more than 0.29% of System SAIFI

0.29% System SAIFI □ ~11,200 Customer Count

2021-2023 Average weighted SAIFI Excluding major storms

1,192 circuits contributed to SAIFI (2021-2023)

All circuits studied in previous years were excluded, regardless if they were poor performing

Basis for Project Estimates

Estimates are prepared utilizing historical estimating tools comparing against actual investments in similar projects as basis for project initiation and are revised through the project as new information is received.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 35	\$ 16	\$ 19	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,701	\$ 692	\$ 1,009	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 294	\$ 161	\$ 133	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 233	\$ 113	\$ 120	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 645	\$ 531	\$ 114	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 249	\$ 97	\$ 153	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 3,157	\$ 1,609	\$ 1,548	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 32	\$ 32	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 32	\$ 32	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

NYSEG Automation - Binghamton

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-005866	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2025

Project description:

NYSEG Automation - Binghamton is a 2025 Distribution Automation Project, focusing on Automated Recloser deployment of sequential reclosing schemes on circuits in the Binghamton Division. Circuits are selected from substations where the circuits contribute more than 0.29% of System SAIFI (11,200 Customer Count), using 2021-2023 SAIFI data (3 Year Average Data), prioritizing worst performing service territories. Circuits are analyzed holistically to maximize reliability improvement (approximately 500 customers and/or 10 miles).

Project Scope:

Deployment of 48 Devices, 3 reprograms, and 1 comms cabinet on 17 circuits utilizing Sequential Reclosing.

These circuits include:

Fuller Hollow 615, 616, & 617

Lisle 417

Canal St Tap 513

Glenwood 681, 684, & 686

Goudey 722 & 723

Harpur 671

Jarvis St 687, 689 & 692

Rano 693 & 694

Tarbell 602

*These totals are pending the coordination review as part of the engineering process. Additional Scope may be added to include fuse downsizing, tripsavers, and/or additional reprogramming on existing devices.

Project Benefits:

Fundamental objective is to improve system SAIFI by enabling automatic fault clearing or SCADA controlled device operation to minimize customer outage impact.

Provides better quality data for Distribution Planning analyses (ability to gather data remotely) and System Operators with an increased level of visibility enabling more informed decision making in real-time operations.

Remotely controlled and communicating devices.

Improves reliability in a safe, efficient, and cost-effective way.

Reclosers.

Sequential Reclosing: All devices installed will be reclosers, including tie points (more than 3 reclosers in series).

Distribution Engineering (DE) / Projects to conduct a feasibility/field assessment, propose settings for reclosers, and develop refined cost estimates (+50/-25%) in support of annual IP2 activities.

Supervisory Control and Data Acquisition (SCADA) Devices.

Circuit tie points to receive new SCADA reclosers, or become SCADA enabled, which are programmed as switches.

Completing this project will improve system SAIFI (System Average Interruption Frequency Index) by 0.457

Project Risks and Mitigation Plan:

Risks exist in project execution particularly as it relates to engineering and material procurement. In order to ensure materials are received on time, we will order long lead materials in advance to ensure they are received within 1 year of ordering (Poles, devices, wire, etc.).

Weather delays are a risk in distribution construction because our resources often support storm restoration efforts. We address these types of weather delay risks by incorporating contingency into our construction schedules.

Health and Safety of our workers are of a primary concern. Risks related to traffic control, working with energized equipment, slips and trips, etc. are a concern on most projects, we mitigate these risks with project specific health and safety plans.

Financial risks are always present with new information learned during project execution, financial risks are mitigated utilizing available scheduling and forecasting tools for project management (ie. Primavera), we forecast project specific activities in the living tool as the project progress and update monthly project progress to accurately forecast project completion including estimate at completion.

Risk of No Action:

Circuits will continue to contribute significantly to company wide SAIFI metrics.

Project Alternatives:

Distribution Automation Ranking

Used 2021-2023 SAIFI data (3 Year Average Data) to identify worst performing circuits

Selection of device locations using the following criteria:

Every circuit is analyzed holistically to maximize reliability improvement

500 customers and/or 10 miles

Prioritized by Worst Performing Service Territory

Circuits selected from Stations where the circuits contribute more than 0.29% of System SAIFI

0.29% System SAIFI □ ~11,200 Customer Count

2021-2023 Average weighted SAIFI Excluding major storms

1,192 circuits contributed to SAIFI (2021-2023)

All circuits studied in previous years were excluded, regardless if they were poor performing

Basis for Project Estimates

Estimates are prepared utilizing historical estimating tools comparing against actual investments in similar projects as basis for project initiation and are revised through the project as new information is received.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 120	\$ 65	\$ 54	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 5,682	\$ 1,309	\$ 4,373	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 1,033	\$ 653	\$ 379	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 928	\$ 457	\$ 471	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 3,945	\$ 656	\$ 3,289	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 935	\$ 392	\$ 543	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 12,643	\$ 3,533	\$ 9,110	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 131	\$ 131	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 131	\$ 131	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

NYSEG Automation - Auburn

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-005865	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2025

Project description:

NYSEG Automation - Auburn is a 2025 Distribution Automation Project, focusing on Automated Recloser deployment of sequential reclosing schemes on circuits in the Auburn Division. Circuits are selected from substations where the circuits contribute more than 0.29% of System SAIFI (11,200 Customer Count), using 2021-2023 SAIFI data (3 Year Average Data), prioritizing worst performing service territories. Circuits are analyzed holistically to maximize reliability improvement (approximately 500 customers and/or 10 miles).

Project Scope:

This project will deploy 10 New Devices across 5 Circuits in the Division, including 3 existing device reprograms utilizing the sequential reclosing mode of operation.

These circuits include:

Grant Ave 718, 719 & 720

Marietta 511

Whiting 526

*These totals are pending the coordination review as part of the engineering process. Additional Scope may be added to include fuse downsizing, tripsavers, and/or additional reprogramming on existing devices.

Project Benefits:

Fundamental objective is to improve system SAIFI by enabling automatic fault clearing or SCADA controlled device operation to minimize customer outage impact.

Provides better quality data for Distribution Planning analyses (ability to gather data remotely) and System Operators with an increased level of visibility enabling more informed decision making in real-time operations.

Remotely controlled and communicating devices.

Improves reliability in a safe, efficient, and cost-effective way.

Reclosers.

Sequential Reclosing: All devices installed will be reclosers, including tie points (more than 3 reclosers in series).

Distribution Engineering (DE) / Projects to conduct a feasibility/field assessment, propose settings for reclosers, and develop refined cost estimates (+50/-25%) in support of annual IP2 activities.

Supervisory Control and Data Acquisition (SCADA) Devices.

Circuit tie points to receive new SCADA reclosers, or become SCADA enabled, which are programmed as switches.

Completing this project will improve system SAIFI (System Average Interruption Frequency Index) by 0.457

Project Risks and Mitigation Plan:

Risks exist in project execution particularly as it relates to engineering and material procurement. In order to ensure materials are received on time, we will order long lead materials in advance to ensure they are received within 1 year of ordering (Poles, devices, wire, etc.).

Weather delays are a risk in distribution construction because our resources often support storm restoration efforts. We address these types of weather delay risks by incorporating contingency into our construction schedules.

Health and Safety of our workers are of a primary concern. Risks related to traffic control, working with energized equipment, slips and trips, etc. are a concern on most projects, we mitigate these risks with project specific health and safety plans.

Financial risks are always present with new information learned during project execution, financial risks are mitigated utilizing available scheduling and forecasting tools for project management (ie. Primavera), we forecast project specific activities in the living tool as the project progress and update monthly project progress to accurately forecast project completion including estimate at completion.

Risk of No Action:

Circuits will continue to contribute significantly to company wide SAIFI metrics.

Project Alternatives:

Distribution Automation Ranking

Used 2021-2023 SAIFI data (3 Year Average Data) to identify worst performing circuits

Selection of device locations using the following criteria:

Every circuit is analyzed holistically to maximize reliability improvement

500 customers and/or 10 miles

Prioritized by Worst Performing Service Territory

Circuits selected from Stations where the circuits contribute more than 0.29% of System SAIFI

0.29% System SAIFI □ ~11,200 Customer Count

2021-2023 Average weighted SAIFI Excluding major storms

1,192 circuits contributed to SAIFI (2021-2023)

All circuits studied in previous years were excluded, regardless if they were poor performing

Basis for Project Estimates

Estimates are prepared utilizing historical estimating tools comparing against actual investments in similar projects as basis for project initiation and are revised through the project as new information is received.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 41	\$ 11	\$ 31	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,084	\$ 462	\$ 1,623	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 107	\$ 107	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 337	\$ 75	\$ 262	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,365	\$ 354	\$ 1,010	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 320	\$ 64	\$ 256	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 4,255	\$ 1,074	\$ 3,181	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 21	\$ 21	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 21	\$ 21	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

NYSEG Resiliency - Greenidge 596

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-005858	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

Greenidge 596 is a 2025 Resiliency Project selected based on a weighted average ranking including all NYSEG Circuits. The ranking includes major storms SAIFI contributions and prioritizes circuits with SAIFI above 2.2 and individual SAIFI contributions lower than 0.14%. The objective of this project is to improve this circuit's SAIFI.

Resiliency focuses on, preventing and limiting the scope and impact of outages when they occur. The ability to expediently restore power after a significant outage.

This is achieved through Topology with Automation (Circuit Ties) - Circuit reconfiguration and sectionalizing with switching device automation Infrastructure

Hardening - Tree-wire (where applicable), pole replacement, and relocate lines closer to roads (where applicable).

Enhanced Vegetation Management - Ground-to-sky clearance

Project Scope:

Greenidge 596 will Create a 34.5KV internal loop, adding 3 SCADA devices and Converting 3.7 miles of 1P 4.8kV/7.2kV Delta to 3P 34.5KV 477AL, relocating 1.5 miles of backlot line to road side and Eliminate 250KVA step bank (70% capacity), creating a new Greenidge Loop to back feed up to 1,127 customers. The project also Relocates 2 step transformers, Installs 1 step transformer and Installs 1.0 mile of new 34.5KV line 477AL. Reconfiguring 0.1 miles of 1P 34.5KV to 3P 477AL will Transfer 51 customers from Dundee 205 to Greenidge 596. The project also Relocates 0.4 miles of 3P 477AL (off-road section).

Project Benefits:

Completing this project will improve system SAIFI (System Average Interruption Frequency Index)
0.0548 % (Including Storm)
0.0343% (Excluding Storm)

Project Risks and Mitigation Plan:

Risks exist in project execution particularly as it relates to engineering and material procurement. In order to ensure materials are received on time, we will order long lead materials in advance to ensure they are received within 1 year of ordering (Poles, devices, wire, etc.).

Weather delays are a risk in distribution construction because our resources often support storm restoration efforts. We address these types of weather delay risks by incorporating contingency into our construction schedules.

Health and Safety of our workers are of a primary concern. Risks related to traffic control, working with energized equipment, slips and trips, etc. are a concern on most projects, we mitigate these risks with project specific health and safety plans.

Financial risks are always present with new information learned during project execution, financial risks are mitigated utilizing available scheduling and forecasting tools for project management (ie. Primavera), we forecast project specific activities in the living tool as the project progress and update monthly project progress to accurately forecast project completion including estimate at completion.

Risk of No Action:

CAIDI and SAIFI metrics will continue to be an issue for the circuits and the customers in the region will have more frequent prolonged outages. In the event of an outage these improvements will help to reduce outage frequency and facilitate restoration of power to a greater number of customers in a shorter timeframe

Project Alternatives:

Projects are developed using the following criteria and therefore alternatives are not provided.

Rank and Prioritize Worst Performing Circuits:

Based on SAIFI data (3 Year Weighted Average)* including major storms

Prioritize circuits with SAIFI above 2.2 and individual SAIFI contribution lower than 0.14%

Consider feedback from Operations and Field Evaluations

*Weighted values taken from reliability calculator

Resiliency focuses on:

Preventing and limiting the scope and impact of outages when they occur

The ability to expediently restore power after a significant outage

Achieved through:

Topology with Automation (Circuit Ties) - Circuit reconfiguration and sectionalizing with switching device automation

Infrastructure Hardening - Tree-wire (where applicable), pole replacement, and relocate lines closer to roads (where applicable).

Enhanced Vegetation Management - Ground-to-sky clearance

Basis for Project Estimates

Estimates are prepared utilizing historical estimating tools comparing against actual investments in similar projects as basis for project initiation and are revised through the project as new information is received.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 44	\$ 13	\$ 31	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 2,315	\$ 148	\$ 2,167	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 354	\$ 91	\$ 263	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 1,442	\$ 429	\$ 1,013	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 334	\$ 78	\$ 256	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 4,489	\$ 759	\$ 3,730	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 107	\$ 52	\$ 55	\$ -	\$ -	\$ -	\$ -	\$ -
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 107	\$ 52	\$ 55	\$ -	\$ -	\$ -	\$ -	\$ -

NYSEG Resiliency - Kattleville 422

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-005853	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

Kattleville 422 is a 2025 Resiliency Project selected based on a weighted average ranking including all NYSEG Circuits. The ranking includes major storms SAIFI contributions and prioritizes circuits with SAIFI above 2.2 and individual SAIFI contributions lower than 0.14%. The objective of this project is to improve this circuit's SAIFI.

Resiliency focuses on, preventing and limiting the scope and impact of outages when they occur. The ability to expediently restore power after a significant outage.

This is Achieved through Topology with Automation (Circuit Ties) - Circuit reconfiguration and sectionalizing with switching device automation Infrastructure

Hardening - Tree-wire (where applicable), pole replacement, and relocate lines closer to roads (where applicable).

Enhanced Vegetation Management - Ground-to-sky clearance

Project Scope:

Kattleville 422 will; remove 1P 4.8KV step, Reconductor approximately 3.4 miles 1P line to 3P line 34.5KV, Install 3 SCADA devices and 3 step transformers to utilize the internal loop and upgrade several step transformers. This project will create a 34.5KV tie between Kattleville 422 and Chenango Bridge 428, Install 2 SCADA devices to utilize the tie, Install a step transformer, Rebuild and reconductor approximately 0.35 miles of 34.5KV from 1P to 3P and Install a new line (aerial cable) approximately 3.43 miles including an open gap on Knapp Hill Road. The project will remove 4.8KV step and convert approximately 1.01 miles of 4.8KV 1P to 3P.

Project Benefits:

Completing this project will improve system SAIFI (System Average Interruption Frequency Index) by:
0.443% (Including Storm)
0.461% (Excluding Storm)

Project Risks and Mitigation Plan:

Risks exist in project execution particularly as it relates to engineering and material procurement. In order to ensure materials are received on time, we will order long lead materials in advance to ensure they are received within 1 year of ordering (Poles, devices, wire, etc.).

Weather delays are a risk in distribution construction because our resources often support storm restoration efforts. We address these types of weather delay risks by incorporating contingency into our construction schedules.

Health and Safety of our workers are of a primary concern. Risks related to traffic control, working with energized equipment, slips and trips, etc. are a concern on most projects, we mitigate these risks with project specific health and safety plans.

Financial risks are always present with new information learned during project execution, financial risks are mitigated utilizing available scheduling and forecasting tools for project management (ie. Primavera), we forecast project specific activities in the living tool as the project progress and update monthly project progress to accurately forecast project completion including estimate at completion.

Risk of No Action:

CAIDI and SAIFI metrics will continue to be an issue for the circuits and the customers in the region will have more frequent prolonged outages. In the event of an outage these improvements will help to reduce outage frequency and facilitate restoration of power to a greater number of customers in a shorter timeframe

Project Alternatives:

Projects are developed using the following criteria and therefore alternatives are not provided.

Rank and Prioritize Worst Performing Circuits:

Based on SAIFI data (3 Year Weighted Average)* including major storms

Prioritize circuits with SAIFI above 2.2 and individual SAIFI contribution lower than 0.14%

Consider feedback from Operations and Field Evaluations

*Weighted values taken from reliability calculator

Resiliency focuses on:

Preventing and limiting the scope and impact of outages when they occur

The ability to expediently restore power after a significant outage

Achieved through:

Topology with Automation (Circuit Ties) - Circuit reconfiguration and sectionalizing with switching device automation

Infrastructure Hardening - Tree-wire (where applicable), pole replacement, and relocate lines closer to roads (where applicable).

Enhanced Vegetation Management - Ground-to-sky clearance

Basis for Project Estimates

Estimates are prepared utilizing historical estimating tools comparing against actual investments in similar projects as basis for project initiation and are revised through the project as new information is received.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 0	\$ -	\$ -	\$ -	\$ -	\$ 0		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ 5	\$ -	\$ -	\$ -	\$ -	\$ 5		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ 1	\$ -	\$ -	\$ -	\$ -	\$ 1		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ 1	\$ -	\$ -	\$ -	\$ -	\$ 1		
Total	\$ 6	\$ -	\$ -	\$ -	\$ -	\$ 6		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 106	\$ 30	\$ 76	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 5,607	\$ 1,590	\$ 4,017	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 858	\$ 210	\$ 648	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 3,491	\$ 990	\$ 2,501	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 813	\$ 180	\$ 633	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 10,876	\$ 3,000	\$ 7,876	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 246	\$ 120	\$ 126	\$ -	\$ -	\$ -	\$ -	\$ -
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 246	\$ 120	\$ 126	\$ -	\$ -	\$ -	\$ -	\$ -

Trip Saver

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-003585	Charge Code: Electric Distribution	Project Sponsor: Shail, Joshua	Project Type: Annual Program
Business Area: Electric Operations	Rate Case Category Resiliency	Project Stage: IP3 Financial Execute	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

The Trip Saver program is implemented to enhance reliability by reducing the number of interruptions caused by temporary faults in the distribution network, which contribute to approximately 20 percent of the Company's System Average Interruption Frequency Index (SAIFI). The installations associated with this program contribute to improvements in both the System Average Interruption Frequency Index (SAIFI) and the Customer Average Interruption Duration Index (CAIDI).

Project Scope:

The Trip Saver program aims to install Trip Saver reclosers to prevent temporary faults from becoming sustained outages. These reclosers minimize outages on feeders by only blinking the affected branch, allowing for automatic restoration of power during temporary faults. By mitigating a significant number of outages, Trip Saver reclosers enhance the SAIDI and SAIFI.

Trip Saver reclosers improve the distribution system by reducing the zone of protection for reclosing and minimizing risks when circuits are NRA-enabled. Additionally, they help avoid Operations & Maintenance (O&M) crew truck rolls to replace blown fuses.

The TripSaver Program is prioritized by ranking 1ph and 2ph laterals from highest number of customers affected by potential transient faults to lowest. Technical specifications, including but not limited to type of connection and circuit topography, are also considered when validating possible installation points. This program has had a 42% reduction of incidents and a 25% reduction of customers affected downstream of installed tripsavers. These zones of protection where tripsavers have been installed interrupt on average 11,388 customers annually.

Using a circuit-by-circuit approach, prioritization was based on applying work to improve customer experience outcomes. When looking at all circuits across the divisions, in aggregate, this resulted in some divisions requiring less attention than others, which allowed other divisions, that were underperforming, to receive more attention. There are additional qualifications that require an examination of each location to ensure the upgrade is viable. For example, the nearness of neighboring Trip Saver devices may cause a location to fall off the list. Likewise, if a suggested location is offroad, beyond the reach of the standard process, that location may be temporarily disqualified. In the end, all the focused vetting results in a more robust deployment, yielding an improved customer experience.

The following units and average unit costs will be addressed between 2025-2031:

2025 - 128 (units) / \$18,666 (unit cost)
2026 - 124 (units) / \$19,226 (unit cost)
2027 - 128 (units) / \$19,802 (unit cost)
2028 - 133 (units) / \$20,397 (unit cost)
2029 - 138 (units) / \$21,008 (unit cost)
2030 - 143 (units) / \$21,639 (unit cost)
2031 - 148 (units) / \$22,288 (unit cost)

Project Benefits:

The primary benefit of the Trip Saver program is to minimize the number of consumers affected during temporary faults and ensure prompt restoration.

Project Risks and Mitigation Plan:

Trip Saver reclosers prevent temporary faults from becoming sustained outages, and they avoid outages on feeders by only blinking the affected branch. By mitigating a significant amount of outages, Trip Saver reclosers improve SAIDI and SAIFI indexes.

The company uses a series of criteria to prioritize the list including:

Worst Performing Circuits
Not under the scope of the Resiliency plan
More SAIFI benefit with customers downstream
Poles under 40 years old
Alignment with others initiatives, such as Distribution Automation Projects and Fuse Coordination.

Risk of No Action:

Without the Trip Saver, power will not be automatically restored when temporary faults occur. This can lead to prolonged outages and increased disruption for consumers.

Trip Savers improve the distribution system by reducing the zone of protection for reclosing and minimizing risks when circuits are NRA-enabled. Additionally, they help avoid O&M crew truck rolls to replace blown fuses.

Project Alternatives:

The Trip Saver program primarily focuses on one-for-one asset replacements. Alternatives are considered on a case-by-case basis to ensure the most effective solutions are implemented.

Basis for Project Estimates

The financial plan is based on an average cost per trip saver. The average cost is determined by the cost of construction crews, internal labor costs, material costs, and overheads applicable to replacing a trip saver.

FINANCIAL INFORMATION**Actual Capital Spent, all amounts shown below in thousands (\$000's)**

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ 286	\$ -	\$ -	\$ 19	\$ 91	\$ 175		
# CIAC	\$ -4	\$ -	\$ -	\$ -	\$ -2	\$ -2		
# External Services	\$ 282	\$ -	\$ -	\$ 7	\$ 199	\$ 76		
# Internal - Non-AC	\$ 0	\$ -	\$ -	\$ -	\$ -	\$ 0		
# Internal, Labor	\$ 359	\$ -	\$ -	\$ 87	\$ 105	\$ 166		
# Internal, Overheads	\$ 989	\$ -	\$ -	\$ 174	\$ 433	\$ 381		
# Materials	\$ 4,741	\$ -	\$ -	\$ 825	\$ 2,184	\$ 1,733		
# Overheads - External	\$ 1,327	\$ -	\$ -	\$ 220	\$ 624	\$ 484		
Total	\$ 7,981	\$ -	\$ -	\$ 1,333	\$ 3,634	\$ 3,014		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ 7	\$ -	\$ -	\$ -	\$ 1	\$ 5		
Materials	\$ 32	\$ -	\$ -	\$ 15	\$ 12	\$ 5		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ 38	\$ -	\$ -	\$ 15	\$ 14	\$ 10		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 253	\$ 30	\$ 33	\$ 33	\$ 35	\$ 38	\$ 40	\$ 43
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 10,107	\$ 1,298	\$ 1,295	\$ 1,360	\$ 1,428	\$ 1,499	\$ 1,574	\$ 1,653
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 2,152	\$ 276	\$ 276	\$ 290	\$ 304	\$ 319	\$ 335	\$ 352
# Internal, Overheads	\$ 1,639	\$ 220	\$ 239	\$ 201	\$ 202	\$ 212	\$ 246	\$ 320
# Materials	\$ 6,824	\$ 785	\$ 783	\$ 861	\$ 947	\$ 1,042	\$ 1,146	\$ 1,261
# Overheads - External	\$ 1,994	\$ 255	\$ 296	\$ 249	\$ 248	\$ 259	\$ 299	\$ 388
Total	\$ 22,968	\$ 2,864	\$ 2,922	\$ 2,993	\$ 3,164	\$ 3,368	\$ 3,641	\$ 4,017

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 66	\$ 9	\$ 9	\$ 9	\$ 9	\$ 10	\$ 10	\$ 10
Materials	\$ 319	\$ 42	\$ 44	\$ 45	\$ 46	\$ 47	\$ 48	\$ 49
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 385	\$ 50	\$ 53	\$ 54	\$ 55	\$ 56	\$ 58	\$ 59

New York 21st Century Grid Plan (Cheektowaga)

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-004650	Charge Code: Electric Distribution	Project Sponsor: Malone, Chris	Project Type: Project
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: IP2 Technical	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

The Walden Ave. - Substation Rebuild project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Division Grid Modernization Pilot is a comprehensive initiative aimed at addressing critical needs related to system reliability, aging infrastructure, electrification readiness, and network resilience. The project aligns with state energy policy objectives and utility planning standards, providing a forward-looking framework to modernize both the distribution and sub-transmission networks.

This project also represents a shift in planning philosophy. It introduces a differentiated approach not only in execution, but in how system needs are identified and addressed. Rather than applying traditional asset-by-asset solutions, NYSEG has adopted a zonal planning model, grounded in an in-depth analysis of local network performance, asset condition, and long-term demand forecasts. The result is a holistic solution tailored to the specific needs of the Lancaster area—improving reliability, optimizing capacity, reducing operational costs, and enabling future growth in a coordinated and scalable way.

Project Justification

- **Reliability:** Between 2020 and 2022, the Lancaster Division accounted for approximately 19% of NYSEG's total SAIFI (System Average Interruption Frequency Index) impact. Three substations—Losson Rd, Blossom Rd, and Walden Ave—were among the poorest performers system-wide.
- **Asset Condition:** Multiple substations were identified with outdated transformers, electromechanical relays, deteriorated switchgear, and poor structural conditions, many lacking SCADA visibility or control.
- **Resiliency & Redundancy:** The area lacks sufficient N-1 contingency support, making it vulnerable to prolonged outages and limiting the ability to automatically isolate and restore faults.
- **Load Growth:** Forecasts project a 30% increase in peak demand by 2037, driven by building electrification and electric vehicle (EV) adoption.

Project Scope:

The Walden Ave. - Substation Rebuild project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Grid Modernization Pilot proposes a comprehensive reconfiguration of the electric distribution and sub-transmission network in one of NYSEG's highest-impact service areas. The initiative targets a region that serves approximately 177,000 customers and carries roughly 690 MW of system load, representing a substantial portion of NYSEG's reliability performance metrics. The scope includes infrastructure upgrades, voltage conversions, substation retirements, and implementation of advanced system automation, all designed to improve reliability, resilience, and operational efficiency.

Main Infrastructure Components

1. Rebuild of Key Substations
 - Losson Road (34.5/12.5 kV GIS): Full rebuild with 9 feeders and 2×50 MVA transformers
 - Blossom Road (34.5/12.5 kV GIS): Full rebuild with 6 feeders and 2×37.3 MVA transformers
 - Walden Avenue (115/12.5 kV AIS): Upgrade with 9 feeders, 2×50 MVA transformers, new breakers, and control house
2. Substation Retirements - Aging infrastructure with poor condition ratings, obsolete equipment, and limited operational visibility
 - Five legacy substations to be retired: Sloan, Ellicott, Ebenezer, Indian Church, and Depew
3. Construction of two new 12.5 kV distribution centers to serve as centralized and automated feeder hubs strategically located at Sloan and Losson to enable rapid fault isolation, load transfer, and network reconfiguration
4. North Broadway Substation Expansion and Depew Line Replacement
 - Installation of three new 115 kV breakers and expansion of the 34.5 kV yard with three new breakers
 - Addition of a new 50 MVA 115/34.5 kV transformer
 - Construction of a new 34.5 kV line to reroute Line 532 into North Broadway, enabling the full retirement of Depew substation
5. Distribution upgrades (Blossom Rd, Losson Rd and Walden Ave & Sloan)
 - Conversion of approximately 75 miles of distribution circuits from legacy 4.8 kV to standard 12.5 kV
 - Upgrades to conductor sizes (up to 477 AL) to increase thermal capacity and reduce voltage drop
6. Installation of multiple 12.5 kV express feeders between substations and distribution centers (~10 miles total).

Additional Technical Elements

- Integration of SCADA control and visibility across all new and upgraded facilities
- Enhanced remote operation capabilities and automated restoration (self-healing features)
- System-wide reconfiguration to ensure all 12.5 kV feeders operate in phase
- Elimination of backlot lines and inaccessible equipment to improve maintenance and safety

Project Benefits:**1. Enhanced System Reliability**

The project directly addresses chronic reliability issues in one of NYSEG's most outage-prone areas. By replacing obsolete substations and reconfiguring the network, the initiative is expected to reduce SAIFI across the NYSEG system by an estimated 2.15%. This translates into fewer and shorter outages for nearly 177,000 customers, aligning with state reliability standards and improving service equity across the grid.

2. Improved Resilience and Contingency Support

Through the construction of new distribution centers and the expansion of strategic substations like North Broadway, the project introduces much-needed N-1 contingency capability to the area. This ensures that the system can withstand the failure of a single major component without causing widespread outages, significantly strengthening grid resilience in the face of storms and equipment failures.

3. Optimization of System Capacity and Load Transfer Flexibility

The conversion of legacy 4.8 kV circuits to 12.5 kV and the installation of express feeders improve the system's ability to transfer load between feeders and substations efficiently. This expanded tie capability allows for faster restoration and real-time operational flexibility, which is especially important as demand increases and load patterns shift due to electrification.

4. Long-Term Cost Efficiency

By retiring five aging substations and consolidating infrastructure, the project eliminates high-maintenance assets and reduces operational expenditures. NYSEG estimates annual O&M savings of approximately \$815,000, providing financial relief over the long term while maintaining or improving service levels. These savings also help moderate future rate impacts for customers.

5. Grid Readiness for Electrification and Future Growth

The upgraded network will support up to 52 MVA of additional load, preparing the system for forecasted growth in electric vehicles, electric heating, and distributed energy resources (DERs). With capacity in place, NYSEG can accommodate customer transitions to cleaner energy without compromising reliability or triggering reactive investment.

6. Modernized Operational Capabilities

All rebuilt and new facilities will be integrated into NYSEG's SCADA system, enabling full remote visibility and control. Combined with automated switching and advanced protection schemes, this will shorten restoration times, enable predictive maintenance, and improve outage response across the service area.

7. Risk Mitigation and Safety Improvements

The project eliminates numerous backlot lines and inaccessible infrastructure, reducing risk for field crews and enhancing public safety. Retired substations and upgraded sites also reduce the likelihood of equipment-related environmental incidents, aligning with modern utility safety and compliance standards.

Project Risks and Mitigation Plan:**1. Construction and Execution Risk**

Due to the scale and complexity of the project, there is a risk of delays related to permitting, material lead times, contractor mobilization, and construction sequencing. To mitigate this, NYSEG will adopt a phased execution strategy, prioritize early design finalization, and initiate procurement of long-lead equipment such as transformers and breakers well in advance. A detailed construction schedule will be developed and closely monitored to manage critical path activities.

2. Cost Escalation and Budget Risk

Material price volatility, labor cost increases, and potential supply chain disruptions could impact the project budget. NYSEG will include contingency allowances in the financial planning and will implement cost tracking systems to monitor expenditures. Regular budget reviews and a formal process for identifying and responding to cost deviations will be established to maintain financial discipline.

3. System Integration and Operational Transition Risk

Transitioning from legacy infrastructure to the new network configuration—especially during substation retirements and feeder reconfigurations—could pose operational risks, including service interruptions. NYSEG will prepare detailed transition and cutover plans, including temporary configurations and backup solutions such as mobile substations, to minimize impacts to customers during system switchover periods.

4. Stakeholder and Community Impact Risk

Construction activities may temporarily affect local communities through traffic disruptions, noise, or access limitations. To address this, NYSEG will engage proactively with municipalities and stakeholders, provide advance notice of planned work, and coordinate closely to minimize disruptions. Communication plans will be put in place to keep the public informed throughout the project.

5. Environmental and Regulatory Compliance Risk

Project components involving civil works or equipment installation may require environmental permitting and regulatory reviews. NYSEG will conduct thorough pre-construction environmental assessments and will work with regulatory agencies to secure all necessary approvals. Compliance will be monitored throughout the project by internal teams and external environmental consultants.

6. Technology Integration and Cybersecurity Risk

The integration of SCADA systems, protection relays, and remote switching technologies introduces risks related to system compatibility and cybersecurity. NYSEG will perform comprehensive factory and site acceptance testing, follow standard protocols for equipment integration, and implement cybersecurity reviews in line with internal policies and industry best practices.

Risk of No Action:

In addition to the project execution risks, it is important to highlight the significant consequences of inaction—should the Lancaster Grid Modernization Project be delayed, deferred, or not implemented. These risks would affect both operational performance and long-term strategic objectives:

1. Continued System Reliability Degradation

Several of the substations in the project scope are among the worst performers in NYSEG's service territory in terms of SAIFI and SAIDI. Without modernization, customers in the region would continue to experience frequent and prolonged outages. Aging infrastructure increases the likelihood of unplanned failures, which could further degrade service quality and lead to regulatory penalties.

2. Inability to Support Load Growth and Electrification

The existing 4.8 kV infrastructure and current system configuration cannot accommodate forecasted demand growth driven by electrification (EVs, heat pumps, DERs). Delaying the project would constrain NYSEG's ability to connect new load and meet statewide decarbonization and electrification goals. It may also lead to more reactive, less efficient capital spending in the future.

3. Escalating Maintenance and Operational Costs

Aging substations and equipment require increasingly frequent maintenance and emergency repairs. Without proactive investment, O&M costs will continue to rise, driven by unplanned interventions and inefficient asset management. This also ties up workforce resources that could otherwise support strategic initiatives.

4. Increased Risk of Equipment Failure and Safety Incidents

Legacy equipment poses not only reliability risks but also safety and environmental risks. Continued operation of deteriorated assets increases the chance of equipment failure, potential fire hazards, oil spills, and unsafe working conditions for field personnel.

5. Missed Opportunity for Operational Modernization

Postponing the project would delay the deployment of advanced grid functionalities such as SCADA, remote switching, and self-healing networks. This limits NYSEG's ability to improve outage response times, reduce truck rolls, and integrate data-driven system operations.

6. Reduced Long-Term Cost Efficiency

Failure to act now could result in higher future capital expenditures. Delaying coordinated modernization may force NYSEG to invest in piecemeal upgrades under time and reliability pressures, which are typically less cost-effective than comprehensive, planned reinforcements.

Project Alternatives:

As part of the planning process, NYSEG evaluated multiple alternatives to address the reliability, capacity, and asset condition issues in the Lancaster Division. Each alternative was assessed based on technical feasibility, cost-effectiveness, reliability benefits, future readiness, and constructability. The alternatives ranged from minimal intervention to full system reconfiguration.

Alternative 0 – Do Nothing

This baseline alternative would involve no proactive investment and would rely on continued operation and maintenance of the existing infrastructure.

- Pros: No upfront capital cost
- Cons: No improvement in reliability or capacity, continued deterioration of assets, increasing O&M costs, and high risk of equipment failure
- Conclusion: Not viable. This alternative fails to meet basic planning criteria and leaves the system vulnerable.

Alternative 1 – Limited Substation Replacement

This alternative proposed rebuilding only one or two of the most critical substations (e.g., Walden Avenue and Blossom Road), while keeping the rest of the network intact.

- Pros: Moderate capital cost, localized improvement at high-impact substations
- Cons: Minimal impact on broader network reliability and redundancy; does not address 4.8 kV conversion or N-1 contingency gaps; limited long-term scalability
- Conclusion: Provides partial benefit but does not support a comprehensive modernization strategy.

Alternative 2 – Comprehensive Grid Modernization (Selected)

This alternative includes the full rebuild of three major substations, retirement of five legacy substations, conversion of 4.8 kV to 12.5 kV, construction of two new distribution centers, and expansion of North Broadway.

- Pros: Maximizes reliability improvement (2.15% SAIFI reduction), fully resolves N-1 contingency deficiencies, supports long-term electrification, enables flexible load transfer, and reduces O&M costs
- Cons: Higher initial capital investment
- Additional Note: Within this alternative, multiple grid modernization configurations were evaluated, varying in substation design, feeder layout, and sequencing strategy. The selected configuration was found to be the most cost-effective while meeting all technical and operational objectives.
- Conclusion: Selected as the preferred solution due to its comprehensive, long-term value and alignment with utility and regulatory objectives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 4,170	\$ 1,705	\$ 1,200	\$ 979	\$ 255	\$ 31	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 18,906	\$ 12,865	\$ 2,942	\$ 2,398	\$ 625	\$ 76	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 761	\$ 148	\$ 299	\$ 243	\$ 63	\$ 8	\$ -	\$ -
# Internal, Overheads	\$ 5,466	\$ 3,273	\$ 1,206	\$ 775	\$ 189	\$ 23	\$ -	\$ -
# Materials	\$ 30,418	\$ 14,107	\$ 7,944	\$ 6,476	\$ 1,686	\$ 205	\$ -	\$ -
# Overheads - External	\$ 4,698	\$ 2,540	\$ 1,187	\$ 763	\$ 186	\$ 22	\$ -	\$ -
Total	\$ 64,418	\$ 34,637	\$ 14,778	\$ 11,634	\$ 3,004	\$ 365	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Lancaster Project - North Broadway - Expansion

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007399	Charge Code: Electric Transmission	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

The North Broadway - Expansion project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Division Grid Modernization Pilot is a comprehensive initiative aimed at addressing critical needs related to system reliability, aging infrastructure, electrification readiness, and network resilience. The project aligns with state energy policy objectives and utility planning standards, providing a forward-looking framework to modernize both the distribution and sub-transmission networks.

This project also represents a shift in planning philosophy. It introduces a differentiated approach not only in execution, but in how system needs are identified and addressed. Rather than applying traditional asset-by-asset solutions, NYSEG has adopted a zonal planning model, grounded in an in-depth analysis of local network performance, asset condition, and long-term demand forecasts. The result is a holistic solution tailored to the specific needs of the Lancaster area—improving reliability, optimizing capacity, reducing operational costs, and enabling future growth in a coordinated and scalable way.

Project Justification

- **Reliability:** Between 2020 and 2022, the Lancaster Division accounted for approximately 19% of NYSEG's total SAIFI (System Average Interruption Frequency Index) impact. Three substations—Losson Rd, Blossom Rd, and Walden Ave—were among the poorest performers system-wide.
- **Asset Condition:** Multiple substations were identified with outdated transformers, electromechanical relays, deteriorated switchgear, and poor structural conditions, many lacking SCADA visibility or control.
- **Resiliency & Redundancy:** The area lacks sufficient N-1 contingency support, making it vulnerable to prolonged outages and limiting the ability to automatically isolate and restore faults.
- **Load Growth:** Forecasts project a 30% increase in peak demand by 2037, driven by building electrification and electric vehicle (EV) adoption.

Project Scope:

The North Broadway - Expansion is a subproject of the Lancaster Grid Modernization Project. The Lancaster Grid Modernization Pilot proposes a comprehensive reconfiguration of the electric distribution and sub-transmission network in one of NYSEG's highest-impact service areas. The initiative targets a region that serves approximately 177,000 customers and carries roughly 690 MW of system load, representing a substantial portion of NYSEG's reliability performance metrics. The scope includes infrastructure upgrades, voltage conversions, substation retirements, and implementation of advanced system automation, all designed to improve reliability, resilience, and operational efficiency.

Main Infrastructure Components

1. Rebuild of Key Substations

- Losson Road (34.5/12.5 kV GIS): Full rebuild with 9 feeders and 2×50 MVA transformers
- Blossom Road (34.5/12.5 kV GIS): Full rebuild with 6 feeders and 2×37.3 MVA transformers
- Walden Avenue (115/12.5 kV AIS): Upgrade with 9 feeders, 2×50 MVA transformers, new breakers, and control house

2. Substation Retirements - Aging infrastructure with poor condition ratings, obsolete equipment, and limited operational visibility

- Five legacy substations to be retired: Sloan, Ellicott, Ebenezer, Indian Church, and Depew

3. Construction of two new 12.5 kV distribution centers to serve as centralized and automated feeder hubs strategically located at Sloan and Losson to enable rapid fault isolation, load transfer, and network reconfiguration

4. North Broadway Substation Expansion and Depew Line Replacement

- Installation of three new 115 kV breakers and expansion of the 34.5 kV yard with three new breakers
- Addition of a new 50 MVA 115/34.5 kV transformer
- Construction of a new 34.5 kV line to reroute Line 532 into North Broadway, enabling the full retirement of Depew substation

5. Distribution upgrades (Blossom Rd, Losson Rd and Walden Ave & Sloan)

- Conversion of approximately 75 miles of distribution circuits from legacy 4.8 kV to standard 12.5 kV
- Upgrades to conductor sizes (up to 477 AL) to increase thermal capacity and reduce voltage drop

6. Installation of multiple 12.5 kV express feeders between substations and distribution centers (~10 miles total).

Additional Technical Elements

- Integration of SCADA control and visibility across all new and upgraded facilities
- Enhanced remote operation capabilities and automated restoration (self-healing features)
- System-wide reconfiguration to ensure all 12.5 kV feeders operate in phase
- Elimination of backlot lines and inaccessible equipment to improve maintenance and safety

Project Benefits:**1. Enhanced System Reliability**

The project directly addresses chronic reliability issues in one of NYSEG's most outage-prone areas. By replacing obsolete substations and reconfiguring the network, the initiative is expected to reduce SAIFI across the NYSEG system by an estimated 2.15%. This translates into fewer and shorter outages for nearly 177,000 customers, aligning with state reliability standards and improving service equity across the grid.

2. Improved Resilience and Contingency Support

Through the construction of new distribution centers and the expansion of strategic substations like North Broadway, the project introduces much-needed N-1 contingency capability to the area. This ensures that the system can withstand the failure of a single major component without causing widespread outages, significantly strengthening grid resilience in the face of storms and equipment failures.

3. Optimization of System Capacity and Load Transfer Flexibility

The conversion of legacy 4.8 kV circuits to 12.5 kV and the installation of express feeders improve the system's ability to transfer load between feeders and substations efficiently. This expanded tie capability allows for faster restoration and real-time operational flexibility, which is especially important as demand increases and load patterns shift due to electrification.

4. Long-Term Cost Efficiency

By retiring five aging substations and consolidating infrastructure, the project eliminates high-maintenance assets and reduces operational expenditures. NYSEG estimates annual O&M savings of approximately \$815,000, providing financial relief over the long term while maintaining or improving service levels. These savings also help moderate future rate impacts for customers.

5. Grid Readiness for Electrification and Future Growth

The upgraded network will support up to 52 MVA of additional load, preparing the system for forecasted growth in electric vehicles, electric heating, and distributed energy resources (DERs). With capacity in place, NYSEG can accommodate customer transitions to cleaner energy without compromising reliability or triggering reactive investment.

6. Modernized Operational Capabilities

All rebuilt and new facilities will be integrated into NYSEG's SCADA system, enabling full remote visibility and control. Combined with automated switching and advanced protection schemes, this will shorten restoration times, enable predictive maintenance, and improve outage response across the service area.

7. Risk Mitigation and Safety Improvements

The project eliminates numerous backlot lines and inaccessible infrastructure, reducing risk for field crews and enhancing public safety. Retired substations and upgraded sites also reduce the likelihood of equipment-related environmental incidents, aligning with modern utility safety and compliance standards.

Project Risks and Mitigation Plan:**1. Construction and Execution Risk**

Due to the scale and complexity of the project, there is a risk of delays related to permitting, material lead times, contractor mobilization, and construction sequencing. To mitigate this, NYSEG will adopt a phased execution strategy, prioritize early design finalization, and initiate procurement of long-lead equipment such as transformers and breakers well in advance. A detailed construction schedule will be developed and closely monitored to manage critical path activities.

2. Cost Escalation and Budget Risk

Material price volatility, labor cost increases, and potential supply chain disruptions could impact the project budget. NYSEG will include contingency allowances in the financial planning and will implement cost tracking systems to monitor expenditures. Regular budget reviews and a formal process for identifying and responding to cost deviations will be established to maintain financial discipline.

3. System Integration and Operational Transition Risk

Transitioning from legacy infrastructure to the new network configuration—especially during substation retirements and feeder reconfigurations—could pose operational risks, including service interruptions. NYSEG will prepare detailed transition and cutover plans, including temporary configurations and backup solutions such as mobile substations, to minimize impacts to customers during system switchover periods.

4. Stakeholder and Community Impact Risk

Construction activities may temporarily affect local communities through traffic disruptions, noise, or access limitations. To address this, NYSEG will engage proactively with municipalities and stakeholders, provide advance notice of planned work, and coordinate closely to minimize disruptions. Communication plans will be put in place to keep the public informed throughout the project.

5. Environmental and Regulatory Compliance Risk

Project components involving civil works or equipment installation may require environmental permitting and regulatory reviews. NYSEG will conduct thorough pre-construction environmental assessments and will work with regulatory agencies to secure all necessary approvals. Compliance will be monitored throughout the project by internal teams and external environmental consultants.

6. Technology Integration and Cybersecurity Risk

The integration of SCADA systems, protection relays, and remote switching technologies introduces risks related to system compatibility and cybersecurity. NYSEG will perform comprehensive factory and site acceptance testing, follow standard protocols for equipment integration, and implement cybersecurity reviews in line with internal policies and industry best practices.

Risk of No Action:

In addition to the project execution risks, it is important to highlight the significant consequences of inaction—should the Lancaster Grid Modernization Project be delayed, deferred, or not implemented. These risks would affect both operational performance and long-term strategic objectives:

1. Continued System Reliability Degradation

Several of the substations in the project scope are among the worst performers in NYSEG's service territory in terms of SAIFI and SAIDI. Without modernization, customers in the region would continue to experience frequent and prolonged outages. Aging infrastructure increases the likelihood of unplanned failures, which could further degrade service quality and lead to regulatory penalties.

2. Inability to Support Load Growth and Electrification

The existing 4.8 kV infrastructure and current system configuration cannot accommodate forecasted demand growth driven by electrification (EVs, heat pumps, DERs). Delaying the project would constrain NYSEG's ability to connect new load and meet statewide decarbonization and electrification goals. It may also lead to more reactive, less efficient capital spending in the future.

3. Escalating Maintenance and Operational Costs

Aging substations and equipment require increasingly frequent maintenance and emergency repairs. Without proactive investment, O&M costs will continue to rise, driven by unplanned interventions and inefficient asset management. This also ties up workforce resources that could otherwise support strategic initiatives.

4. Increased Risk of Equipment Failure and Safety Incidents

Legacy equipment poses not only reliability risks but also safety and environmental risks. Continued operation of deteriorated assets increases the chance of equipment failure, potential fire hazards, oil spills, and unsafe working conditions for field personnel.

5. Missed Opportunity for Operational Modernization

Postponing the project would delay the deployment of advanced grid functionalities such as SCADA, remote switching, and self-healing networks. This limits NYSEG's ability to improve outage response times, reduce truck rolls, and integrate data-driven system operations.

6. Reduced Long-Term Cost Efficiency

Failure to act now could result in higher future capital expenditures. Delaying coordinated modernization may force NYSEG to invest in piecemeal upgrades under time and reliability pressures, which are typically less cost-effective than comprehensive, planned reinforcements.

Project Alternatives:

As part of the planning process, NYSEG evaluated multiple alternatives to address the reliability, capacity, and asset condition issues in the Lancaster Division. Each alternative was assessed based on technical feasibility, cost-effectiveness, reliability benefits, future readiness, and constructability. The alternatives ranged from minimal intervention to full system reconfiguration.

Alternative 0 – Do Nothing

This baseline alternative would involve no proactive investment and would rely on continued operation and maintenance of the existing infrastructure.

- Pros: No upfront capital cost
- Cons: No improvement in reliability or capacity, continued deterioration of assets, increasing O&M costs, and high risk of equipment failure
- Conclusion: Not viable. This alternative fails to meet basic planning criteria and leaves the system vulnerable.

Alternative 1 – Limited Substation Replacement

This alternative proposed rebuilding only one or two of the most critical substations (e.g., Walden Avenue and Blossom Road), while keeping the rest of the network intact.

- Pros: Moderate capital cost, localized improvement at high-impact substations
- Cons: Minimal impact on broader network reliability and redundancy; does not address 4.8 kV conversion or N-1 contingency gaps; limited long-term scalability
- Conclusion: Provides partial benefit but does not support a comprehensive modernization strategy.

Alternative 2 – Comprehensive Grid Modernization (Selected)

This alternative includes the full rebuild of three major substations, retirement of five legacy substations, conversion of 4.8 kV to 12.5 kV, construction of two new distribution centers, and expansion of North Broadway.

- Pros: Maximizes reliability improvement (2.15% SAIFI reduction), fully resolves N-1 contingency deficiencies, supports long-term electrification, enables flexible load transfer, and reduces O&M costs
- Cons: Higher initial capital investment
- Additional Note: Within this alternative, multiple grid modernization configurations were evaluated, varying in substation design, feeder layout, and sequencing strategy. The selected configuration was found to be the most cost-effective while meeting all technical and operational objectives.
- Conclusion: Selected as the preferred solution due to its comprehensive, long-term value and alignment with utility and regulatory objectives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

[illegible]

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,583	\$ 108	\$ 1,002	\$ 333	\$ 140	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,881	\$ 265	\$ 2,456	\$ 817	\$ 343	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 394	\$ 27	\$ 249	\$ 83	\$ 35	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 1,465	\$ 90	\$ 1,007	\$ 264	\$ 104	\$ -	\$ -	\$ -
# Materials	\$ 10,477	\$ 716	\$ 6,631	\$ 2,206	\$ 925	\$ -	\$ -	\$ -
# Overheads - External	\$ 1,472	\$ 119	\$ 991	\$ 260	\$ 102	\$ -	\$ -	\$ -
Total	\$ 19,272	\$ 1,325	\$ 12,335	\$ 3,964	\$ 1,648	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

Lancaster Project - Blosson Road - Distribution upgrades

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007383	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2028

Project description:

The Blosson Road - Distribution upgrades project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Division Grid Modernization Pilot is a comprehensive initiative aimed at addressing critical needs related to system reliability, aging infrastructure, electrification readiness, and network resilience. The project aligns with state energy policy objectives and utility planning standards, providing a forward-looking framework to modernize both the distribution and sub-transmission networks.

This project also represents a shift in planning philosophy. It introduces a differentiated approach not only in execution, but in how system needs are identified and addressed. Rather than applying traditional asset-by-asset solutions, NYSEG has adopted a zonal planning model, grounded in an in-depth analysis of local network performance, asset condition, and long-term demand forecasts. The result is a holistic solution tailored to the specific needs of the Lancaster area—improving reliability, optimizing capacity, reducing operational costs, and enabling future growth in a coordinated and scalable way.

Project Justification

- **Reliability:** Between 2020 and 2022, the Lancaster Division accounted for approximately 19% of NYSEG's total SAIFI (System Average Interruption Frequency Index) impact. Three substations—Losson Rd, Blossom Rd, and Walden Ave—were among the poorest performers system-wide.
- **Asset Condition:** Multiple substations were identified with outdated transformers, electromechanical relays, deteriorated switchgear, and poor structural conditions, many lacking SCADA visibility or control.
- **Resiliency & Redundancy:** The area lacks sufficient N-1 contingency support, making it vulnerable to prolonged outages and limiting the ability to automatically isolate and restore faults.
- **Load Growth:** Forecasts project a 30% increase in peak demand by 2037, driven by building electrification and electric vehicle (EV) adoption.

Project Scope:

The Blosson Road - Distribution upgrades project is a subproject of the Lancaster Grid Modernization Project. The Lancaster Grid Modernization Pilot proposes a comprehensive reconfiguration of the electric distribution and sub-transmission network in one of NYSEG's highest-impact service areas. The initiative targets a region that serves approximately 177,000 customers and carries roughly 690 MW of system load, representing a substantial portion of NYSEG's reliability performance metrics. The scope includes infrastructure upgrades, voltage conversions, substation retirements, and implementation of advanced system automation, all designed to improve reliability, resilience, and operational efficiency.

Main Infrastructure Components

1. Rebuild of Key Substations
 - Losson Road (34.5/12.5 kV GIS): Full rebuild with 9 feeders and 2×50 MVA transformers
 - Blossom Road (34.5/12.5 kV GIS): Full rebuild with 6 feeders and 2×37.3 MVA transformers
 - Walden Avenue (115/12.5 kV AIS): Upgrade with 9 feeders, 2×50 MVA transformers, new breakers, and control house
 2. Substation Retirements - Aging infrastructure with poor condition ratings, obsolete equipment, and limited operational visibility
 - Five legacy substations to be retired: Sloan, Ellicott, Ebenezer, Indian Church, and Depew
 3. Construction of two new 12.5 kV distribution centers to serve as centralized and automated feeder hubs strategically located at Sloan and Losson to enable rapid fault isolation, load transfer, and network reconfiguration
 4. North Broadway Substation Expansion and Depew Line Replacement
 - Installation of three new 115 kV breakers and expansion of the 34.5 kV yard with three new breakers
 - Addition of a new 50 MVA 115/34.5 kV transformer
 - Construction of a new 34.5 kV line to reroute Line 532 into North Broadway, enabling the full retirement of Depew substation
 5. Distribution upgrades (Blosson Rd, Losson Rd and Walden Ave & Sloan)
 - Conversion of approximately 75 miles of distribution circuits from legacy 4.8 kV to standard 12.5 kV
 - Upgrades to conductor sizes (up to 477 AL) to increase thermal capacity and reduce voltage drop
 6. Installation of multiple 12.5 kV express feeders between substations and distribution centers (~10 miles total).
- #### Additional Technical Elements
- Integration of SCADA control and visibility across all new and upgraded facilities
 - Enhanced remote operation capabilities and automated restoration (self-healing features)
 - System-wide reconfiguration to ensure all 12.5 kV feeders operate in phase
 - Elimination of backlot lines and inaccessible equipment to improve maintenance and safety

Project Benefits:**1. Enhanced System Reliability**

The project directly addresses chronic reliability issues in one of NYSEG's most outage-prone areas. By replacing obsolete substations and reconfiguring the network, the initiative is expected to reduce SAIFI across the NYSEG system by an estimated 2.15%. This translates into fewer and shorter outages for nearly 177,000 customers, aligning with state reliability standards and improving service equity across the grid.

2. Improved Resilience and Contingency Support

Through the construction of new distribution centers and the expansion of strategic substations like North Broadway, the project introduces much-needed N-1 contingency capability to the area. This ensures that the system can withstand the failure of a single major component without causing widespread outages, significantly strengthening grid resilience in the face of storms and equipment failures.

3. Optimization of System Capacity and Load Transfer Flexibility

The conversion of legacy 4.8 kV circuits to 12.5 kV and the installation of express feeders improve the system's ability to transfer load between feeders and substations efficiently. This expanded tie capability allows for faster restoration and real-time operational flexibility, which is especially important as demand increases and load patterns shift due to electrification.

4. Long-Term Cost Efficiency

By retiring five aging substations and consolidating infrastructure, the project eliminates high-maintenance assets and reduces operational expenditures. NYSEG estimates annual O&M savings of approximately \$815,000, providing financial relief over the long term while maintaining or improving service levels. These savings also help moderate future rate impacts for customers.

5. Grid Readiness for Electrification and Future Growth

The upgraded network will support up to 52 MVA of additional load, preparing the system for forecasted growth in electric vehicles, electric heating, and distributed energy resources (DERs). With capacity in place, NYSEG can accommodate customer transitions to cleaner energy without compromising reliability or triggering reactive investment.

6. Modernized Operational Capabilities

All rebuilt and new facilities will be integrated into NYSEG's SCADA system, enabling full remote visibility and control. Combined with automated switching and advanced protection schemes, this will shorten restoration times, enable predictive maintenance, and improve outage response across the service area.

7. Risk Mitigation and Safety Improvements

The project eliminates numerous backlot lines and inaccessible infrastructure, reducing risk for field crews and enhancing public safety. Retired substations and upgraded sites also reduce the likelihood of equipment-related environmental incidents, aligning with modern utility safety and compliance standards.

Project Risks and Mitigation Plan:**1. Construction and Execution Risk**

Due to the scale and complexity of the project, there is a risk of delays related to permitting, material lead times, contractor mobilization, and construction sequencing. To mitigate this, NYSEG will adopt a phased execution strategy, prioritize early design finalization, and initiate procurement of long-lead equipment such as transformers and breakers well in advance. A detailed construction schedule will be developed and closely monitored to manage critical path activities.

2. Cost Escalation and Budget Risk

Material price volatility, labor cost increases, and potential supply chain disruptions could impact the project budget. NYSEG will include contingency allowances in the financial planning and will implement cost tracking systems to monitor expenditures. Regular budget reviews and a formal process for identifying and responding to cost deviations will be established to maintain financial discipline.

3. System Integration and Operational Transition Risk

Transitioning from legacy infrastructure to the new network configuration—especially during substation retirements and feeder reconfigurations—could pose operational risks, including service interruptions. NYSEG will prepare detailed transition and cutover plans, including temporary configurations and backup solutions such as mobile substations, to minimize impacts to customers during system switchover periods.

4. Stakeholder and Community Impact Risk

Construction activities may temporarily affect local communities through traffic disruptions, noise, or access limitations. To address this, NYSEG will engage proactively with municipalities and stakeholders, provide advance notice of planned work, and coordinate closely to minimize disruptions. Communication plans will be put in place to keep the public informed throughout the project.

5. Environmental and Regulatory Compliance Risk

Project components involving civil works or equipment installation may require environmental permitting and regulatory reviews. NYSEG will conduct thorough pre-construction environmental assessments and will work with regulatory agencies to secure all necessary approvals. Compliance will be monitored throughout the project by internal teams and external environmental consultants.

6. Technology Integration and Cybersecurity Risk

The integration of SCADA systems, protection relays, and remote switching technologies introduces risks related to system compatibility and cybersecurity. NYSEG will perform comprehensive factory and site acceptance testing, follow standard protocols for equipment integration, and implement cybersecurity reviews in line with internal policies and industry best practices.

Risk of No Action:

In addition to the project execution risks, it is important to highlight the significant consequences of inaction—should the Lancaster Grid Modernization Project be delayed, deferred, or not implemented. These risks would affect both operational performance and long-term strategic objectives:

1. Continued System Reliability Degradation

Several of the substations in the project scope are among the worst performers in NYSEG's service territory in terms of SAIFI and SAIDI. Without modernization, customers in the region would continue to experience frequent and prolonged outages. Aging infrastructure increases the likelihood of unplanned failures, which could further degrade service quality and lead to regulatory penalties.

2. Inability to Support Load Growth and Electrification

The existing 4.8 kV infrastructure and current system configuration cannot accommodate forecasted demand growth driven by electrification (EVs, heat pumps, DERs). Delaying the project would constrain NYSEG's ability to connect new load and meet statewide decarbonization and electrification goals. It may also lead to more reactive, less efficient capital spending in the future.

3. Escalating Maintenance and Operational Costs

Aging substations and equipment require increasingly frequent maintenance and emergency repairs. Without proactive investment, O&M costs will continue to rise, driven by unplanned interventions and inefficient asset management. This also ties up workforce resources that could otherwise support strategic initiatives.

4. Increased Risk of Equipment Failure and Safety Incidents

Legacy equipment poses not only reliability risks but also safety and environmental risks. Continued operation of deteriorated assets increases the chance of equipment failure, potential fire hazards, oil spills, and unsafe working conditions for field personnel.

5. Missed Opportunity for Operational Modernization

Postponing the project would delay the deployment of advanced grid functionalities such as SCADA, remote switching, and self-healing networks. This limits NYSEG's ability to improve outage response times, reduce truck rolls, and integrate data-driven system operations.

6. Reduced Long-Term Cost Efficiency

Failure to act now could result in higher future capital expenditures. Delaying coordinated modernization may force NYSEG to invest in piecemeal upgrades under time and reliability pressures, which are typically less cost-effective than comprehensive, planned reinforcements.

Project Alternatives:

As part of the planning process, NYSEG evaluated multiple alternatives to address the reliability, capacity, and asset condition issues in the Lancaster Division. Each alternative was assessed based on technical feasibility, cost-effectiveness, reliability benefits, future readiness, and constructability. The alternatives ranged from minimal intervention to full system reconfiguration.

Alternative 0 – Do Nothing

This baseline alternative would involve no proactive investment and would rely on continued operation and maintenance of the existing infrastructure.

- Pros: No upfront capital cost
- Cons: No improvement in reliability or capacity, continued deterioration of assets, increasing O&M costs, and high risk of equipment failure
- Conclusion: Not viable. This alternative fails to meet basic planning criteria and leaves the system vulnerable.

Alternative 1 – Limited Substation Replacement

This alternative proposed rebuilding only one or two of the most critical substations (e.g., Walden Avenue and Blossom Road), while keeping the rest of the network intact.

- Pros: Moderate capital cost, localized improvement at high-impact substations
- Cons: Minimal impact on broader network reliability and redundancy; does not address 4.8 kV conversion or N-1 contingency gaps; limited long-term scalability
- Conclusion: Provides partial benefit but does not support a comprehensive modernization strategy.

Alternative 2 – Comprehensive Grid Modernization (Selected)

This alternative includes the full rebuild of three major substations, retirement of five legacy substations, conversion of 4.8 kV to 12.5 kV, construction of two new distribution centers, and expansion of North Broadway.

- Pros: Maximizes reliability improvement (2.15% SAIFI reduction), fully resolves N-1 contingency deficiencies, supports long-term electrification, enables flexible load transfer, and reduces O&M costs
- Cons: Higher initial capital investment
- Additional Note: Within this alternative, multiple grid modernization configurations were evaluated, varying in substation design, feeder layout, and sequencing strategy. The selected configuration was found to be the most cost-effective while meeting all technical and operational objectives.
- Conclusion: Selected as the preferred solution due to its comprehensive, long-term value and alignment with utility and regulatory objectives.

Basis for Project Estimates

The project cost estimates encompass required internal labor, external resources, materials, internal and external engineering, and appropriate project support costs. These estimates are derived from multiple sources, including the analysis of historical man-hour data and construction costs for similar activities, budgetary quotes from suppliers for necessary materials, equipment, and services, and analogous cost estimates from similar projects within NYSEG. Additionally, appropriate project support costs and applicable overheads and allocations are considered. Project estimates are routinely reviewed and updated as the project progresses, and more detailed information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 1,343	\$ 13	\$ 202	\$ 445	\$ 674	\$ 9	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 3,379	\$ 33	\$ 495	\$ 1,090	\$ 1,652	\$ 109	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 377	\$ 3	\$ 50	\$ 111	\$ 168	\$ 45	\$ -	\$ -
# Internal, Overheads	\$ 1,078	\$ 11	\$ 203	\$ 352	\$ 500	\$ 11	\$ -	\$ -
# Materials	\$ 8,829	\$ 89	\$ 1,338	\$ 2,943	\$ 4,459	\$ -	\$ -	\$ -
# Overheads - External	\$ 1,073	\$ 15	\$ 200	\$ 347	\$ 493	\$ 19	\$ -	\$ -
Total	\$ 16,080	\$ 165	\$ 2,489	\$ 5,288	\$ 7,946	\$ 193	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG RESILIENCY 2027 - LYON MTN 510

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006425	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Resiliency	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

Background: NYSEG implemented the Resiliency Program to deploy investments in its transmission and distribution systems designed to reduce the frequency and impact of outages from severe weather and major storms. Improving grid resiliency is critical for maintaining safe, reliable electricity service for our customers and communities, particularly in response to growing risks from climate change. The primary objectives of investments under the Resiliency Program are to (1) prevent and limit the scope and impact of outages and (2) increase our ability to quickly restore power after a significant outage.

Projects included in the Resiliency Program generally deploy one or more of the following strategies to improve circuit resiliency:

1. Circuit Ties and Automation: Create connections between adjacent circuits ("circuit ties") to provide an N-1 backup power source during outages and use automation technology to operate these circuit ties without sending electrical workers into the field.
2. Infrastructure Hardening: Utilize Avangrid's Distribution Resiliency Guide to apply stronger designs and infrastructure standards to damage-susceptible circuits, reducing the frequency and impact of outages.
3. Enhanced Vegetation Management (EVM): Implement Enhanced Vegetation Management techniques, such as ground-to-sky clearing, to reduce the probability of tree-related outages along targeted line sections.

Project Justification: NYSEG prioritizes resiliency investments based on a three-year ranking from customer count outages, including storms. Lyon Mountain circuit #510 has been identified as a priority for resiliency improvements and is ranked number 34 on NYSEG's resiliency prioritization list of circuits with poor reliability between 2020 and 2022. When excluding circuits for which resiliency projects are in-service or being executed, Lyon Mountain circuit #510 is ranked number 6.

Project Scope:

Lyon Mountain Circuit #510 has been identified as a priority for the Resiliency Program in 2027, but further analysis is required to determine the specific scope of work. NYSEG Distribution Planners will initiate a needs assessment and develop solution alternatives for resiliency improvements on Lyon Mountain circuit #510 in 2025.

The developed project will seek to reduce total SAIFI and SAIDI contributions by implementing solutions such as:

- The application of animal guards.
- Replacement of susceptible equipment with more resilient designs according to Avangrid's Distribution Resiliency Guide (e.g., stronger poles, covered wire).
- Enhanced vegetation management, including hazard tree removal (as appropriate).
- Distribution automation and topology changes that enable circuit reconfiguration and power rerouting. Upgrades to adjacent circuits may be required to allow for sufficiently robust circuit ties to be formed.

Based on historical reliability data, Circuit Lyon Mtn 510 has been analyzed, and several upgrades are recommended to chance the performance and reliability. The proposed upgrades include replacing 11.9miles of existing undersized 3 phase overhead conductor, consisting of 4/0AL and 1/0AL, and replacing with 3 phase, 477AL overhead wire for all mainline. This will improve voltage and thermal violations, increase existing fault current limitations, increase circuit capacity, and improve n-1 performance in the event of a fault. Additionally, Reprogram (4) existing SCADA Devices from switch mode to recloser mode. Lastly, trim trees on all mainline and install tree wire where outages are condensed due to transient faults due to trees and relocate line to roadside from backlot if deemed necessary pending field review.

Based on the characteristics of Lyon Mountain circuit #510 and the cost and scope of previous Resiliency Program projects, NYSEG has estimated a preliminary budget of \$15.0 million. The expected project in-service date is Q4 2027.

Project Benefits:

The Lyon Mountain Circuit #510 Resiliency Project will improve system SAIFI by limiting the scope and impact of outages. The specific scope of work is pending distribution planning analysis, but it is expected that the project will reduce outage duration and frequency by replacing inadequate or aging poles, installing tree wire, and performing targeted enhanced "ground-to-sky" clearance of vegetation.

Project Risks and Mitigation Plan:

1. Delays in Project Implementation: Project delays could lead to an increase in customer outages, resulting in worsening reliability performance. The project schedule could be impacted by field conditions, particularly in heavily wooded or environmentally sensitive areas, where it can be difficult to access infrastructure with heavy equipment. Weather delays are also a risk in distribution construction due to worker safety concerns. These risks will be addressed by incorporating contingency into our construction schedules. Long lead-time equipment delays can also adversely impact project schedules. Equipment sourcing risks will be mitigated by identifying proposed equipment subject to long lead times and ordering such equipment proactively, as appropriate, to minimize the risk of project delays.

2. Scope Uncertainty: Lyon Mountain Circuit #510 has not yet been fully assessed, and the scope of the resiliency project has not yet been defined in detail. There is a possibility that the cost of the project could deviate from the preliminary estimate if the required scope of work, determined following thorough analysis, differs from current expectations. This risk will be mitigated by re-evaluating the project and its relative priority with respect to other candidate circuits for resiliency investments once the full scope of work and associated cost estimates have been determined.

3. Circuit Reprioritization: Lyon Mountain Circuit #510 is currently ranked #34 based on the 2020-2022 customer count, including storms. Based on new outage data in preparation for the 2027 Resiliency Program, there may be different circuits that contribute to worse reliability than Lyon Mountain Circuit #510, thus changing the priority of which circuit will be studied for the 2027 year. In this case, the new worst-performing circuits will be scoped and evaluated in the same manner as Lyon Mountain Circuit #510, as stated in the Project Scope.

4. Property Owner Opposition: Customers with property abutting electric infrastructure may oppose aspects of the project, such as infrastructure relocation or vegetation trimming/clearing. In certain circumstances, failure to perform proposed work that is opposed by property owners can negatively affect the efficacy of resiliency projects. To mitigate this risk, NYSEG will proactively engage in outreach to abutting property owners to notify them of the proposed work. If concerns are raised, NYSEG will engage in a dialogue to determine what accommodations can reasonably be made and to emphasize the benefits of the project to the community. If work cannot proceed as planned due to opposition from a property owner, the scope of work will be re-evaluated.

Risk of No Action:

The area is currently facing multiple reliability challenges, including tree-related outages and N-1 reliability deficiencies, as Lyon Mountain #510 shares an existing tie with Chateaugay #514. Both are 34.5kV distribution circuits with the ability to back-feed for customer restoration. Opting to take no action on this circuit would result in a continued elevated risk of weather-related customer outages and damage to utility facilities. Outages involving utility equipment that is damaged or destroyed by weather-initiated incidents, such as falling trees, are generally more costly and take longer for the utility to restore, negatively impacting both the cost and quality of service for customers. Weather-related outages, particularly those resulting from damaging storms, can have a significant negative impact on our customers, especially in instances where power outages extend over multiple days.

Project Alternatives:

Lyon Mountain circuit #510 will be evaluated for alternative solutions when the circuit is assessed in 2025. Project alternatives may seek to include additional project scope beyond purely resiliency-oriented upgrades where justified and supported. Such additional scope may include addressing needs such as improving power quality, replacing overloaded equipment, or replacing aging infrastructure. Project alternatives may also consider solutions such as selective undergrounding, where appropriate and cost-efficient.

Basis for Project Estimates

The cost estimate for this project was based on the characteristics of Lyon Mountain circuit #510 and the cost of previous Resiliency Program projects. The estimate will be updated and refined as more information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 150	\$ -	\$ -	\$ -	\$ 31	\$ 89	\$ 29	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 7,931	\$ -	\$ -	\$ -	\$ 1,631	\$ 4,737	\$ 1,563	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 948	\$ -	\$ -	\$ -	\$ 195	\$ 555	\$ 199	\$ -
# Materials	\$ 4,938	\$ -	\$ -	\$ -	\$ 1,015	\$ 2,950	\$ 973	\$ -
# Overheads - External	\$ 925	\$ -	\$ -	\$ -	\$ 190	\$ 541	\$ 194	\$ -
Total	\$ 14,893	\$ -	\$ -	\$ -	\$ 3,062	\$ 8,872	\$ 2,959	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ 377	\$ -	\$ -	\$ -	\$ 123	\$ 126	\$ 128	\$ -

NYSEG RESILIENCY 2027 - GOLDEN BRIDGE 418

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006426	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Resiliency	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

Background: NYSEG implemented the Resiliency Program to deploy investments in its transmission and distribution systems designed to reduce the frequency and impact of outages from severe weather and major storms. Improving grid resiliency is critical for maintaining safe, reliable electricity service for our customers and communities, particularly in response to growing risks from climate change. The primary objectives of investments under the Resiliency Program are to (1) prevent and limit the scope and impact of outages and (2) increase our ability to quickly restore power after a significant outage.

Projects included in the Resiliency Program generally deploy one or more of the following strategies to improve circuit resiliency:

1. Circuit Ties and Automation: Create connections between adjacent circuits ("circuit ties") to provide an N-1 backup power source during outages and use automation technology to operate these circuit ties without sending electrical workers into the field.
2. Infrastructure Hardening: Utilize Avangrid's Distribution Resiliency Guide to apply stronger designs and infrastructure standards to damage-susceptible circuits, reducing the frequency and impact of outages.
3. Enhanced Vegetation Management (EVM): Implement Enhanced Vegetation Management techniques, such as ground-to-sky clearing, to reduce the probability of tree-related outages along targeted line sections.

Project Justification: NYSEG prioritizes resiliency investments based on a three-year ranking from customer count outages, including storms. Golden Bridge Circuit #418 has been identified as a priority for resiliency improvements and is ranked number 115 on NYSEG's resiliency prioritization list of circuits with poor reliability between 2020 and 2022. When excluding circuits for which resiliency projects are in-service or being executed, Golden Bridge Circuit #418 is ranked number 18.

Project Scope:

Golden Bridge Circuit #418 has been identified as a priority for the Resiliency Program in 2027, but further analysis is required to identify the specific scope of work. NYSEG Distribution Planners will initiate a needs assessment and develop solution alternatives for resiliency improvements on Golden Bridge Circuit #418 in 2025.

The developed project will seek to reduce total SAIFI and SAIDI contributions by implementing solutions such as:

- The application of animal guards
- Replacement of susceptible equipment with more resilient designs according to Avangrid's Distribution Resiliency Guide (e.g., stronger poles, covered wire)
- Enhanced vegetation management, including hazard tree removal (as appropriate)
- Distribution automation and topology changes that enable circuit reconfiguration and power rerouting. Upgrades to adjacent circuits may be required to allow for sufficiently robust circuit ties to be formed.

Based on historical reliability data, Circuit Golden Bridge 418 has been analyzed, and several upgrades are recommended to chance the performance and reliability. The proposed upgrades include replacing 1.3miles of existing undersized 3 phase overhead conductor, consisting of 4/0AL and 1/0AL, and replacing with 3 phase, 477AL overhead wire for all mainline. This will improve voltage and thermal violations, increase existing fault current limitations, increase circuit capacity, and improve n-1 performance in the event of a fault. Lastly, trim trees on all mainline and install tree wire where outages are condensed due to transient faults due to trees and relocate line to roadside from backlot if deemed necessary pending field review.

Based on the characteristics of Golden Bridge Circuit #418 and the cost and scope of previous Resiliency Program projects, NYSEG has estimated a preliminary budget of \$1.8 million. The expected project in-service date is Q4 2027.

Project Benefits:

The Golden Bridge Circuit #418 Resiliency Project will improve system SAIFI by limiting the scope and impact of outages. The specific scope of work is pending distribution planning analysis, but it is expected that the project will reduce outage duration and frequency by replacing inadequate or aging poles, installing tree wire, and performing targeted enhanced "ground-to-sky" clearance of vegetation.

Project Risks and Mitigation Plan:

1. Delays in Project Implementation: Project delays could lead to an increase in customer outages, resulting in worsening reliability performance. The project schedule could be impacted by field conditions, particularly in heavily wooded or environmentally sensitive areas, where it can be difficult to access infrastructure with heavy equipment. Weather delays are also a risk in distribution construction due to worker safety concerns. These risks will be addressed by incorporating contingency into our construction schedules. Long lead-time equipment delays can also adversely impact project schedules. Equipment sourcing risks will be mitigated by identifying proposed equipment subject to long lead times and ordering such equipment proactively, as appropriate, to minimize the risk of project delays.

2. Scope Uncertainty: Golden Bridge Circuit #418 has not yet been fully assessed, and the scope of the resiliency project has not yet been defined in detail. There is a possibility that the cost of the project could deviate from the preliminary estimate if the required scope of work, determined following thorough analysis, differs from current expectations. This risk will be mitigated by re-evaluating the project and its relative priority with respect to other candidate circuits for resiliency investments once the full scope of work and associated cost estimates have been determined.

3. Circuit Reprioritization: Golden Bridge Circuit #418 is currently ranked #115 based on the 2020-2022 customer count, including storms. Based on new outage data in preparation for the 2027 Resiliency Program, there may be different circuits that contribute to worse reliability than Golden Bridge Circuit #418, thus changing the priority of which circuit will be studied for the 2027 year. In this case, the new worst-performing circuits will be scoped and evaluated in the same manner as Golden Bridge Circuit #418, as stated in the Project Scope.

4. Property Owner Opposition: Customers with property abutting electric infrastructure may oppose aspects of the project, such as infrastructure relocation or vegetation trimming/clearing. In certain circumstances, failure to perform proposed work that is opposed by property owners can negatively affect the efficacy of resiliency projects. To mitigate this risk, NYSEG will proactively engage in outreach to abutting property owners to notify them of the proposed work. If concerns are raised, NYSEG will engage in a dialogue to determine what accommodations can reasonably be made and to emphasize the benefits of the project to the community. If work cannot proceed as planned due to opposition from a property owner, the scope of work will be re-evaluated.

Risk of No Action:

The area is currently facing multiple reliability challenges, including tree-related outages and N-1 reliability deficiencies, as Golden Bridge Circuit #418 shares an existing tie with Golden Bridge #417, Golden Bridge #420, Golden Bridge #421, and Teakettle Spout #490. These are all 13.2kV distribution circuits with the ability to back-feed for customer restoration. Opting to take no action on this circuit would result in a continued elevated risk of weather-related customer outages and damage to utility facilities. Outages involving utility equipment that is damaged or destroyed by weather-initiated incidents, such as falling trees, are generally more costly and take longer for the utility to restore, negatively impacting both the cost and quality of service for customers. Weather-related outages, particularly those resulting from damaging storms, can have a significant negative impact on our customers, especially in instances where power outages extend over multiple days.

Project Alternatives:

Golden Bridge Circuit #418 will be evaluated for alternative solutions when the circuit is assessed in 2025. Project alternatives may seek to include additional project scope beyond purely resiliency-oriented upgrades where justified and supported. Such additional scope may include addressing needs such as, but not limited to, improving power quality, replacing overloaded equipment, or replacing aging infrastructure. Project alternatives may also include the consideration of solutions such as selective undergrounding, where appropriate and cost-efficient.

Basis for Project Estimates

The cost estimate for this project was based on the characteristics of Golden Bridge Circuit #418 and the cost of previous Resiliency Program projects. The estimate will be updated and refined as more information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 18	\$ -	\$ -	\$ -	\$ 3	\$ 11	\$ 4	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 937	\$ -	\$ -	\$ -	\$ 183	\$ 563	\$ 191	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 112	\$ -	\$ -	\$ -	\$ 22	\$ 66	\$ 24	\$ -
# Materials	\$ 583	\$ -	\$ -	\$ -	\$ 114	\$ 351	\$ 119	\$ -
# Overheads - External	\$ 109	\$ -	\$ -	\$ -	\$ 21	\$ 64	\$ 24	\$ -
Total	\$ 1,759	\$ -	\$ -	\$ -	\$ 343	\$ 1,055	\$ 361	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ 42	\$ -	\$ -	\$ -	\$ 14	\$ 14	\$ 14	\$ -

NYSEG RESILIENCY 2027 - CROSS RIVER 469

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006427	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Resiliency	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

Background: NYSEG implemented the Resiliency Program to deploy investments in its transmission and distribution systems designed to reduce the frequency and impact of outages from severe weather and major storms. Improving grid resiliency is critical for maintaining safe, reliable electricity service for our customers and communities, particularly in response to growing risks from climate change. The primary objectives of investments under the Resiliency Program are to (1) prevent and limit the scope and impact of outages and (2) increase our ability to quickly restore power after a significant outage.

Projects included in the Resiliency Program generally deploy one or more of the following strategies to improve circuit resiliency:

1. Circuit Ties and Automation: Create connections between adjacent circuits ("circuit ties") to provide an N-1 backup power source during outages and use automation technology to operate these circuit ties without sending electrical workers into the field.
2. Infrastructure Hardening: Utilize Avangrid's Distribution Resiliency Guide to apply stronger designs and infrastructure standards to damage-susceptible circuits, reducing the frequency and impact of outages.
3. Enhanced Vegetation Management (EVM): Implement Enhanced Vegetation Management techniques, such as ground-to-sky clearing, to reduce the probability of tree-related outages along targeted line sections.

Project Justification: NYSEG prioritizes resiliency investments based on a three-year ranking from customer count outages, including storms. Cross River Circuit #469 has been identified as a priority for resiliency improvements and is ranked number 137 on NYSEG's resiliency prioritization list of circuits with poor reliability between 2020 and 2022. When excluding circuits for which resiliency projects are in-service or being executed, Cross River Circuit #469 is ranked number 22.

Project Scope:

Cross River Circuit #469 has been identified as a priority for the Resiliency Program in 2027, but further analysis is required to determine the specific scope of work. NYSEG Distribution Planners will initiate a needs assessment and develop solution alternatives for resiliency improvements on Cross River Circuit #469 in 2025.

The developed project will seek to reduce total SAIFI and SAIDI contributions by implementing solutions such as:

- The application of animal guards.
- Replacement of susceptible equipment with more resilient designs according to Avangrid's Distribution Resiliency Guide (e.g., stronger poles, covered wire).
- Enhanced vegetation management, including hazard tree removal (as appropriate).
- Distribution automation and topology changes that enable circuit reconfiguration and power rerouting. Upgrades to adjacent circuits may be required to allow for sufficiently robust circuit ties to be formed.

Based on historical reliability data, Circuit Cross River 469 has been analyzed, and several upgrades are recommended to chance the performance and reliability. The proposed upgrades include replacing 6miles of existing undersized 3 phase overhead conductor, consisting of 4/0AL and 1/0AL, and replacing with 3 phase, 477AL overhead wire for all mainline. This will improve voltage and thermal violations, increase existing fault current limitations, increase circuit capacity, and improve N-1 performance in the event of a fault. Additionally, install (1) N.C. SCADA Recloser to make use of existing circuit tie with Pound Ridge 436. Install (1) N.C. SCADA Recloser to replace existing SCADA Device. Install (1) N.C. SCADA Recloser due to multiple outages due to trees on an existing zone due to the existing scheme, would render the other zones of protection useless. Lastly, trim trees on all mainline and install tree wire where outages are condensed due to transient faults due to trees and relocate line to roadside from backlot if deemed necessary pending field review.

Based on the characteristics of Cross River Circuit #469 and the cost and scope of previous Resiliency Program projects, NYSEG has estimated a preliminary budget of \$8.0 million. The expected project in-service date is Q4 2027.

Project Benefits:

The Cross River Circuit #469 Resiliency Project aims to improve system SAIFI by limiting the scope and impact of outages. While the specific scope of work is pending distribution planning analysis, it is anticipated that the project will reduce outage duration and frequency by replacing inadequate or aging poles, installing tree wire, and performing targeted enhanced "ground-to-sky" clearance of vegetation.

Project Risks and Mitigation Plan:

1. Delays in Project Implementation: Project delays could lead to an increase in customer outages, resulting in worsening reliability performance. The project schedule could be impacted by field conditions, particularly in heavily wooded or environmentally sensitive areas, where it can be difficult to access infrastructure with heavy equipment. Weather delays are also a risk in distribution construction due to worker safety concerns. These risks will be addressed by incorporating contingency into our construction schedules. Long lead-time equipment delays can also adversely impact project schedules. Equipment sourcing risks will be mitigated by identifying proposed equipment subject to long lead times and ordering such equipment proactively, as appropriate, to minimize the risk of project delays.

2. Scope Uncertainty: Cross River Circuit #469 has not yet been fully assessed, and the scope of the resiliency project has not yet been defined in detail. There is a possibility that the cost of the project could deviate from the preliminary estimate if the required scope of work, determined following thorough analysis, differs from current expectations. This risk will be mitigated by re-evaluating the project and its relative priority with respect to other candidate circuits for resiliency investments once the full scope of work and associated cost estimates have been determined.

3. Circuit Reprioritization: Cross River Circuit #469 is currently ranked #137 based on the 2020-2022 customer count, including storms. Based on new outage data in preparation for the 2027 Resiliency Program, there may be different circuits that contribute to worse reliability than Cross River Circuit #469, thus changing the priority of which circuit will be studied for the 2027 year. In this case, the new worst-performing circuits will be scoped and evaluated in the same manner as Cross River Circuit #469, as stated in the Project Scope.

4. Property Owner Opposition: Customers with property abutting electric infrastructure may oppose aspects of the project, such as infrastructure relocation or vegetation trimming/clearing. In certain circumstances, failure to perform proposed work that is opposed by property owners can negatively affect the efficacy of resiliency projects. To mitigate this risk, NYSEG will proactively engage in outreach to abutting property owners to notify them of the proposed work. If concerns are raised, NYSEG will engage in a dialogue to determine what accommodations can reasonably be made and to emphasize the benefits of the project to the community. If work cannot proceed as planned due to opposition from a property owner, the scope of work will be re-evaluated.

Risk of No Action:

The area is currently facing multiple reliability challenges, including tree-related outages and N-1 reliability deficiencies, as Cross River Circuit #469 shares an existing tie with Cross River #468 and Pound Ridge #436. Both are 13.2kV distribution circuits with the ability to back-feed for customer restoration. Opting to take no action on this circuit would result in a continued elevated risk of weather-related customer outages and damage to utility facilities. Outages involving utility equipment that is damaged or destroyed by weather-initiated incidents, such as falling trees, are generally more costly and take longer for the utility to restore, negatively impacting both the cost and quality of service for customers. Weather-related outages, particularly those resulting from damaging storms, can have a significant negative impact on our customers, especially in instances where power outages extend over multiple days.

Project Alternatives:

Cross River Circuit #469 will be evaluated for alternative solutions when the circuit is assessed in 2025. Project alternatives may seek to include additional project scope beyond purely resiliency-oriented upgrades where justified and supported. Such additional scope may address needs such as improving power quality, replacing overloaded equipment, or replacing aging infrastructure. Project alternatives may also consider solutions such as selective undergrounding, where appropriate and cost-efficient.

Basis for Project Estimates

The cost estimate for this project was based on the characteristics of Cross River Circuit #469 and the costs of previous Resiliency Program projects. The estimate will be updated and refined as more information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 80	\$ -	\$ -	\$ -	\$ 18	\$ 47	\$ 15	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 4,243	\$ -	\$ -	\$ -	\$ 931	\$ 2,492	\$ 820	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 507	\$ -	\$ -	\$ -	\$ 111	\$ 292	\$ 104	\$ -
# Materials	\$ 2,642	\$ -	\$ -	\$ -	\$ 580	\$ 1,551	\$ 511	\$ -
# Overheads - External	\$ 495	\$ -	\$ -	\$ -	\$ 108	\$ 285	\$ 102	\$ -
Total	\$ 7,967	\$ -	\$ -	\$ -	\$ 1,748	\$ 4,667	\$ 1,552	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ 215	\$ -	\$ -	\$ -	\$ 70	\$ 72	\$ 73	\$ -

NYSEG RESILIENCY 2027 - MILFORD 227

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006428	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Resiliency	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2027

Project description:

Background: NYSEG implemented the Resiliency Program to deploy investments in its transmission and distribution systems designed to reduce the frequency and impact of outages from severe weather and major storms. Improving grid resiliency is critical for maintaining safe, reliable electricity service for our customers and communities, particularly in response to growing risks from climate change. The primary objectives of investments under the Resiliency Program are to (1) prevent and limit the scope and impact of outages and (2) increase our ability to quickly restore power after a significant outage.

Projects included in the Resiliency Program generally deploy one or more of the following strategies to improve circuit resiliency:

1. Circuit Ties and Automation: Create connections between adjacent circuits ("circuit ties") to provide an N-1 backup power source during outages and use automation technology to operate these circuit ties without sending electrical workers into the field.
2. Infrastructure Hardening: Utilize Avangrid's Distribution Resiliency Guide to apply stronger designs and infrastructure standards to damage-susceptible circuits, reducing the frequency and impact of outages.
3. Enhanced Vegetation Management (EVM): Implement Enhanced Vegetation Management techniques, such as ground-to-sky clearing, to reduce the probability of tree-related outages along targeted line sections.

Project Justification: NYSEG prioritizes resiliency investments based on a three-year ranking from customer count outages, including storms. Milford Circuit #227 has been identified as a priority for resiliency improvements and is ranked number 296 on NYSEG's resiliency prioritization list of circuits with poor reliability between 2020 and 2022. When excluding circuits for which resiliency projects are in-service or being executed, Milford Circuit #227 is ranked number 35.

Project Scope:

Milford Circuit #227 has been identified as a priority for the Resiliency Program in 2027, but further analysis is required to identify the specific scope of work. NYSEG Distribution Planners will initiate a needs assessment and develop solution alternatives for resiliency improvements on Milford Circuit #227 in 2025.

The developed project will seek to reduce total SAIFI and SAIDI contributions by implementing solutions such as:

- The application of animal guards
- Replacement of susceptible equipment with more resilient designs according to Avangrid's Distribution Resiliency Guide (e.g., stronger poles, covered wire)
- Enhanced vegetation management, including hazard tree removal (as appropriate)
- Distribution automation and topology changes that enable circuit reconfiguration and power rerouting. Upgrades to adjacent circuits may be required to allow for sufficiently robust circuit ties to be formed.

Based on historical reliability data, Circuit Milford 227 has been analyzed, and several upgrades are recommended to improve the performance and reliability. The proposed upgrades include replacing 17.3miles of existing undersized 3 phase overhead conductor, consisting of 4/OAL and 1/OAL, and replacing with 3 phase, 477AL overhead wire for all mainline. This will improve voltage and thermal violations, increase existing fault current limitations, and increase circuit capacity. Lastly, trim trees on all mainline and install tree wire where outages are condensed due to transient faults due to trees and relocate line to roadside from backlot if deemed necessary pending field review.

Project Benefits:

Milford Circuit #227 Resiliency Project will improve system SAIFI by limiting the scope and impact of outages. The specific scope of work is pending distribution planning analysis but it is expected that the project will reduce outage duration and frequency by replacing inadequate or aging poles, installing tree wire, and performing targeted enhanced "ground-to-sky" clearance of vegetation.

Project Risks and Mitigation Plan:

1. Delays in Project Implementation: Project delays could lead to an increase in customer outages, resulting in worsening reliability performance. The project schedule could be impacted by field conditions, particularly in heavily wooded or environmentally sensitive areas, where it can be difficult to access infrastructure with heavy equipment. Weather delays are also a risk in distribution construction due to worker safety concerns. These risks will be addressed by incorporating contingency into our construction schedules. Long lead-time equipment delays can also adversely impact project schedules. Equipment sourcing risks will be mitigated by identifying proposed equipment subject to long lead times and ordering such equipment proactively, as appropriate, to minimize the risk of project delays.

2. Scope Uncertainty: Milford Circuit #227 has not yet been fully assessed, and the scope of the resiliency project has not yet been defined in detail. There is a possibility that the cost of the project could deviate from the preliminary estimate if the required scope of work, determined following thorough analysis, differs from current expectations. This risk will be mitigated by re-evaluating the project and its relative priority with respect to other candidate circuits for resiliency investments once the full scope of work and associated cost estimates have been determined.

3. Circuit Reprioritization: Milford Circuit #227 is currently ranked #34 based on the 2020-2022 customer count, including storms. Based on new outage data in preparation for the 2027 Resiliency Program, there may be different circuits that contribute to worse reliability than Milford Circuit #227, thus changing the priority of which circuit will be studied for the 2027 year. In this case, the new worst-performing circuits will be scoped and evaluated in the same manner as Milford Circuit #227, as stated in the Project Scope.

4. Property Owner Opposition: Customers with property abutting electric infrastructure may oppose aspects of the project, such as infrastructure relocation or vegetation trimming/clearing. In certain circumstances, failure to perform proposed work that is opposed by property owners can negatively affect the efficacy of resiliency projects. To mitigate this risk, NYSEG will proactively engage in outreach to abutting property owners to notify them of the proposed work. If concerns are raised, NYSEG will engage in a dialogue to determine what accommodations can reasonably be made and to emphasize the benefits of the project to the community. If work cannot proceed as planned due to opposition from a property owner, the scope of work will be re-evaluated.

Risk of No Action:

The area is currently facing multiple reliability challenges, including tree-related outages and but zero N-1 reliability deficiencies, as Milford Circuit #227 shares zero existing ties with any distribution circuits. Opting to take no action on this circuit would result in a continued elevated risk of weather-related customer outages and damage to utility facilities. Outages involving utility equipment that is damaged or destroyed by weather-initiated incidents, such as falling trees, are generally more costly and take longer for the utility to restore, negatively impacting both the cost and quality of service for customers. Weather-related outages, particularly those resulting from damaging storms, can have a significant negative impact on our customers, especially in instances where power outages extend over multiple days.

Project Alternatives:

Milford Circuit #227 will be evaluated for alternative solutions when the circuit is evaluated in 2025. Project alternatives may seek to include additional project scope beyond purely resiliency-oriented upgrades where it is justified and supported. Such additional scope may include addressing needs such as, but not limited to, improving power quality, replacing overloaded equipment, or replacing aging infrastructure. Project alternative may also include the consideration of solutions such as selective undergrounding, where appropriate and cost-efficient.

Basis for Project Estimates

The cost estimate for this project was based on the characteristics of Milford Circuit #227 and the cost of previous Resiliency Program projects. The estimate will be updated and refined as more information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 202	\$ -	\$ -	\$ 35	\$ 125	\$ 42	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 10,726	\$ -	\$ -	\$ 1,876	\$ 6,645	\$ 2,204	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 1,290	\$ -	\$ -	\$ 239	\$ 793	\$ 258	\$ -	\$ -
# Materials	\$ 6,678	\$ -	\$ -	\$ 1,168	\$ 4,138	\$ 1,373	\$ -	\$ -
# Overheads - External	\$ 1,259	\$ -	\$ -	\$ 233	\$ 774	\$ 252	\$ -	\$ -
Total	\$ 20,155	\$ -	\$ -	\$ 3,551	\$ 12,475	\$ 4,129	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ 1,678	\$ -	\$ -	\$ 142	\$ 502	\$ 512	\$ 523	\$ -

NYSEG RESILIENCY 2027 - WALES CENTER 326

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006430	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Resiliency	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2028

Project description:

Background: NYSEG implemented the Resiliency Program to deploy investments in its transmission and distribution systems designed to reduce the frequency and impact of outages from severe weather and major storms. Improving grid resiliency is critical for maintaining safe, reliable electricity service for our customers and communities, particularly in response to growing risks from climate change. The primary objectives of investments under the Resiliency Program are to (1) prevent and limit the scope and impact of outages and (2) increase our ability to quickly restore power after a significant outage.

Projects included in the Resiliency Program generally deploy one or more of the following strategies to improve circuit resiliency:

1. Circuit Ties and Automation: Create connections between adjacent circuits ("circuit ties") to provide an N-1 backup power source during outages and use automation technology to operate these circuit ties without sending electrical workers into the field.
2. Infrastructure Hardening: Utilize Avangrid's Distribution Resiliency Guide to apply stronger designs and infrastructure standards to damage-susceptible circuits, reducing the frequency and impact of outages.
3. Enhanced Vegetation Management (EVM): Implement Enhanced Vegetation Management techniques, such as ground-to-sky clearing, to reduce the probability of tree-related outages along targeted line sections.

Project Justification: NYSEG prioritizes resiliency investments based on a three-year ranking from customer count outages, including storms. Wales Ctr Circuit #326 has been identified as a priority for resiliency improvements and is ranked number 673 on NYSEG's resiliency prioritization list of circuits with poor reliability between 2020 and 2022. When excluding circuits for which resiliency projects are in-service or being executed, Wales Ctr Circuit #326 is ranked number 44.

Project Scope:

Wales Ctr Circuit #326 has been identified as a priority for the Resiliency Program in 2027, but further analysis is required to identify the specific scope of work. NYSEG Distribution Planners will initiate a needs assessment and develop solution alternatives for resiliency improvements on Wales Ctr Circuit #326 in 2025.

The developed project will seek to reduce total SAIFI and SAIDI contributions by implementing solutions such as:

- The application of animal guards
- Replacement of susceptible equipment with more resilient designs according to Avangrid's Distribution Resiliency Guide (e.g., stronger poles, covered wire)
- Enhanced vegetation management, including hazard tree removal (as appropriate)
- Distribution automation and topology changes that enable circuit reconfiguration and power rerouting. Upgrades to adjacent circuits may be required to allow for sufficiently robust circuit ties to be formed.

Based on historical reliability data, Circuit Wales Center 326 has been analyzed, and several upgrades are recommended to chance the performance and reliability. The proposed upgrades include replacing 7.9mi of existing undersized 3 phase overhead conductor, consisting of 4/0AL and 1/0AL, and replacing with 3 phase, 477AL overhead wire for all mainline. This will improve voltage and thermal violations, increase existing fault current limitations, increase circuit capacity, and improve n-1 performance in the event of a fault. There are no SCADA Devices on this circuit and can create circuit ties with (3) circuits, yielding (4) tie points. So, install (4) N.O. SCADA Switches to crease circuit ties with Java 281, West Varysburgh 355, and (2) with Wales Center 325. Install (3) N.C. SCADA Reclosers to make use of these new circuit ties. Lastly, trim trees on all mainline and install tree wire where outages are condensed due to transient faults due to trees and relocate line to roadside from backlot if deemed necessary pending field review.

Project Benefits:

The Wales Ctr Circuit #326 Resiliency Project will improve system SAIFI by limiting the scope and impact of outages. The specific scope of work is pending distribution planning analysis, but it is expected that the project will reduce outage duration and frequency by replacing inadequate or aging poles, installing tree wire, and performing targeted enhanced "ground-to-sky" clearance of vegetation.

Project Risks and Mitigation Plan:

1. Delays in Project Implementation: Project delays could lead to an increase in customer outages, resulting in worsening reliability performance. The project schedule could be impacted by field conditions, particularly in heavily wooded or environmentally sensitive areas, where it can be difficult to access infrastructure with heavy equipment. Weather delays are also a risk in distribution construction due to worker safety concerns. These risks will be addressed by incorporating contingency into our construction schedules. Long lead-time equipment delays can also adversely impact project schedules. Equipment sourcing risks will be mitigated by identifying proposed equipment subject to long lead times and ordering such equipment proactively, as appropriate, to minimize the risk of project delays.

2. Scope Uncertainty: Wales Ctr Circuit #326 has not yet been fully assessed, and the scope of the resiliency project has not yet been defined in detail. There is a possibility that the cost of the project could deviate from the preliminary estimate if the required scope of work, determined following thorough analysis, differs from current expectations. This risk will be mitigated by re-evaluating the project and its relative priority with respect to other candidate circuits for resiliency investments once the full scope of work and associated cost estimates have been determined.

3. Circuit Reprioritization: Wales Ctr Circuit #326 is currently ranked #673 based on the 2020-2022 customer count, including storms. Based on new outage data in preparation for the 2027 Resiliency Program, there may be different circuits that contribute to worse reliability than Wales Ctr Circuit #326, thus changing the priority of which circuit will be studied for the 2027 year. In this case, the new worst-performing circuits will be scoped and evaluated in the same manner as Wales Ctr Circuit #326, as stated in the Project Scope.

4. Property Owner Opposition: Customers with property abutting electric infrastructure may oppose aspects of the project, such as infrastructure relocation or vegetation trimming/clearing. In certain circumstances, failure to perform proposed work that is opposed by property owners can negatively affect the efficacy of resiliency projects. To mitigate this risk, NYSEG will proactively engage in outreach to abutting property owners to notify them of the proposed work. If concerns are raised, NYSEG will engage in a dialogue to determine what accommodations can reasonably be made and to emphasize the benefits of the project to the community. If work cannot proceed as planned due to opposition from a property owner, the scope of work will be re-evaluated.

Risk of No Action:

The area is currently facing multiple reliability challenges, including tree-related outages and N-1 reliability deficiencies, as Wales Ctr Circuit #326 shares existing ties with West Varysburgh #355 and Wales Ctr #325, both of which share a 4.8kV tie. While West Varysburgh #355 is a native 12.5kV circuit, it has a 500kVA step transformer that steps voltages from 12.5kV to 4.8kV, allowing West Varysburgh #355 to back-feed Wales Ctr #326 for customer restoration. Opting to take no action on this circuit would result in a continued elevated risk of weather-related customer outages and damage to utility facilities. Outages involving utility equipment that is damaged or destroyed by weather-initiated incidents, such as falling trees, are generally more costly and take longer for the utility to restore, negatively impacting both the cost and quality of service for customers. Weather-related outages, particularly those resulting from damaging storms, can have a significant negative impact on our customers, especially in instances where power outages extend over multiple days.

Project Alternatives:

Wales Ctr Circuit #326 will be evaluated for alternative solutions when the circuit is assessed in 2025. Project alternatives may seek to include additional project scope beyond purely resiliency-oriented upgrades where justified and supported. Such additional scope may include addressing needs such as, but not limited to, improving power quality, replacing overloaded equipment, or replacing aging infrastructure. Project alternatives may also include the consideration of solutions such as selective undergrounding, where appropriate and cost-efficient.

Basis for Project Estimates

The cost estimate for this project was based on the characteristics of Wales Ctr Circuit #326 and the cost of previous Resiliency Program projects. The estimate will be updated and refined as more information becomes available.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 109	\$ -	\$ -	\$ -	\$ 24	\$ 64	\$ 21	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 5,754	\$ -	\$ -	\$ -	\$ 1,247	\$ 3,398	\$ 1,109	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 688	\$ -	\$ -	\$ -	\$ 149	\$ 398	\$ 141	\$ -
# Materials	\$ 3,582	\$ -	\$ -	\$ -	\$ 776	\$ 2,116	\$ 690	\$ -
# Overheads - External	\$ 671	\$ -	\$ -	\$ -	\$ 145	\$ 388	\$ 138	\$ -
Total	\$ 10,803	\$ -	\$ -	\$ -	\$ 2,341	\$ 6,364	\$ 2,098	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ 288	\$ -	\$ -	\$ -	\$ 94	\$ 96	\$ 98	\$ -

NYSEG Resiliency Cemetery Rd 490/ North Broadway 535

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006734	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Digital Grid	Rate Case Category Resiliency	Project Stage: 0	Start Date: H1 2025	In-Service Date: H2 2026

Project description:

Cemetery Rd. & N. Broadway is a 2026 Resiliency Project selected based on a weighted average ranking including all NYSEG Circuits. The ranking includes major storms SAIFI contribution and excludes circuits with individual SAIFI below 2.2 for NYSEG. The objective of this project is to improve this circuits SAIFI.

Resiliency focuses on, preventing and limiting the scope and impact of outages when they occur. The ability to expediently restore power after a significant outage.

This is Achieved through Topology with Automation (Circuit Ties) - Circuit reconfiguration and sectionalizing with switching device automation Infrastructure

Hardening - Tree-wire (where applicable), pole replacement, and relocate lines closer to roads (where applicable).

Enhanced Vegetation Management - Ground-to-sky clearance

Project Scope:

- 1.1 - Install 3P 477AL Tree Wire with neutral wire (1.9 total miles) from L517 P192 to L289 P12 for increased capacity benefits and reduction of major outages
- 1.2 – Install 3P 477AL Tree Wire with neutral wire (1.2 total miles) from L289 P138 to L289 P173 for increased capacity benefits and reduction of major outages
- 2.1 – Upgrade 4.8D/12.47Y 3-333kVA Step bank on Erie St. 207 to a 3-500kVA
- 2.2 – Load Transfer 259kVA (90 Customers) from Cemetery Rd 490 to Erie St 207
- 3.1 - Install SCADA Recloser at L256 P2
- 3.2 - Install SCADA Recloser at L243 P60
- 3.3 - Install communications for existing non-scada enabled recloser at L220 P39
- 4.1 - Install 328A Regulator at L289 P138
- 4.2 - Install 656A Regulator at L511 P21
- 4.3 - Upgrade existing 3P 219A Regulator to a 3P 336A at L289 P15
- 5.1 - Upgrade 2ALURD Cable to 3P 750ALURD with neutral wire (0.1 mile) at LU1622 PU1 to L289 P137A

Project Benefits:

Completing this project will improve system SAIFI (System Average Interruption Frequency Index) by 0.107

Project Risks and Mitigation Plan:

Risks exist in project execution particularly as it relates to engineering and material procurement. In order to ensure materials are received on time, we will order long lead materials in advance to ensure they are received within 1 year of ordering (Poles, devices, wire, etc.).

Weather delays are a risk in distribution construction because our resources often support storm restoration efforts. We address these types of weather delay risks by incorporating contingency into our construction schedules.

Health and Safety of our workers are of a primary concern. Risks related to traffic control, working with energized equipment, slips and trips, etc. are a concern on most projects, we mitigate these risks with project specific health and safety plans.

Financial risks are always present with new information learned during project execution, financial risks are mitigated utilizing available scheduling and forecasting tools for project management (ie. Primavera), we forecast project specific activities in the living tool as the project progress and update monthly project progress to accurately forecast project completion including estimate at completion.

Risk of No Action:

CAIDI and SAIFI metrics will continue to be an issue for the circuits and the customers in the region will have more frequent prolonged outages. In the event of an outage these improvements will help to reduce outage frequency and facilitate restoration of power to a greater number of customers in a shorter timeframe

Project Alternatives:

Projects are developed using the following criteria and therefore alternatives are not provided.

Rank and Prioritize Worst Performing Circuits:

Based on SAIFI data (3 Year Weighted Average)* including major storms

Prioritize circuits with SAIFI above 2.2 and individual SAIFI contribution lower than 0.14%

Consider feedback from Operations and Field Evaluations

*Weighted values taken from reliability calculator

Resiliency focuses on:

Preventing and limiting the scope and impact of outages when they occur

The ability to expediently restore power after a significant outage

Achieved through:

Topology with Automation (Circuit Ties) - Circuit reconfiguration and sectionalizing with switching device automation

Infrastructure Hardening - Tree-wire (where applicable), pole replacement, and relocate lines closer to roads (where applicable).

Enhanced Vegetation Management - Ground-to-sky clearance

Basis for Project Estimates

Estimates are prepared utilizing historical estimating tools comparing against actual investments in similar projects as basis for project initiation and are revised through the project as new information is received.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Outside Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 27	\$ 2	\$ 25	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 1,140	\$ 86	\$ 1,054	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 265	\$ 20	\$ 245	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 230	\$ 14	\$ 216	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 875	\$ 66	\$ 809	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 278	\$ 12	\$ 266	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 2,814	\$ 200	\$ 2,614	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Outside Services	\$ 49	\$ -	\$ 49	\$ -	\$ -	\$ -	\$ -	\$ -
Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Other O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 49	\$ -	\$ 49	\$ -	\$ -	\$ -	\$ -	\$ -

NYSEG Resiliency 2026 - Cantitoe 497

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007246	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Resiliency	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2027

Project description:

Cantitoe 497 is a 2028 Resiliency Project selected based on a weighted average ranking including all NYSEG Circuits. The ranking includes major storms SAIFI contribution and excludes circuits with individual SAIFI below 2.2 for NYSEG. The objective of this project is to improve this circuits SAIFI.

Resiliency focuses on, preventing and limiting the scope and impact of outages when they occur. The ability to expediently restore power after a significant outage.

This is Achieved through Topology with Automation (Circuit Ties) - Circuit reconfiguration and sectionalizing with switching device automation Infrastructure

Hardening - Tree-wire (where applicable), pole replacement, and relocate lines closer to roads (where applicable).

Enhanced Vegetation Management - Ground-to-sky clearance

Project Scope:

Proposal includes upgrading conductors and increase capacities at existing tie points to other circuits to better address these vulnerabilities by isolating fault events coupled with remote operated load swapping capabilities where possible to minimize the total customer exposure. In addition to above, add SCADA Devices every 300 to 500 customers, at tie points, and add Comms kits to any existing devices that are not SCADA.

- 1) Create 4.16kv Internal Loop #1 Beach Rd. and Union Rd. Upgrade all 3 step banks to 3-500kva,
- 2) Old Post Rd to Seminary to Pound Ridge reconductor 1.5 miles of upgrade to TW or spacer cable.
- 3) Aerial Cable Installation 1 Mile Cantitoe to Pound Ridge 477 TW.
- 4) Poundridge Upgrade upgrade 1.0 miles of 2/0 Cu 3ph 13.2 Kv mainline to 477 Tw or space conductor from L#980, p-2618 (Recloser 497R2-2) to L#92, p-66, TIE with Pound Ridge 457 at 457-T2-497 Recloser in switch mode.
- 5) S. Bedford Rd, upgrade 1.6 miles of 1ph line to 3ph 13.2kv line with 477 tw to create a tie with Pound Ridge 458 circuit and install on NO SCADA Device.
- 8) Pound Ridge 458 Tie Point Upgrade 3.8 to 477 Miles to TW, 1.6 miles of upgrade and 1 SCADA Device to create tie with Pound Ridge 458.
- 9) Pound Ridge 497 Tie Point Upgrade 3.3 to 477 Miles to TW
- 10) Indian Hill Road to Pound Ridge Upgrade single phase to 3 Phase 477 TW to create loop with Seminary Rd 1.5 Miles.

Project Benefits:

Completing this project will improve system SAIFI (System Average Interruption Frequency Index)

Project Risks and Mitigation Plan:

Risks exist in project execution particularly as it relates to engineering and material procurement. In order to ensure materials are received on time, we will order long lead materials in advance to ensure they are received within 1 year of ordering (Poles, devices, wire, etc.).

Weather delays are a risk in distribution construction because our resources often support storm restoration efforts. We address these types of weather delay risks by incorporating contingency into our construction schedules.

Health and Safety of our workers are of a primary concern. Risks related to traffic control, working with energized equipment, slips and trips, etc. are a concern on most projects, we mitigate these risks with project specific health and safety plans.

Finanacial risks are always present with new information learned during project execution, financial risks are mitigated utilizing available scheduling and forecasting tools for project management (ie. Primavera), we forecast project specific activities in the living tool as the project progress and update monthly project progress to accurately forecast project completion including estimate at completion.

Risk of No Action:

CAIDI and SAIFI metrics will continue to be an issue for the circuits and the customers in the region will have more frequent prolonged outages. In the event of an outage these improvements will help to reduce outage frequency and facilitate rstoration of power to a greater number of customers in a shorter timeframe

Project Alternatives:

Projects are developed using the following criteria and therefore alternatives are not provided.

Rank and Prioritize Worst Performing Circuits:

Based on SAIFI data (3 Year Weighted Average)* including major storms

Prioritize circuits with SAIFI above 2.2 and individual SAIFI contribution lower than 0.14%

Consider feedback from Operations and Field Evaluations

*Weighted values taken from reliability calculator

Resiliency focuses on:

Preventing and limiting the scope and impact of outages when they occur

The ability to expediently restore power after a significant outage

Achieved through:

Topology with Automation (Circuit Ties) - Circuit reconfiguration and sectionalizing with switching device automation

Infrastructure Hardening - Tree-wire (where applicable), pole replacement, and relocate lines closer to roads (where applicable).

Enhanced Vegetation Management - Ground-to-sky clearance

Basis for Project Estimates

Estimates are prepared utilizing historical estimating tools comparing against actual investments in similar projects as basis for project initiation and are revised through the project as new information is received.

FINANCIAL INFORMATION**Actual Capital Spent, all amounts shown below in thousands (\$000's)**

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 171	\$ -	\$ -	\$ 108	\$ 64	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 9,069	\$ -	\$ -	\$ 5,701	\$ 3,369	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 1,128	\$ -	\$ -	\$ 726	\$ 402	\$ -	\$ -	\$ -
# Materials	\$ 5,647	\$ -	\$ -	\$ 3,549	\$ 2,097	\$ -	\$ -	\$ -
# Overheads - External	\$ 1,101	\$ -	\$ -	\$ 708	\$ 392	\$ -	\$ -	\$ -
Total	\$ 17,116	\$ -	\$ -	\$ 10,791	\$ 6,324	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ 870	\$ -	\$ -	\$ 430	\$ 439	\$ -	\$ -	\$ -

NYSEG Resiliency 2027 - S. Owego 540

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007247	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Resiliency	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2027

Project description:

NYSEG implemented the Resiliency Program to deploy investments in its transmission and distribution systems designed to reduce the frequency and impact of outages from severe weather and major storms. Improving grid resiliency is critical for maintaining safe, reliable electricity service for our customers and communities, particularly in response to growing risks from climate change. The primary objectives of investments under the Resiliency Program are to (1) prevent and limit the scope and impact of outages and (2) increase our ability to quickly restore power after a significant outage.

Projects included in the Resiliency Program generally deploy one or more of the following strategies to improve circuit resiliency:

1. Circuit Ties and Automation: Create connections between adjacent circuits ("circuit ties") to provide an N-1 backup power source during outages and use automation technology to operate these circuit ties without sending electrical workers into the field.
2. Infrastructure Hardening: Utilize Avangrid's Distribution Resiliency Guide to apply stronger designs and infrastructure standards to damage-susceptible circuits, reducing the frequency and impact of outages.
3. Enhanced Vegetation Management (EVM): Implement Enhanced Vegetation Management techniques, such as ground-to-sky clearing, to reduce the probability of tree-related outages along targeted line sections.

S. Oswego 540 is a 2027 Resiliency Project selected based on a weighted average ranking including all NYSEG Circuits.

The ranking includes major storms SAIFI contribution and excludes circuits with individual SAIFI below 2.2 for NYSEG. The objective of this project is to improve this circuits SAIFI. Resiliency focuses on, preventing and limiting the scope and impact of outages when they occur. The ability to expediently restore power after a significant outage.

Project Scope:

Proposal includes upgrading conductors and increase capacities at existing tie points to other circuits to better address these vulnerabilities by isolating fault events coupled with remote operated load swapping capabilities where possible to minimize the total customer exposure.

In addition to above, add SCADA Devices every 300 to 500 customers, at tie points, and add Comms kits to any existing devices that are not SCADA.

- 1) Canal St., upgrade 1.3 miles of mix of 477 and 4/0Al, 3ph 35kv mainline to 477 tw
- 2) Caitlyn Hill reconductor with 1/0 TW or spacer conductor for 0.6miles from L#549, p-87 to L#1902
- 3) Canal St 513 Upgrade 1 Mile to 3PH 477 TW
- 4) Southside Rd/Stanton Hill Upgrade Conversion to 34.5kV 477 TW, 3.6 Miles

Project Benefits:

The S. Oswego 540 Resiliency Project will improve system SAIFI by limiting the scope and impact of outages. The specific scope of work is pending distribution planning analysis, but it is expected that the project will reduce outage duration and frequency by replacing inadequate or aging poles, installing tree wire, and performing targeted enhanced "ground-to-sky" clearance of vegetation.

Project Risks and Mitigation Plan:

1. Delays in Project Implementation: Project delays could lead to an increase in customer outages, resulting in worsening reliability performance. The project schedule could be impacted by field conditions, particularly in heavily wooded or environmentally sensitive areas, where it can be difficult to access infrastructure with heavy equipment. Weather delays are also a risk in distribution construction due to worker safety concerns. These risks will be addressed by incorporating contingency into our construction schedules. Long lead-time equipment delays can also adversely impact project schedules. Equipment sourcing risks will be mitigated by identifying proposed equipment subject to long lead times and ordering such equipment proactively, as appropriate, to minimize the risk of project delays.

2. Scope Uncertainty: Lyon Mountain Circuit #510 has not yet been fully assessed, and the scope of the resiliency project has not yet been defined in detail. There is a possibility that the cost of the project could deviate from the preliminary estimate if the required scope of work, determined following thorough analysis, differs from current expectations. This risk will be mitigated by re-evaluating the project and its relative priority with respect to other candidate circuits for resiliency investments once the full scope of work and associated cost estimates have been determined.

3. Circuit Reprioritization: Lyon Mountain Circuit #510 is currently ranked #34 based on the 2020-2022 customer count, including storms. Based on new outage data in preparation for the 2027 Resiliency Program, there may be different circuits that contribute to worse reliability than Lyon Mountain Circuit #510, thus changing the priority of which circuit will be studied for the 2027 year. In this case, the new worst-performing circuits will be scoped and evaluated in the same manner as Lyon Mountain Circuit #510, as stated in the Project Scope.

4. Property Owner Opposition: Customers with property abutting electric infrastructure may oppose aspects of the project, such as infrastructure relocation or vegetation trimming/clearing. In certain circumstances, failure to perform proposed work that is opposed by property owners can negatively affect the efficacy of resiliency projects. To mitigate this risk, NYSEG will proactively engage in outreach to abutting property owners to notify them of the proposed work. If concerns are raised, NYSEG will engage in a dialogue to determine what accommodations can reasonably be made and to emphasize the benefits of the project to the community. If work cannot proceed as planned due to opposition from a property owner, the scope of work will be re-evaluated.

Risk of No Action:

Opting to take no action on this circuit would result in a continued elevated risk of weather-related customer outages and damage to utility facilities. Outages involving utility equipment that is damaged or destroyed by weather-initiated incidents, such as falling trees, are generally more costly and take longer for the utility to restore, negatively impacting both the cost and quality of service for customers. Weather-related outages, particularly those resulting from damaging storms, can have a significant negative impact on our customers, especially in instances where power outages extend over multiple days.

Project Alternatives:

Projects are developed using the following criteria and therefore alternatives are not provided.

Rank and Prioritize Worst Performing Circuits:

Based on SAIFI data (3 Year Weighted Average)* including major storms

Prioritize circuits with SAIFI above 2.2 and individual SAIFI contribution lower than 0.14%

Consider feedback from Operations and Field Evaluations

*Weighted values taken from reliability calculator

Resiliency focuses on:

Preventing and limiting the scope and impact of outages when they occur

The ability to expediently restore power after a significant outage

Achieved through:

Topology with Automation (Circuit Ties) - Circuit reconfiguration and sectionalizing with switching device automation

Infrastructure Hardening - Tree-wire (where applicable), pole replacement, and relocate lines closer to roads (where applicable).

Enhanced Vegetation Management - Ground-to-sky clearance

Basis for Project Estimates

Estimates are prepared utilizing historical estimating tools comparing against actual investments in similar projects as basis for project initiation and are revised through the project as new information is received.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 102	\$ -	\$ 10	\$ 92	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 5,389	\$ -	\$ 530	\$ 4,859	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 704	\$ -	\$ 86	\$ 618	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 3,355	\$ -	\$ 330	\$ 3,025	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 687	\$ -	\$ 84	\$ 604	\$ -	\$ -	\$ -	\$ -
Total	\$ 10,236	\$ -	\$ 1,039	\$ 9,197	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ 407	\$ -	\$ 40	\$ 367	\$ -	\$ -	\$ -	\$ -

NYSEG Resiliency 2027 - Genegantslets 422

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007248	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Resiliency	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2027

Project description:

Background: NYSEG implemented the Resiliency Program to deploy investments in its transmission and distribution systems designed to reduce the frequency and impact of outages from severe weather and major storms. Improving grid resiliency is critical for maintaining safe, reliable electricity service for our customers and communities, particularly in response to growing risks from climate change. The primary objectives of investments under the Resiliency Program are to (1) prevent and limit the scope and impact of outages and (2) increase our ability to quickly restore power after a significant outage.

Projects included in the Resiliency Program generally deploy one or more of the following strategies to improve circuit resiliency:

1. Circuit Ties and Automation: Create connections between adjacent circuits ("circuit ties") to provide an N-1 backup power source during outages and use automation technology to operate these circuit ties without sending electrical workers into the field.
2. Infrastructure Hardening: Utilize Avangrid's Distribution Resiliency Guide to apply stronger designs and infrastructure standards to damage-susceptible circuits, reducing the frequency and impact of outages.
3. Enhanced Vegetation Management (EVM): Implement Enhanced Vegetation Management techniques, such as ground-to-sky clearing, to reduce the probability of tree-related outages along targeted line sections.

Project Justification: Genegantslet Corners is a 2027 Resiliency Project selected based on a weighted average ranking including all NYSEG Circuits. The ranking includes major storms SAIFI contribution and excludes circuits with individual SAIFI below 2.2 for NYSEG. The objective of this project is to improve this circuits SAIFI. Resiliency focuses on, preventing and limiting the scope and impact of outages when they occur. The ability to expediently restore power after a significant outage.

Project Scope:

Proposal includes upgrading conductors and increase capacities at existing tie points to other circuits to better address these vulnerabilities by isolating fault events coupled with remote operated load swapping capabilities where possible to minimize the total customer exposure.

1) Genegantslet 422 Circuit:

(am) convert 5.3 mile 1 ph 4.8kv to 3ph 35kv with either 477 or 4/0 (EDP to determine), along Rte. 79 from Whitney Point to South St. to Pixley Rd, (b,d) on both Pixley Rd. and South St. install .4 miles (total .8 miles) of new 3ph 35 kv with either 477 or 4/0 (EDP to determine) line and South St

2) Rt. 206/26 5.1 miles of relocation to road, TW or space wire

Project Benefits:

The Genegantslet Corners 422 Resiliency Project will improve system SAIFI by limiting the scope and impact of outages. The specific scope of work is pending distribution planning analysis, but it is expected that the project will reduce outage duration and frequency by replacing inadequate or aging poles, installing tree wire, and performing targeted enhanced "ground-to-sky" clearance of vegetation.

Project Risks and Mitigation Plan:

1. Delays in Project Implementation: Project delays could lead to an increase in customer outages, resulting in worsening reliability performance. The project schedule could be impacted by field conditions, particularly in heavily wooded or environmentally sensitive areas, where it can be difficult to access infrastructure with heavy equipment. Weather delays are also a risk in distribution construction due to worker safety concerns. These risks will be addressed by incorporating contingency into our construction schedules. Long lead-time equipment delays can also adversely impact project schedules. Equipment sourcing risks will be mitigated by identifying proposed equipment subject to long lead times and ordering such equipment proactively, as appropriate, to minimize the risk of project delays.

2. Scope Uncertainty: Lyon Mountain Circuit #510 has not yet been fully assessed, and the scope of the resiliency project has not yet been defined in detail. There is a possibility that the cost of the project could deviate from the preliminary estimate if the required scope of work, determined following thorough analysis, differs from current expectations. This risk will be mitigated by re-evaluating the project and its relative priority with respect to other candidate circuits for resiliency investments once the full scope of work and associated cost estimates have been determined.

3. Circuit Reprioritization: Lyon Mountain Circuit #510 is currently ranked #34 based on the 2020-2022 customer count, including storms. Based on new outage data in preparation for the 2027 Resiliency Program, there may be different circuits that contribute to worse reliability than Lyon Mountain Circuit #510, thus changing the priority of which circuit will be studied for the 2027 year. In this case, the new worst-performing circuits will be scoped and evaluated in the same manner as Lyon Mountain Circuit #510, as stated in the Project Scope.

4. Property Owner Opposition: Customers with property abutting electric infrastructure may oppose aspects of the project, such as infrastructure relocation or vegetation trimming/clearing. In certain circumstances, failure to perform proposed work that is opposed by property owners can negatively affect the efficacy of resiliency projects. To mitigate this risk, NYSEG will proactively engage in outreach to abutting property owners to notify them of the proposed work. If concerns are raised, NYSEG will engage in a dialogue to determine what accommodations can reasonably be made and to emphasize the benefits of the project to the community. If work cannot proceed as planned due to opposition from a property owner, the scope of work will be re-evaluated.

Risk of No Action:

Opting to take no action on this circuit would result in a continued elevated risk of weather-related customer outages and damage to utility facilities. Outages involving utility equipment that is damaged or destroyed by weather-initiated incidents, such as falling trees, are generally more costly and take longer for the utility to restore, negatively impacting both the cost and quality of service for customers. Weather-related outages, particularly those resulting from damaging storms, can have a significant negative impact on our customers, especially in instances where power outages extend over multiple days.

Project Alternatives:

Projects are developed using the following criteria and therefore alternatives are not provided.

Rank and Prioritize Worst Performing Circuits:

Based on SAIFI data (3 Year Weighted Average)* including major storms

Prioritize circuits with SAIFI above 2.2 and individual SAIFI contribution lower than 0.14%

Consider feedback from Operations and Field Evaluations

*Weighted values taken from reliability calculator

Resiliency focuses on:

Preventing and limiting the scope and impact of outages when they occur

The ability to expediently restore power after a significant outage

Achieved through:

Topology with Automation (Circuit Ties) - Circuit reconfiguration and sectionalizing with switching device automation

Infrastructure Hardening - Tree-wire (where applicable), pole replacement, and relocate lines closer to roads (where applicable).

Enhanced Vegetation Management - Ground-to-sky clearance

Basis for Project Estimates

Estimates are prepared utilizing historical estimating tools comparing against actual investments in similar projects as basis for project initiation and are revised through the project as new information is received.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 227	\$ 6	\$ 138	\$ 83	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 9,771	\$ 258	\$ 5,934	\$ 3,578	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ 2,272	\$ 60	\$ 1,380	\$ 832	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 1,839	\$ 42	\$ 1,218	\$ 579	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 7,499	\$ 198	\$ 4,554	\$ 2,746	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 2,244	\$ 36	\$ 1,497	\$ 712	\$ -	\$ -	\$ -	\$ -
Total	\$ 23,852	\$ 600	\$ 14,721	\$ 8,531	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ 885	\$ -	\$ 552	\$ 333	\$ -	\$ -	\$ -	\$ -

Climate Change Resilience - Targeted Undergrounding - NYSEG

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-007204	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Resiliency	Project Stage: 0	Start Date: Ongoing	In-Service Date: Ongoing

Project description:

This program is part of the company's Climate Change Resilience Plan filed in March of 2025.

As extreme weather events increase due to climate change, the use of Targeted Undergrounding on portions of the electric distribution system is a proactive solution to significantly enhance the reliability and resiliency of the distribution system. This program aims to improve system resilience by identifying and performing undergrounding on specific sections of overhead distribution lines that may be more prone to outages, are in locations that are difficult to repair, or, if outaged, could have an outsized impact on the community; for example, based on the number or type of customers that they serve. The goal is to underground approximately two miles per year, with the initial focus on development of a process or framework to identify high-impact locations for undergrounding.

The Targeted Undergrounding Program represents an investment to enhance the resiliency for select portions of the electric distribution system. Initially, the program will include identification of locations to deploy Targeted Undergrounding with the goal of undergrounding approximately two miles per year. The initial years of the program will be used to build a foundation that will be utilized to determine the realized benefits and expand the program.

Year 1 of the program will be for design/planning of the first ~2 miles of undergrounding.

Year 2 and onward will be for construction of the ~2 miles designed in the previous Year; and design/planning of the next ~2 miles.

The estimated costs per mile of underground is ~\$5.95M.

Project Scope:

Develop projects that efficiently build resiliency through undergrounding portions of circuits. This will incorporate a variety of factors including historical outage performance, local topology, and supplied customers. The process to identify locations to utilize Targeted Undergrounding will consider some or all of the following characteristics:

Outage History: Analysis of appropriate customer outage metrics potentially including the list of worst performing circuits.

Community Resilience: Analysis of what connected facilities (e.g., hospitals, town centers, community shelters) could benefit from the undergrounding.

Disadvantaged Communities: Does the undergrounding section contribute to serving or backing-up a disadvantaged community?

Local topology Considerations: Including items like difficult to access areas (e.g., steep or offroad terrain), potential for out-of-ROW tree related outages, major road or water crossings, multiple circuit rights-of-way, etc.

Other Needs: If an area is known to have recent projects deployed or is expected to have future needs, these factors should be considered to determine how this affects the priority (e.g., asset condition, recent vegetation management/hardening efforts.)

The program aims to underground approximately 2 miles per year, with an estimated cost of \$5.9M per mile.

Project Benefits:

Enhance reliability and resiliency to customers and communities by relocating targeted sections of the distribution system underground away from weather-related outage causes. These projects will effectively eliminate storm and other weather related outages on the undergrounded portion of the circuit; with the candidate sections for undergrounding being identified based on a variety of characteristics. These projects will also demonstrate our company's commitment to customer and community resilience through the filed Climate Change Resilience Plan.

Project Risks and Mitigation Plan:

Risks include incorrect identification of circuit locations to underground, and coordination challenges with telecom companies, municipalities, and potential supply chain constraints. Performing the planning/design phase of the project in Year 1 and construction activities in Year 2 allows for these coordination risks to be identify early and the necessary stakeholder engaged.

Construction for underground facilities is highly dependent on the what type of subsurface must be excavated and can have impacts to the schedule and costs for construction. For example, encountered ledge would be more difficult to excavate than sandy soil. During the design/planning phase the expected subsurface characteristics will be profiled including if modification to the design is warranted (e.g., changing underground route.) Finally, there is the potential schedule for risks to the project schedule if the identified underground route requires excavation and repair of roadways there may be certain times of year where these activities are limited by the town or city regulations, or by the availability of asphalt to repair the roadway.

Performing the planning/design phase of the project in Year 1 and construction activities in Year 2 allows for these scheduling risks to be mitigated as the entirety of the warmer season in Year 2 is available for construction.

In addition to not completing portions of our filed Climate Change Resilience Plan, the potential sections of the distribution system that would have been moved underground would remain overhead and exposed to weather-related outage causes; potentially impacting customer reliability and resiliency during major weather events.

Alternatives to Targeted Undergrounding include potential use of aerial or space cable, vegetation management, and other Distribution resilience activities like installation of tree-wire or circuit automation. Targeted Undergrounding is expected to be particularly beneficial when other alternatives that can improve resilience to portions of distribution circuits, like inclusion tree-wire or vegetation management, are not able to provide their complete benefit. For example, in areas where there are multiple circuits on the same pole-line or when there is vegetation outside of the right-of-way, alternative mitigating measures may not be able to provide comparable benefit as Targeted Undergrounding.

Project estimates are based on a ~\$5.95M per mile estimate derived from an undergrounding construction estimating tool; assuming each sub-project identified would be completed over a 2 year period.

Year 2 and onward will be for construction of the ~2 miles designed in the previous Year; and design/planning of the next ~2 miles.

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Actual O&M, all amounts shown below in thousands (\$000's)

Forecasted Capital, all amounts shown below in thousands (\$000's)

Forecasted O&M, all amounts shown below in thousands (\$000's)

[illegible]

NYSEG DAP 2026 - Mechanicville

PROJECT INFORMATION

OpCo: NYSEG	Project ID: PRJ-006442	Charge Code: Electric Distribution	Project Sponsor: 0	Project Type: 0
Business Area: Planning & Coordination	Rate Case Category Resiliency	Project Stage: 0	Start Date: Ongoing	In-Service Date: H2 2026

Project description:

The NYSEG Distribution Automation Program was established to improve distribution reliability performance metrics by applying the principles of Fault Location, Isolation, and Service Restoration (FLISR) to reduce the scale of outages (e.g., through sectionalizing), improve the speed at which power can be restored to customers (e.g., through remote switching), or avoid outages altogether (e.g., through sequential reclosing). The core scope of the Distribution Automation Program entails the deployment of modern SCADA-enabled devices such as reclosers and switches – and the associated programming and communications upgrades – to distribution circuits at optimized locations, either in new locations, or replacing legacy equipment. The SCADA functionality of the new devices enables significant improvements in system operability and flexibility in response to disturbances when controlled by system operators and also lays the foundation for deployment of systems like Advanced Restoration and Automation (ARA) that can isolate faults and restore power without operator intervention. Additionally, these new devices allow for loading and operating status data to be transmitted to the Company, providing valuable historical data to system planners as well as enabling crucial visibility for system operators.

Background: The 2026 Mechanicville Distribution Automation Project targets distribution circuits within NYSEG's Mechanicville Division for improved FLISR capabilities, prioritized based on historical contribution to system SAIFI. Devices locations were selected to maximize SAIFI improvement by employing strategies such as:

- Limiting the number of customers between sectionalizing devices to 500
- Limiting the exposure (i.e., circuit length) between sectionalizing devices to 10 miles
- Deploying SCADA-operable/automated circuit ties to enable quick restoration
- Utilizing sequential reclosing to avoid outages from momentary faults

Prioritization is based on historical SAIFI performance at the division and station-level performance, rather than for individual circuits. This prioritization methodology intends to target areas with the greatest need for reliability improvements and where forming circuit ties can create mutual benefits between circuits and substations.

Project Scope:

The key components of the program include device deployment (SCADA reclosers, switches, etc.), reprogramming, and communication upgrades. These devices are strategically placed to create customer "zones", each with no more than 500 customers or ten miles of overhead line.

To date, ~99 SCADA devices on 37 circuits have been installed within the Mechanicville division, as part of the DAP program since its inception in 2019. In 2026 12 new SCADA devices on 7 Mechanicville circuits (Chatham 155, Flike Rd Tap 605, Rutland 131, Vaness Rd Tap 604, W. Sand Lake Tap 614, Wynantskill 140, Wynantskill 141).

Project Benefits:

The primary benefit of this project is the enhancement of system reliability and resiliency, as indicated by SAIFI and CAIDI performance metrics. By deploying SCADA-operable sectionalizing and circuit-tie devices, the project aims to:

- Reduce the scale of outages by increasing circuit sectionalizing points and limiting customer count to 500 between devices. (SAIFI benefit)
- Improve the speed at which power can be restored to customers by utilizing remote switching capabilities instead of dispatching field personnel to perform isolation and/or restoration switching operations manually. (CAIDI benefit)
- Avoid outages altogether by using sequential reclosing to automatically restore power in the event of a temporary fault. (SAIFI benefit)
- Reduce fault locating time by providing by field personnel by improving operational awareness and system visibility (CAIDI benefit)

In addition to improving reliability, the deployment of advanced tools and technology will improve the efficiency and quality of utility operations, including better data, monitoring, control, and management of the electrical grid. For example, the interval power flow data provided by the advanced devices can significantly improve the accuracy and practicality of system planning studies and will also support the development of more granular load forecasts. Additionally, the operational awareness and remote operability provided by the project will improve the efficiency of routine maintenance switching operations, reducing operational expenses.

Project Risks and Mitigation Plan:

1. Delays in Project Implementation: Project delays could lead to an increase in frequency and/or duration customer outages, resulting in worsening reliability performance. The project schedule could be impacted by field conditions, particularly in heavily wooded or environmentally sensitive areas, where it can be difficult to access infrastructure with heavy equipment. Weather delays are also a risk in distribution construction due to worker safety concerns. These risks will be addressed by incorporating contingency into our construction schedules. To mitigate this risk, the project team conducts thorough field scouting and feasibility assessments before finalizing device locations. Long lead-time equipment delays can also adversely impact project schedules. Equipment sourcing risks will be mitigated by identifying proposed equipment subject to long lead times and ordering such equipment proactively, as appropriate, to minimize the risk of project delays.

2. Budget Risks: Another risk is the possibility of budget overruns due to unexpected costs associated with device installation, reprogramming, or adding communications. To manage this risk, regular budget reviews and cost tracking are implemented to ensure the project remains within the allocated budget.

3. Technology Integration: There are risks associated with the integration of new devices with existing systems, which could lead to compatibility issues or operational disruptions. To mitigate this risk, the project involves close coordination with the Substation Automation group and other relevant teams to ensure seamless integration.

Risk of No Action:

If the proposed project scope is not executed, the Company must continue to rely on existing infrastructure to manage outage events. As a result, the frequency and duration of outages would likely continue at current levels or worsen, and the Company would miss out on an opportunity to provide a positive reliability benefit to affected customers.

Additionally, without the advanced tools and technologies proposed in the Distribution Automation (DA) program, the benefits to data, monitoring, control, and management of the electric grid would not be realized. This could lead to slower response times to outages, increased operating costs, and inefficiencies in distribution system planning and operations.

In summary, the risks of taking no action include stagnant or worsening reliability metrics, decreased customer satisfaction, and reduced operational efficiency.

Project Alternatives:

An alternative solution is manual operation of devices in the field. This involves installing additional sectionalizing and/or tie points, but forgoes the inclusion of SCADA-operability and, instead, relies on manual operation to perform switching operations. Manual operation involves dispatching field personnel to manually control and manage the electric distribution system under the direction of system operators. This approach requires significant labor and generally leads to much slower response times during outages relative to remote operation. The cost of manual operation includes ongoing labor expenses, training, and the potential for higher operating costs due to inefficiencies and slower restoration times.

Basis for Project Estimates

Historical data and past project experiences were used to inform the cost estimates. By leveraging historical data, the project team can make more informed predictions about the costs involved in the current project. Furthermore, the project team conducts field scouting and feasibility assessments to identify any potential challenges or additional costs that might arise during the deployment.

Finally, a contingency budget was included to cover any unforeseen expenses that might arise during the project. This helps to ensure that the project remains within the allocated budget, even if unexpected costs are encountered.

FINANCIAL INFORMATION

Actual Capital Spent, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2020	2021	2022	2023	2024		
# AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# External Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Internal, Overheads	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Materials	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
# Overheads - External	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Actual O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2020	2021	2022	2023	2024		
Total	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		

Forecasted Capital, all amounts shown below in thousands (\$000's)

Capital Details:	Total	2025	2026	2027	2028	2029	2030	2031
# AFUDC	\$ 13	\$ -	\$ 13	\$ -	\$ -	\$ -	\$ -	\$ -
# CIAC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# External Services	\$ 679	\$ -	\$ 679	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal - Non-AC	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Labor	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
# Internal, Overheads	\$ 110	\$ -	\$ 110	\$ -	\$ -	\$ -	\$ -	\$ -
# Materials	\$ 422	\$ -	\$ 422	\$ -	\$ -	\$ -	\$ -	\$ -
# Overheads - External	\$ 107	\$ -	\$ 107	\$ -	\$ -	\$ -	\$ -	\$ -
Total	\$ 1,330	\$ -	\$ 1,330	\$ -	\$ -	\$ -	\$ -	\$ -

Forecasted O&M, all amounts shown below in thousands (\$000's)

O&M Details:	Total	2025	2026	2027	2028	2029	2030	2031
Total	\$ 26	\$ -	\$ 26	\$ -	\$ -	\$ -	\$ -	\$ -