# ATTACHMENT A

Direct Testimony and Exhibits of

Alan Trotta

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

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| **New York State Electric & Gas Corporation** | **)** | **Docket Nos. ER24-___-000** |
| **New York Independent System Operator, Inc.** | **)** | |
| **Rochester Gas and Electric Corporation** | **)** | **ER24-___-000** |
| **New York Independent System Operator, Inc.** | **)** | |

# DIRECT TESTIMONY
# OF
# ALAN TROTTA

**ON BEHALF OF**
**NEW YORK STATE ELECTRIC & GAS CORPORATION**
**AND**
**ROCHESTER GAS AND ELECTRIC CORPORATION**

**May 1, 2024**

**DIRECT TESTIMONY OF ALAN TROTTA**

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**DIRECT TESTIMONY OF ALAN TROTTA**

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| Exhibit 2 | The April 19, 2024, NYPSC Order ("Phase 2 CWIP Order") Authorizing Applicants to Seek FERC Authorization to Utilize 100% of Prudently Incurred Construction Work in Progress (the "100% CWIP Incentive") in Rate Base for Their Phase 2 Projects. |
| Exhibit 3 | Map and Description of Applicants' Phase 2 Projects. |

**DIRECT TESTIMONY OF**

**ALAN TROTTA**

## I. INTRODUCTION AND EXPERIENCE

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Alan Trotta, and my business address is 100 Marsh Hill Road, Orange, Connecticut, 06477.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?**

A. I am employed by Avangrid Service Company as Senior Director of Transmission and Regional Energy Policy. I am responsible for policy matters related to electric transmission and independent system operator tariffs on behalf of the electric utility subsidiaries of Avangrid Networks, Inc. ("Avangrid Networks") in New York and New England. In this docket, I am testifying on behalf of Avangrid Networks' subsidiaries New York State Electric & Gas Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RG&E") (collectively, "Applicants").

**Q. PLEASE DESCRIBE THE APPLICANTS.**

A. Applicants are each a subsidiary of Avangrid, Inc. NYSEG operates approximately 35,000 miles of electric distribution lines and 4,500 miles of electric transmission lines across more than 40% of upstate New York. It also operates more than 8,300 miles of natural gas distribution pipelines and 20 miles of gas transmission pipelines. It serves approximately 907,000 electricity customers and 270,000 natural gas customers. RG&E operates approximately 8,900 miles of electric distribution lines and 1,100 miles of electric transmission lines. It also operates approximately 10,600 miles of natural gas distribution pipelines and 105 miles of gas transmission pipelines. It serves

approximately 385,900 electricity customers and 319,000 natural gas customers in a nine-county region in New York surrounding the City of Rochester.

Avangrid, Inc. is a leading, sustainable energy company with $45 billion in assets and operations in 24 U.S. states. Avangrid, Inc. is part of the Iberdrola Group. Iberdrola, S.A. is an energy pioneer with one of the largest renewable asset bases of any company in the world. Avangrid, Inc. has two primary lines of business: Avangrid Networks, of which the Applicants are a part, and Avangrid Renewables, LLC.

**Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.**

A. I graduated from Charter Oak State College with a Bachelor's Degree in Business Administration.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE FERC?**

A. Yes, most recently in the Federal Energy Regulatory Commission ("FERC" or "Commission") Docket Nos. ER22-2180, ER22-2181, and ER22-2154 regarding the NY transmission owners' voluntary Cost Sharing and Recovery Agreement ("CSRA") to allow for statewide cost allocation and recovery of the revenue requirements for certain local transmission investments, including the transmission investments that are the subject of this proceeding as well as the New York Independent System Operator's ("NYISO") new Rate Schedule 19 to be utilized for cost recovery for transmission projects subject to the CSRA. Also, in 2015, I testified on behalf of the New England Power Pool in Docket No. ER15-2208, ISO New England Inc., and New England Power Pool Filings of Winter Reliability Programs. I have also testified in numerous state regulatory proceedings.

## II. PURPOSE AND SCOPE OF TESTIMONY

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to describe the Applicants, provide a general overview of the Phase 2 "Area of Concern" transmission projects approved by the New York Public Service Commission ("NYPSC") on February 16, 2023 ("Phase 2 Projects"), and support the Applicants' request for incentive rate treatment for the Phase 2 Projects.

**Q. ARE YOU SPONSORING ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY IN THIS CASE?**

A. Yes. My testimony includes the following exhibits:

Exhibit 1: The February 16, 2023, NYPSC Order ("Phase 2 Order") Approving the Phase 2 Projects Areas of Concern Transmission Upgrades, Case 20-E-0197.

Exhibit 2: The April 19, 2024, NYPSC Order ("Phase 2 CWIP Order") Authorizing Applicants to Seek FERC Authorization to Utilize 100% of Prudently Incurred Construction Work in Progress (the "100% CWIP Incentive") in Rate Base for Their Phase 2 Projects.

Exhibit 3: Map and Description of Applicants' Phase 2 Projects.

**Q. ARE THERE ADDITIONAL WITNESSES PROVIDING TESTIMONY IN SUPPORT OF THE APPLICATION?**

A. Yes, in addition to my testimony, the following witnesses will provide more detailed testimony on various aspects of the Application:

- **James Michael Yeske Jr.**
    - Describes the Phase 2 Projects and the risks and challenges associated with their development as it relates to the Abandoned Plant Incentive.
- **Andrea Vanluling & Michael Panichi**
    - Describes the relevant quantitative and qualitative financial information as it relates to the financial challenges associated with developing the Phase

2 Projects as it relates to the 100% CWIP in Rate Base and Abandoned Plant Incentives.

- **April Theberge & Angela Bassano**
    - Describes the accounting processes and tracking mechanisms to ensure compliant implementation of the 100% CWIP in Rate Base and Abandoned Plant Incentives, as well as the necessary tariff revisions.

## III. OVERVIEW OF THE NYPSC PROCESS AND THE PHASE 2 PROJECTS

**Q. PLEASE DESCRIBE THE NYPSC PROCESS RELEVANT TO THE PHASE 2 PROJECTS.**

A. The Phase 2 Projects are intended to support the public policy objectives established by New York State through its Climate Leadership and Community Protection Act ("CLCPA") and the associated Accelerated Renewable Energy Growth and Community Benefit Act ("AREGCBA"). Pursuant to a process established by the NYPSC, as directed by the AREGCBA, the New York utilities, including the Applicants, submitted a comprehensive report identifying the local transmission and distribution investments necessary to support the New York State's policy objectives ("2020 CLCPA Study"). In the 2020 CLCPA Study, the utilities recommended dividing local transmission projects into phases. Phase 1 Projects are those responsive to the Initiating Order's discussion of "Business as Usual" transmission projects that are projects already needed under existing planning criteria, but which also have the benefit of adding incremental headroom for renewable generation. Cost recovery for Phase 1 Projects is achieved through NYSEG and RG&E's bundled local transmission and distribution rates in NYPSC rate cases. Phase 1 Projects are not the subject of this application for transmission incentives, but the incremental investments that Applicants need to make in Phase 1 Projects is relevant to

the cash flow and credit risks and challenges that the Applicants will face. Phase 2 Projects include incremental transmission projects that are proposed primarily to increase system headroom in support of renewable energy development.

On September 9, 2021, the NYPSC issued an order identifying specific "Areas of Concern" in New York "characterized by the presence of existing renewable generation that is already experiencing curtailments and a strong level of developer interest that exceeds the capability of the local transmission system." To address the "Areas of Concern," the NYPSC ordered a subset of New York utilities, including the Applicants, to consult with the New York Department of Public Service staff and present at least two options for each Area of Concern that identified the most cost-effective Phase 2 upgrades on a dollar per megawatt basis. In addition to Applicants, the other utilities with Areas of Concern are Central Hudson Gas & Electric Corporation and Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid"). This group of New York utilities, including the Applicants, submitted a joint petition in compliance with the September 9, 2021, Order's directive on March 8, 2022.

On February 16, 2023, the NYPSC approved nearly all of the Applicants' proposed Phase 2 Projects with an estimated $2.25 billion investment ("Phase 2 Order"). On May 3, 2023, NYISO, on behalf of the Applicants, filed proposed formula rates with FERC, which were approved on December 4, 2023 (185 FERC ¶ 61,164), subject to further compliance and settlement judge procedures for the return on equity "ceiling." NYSEG and RG&E submitted compliance filings on January 23, 2024. Pursuant to the CSRA, Applicants are required to obtain NYPSC approval before seeking FERC authorization to utilize the 100% CWIP Incentive. On April 19, 2024, the NYPSC issued the Phase 2

CWIP Order approving the Applicants' petition to utilize 100% CWIP in rate base for the Phase 2 Projects.

**Q. PLEASE DESCRIBE THE APPLICANTS' PHASE 2 PROJECTS.**

A. In the Phase 2 Order, the NYPSC approved 33 of the Applicants' Phase 2 Projects; 32 of the approved Phase 2 Projects were proposed by Applicants and one was proposed by National Grid, which is discussed further below. A map and description of the Phase 2 Projects approved for Applicants is shown in Exhibit 3 to my testimony. The projects include approximately 300 miles of transmission line rebuilds as well as major upgrades or rebuilds of nine substations and minor upgrades at several others. The Phase 2 Projects include significantly aged infrastructure that will also improve resiliency and reliability of the transmission system once completed: seven of the transmission circuits being rebuilt are at least 70 years old and another ten are between 50 and 70 years old, four of the substations being rebuilt are at least 93 years old. Additionally, two substations are being relocated out of flood plains.

## IV. INCENTIVE RATE TREATMENT

**Q. ARE THE APPLICANTS REQUESTING INCENTIVE RATE TREATMENT FOR THEIR INVESTMENT IN THE PHASE 2 PROJECTS?**

A. Yes, the Phase 2 Projects qualify for transmission incentive rate treatments in accordance with FERC's policies under Order No. 679. The Phase 2 Projects involve significant capital investment by the Applicants and will involve development in a complex permitting and regulatory environment. The Applicants have carefully chosen the appropriate incentive rate treatments that best address the specific risks and challenges associated with the development of projects of this size and scope.

**Q. PLEASE DESCRIBE THE INCENTIVE RATE TREATMENTS THAT THE APPLICANTS ARE REQUESTING FOR THE PHASE 2 PROJECTS.**

A. Consistent with FERC orders granting requests for incentive rate treatments for projects of similar size and scope and Order No. 679 and the associated Policy Statement, the Applicants request authorization to (1) utilize 100% of prudently incurred Construction Work in Progress in rate base for their Phase 2 Projects ("100% CWIP Incentive") and (2) recover 100% of prudently incurred costs associated with investment in the Phase 2 Projects if such projects are abandoned or cancelled for reasons beyond the control of the Applicants ("Abandoned Plant Incentive").

## V. PROJECT NEED TEST

**Q. WHAT MUST THE APPLICANTS DEMONSTRATE IN ORDER TO HAVE THE TRANSMISSION RATE INCENTIVES APPROVED BY FERC?**

A. I understand that Order No. 679 requires an applicant to demonstrate that the proposed transmission project will either ensure reliability or reduce the cost of delivered power by reducing transmission congestion. Furthermore, as part of Order No. 679, FERC established a rebuttable presumption that this standard is met if the transmission project results from a fair and open regional planning process that considers and evaluates the project for reliability and/or congestion or the transmission project has received construction approval from an appropriate state commission or state siting authority. This requirement has been described as the "Project Need Test." In Order No. 679-A, FERC further clarified that to avail itself of the rebuttable presumption, the applicant must explain how the state process included a determination that the project is necessary to ensure reliability or reduce congestion.

**Q. DO THE PHASE 2 PROJECTS SATISFY THE REBUTTABLE PRESUMPTION?**

A. Yes, the Phase 2 Projects received explicit construction approval from the NYPSC, the appropriate state commission or state siting authority in this context. More specifically, the Phase 2 Order expressly approved the Phase 2 Projects, which is stated in Ordering Clause 1 on page 45:

> The projects proposed in the Petition, filed on March 8, 2022, by Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation are hereby approved, as discussed in Table 5 and the body of this Order. (emphasis added).

Table 5 and the body of the Phase 2 Order provide details regarding the projects that were approved. Specifically, Table 5, with additional detail provided in Table 14 of the Technical Assessment Appendix to the Phase 2 Order ("Technical Assessment"), identifies a portfolio of 32 NYSEG and RG&E projects in the Southern Tier of New York, many of which are interdependent, that were approved by the NYPSC. Additionally, Table 5 identifies a portfolio of approved projects submitted by Niagara Mohawk, and Table 8 of the Technical Assessment identifies Project WO12 as a NYSEG project sponsored by Niagara Mohawk as part of its Phase 2 transmission solution.

**Q. TO WHAT EXTENT DID THE PHASE 2 ORDER CONSIDER THE DEGREE TO WHICH THE PHASE 2 PROJECTS WOULD ENSURE RELIABILITY OR REDUCE CONGESTION?**

A. In the Phase 2 Order and the associated Technical Assessment, the NYPSC explicitly notes the reliability and congestion reduction benefits of the Phase 2 Projects. The reduction of congestion is the Phase 2 Projects' primary purpose. The Phase 2 Order, on page 22, commences with a clear and unambiguous statement that congestion is the primary need that the NYPSC was seeking to address: "[t]he rapid growth of renewable generation in the [Area of Concern], combined with the relatively slow pace of

transmission development, has created the congestion conditions this Order seeks to alleviate." (emphasis added). In arriving at this determination of need, the NYPSC cited a July 2020 report by the NYISO, the 2019 "Congestion Assessment and Resource Integration Study" ("2019 CARIS Report"). On page 97 of the 2019 CARIS Report, NYISO found that the area where NYSEG's Phase 2 Projects are located was expected to experience high levels of congested hours in 2030 under its scenario where the state complies with its statutory renewable energy goals:

> In general, the wind and solar generation in this pocket experience high levels of curtailments, and the transmission facilities in this pocket show high levels of congested hours. This congestion results mainly from the lack of strongly interconnected bulk power transmission facilities near injection points, and the 115 kV network was not designed for large power transfers.

Furthermore, in approving the Phase 2 Projects, the NYPSC explicitly addressed the reduction of congestion in its rationale for approval on page 45 of the Phase 2 Order: "[t]he Commission finds that the Sponsoring Utilities complied with the directions given in the [Order on Local Transmission and Distribution Planning Process and Phase 2 Project Proposals] concerning the identification of transmission upgrades to address congestion in the Areas of Concern." (emphasis added). This is further reinforced in detail on page 1 of the Technical Assessment, which states:

> The fundamental objective for the Areas of Concern (AOC) is to develop and construct local transmission upgrades to reduce congestion and, therefore, improve deliverability for existing and expected renewable generators in these areas by increasing "headroom." Headroom represents the ability of the power system to deliver additional energy output from generators to load under a specific set of circumstances. Increases in headroom generally result in decreased levels of generator curtailment, though not necessarily total elimination of curtailments.

While the primary purpose of the Phase 2 Projects is to reduce congestion, as discussed in more detail below, the Technical Appendix at page 34 states:

> While considerations of reliability and resiliency are not explicitly required in the CLCPA Phase 2 Order, we note that four substations proposed for rebuild in the Southern Tier are at least 93 years old (one is 80 years old). Additionally, seven circuits proposed for rebuild are at least 70 years old and another ten circuits are between 50 and 70 years old. Thus, the rebuilt facilities will improve both reliability and resiliency of the system.

Therefore, the NYPSC explicitly considered and made its decision, in part, based on the reliability and congestion reduction benefits of the Phase 2 Projects.

## VI. NEXUS TEST

**Q. DO THE INCENTIVES SOUGHT ADDRESS RISKS AND CHALLENGES FACED BY THE PHASE 2 PROJECTS?**

A. Yes. In Order No. 679 at P 26, FERC stated that "each applicant must demonstrate that there is a nexus between the incentive sought and the investment being made." In Order No. 679-A at P 21, FERC further clarified that "[i]n evaluating whether the applicant has satisfied the required nexus test, the Commission will examine the total package of incentives being sought, the inter-relationship between any incentives, and how any requested incentives address the risks and challenges faced by the project."

The incentives being sought in this Application are narrowly tailored to address demonstrable risks and challenges faced by Applicants in developing and constructing the Phase 2 Projects. First, the joint testimony of Andrea Vanluling and Michael Panichi provides relevant financial information to demonstrate how both the 100% CWIP Incentive and the Abandoned Plant Incentive address specific financial risks and challenges faced by Applicants in financing the significant capital investment required to construct the portfolio of Phase 2 Projects on the accelerated timeline contemplated by New York State. Second, the testimony of James Yeske Jr. provides details regarding a host of risks and challenges associated with the siting and construction of the Phase 2 Projects on an expedited schedule that demonstrates the risk that investment in one or

more of the projects may be abandoned for reasons beyond Applicants' control and how the Abandoned Plant Incentive addresses these risks.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.

# Exhibit 1

# February 16, 2023, NYPSC Order Approving the Phase 2 Projects Areas of Concern Transmission Upgrades, Case 20-E-0197

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 20-E-0197 - Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act.

# ORDER APPROVING PHASE 2 AREAS OF CONCERN TRANSMISSION UPGRADES

Issued and Effective: February 16, 2023

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on February 16, 2023

COMMISSIONERS PRESENT:

Rory M. Christian, Chair
Diane X. Burman, dissenting
James S. Alesi
Tracey A. Edwards
John B. Howard, dissenting
David J. Valesky
John B. Maggiore

CASE 20-E-0197 - Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act.

ORDER APPROVING PHASE 2 AREAS OF CONCERN TRANSMISSION UPGRADES

(Issued and Effective February 16, 2023)

BY THE COMMISSION:

## INTRODUCTION

With this Order, the Public Service Commission (Commission) takes another step in its implementation of the Accelerated Renewable Energy Growth and Community Benefit Act (Accelerated Renewables Act or Act).[1] As explained in prior orders, the Act requires the Commission and the Department of Public Service (Department) to plan the electric transmission infrastructure necessary to meet the renewable energy targets established in the Climate Leadership and Community Protection

[1] Chapter 58 (Part JJJ) of the Laws of 2020, §2(2)(b).

Act (CLCPA).[2] At issue here is the petition, filed on March 8, 2022, by Central Hudson Gas & Electric Corporation (Central Hudson), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), and Rochester Gas and Electric Corporation (RG&E) (collectively, Sponsoring Utilities or Companies), seeking authority to develop and construct local transmission upgrades whose primary function is to achieve the objectives established under those statutes (the Petition). As discussed below, the Commission grants the Petition and approves the proposed upgrades, with modifications. The Sponsoring Utilities are also authorized to seek cost allocation and cost recovery through the mechanisms identified in the Phase 2 Order.[3]

## BACKGROUND

On April 3, 2020, the Governor signed the Accelerated Renewables Act into law. Prior to the Act, the Commission's transmission infrastructure investment decisions were primarily driven by utility service obligations specified under Public Service Law (PSL) §§65 and 66 related to the provision of safe and reliable service at just and reasonable rates to the specific utility's customers. For over a century, the Commission has used the rate case process to align its capital investment, cost recovery, and cost allocation determinations with the utility's role as the electric service provider to its customers.

When it initiated this proceeding, the Commission recognized that the existing investment and funding paradigms

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[2] Chapter 106 of the Laws of 2019 (codified, in part, in Public Service Law §66-p).

[3] Case 20-E-0197, Order on Local Transmission and Distribution Planning Process and Phase 2 Project Proposals (issued September 9, 2021) (Phase 2 Order), pp. 34-35.

would not necessarily work for transmission projects intended to ensure compliance with the renewable energy mandates specified under PSL §66-p, as added under Section 4 of the CLCPA. The Commission stated that implementing the Accelerated Renewables Act would require it to "revisit the traditional decision-making framework that the Commission and the utilities have relied on up to now for investing in transmission and distribution infrastructure."[4] The necessity of investing in infrastructure for this new purpose set the Commission on course to develop new approaches to system investment, cost allocation, and cost recovery. The Commission responded to the Accelerated Renewables Act with a series of orders that established new categories of local transmission projects, new procedures for the evaluation of investment proposals, new mechanisms for cost allocation and recovery, new approaches to advanced transmission technologies, and new directives to the utilities relating to system planning.

As a first step, the Commission directed the utilities to identify CLCPA-supporting distribution and local transmission projects and to propose criteria for the evaluation of CLCPA-driven investments.[5] In response, the utilities submitted a large portfolio of potential projects in November 2020 (the November 2020 Filing).[6] In February 2021, the Commission issued the Phase 1 Order, which recognized two categories of potential upgrades, denominated "Phase 1" and "Phase 2," with Phase 1 consisting of those projects that are necessary to maintain safety and/or reliability but also facilitate the deliverability of renewable energy, and Phase 2 consisting of projects needed

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[4] Case 20-E-0197, Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (issued May 14, 2020)(Initiating Order), p. 4.

[5] Id., pp. 5-10.

[6] Case 20-E-0197, Utility Transmission and Distribution Investment Working Group Report (filed November 2, 2020).

solely to support new renewable generation sources.[7] The Commission has since authorized National Grid and NYSEG to continue development of a number of Phase 1 upgrades, subject to cost caps and review in either pending or upcoming rate filings.[8] However, the Commission has not, prior to this Order, approved any Phase 2 projects.

The Phase 2 Order

In the Phase 2 Order, the Commission addressed the parts of the November 2020 Filing that included the utilities' Phase 2 project proposals and evaluation criteria. The Commission required, among other things, the utilities to refine and resubmit their investment criteria and approach to benefit/cost analyses. At the same time, the Commission moved to resolve uncertainties relating to cost allocation and cost recovery principles for Phase 2 local transmission upgrades. The Commission determined that "statewide allocation to all customers of the Phase 2 investment costs is appropriate" and found that a "participant funding model," implemented through an agreement between the utilities and approved by the Federal Energy Regulatory Commission (FERC), can "efficiently accomplish the balancing necessary to achieve an equitable cost distribution throughout the State."[9]

While the Phase 2 Order deferred action on the Phase 2 projects and investment criteria, it also recognized a pressing need for investment in three regions of upstate New York. The

[7] Case 20-E-0197, Order on Phase 1 Local Transmission and Distribution Project Proposals (issued February 11, 2021)(Phase 1 Order), p. 5.

[8] Case 20-E-0197, Order Authorizing Development of Phase 1 Transmission Projects and Cost Recovery Measures (issued July 14, 2022); Order Authorizing Continuation of Phase 1 Transmission Projects and Cost Recovery Measures (issued December 15, 2022).

[9] Phase 2 Order, pp. 22, 30-31, 34.

Commission found these areas to be characterized by "the presence of existing renewable generation that is already experiencing curtailments and a strong level of developer interest that exceeds the capability of the local transmission system."[10] The Phase 2 Order identified these areas as Hornell and South Perry (NYSEG/RG&E), the Watertown/Oswego/Porter subzone (National Grid), and an area of southeastern New York consisting of facilities owned by NYSEG, National Grid, and Central Hudson. The same locations – referred to in the Phase 2 Order and here as the Areas of Concern (AOC) – are also identified by the New York Independent System Operator, Inc. (NYISO) in a recent study[11] as Z1, X2 and X3, and Y1 and Y2 in Figure 1 below.

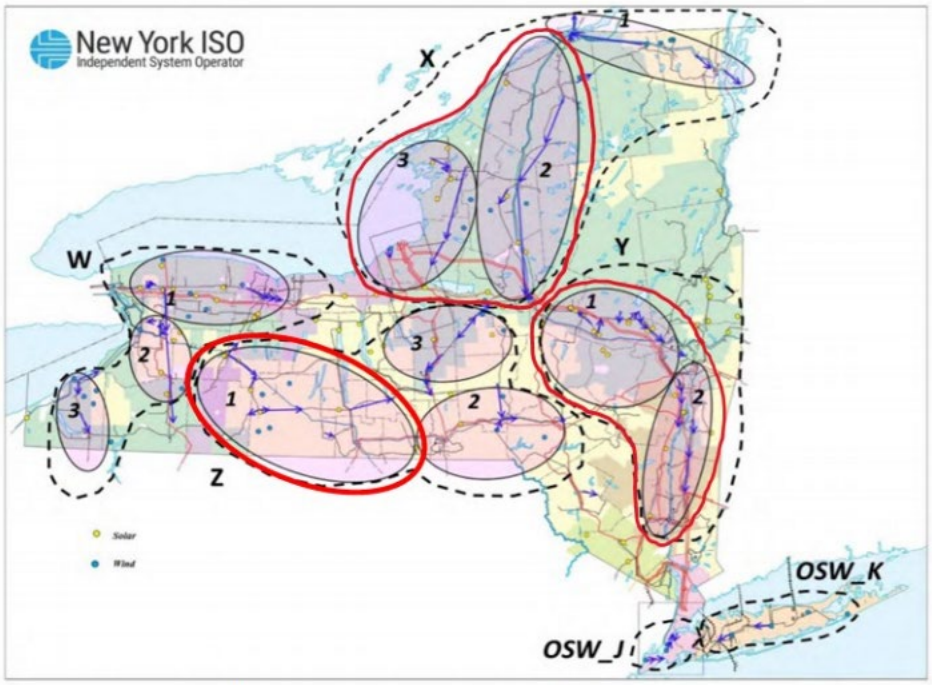


Figure 1: Areas of Concern

Finding that "the problem of existing and likely future curtailments in these areas justifies an immediate effort to

[10] Id., p. 34.

[11] New York Independent System Operator 2019 Congestion Assessment and Resource Integration Study (July 24, 2020), p. 86. https://www.nyiso.com/documents/20142/2226108/2019-CARIS-Phase1-Report-Final.pdf

explore cost-effective solutions," the Commission "directed the utilities serving those regions to propose cost-effective upgrades that would relieve the congestion limiting existing renewable generation and improve the deliverability of the renewable generation expected to develop in those parts of the State."[12] To guide the utilities' analysis, the Commission specified that "[a] close focus on the costs and benefits is needed because the Commission can only assess and prioritize Phase 2 projects on a well-supported and location-specific understanding of how the proposed upgrades support progress towards meeting the State's goals."[13] The Commission also specified that the filing "must also provide... an understanding of that need over different time horizons and show that the Phase 2 project is superior to alternatives, such as a possible Phase 1 investment or a bulk solution."[14]

Consistent with those objectives, the Phase 2 Order required the Sponsoring Utilities to use a specific methodology in developing potential transmission upgrades for the AOC. The Commission gave directions for projecting the likely generation build-out for both short-term and long-term horizons, as well as approaches to determining the incremental transmission capacity that would be needed to support the expected generation. The Commission's directives included the following steps:

- First, the Commission required the Sponsoring Utilities to identify the renewable generating projects that had reached "an advanced development" status in each AOC. The Commission directed the Sponsoring Utilities to include projects that (1) have awards from prior New York State Energy Research and Development (NYSERDA) procurements; (2) are operational or under construction; (3) are the subject of complete siting applications; or (4) are deemed likely to enter operation, which can be informed by

[12] Id., pp. 37-38.
[13] Id., p. 35.
[14] Id., pp. 35-36.

factors such as their status in the NYISO interconnection queue.

- Second, the Commission directed the Sponsoring Utilities to determine incremental transmission capacity (in MW) needed to unbottle the renewable generation projects modeled under the advanced development criterion. The Commission defined this investment as the Near-Term CLCPA Need.
- Third, the Commission instructed the Sponsoring Utilities to develop at least two options for transmission upgrades addressing the Near-Term CLCPA Need. The first option would be designed to fully eliminate curtailment risk for the modeled generation. The second option would eliminate "most, but not all" of that risk.
- Last, in order to assist the Commission's evaluation of the options presented for addressing the Near-Term CLCPA Need, the Commission directed the Sponsoring Utilities to estimate each region's long-term development potential (Long-Term Development Potential) using appropriate forecasts, including the Zero Emissions Study, the most recent NYISO Capacity Assessment and Resource Integration Study 70% renewables by 2030 case, NYSERDA surveys, the NYISO interconnection queue, and other sources. The Sponsoring Utilities were instructed to use "the most conservative sources or estimates" in their filing.[15]

The Phase 2 Order also addressed the need to establish appropriate cost allocation and recovery mechanisms for Phase 2 upgrades. There, the Commission found that Phase 2 costs are appropriately allocated to all customers. Additionally, the Commission stated that using a volumetric load share ratio allocator would be consistent with the funding principles underlying the State's existing environmental programs, such as Renewable Energy Certificate (REC), Offshore Wind Renewable Energy Certificate (OREC), and Zero Emission Certificate (ZEC) purchases. The Commission directed the Joint Utilities[16] to

[15] Id., pp. 36-39.

[16] The Joint Utilities consist of Central Hudson, Consolidated Edison Company of New York, Inc. (Con Edison), NYSEG, National Grid, Orange and Rockland Utilities, Inc., and RG&E.

develop and submit the details of the proposed participant funding agreement and cost allocation mechanism.[17]

The Cost Sharing and Recovery Agreement

On January 7, 2022, the Joint Utilities filed a Cost Sharing and Recovery Agreement (CSRA) reflecting their intention to allocate and pay the costs of local transmission projects developed to meet CLCPA targets according to each utility's volumetric load-ratio share. The CSRA includes the Joint Utilities' commitment to obtain approval from the Commission to proceed with any Phase 2 project. It also memorializes the Joint Utilities' agreement to use the lower of the return on equity (ROE) approved by the FERC or the Commission-approved ROE and capital structure applicable to their existing capital plans for local transmission and distribution investment, for purposes of cost recovery under Section 205 of the Federal Power Act. On April 20, 2022, the Joint Utilities filed a modified CSRA, which the Commission subsequently accepted on May 12, 2022.[18]

On June 21, 2022, the Joint Utilities filed the CSRA with the FERC for approval.[19] At the same time, the NYISO filed a request with the FERC to amend its Open Access Transmission Tariff (OATT) to add Rate Schedule 19, which would provide a mechanism by which it could administer the statewide cost allocation and recovery contemplated in the CSRA.[20] The FERC

[17] Phase 2 Order, pp. 31 and 48-49.
[18] Case 20-E-0197, Order Accepting Compliance Filings (issued May 12, 2022).
[19] Filings related to the CSRA can be found in FERC Docket No. ER22-2154.
[20] Filings related to the tariff revisions can be found in FERC Docket No. ER22-2152.

accepted the CSRA and the NYISO's Rate Schedule 19, effective August 22, 2022.[21]

## THE PETITION

As noted, the Sponsoring Utilities filed the instant Petition on March 8, 2022, proposing upgrades to their local transmission systems. The Petition asks the Commission to: (i) authorize the development and construction of the Sponsoring Utilities' transmission solution recommendations for each AOC planning region (AOC Projects); (ii) approve the use of regional cost allocation and recovery through the NYISO OATT, as approved by FERC (i.e., the CSRA); and (iii) approve deferral for future recovery of incremental operating expenses and related taxes associated with investments, return on capital investment (including initial and ongoing cost of removal), and depreciation associated with the AOC Projects, to the extent such costs are not recovered regionally through a NYISO OATT or through an existing rate plan.[22]

The Petition describes the state of generation development in the AOC planning regions, summarizes the study methodology employed, describes the extent of the congestion-related curtailments, and presents the proposed solutions. While details of the methodology are reflected in Attachment A to the Petition, the Sponsoring Utilities state that they used the inclusion rules specified in the Phase 2 Order to develop their model of the existing and expected generation. They explain how they used congestion and headroom calculations to determine the

[21] Docket No. ER22-2152-000 et al., Consolidated Edison Company of New York, Inc., et al., Order Accepting Proposed Cost Sharing and Recovery Agreement, Rate Schedule, Tariff Revisions, and Certificates of Concurrence (issued August 19, 2022).

[22] Petition, pp. 1-2.

Near-Term CLCPA Need and show how they developed the two alternative scenarios called for in the Phase 2 Order: one eliminating all generation curtailment affecting the modeled generation, and a second eliminating "most but not all" of the curtailment. Finally, the Petition states that the Sponsoring Utilities developed a forecast of the areas' Long-Term Development Potential, based on the NYISO interconnection queue, also as required by the Phase 2 Order.

Using the Commission's definition of "advanced development status," the Petition shows that the generation under development in the AOC regions significantly exceeds the amount of generation that is currently operational. The existing and expected generation in these regions, as determined by the Companies under the Phase 2 Order's inclusion rules, is provided in Table 1 below.

**Table 1: Existing & Expected Renewable Generation Near-Term (MW)**

| Area of Concern | Generator Pocket | Existing Solar and Wind Generation | NYSERDA Contract Awards Generation | Incremental NYISO - Queued Advance Stage of Development Generation | Near-Term Total |
|---|---|---|---|---|---|
| Northern NY | X2 and X3 | 80 | 570 | 754 | 1,404 |
| Capital | Y1 | 74 | 531 | 155 | 760 |
| Capital | Y2* | 0 | 70 | 40 | 110 |
| Southern Tier | Z1 | 535 | 175 | 1,234 | 1,944 |
| | Total > | 689 | 1,346 | 2,183 | 4,218 |

All values exclude Energy Storage since they are technically not renewables.

* Capital Region Y2 Renewable Generation above only includes Renewables interconnected to the North Catskill-Coxsackie 69 kV system which was found to be restricting for expected renewable output.

To comply with the Phase 2 Order's direction to determine the Near-Term CLCPA Need, the Sponsoring Utilities assessed the impacts the modeled generation would have on the current network. The Sponsoring Utilities studied the system with the existing and expected renewable generation operating at

100% and 70% of nameplate capacity to determine whether reliability violations would arise at those levels, requiring curtailment of the generation to avoid such violations. These analyses found the need for "significant curtailments for extended periods of time to keep equipment on the existing system operating within its current limits."[23]

The Sponsoring Utilities then developed upgrades designed to add capacity to the system and address the identified congestion. These were presented in the two scenarios specified in the Phase 2 Order and establish the No Curtailment and Limited Curtailment options.[24] The Sponsoring Utilities proposed 62 AOC Projects at an estimated cost of $4.414 billion. They explain that these upgrades, taken together, would provide 3,529 MW of capacity headroom and over 30,332 gigawatt hours (GWh) of energy headroom annually for renewable generation in these parts of the State. The Petition adds that the Sponsoring Utilities' modeling exercise used the Commission-approved headroom methodology for both assessing the curtailment and measuring the benefits that the proposed transmission solutions provide. The Petition further notes that all proposed AOC Projects were designed to meet local and regional planning criteria to ensure that the reliability of the planned system is not compromised per the reliability rules developed by the North American Electric Reliability Corporation, Northeast Power Coordinating Council, and New York State Reliability Council, as well as applicable utility specifications, procedures, and guidelines.

Table 2 below provides an overview of the 62 AOC Projects proposed by the Sponsoring Utilities. These AOC

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[23] Id., pp. 10-11. The Sponsoring Utilities' congestion assessment is presented in detail in Attachment B to the Petition.

[24] The Petition uses the term "Limited Curtailment" to mean the elimination of most, but not all, curtailment risk.

Projects consist of rebuilds of existing transmission lines, upgrades to existing substations, and construction of three new substations.

**Table 2: Summary of Proposed AOC Projects**

| Region/ Company | Zone | Pro-jects | Project Descriptions | In Service Dates | Proposed Cost ($millions) |
|---|---|---|---|---|---|
| Northern NY - National Grid & NYSEG | X2&3 | 28 | Rebuild/Upgrade 115 kV Lines (402 mi.); Upgrade 13-115 kV Substations; Construct 2 new greenfield 115 kV Substations; Install 4 Synchronous Condensers, 2-PARs and Dynamic Line Ratings. | 2024 - 2029 | $2,071.7 |
| Capital Porter Rotterdam - National Grid | Y1 | 1 | Construct new Marshville 345/115 kV greenfield Substation interconnecting 4-115 kV lines to Bulk System via Edic-Princetown AC Transmission Segment A 345 kV line. | 2028 | $81.3 |
| Capital North Catskill - Coxsackie - Central Hudson | Y2 | 1 | Rebuild/Upgrade 69 kV Line (9 mi.) to 115 kV Standards; initially operate at 69 kV. | 2029 | $15.7 |
| Southern Tier - NYSEG & RG&E | Z1 | 32 | Line Rebuilds: 230 kV (63 mi.); 115 kV (197 mi.); 34.5 kV (27 mi.). Substation Upgrades: new 345/115 kV and 230/115 kV transformers; 1-345 kV, 2-230 kV and 6-115 kV Substation Rebuilds/Upgrades (2 relocations out of flood plain), 7-115 kV voltage support installations; 1-115 kV power flow control device, minor 115 kV Substation upgrades. | 2024 - 2030 | $2,245.7 |
| TOTAL CLCPA AOC | | 62 | | 2024 - 2030 | $4,414.4 |

The remainder of the Petition details the proposed AOC Projects and discusses the benefits these investments would bring to New York consumers. In addition to the benefits associated with addressing climate change and meeting the CLCPA renewables mandates, the Sponsoring Utilities assert that all utility customers would benefit from decreased energy and congestion costs resulting from the projects, as well as added capacity for future beneficial electrification of transportation and heating. The Petition also notes that the proposed AOC Projects would

benefit local customers through improved resiliency and the "double benefit" of efficiency gain by replacing aging infrastructure with upgrades to create renewable pathways, thus satisfying both the immediate renewable needs and future asset replacement needs simultaneously.[25]

PUBLIC NOTICE

A Notice of Proposed Rule Making was published in the State Register on March 30, 2022 [SAPA No. 20-E-0197SP11]. The Secretary to the Commission also issued a Notice Soliciting Comments on April 21, 2022. The comment period under both notices concluded on May 31, 2022. Comments were filed by the Alliance for Clean Energy New York, Inc. (ACENY), Boralex Inc. (Boralex), EDF Renewables New York (EDFR), the Long Island Power Authority (LIPA), LS Power Grid New York Corporation I (LS Power), Multiple Intervenors (MI), NextEra Energy Transmission New York, Inc. (NEETNY), Steuben County Industrial Development Agency (Steuben County or IDA), Transource Energy, LLC and Transource New York, LLC (collectively, Transource), and the Working for Advanced Transmission Technologies Coalition (WATT).

SUMMARY OF COMMENTS

Alliance for Clean Energy New York, Inc.

ACENY urges the Commission to swiftly approve the projects proposed in the Petition on the basis of both their CLCPA benefits in unlocking current and future generation, as well as their role in replacing aging infrastructure. ACENY characterizes the upgrades proposed for the Southern Tier as "no-regrets" projects because the infrastructure would require replacement or investment by 2030, regardless of any CLCPA need,

[25] Petition, pp. 30-31.

and states that several of the proposed upgrades provide additional reliability and resilience benefits.

ACENY emphasizes that timely approval of the proposed upgrades is crucial to the development and construction of renewable energy projects and compliance with the CLCPA. According to ACENY, bid prices for Clean Energy Standard Tier 1 procurements would be higher and some renewable energy projects may not be able to begin construction until transmission constraints are addressed through approval of the proposed upgrades. ACENY recommends that the Commission prioritize and accelerate the upgrades because the projects are needed sooner to mitigate extreme congestion and significant curtailment of clean energy generators. ACENY believes that additional renewable energy projects should be included as "expected generation" in the forecast to reflect the interconnection queue more accurately. ACENY urges the Commission to require the Sponsoring Utilities to identify additional upgrades to eliminate curtailment of renewables that is expected to remain even assuming the AOC upgrades are approved and built.

ACENY suggests that the Commission direct National Grid to consult with stakeholders to discuss potential opportunities to increase headroom while reducing costs without delaying the upgrades. ACENY also suggests that the Commission consider greater utilization of Grid Enhancing Technologies such as dynamic line rating, advanced power flow controllers, and topology optimization, which it claims can lower transmission costs and create more near-term headroom.

Boralex Inc.

Boralex – an independent power producer that develops, builds, and operates renewable energy generation and energy storage facilities – expresses strong support for prioritizing and expediting transmission upgrade solutions in the AOC regions.

However, Boralex expresses its concern that in the Watertown/Oswego/Porter area, even if the proposed 100% dispatch scenario is adopted, additional curtailments would persist. Boralex recommends that the Commission order National Grid to consult with stakeholders again and submit an additional filing with an optimized upgrade proposal that reduces the cost and increases the effectiveness of the proposed upgrades. According to Boralex, while National Grid has engaged stakeholders' input, and no external stakeholder possesses the background, resources, and system data to evaluate all of the projects proposed in the Petition, Boralex believes that a stakeholder input session could help to explore potentially more cost-effective solutions to address the Watertown generation pocket.

Boralex highlights the strong interest of developers in the Watertown generation pocket and notes that any headroom created by the proposed AOC Projects would likely be insufficient for future growth well before the transmission upgrades come online. Boralex anticipates that if more of the renewable energy projects in the Watertown AOC were included in the Existing and Expected Generation volume, the cost of a bulk solution would outweigh the benefits of the proposed projects. Boralex suggests that such bulk solutions could be best pursued through a Public Policy Transmission Need (PPTN) process. Finally, Boralex indicates that Table 1 in Attachment B to the Petition incorrectly states that queue project 843 does not have a NYSERDA Contract Award.

EDF Renewables New York

EDFR identifies itself as an independent power producer and service provider exclusively focused on the development, ownership, and operation of renewable energy projects. EDFR urges the Commission to approve the upgrades proposed in the Watertown/Oswego/Porter and Hornell and South Perry Areas of

Concern. EDFR asserts that there is a clear and immediate need for the proposed upgrades because both existing and contracted clean energy resources are at risk of becoming distressed assets due to congestion and curtailment. EDFR also notes that the upgrades would also replace aging infrastructure and improve resiliency.

EDFR recommends that the Commission accelerate the timing of the proposed upgrades to reduce the impacts of curtailments on clean energy resources. EDFR also recommends consideration of grid enhancing technologies, such as dynamic line ratings, advanced power flow control, and topology optimization, to maximize the capacity of the grid and reduce congestion costs. While EDFR supports development of the proposed upgrades, it also recommends that the Commission declare PPTNs in the Watertown and Hornell and South Perry Areas of Concern. According to EDFR, declaring a PPTN would not necessarily require the approval of bulk solutions. EDFR believes that solutions could be developed as Phase 2 projects in the future Coordinated Grid Planning Process or/and as part of the NYISO's regional planning efforts through the PPTN process.

Long Island Power Authority

LIPA recommends that the Commission only approve the projects providing the most valuable headroom increases, which LIPA characterizes as "no regrets" solutions. LIPA urges the Commission to limit its approval to projects that are needed to unbottle existing generation or generation under construction. LIPA explains that changes to the grid are expected to occur by 2030, including increased energy storage capacity and increased electric load as a result of electrification of heating and transportation, both of which may reduce curtailments. LIPA suggests that the Commission require further evaluation of projects with headroom benefits that may not justify the costs.

LIPA notes that the costs per MWh of additional headroom vary across the proposed projects and recommends that the Commission consider the risk of potential cost overruns. In addition, because the Companies seek deferral and recovery of operating expenses and taxes, LIPA believes that those costs and the costs of financing the projects should be estimated and disclosed before a decision is made.

LS Power Grid New York Corporation I

LS Power advocates for a competitive process to solicit transmission solutions, which it believes could identify cheaper alternatives while mitigating risks and containing costs. LS Power recommends that the Commission direct a process to identify the lowest cost per MW to integrate renewable resources within the State. LS Power expresses concern that the Sponsoring Utilities' assumptions regarding renewable generation at an "advanced state of development" in each AOC do not accurately reflect projects likely to enter service. LS Power also suggests that an independent review by the NYISO could help determine whether more efficient or cost-effective solutions are available. According to LS Power, a competitive process would provide an even better approach, as the two completed processes have proven successful and have identified innovative solutions while containing costs. LS Power advises that there is sufficient time to conduct a competitive process for the Areas of Concern or that the Commission could establish a new process with reduced competition to identify solutions to be in service prior to 2030.

Multiple Intervenors

MI identifies itself as an association of over 50 large commercial, industrial, and institutional energy consumers located throughout the State. MI urges the Commission to authorize expenditures only for projects that are truly necessary at this time. MI expresses concern that the Sponsoring Utilities

appear to be seeking pre-approval of expenditures for proposed upgrades with cost estimates that are subject to a 50%/-25% variance. MI suggests that any approval be provided on a preliminary basis only and be subject to additional and updated justifications for each project with more detailed cost estimates. MI recommends that the expenses for the proposed upgrades be subject to a rigorous review by Department of Public Service Staff (Staff), similar to the review of capital projects in utility rate proceedings. In addition, MI calls upon the Commission to consider the present and future costs imposed on customers as a result of various programs and initiatives.

NextEra Energy Transmission New York, Inc.

NEETNY suggests that a competitive PPTN process could produce a more efficient and cost-effective expansion of headroom for the renewable capacity required by the CLCPA. It argues that the Sponsoring Utilities' assessment and selection process was insufficient in using headroom methodology to estimate energy curtailment without modeling and preforming hourly simulation using product cost models. NEETNY asserts that the local transmission upgrades proposed in the Petition are inadequate and do not provide the transmission solutions required to serve the amount of renewable energy necessary to meet CLCPA goals. NEETNY asserts that the upgrades were designed to address a near-term CLCPA need and that only a fraction of the projects in the NYISO interconnection queue were included in the Sponsoring Utilities' assessment of that need. Instead, NEETNY believes that a bulk power solution could produce greater headroom in the longer-term at nearly 60% lower costs compared to the proposed near-term upgrades proposed in the Petition. NEETY also notes that a PPTN process would allow for the inclusion of cost containment provisions to provide an incentive for developers to construct projects efficiently. According to NEETNY, a combination of bulk

and lower-voltage projects may provide the most cost-effective solution.

Steuben County Industrial Development Agency

Steuben County IDA expresses support for NYSEG's Petition and regional cost allocation and recovery through the NYISO tariff. The Steuben County IDA explains that the CLCPA is driving demand for solar and wind development that will benefit all state residents and, consequently, the costs to upgrade the electric grid and construct the proposed transmission solutions should be distributed equitably across all state residents.

It notes that Steuben County has 845 MW of wind and solar power online or coming online in the next 18 months, as well as eight community-scale solar projects for which costs to interconnect to the NYSEG system account for over 10% of total project budgets. Steuben County IDA indicates that high interconnection costs have halted development in parts of Steuben County. According to Steuben County IDA, in other parts of Steuben County, NYSEG has told developers that there is not enough capacity in the system to interconnect because of bottlenecks. Steuben County IDA asserts the upgrades proposed in the Petition are urgently needed to make traditional economic development projects feasible and enable renewable energy projects that are necessary to meet CLCPA goals.

Transource Energy, LLC and Transource New York, LLC

Transource expresses support for the Sponsoring Utilities' request for authorization to develop the proposed projects. However, Transource believes that advanced transmission technology should be given additional consideration in the design and procurement phases of project development. Specifically, Transource asserts that the use of existing advanced transmission technologies could lower project costs, reduce environmental and aesthetic impacts, and provide a sounder

foundation to unbottle renewable generation in the Areas of Concern.

Transource characterizes the analysis in the Petition of advanced transmission technologies as "little more than a box-checking alternatives analysis" that did not go beyond the list established in the Phase 1 Order and incorporated into the Phase 2 Order. Transource asks the Commission to clarify that there is no exhaustive list of potential or existing advanced transmission technologies. Transource suggests that the Sponsoring Utilities evaluate one of Transource's technologies, which it indicates is already in service or under construction in other states. Transource requests that the Commission condition its approval of the proposed upgrades on a supplemental review of advanced transmission technologies that are already in service or under construction in New York or other states, and a process by which such review would occur.

Working for Advanced Transmission Technologies Coalition

WATT identifies itself as a not-for-profit organization focused on facilitating the adoption of advanced technologies on the electric transmission system that improve reliability, lower costs, and accelerate decarbonization. According to WATT, Grid Enhancing Technologies (GETs), such as dynamic line ratings, topology optimization, and advanced power controls, can provide significant and cost-effective benefits in the near-term with short lead-times and minimal community impact. WATT discusses the benefits of GETs and highlights two recent reports on GETs from the United States Department of Energy. WATT urges the Commission to advance the timeline for Phase 1 GETs projects alongside or ahead of the projects at issue in the Petition, recognizing that GETs can be quickly deployed so ratepayers can realize the near-term benefits while longer-term transmission development proposals are considered.

## LEGAL AUTHORITY

The Act directs the Commission and the Department to take action to ensure that renewable energy can be efficiently and cost-effectively injected into the State's transmission and distribution system for delivery to regions of the state where it is needed.[26] The Act requires the Commission to develop plans that "provide for the timely development of local transmission and distribution upgrades by the State's regulated utilities" and LIPA.[27]

In addition, the PSL provides the Commission with broad authority to direct actions to ensure that energy supplies and transmission resources are adequate to meet demand in a manner that is protective of the environment. In particular, PSL §4(1) expressly imbues the Commission with "all powers necessary or proper to enable [the Commission] to carry out the purposes of [the PSL]" which include, without limitation, the provision of safe and adequate service at just and reasonable rates,[28] environmental stewardship, and the conservation of resources.[29] Further, PSL §5(1) provides that the "jurisdiction, supervision, powers and duties" of the Commission extend to the "manufacture, conveying, transportation, sale or distribution of ... electricity." Under PSL §5(2), the Commission is required to "encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs,

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[26] Act §7(2).

[27] Act §7(3).

[28] See Int'l Ry. Co. v. Pub. Serv. Comm'n, 264 A.D. 506, 510 (1942).

[29] PSL §5(2); see also Consolidated Edison Co. of N.Y., Inc. v. Pub. Serv. Comm'n, 47 N.Y.2d 94 (1979) (overturned on other grounds) (describing the broad delegation of authority to the Commission and the Legislature's unqualified recognition of the importance of environmental stewardship and resource conservation in amending the PSL to include §5).

individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources."

Section 65(1) of the PSL grants the Commission authority to ensure that "every electric corporation and every municipality shall furnish and provide such service, instrumentalities and facilities as shall be safe and adequate and, in all respects, just and reasonable." The Commission has further authority under PSL §66(5) to prescribe the "safe, efficient and adequate property, equipment and appliances thereafter to be used, maintained and operated for the security and accommodation of the public" whenever the Commission determines that the utility's existing equipment is "unsafe, inefficient or inadequate." Moreover, PSL §66(2) provides that the Commission shall "examine or investigate the methods employed by ... persons, corporations and municipalities in manufacturing, distributing and supplying ... electricity ... and have power to order such reasonable improvements as will best promote the public interest, preserve the public health and protect those using such ... electricity." The actions taken in this Order fall within the scope of this authority.

## DISCUSSION

The rapid growth of renewable generation in the AOC, combined with the relatively slow pace of transmission development, has created the congestion conditions this Order seeks to alleviate. As noted above, the Phase 2 Order included the finding that immediate action to address this problem was necessary.[30] Because the Commission was deferring action at that time on the Joint Utilities' proposed evaluation criteria for

[30] Phase 2 Order, p. 35.

CLCPA transmission investments, it laid out a case-specific method for identifying and evaluating AOC upgrade proposals. The objective of this approach was to assess AOC upgrades "on a well-supported and location-specific understanding of how the proposed upgrades support progress towards meeting the State's goals."[31] The Commission intended that approach to provide a means for determining the level of investment necessary to support existing and anticipated future generation development in the AOC.

The Commission recognized that identifying the "correct" level of investment would be complicated by the difficulty of predicting how and where future generation would be developed. The Commission's directions to the Sponsoring Utilities included several requirements designed to address this problem and to reduce the risk to ratepayers of over-building transmission infrastructure. Thus, the Phase 2 Order directed the Sponsoring Utilities to model only the renewable resources located in these regions that had reached an advanced stage of development. The Commission defined "projects in advanced development" to include (1) projects with NYSERDA contracts; (2) projects in operation or under construction; (3) projects whose siting approval applications were complete; and (4) projects likely to enter operation. For this last category, the Commission instructed the Sponsoring Utilities to work with Staff to designate a milestone in the NYISO interconnection process to distinguish between mature and less mature projects.[32]

The Phase 2 Order directed the Sponsoring Utilities to use the specified renewable generation as the basis for determining the Near-Term CLCPA Need, which the Commission defined as the incremental transmission capacity needed to unbottle those existing and expected renewable generation

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[31] Ibid.

[32] Id., p. 36.

projects. The Commission directed the Sponsoring Utilities to propose different levels of potential transmission upgrades to address the Near-Term CLCPA Need reflecting two scenarios: the first would eliminate all curtailment risk for the generation resources represented in the projection; and the second would eliminate "most, but not all" curtailment risk to those resources. These options were intended to illustrate the level of investment needed to support the generation projects most likely to advance to construction and operation.

The Commission next required the Sponsoring Utilities to estimate the Long-Term Development Potential for renewable generation in the AOC.[33] This long-term projection was intended to help the Commission understand the risk of either over-building or under-building transmission sized to support the generation modeled in determining the Near-Term CLCPA Need. The Phase 2 Order directed the Sponsoring Utilities to use conservative forecasts and estimates of the renewable resource potential of each area to support the evaluation of how well proposed solutions to the Near-Term CLCPA Need would support future growth.

The Commission's evaluation of the Sponsoring Utilities' analytical methods and the resulting project proposals are detailed in the Appendix to this Order. As discussed in the Appendix, the Commission finds that the evaluation framework reflected in the Petition, including the Sponsoring Utilities' evaluation of the curtailment options (i.e., Limited Curtailment versus No Curtailment options), complies with the Phase 2 Order. The Commission also finds that the Petition appropriately takes into account that any proposed upgrades must mitigate deliverability violations caused by thermal overloads and low voltage violations that would otherwise lead to curtailment of

[33] Id., pp. 38-39.

renewable generator outputs. For the reasons discussed below, the Commission approves the proposed AOC Projects, as modified herein, with a total estimated expenditure of $4.382 billion, which is approximately $33 million less than the total sought in the Petition. The AOC Projects authorized for development would add a total of 3,429 MW of capacity headroom in these regions by 2030, with some of the upgrades coming into service as early as 2024.

Assessment of Proposed AOC Projects

1. Assessment of AOC Generation Development

The Petition based the proposed AOC Projects on an analysis framework that started with an assessment of the Near-Term CLCPA Need, which is "the incremental local transmission system investment necessary to unbottle the renewable energy projects that have reached an advanced development status."[34] The Commission finds that the Sponsoring Utilities' modeling of the existing and expected renewable generation complies with the directions given in the Phase 2 Order. The analysis described in the Appendix confirms that the Sponsoring Utilities used the inclusion rules we established for this study. Additionally, the Sponsoring Utilities' projections for long-term generation growth in the Areas of Concern suggest that the calculation of the Near-Term CLCPA Need underestimates the amount of transmission investment that will be required as the system approaches the CLCPA targets. The Commission also notes the concern of some commenters (e.g., ACENY, Boralex, and NEETNY) that the Sponsoring Utilities' assessment of the Near-Term CLCPA Need does not accurately reflect generation development interest in these regions of the State.

There is reason to believe that even the Sponsoring Utilities' long-term forecast is overly conservative. As

[34] Id., p. 36.

required under the Phase 2 Order, the generation modeled by the Sponsoring Utilities included renewable projects under contract only through NYSERDA's 2020 solicitation.[35] However, since that time, NYSERDA has issued a 2021 solicitation through which it has entered into contracts for 410 MW of additional renewable generation within the Areas of Concern. In addition, more applications have progressed in the NYISO interconnection queue since the time the Sponsoring Utilities ran their studies, resulting in 200 MW of additional Near-Term CLCPA Need. Table 3 below provides the Sponsoring Utilities' Near-Term and Long-Term renewable forecasts as well as the Updated Near-Term and Long-Term forecasts based on the events that have occurred in the interim.[36] Figure 2 below provides the same comparison in a graph format.

**Table 3: Near-Term and Long-Term Renewable Generation**

| Area of Concern | Generator Pocket | Companies' AOC Petition | | Updated Need | |
|---|---|---|---|---|---|
| | | Near-Term | Long-Term | Near-Term | Long-Term |
| Northern NY* | X2 and X3 | 1,404 | 1,989 | 1,715 | 3,058 |
| Capital | Y1 | 760 | 1,200 | 950 | 1,200 |
| Capital | Y2** | 110 | 110 | 110 | 110 |
| Southern Tier | Z1 | 1,944 | 2,744 | 2,053 | 2,789 |
| | **Total >** | **4,218** | **6,043** | **4,828** | **7,157** |

All Values exclude Energy Storage since they are technically not renewables.

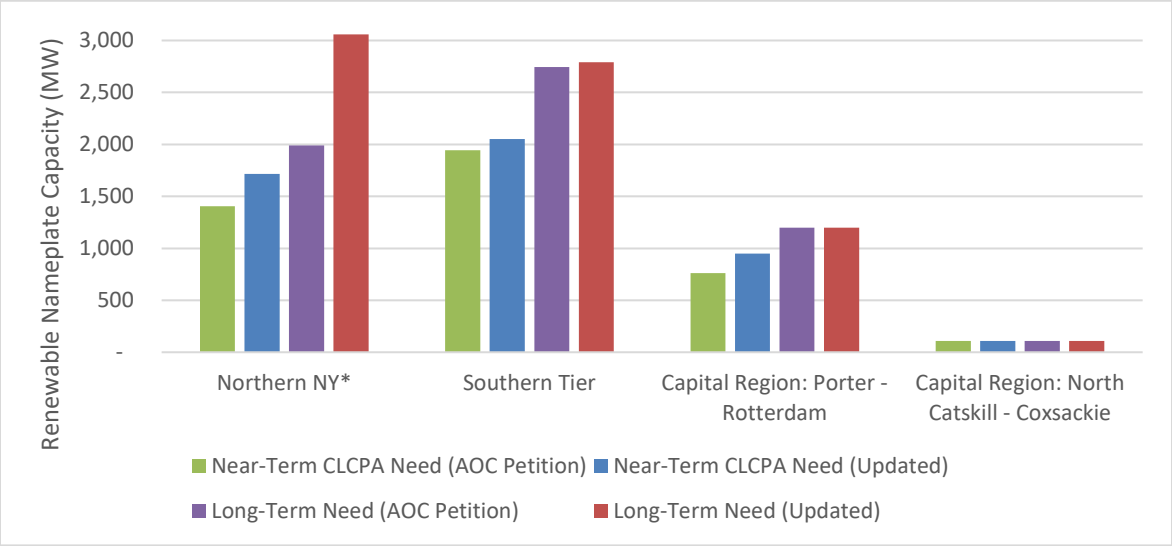
* Northern NY excludes Renewable Generation interconnected to the 230 kV system (projected to be an additional 3,587 MW) since it has a lesser impact on the Northern NY 115 kV system.

** Capital Region Y2 Renewable Generation above includes renewables interconnected to the North Catskill-Coxsackie 69 kV system which was found to be restricting for expected renewable output.

**Figure 2: Forecasted Needs in Petition and as Updated**

[35] Petition, pp. 8-9.

[36] The Updated forecasts in Table 3 indicate a Long-Term need to support over 7 GW of renewable generation, which is an increase of over 1 GW compared to the AOC Petition Long-Term forecast. The Updated Long-Term CLCPA Need cited in Table 3 includes renewable generation in operation and in all stages of the NYSISO interconnection queue.




This information indicates that the universe of projects qualifying now as "in advanced development" has grown significantly from what was assumed for the Sponsoring Utilities' analysis.[37] We can infer from this evidence of continuing high developer interest in these regions that the risk of near-term overinvestment in transmission is low. In other words, we find that the generation growth assumed as the foundation for the Sponsoring Utilities' determination of the Near-Term CLCPA Need is a conservative basis upon which to propose local transmission solutions.

2. Evaluation of Two Scenarios for Near-Term CLCPA Need

We also accept the Sponsoring Utilities' methodology for developing the two required scenarios illustrating the Near-

[37] Boralex commented that the Petition incorrectly identifies one of its projects – Sandy Creek Solar – as not having a NYSERDA contract. We agree that the project was awarded in NYSERDA solicitation RESRFP19-1 and is incorrectly labeled in Table 1 of Attachment B of the Petition. However, Sandy Creek Solar was included in the 1,404 MW of renewable generation modeled by National Grid in the assessment and therefore the error in Table 1 does not impact our determination on the validity of the assessment or project recommendations.

Term CLCPA Need. As described in the Petition, and discussed in the Appendix, the Sponsoring Utilities studied the system impacts of the modeled generation operating at 70% and at 100% of nameplate capacity. We find that the studies based on the 100% dispatch level illustrate the upgrades needed to avoid all curtailments, as required by the Phase 2 Order. Similarly, we accept the Sponsoring Utilities' choice of testing the system at the 70% level as a reasonable response to our directives. We recognized in the Phase 2 Order that upgrades could have varying deliverability benefits and different levels of cost-effectiveness.[38] Testing the system using the 70 percent dispatch level serves our purpose by providing insight into the incremental cost-effectiveness of the proposed upgrades.

Also, in compliance with the Phase 2 Order, the Sponsoring Utilities included approved Phase 1 local transmission projects and other planned network upgrades in the study models. The analyses performed in the Petition on these assumptions were reasonable and appropriate. Those analyses found that reliability violations would occur under both dispatch scenarios such that curtailment of the generation would be required to avoid damage to utility equipment. As explained in the Petition, "[w]hen a generator causes a power flow condition that exceeds the capabilities or ratings of system equipment extensive damage can occur. To prevent this equipment damage, system operators would need to curtail the generation output to ensure the equipment is operated within its capabilities."[39] The analyses allowed the Sponsoring Utilities to determine the specific network elements limiting the deliverability of existing and expected renewable generation in the Near-Term and to calculate

[38] Phase 2 Order, p. 37.
[39] Petition, p. 10.

the incremental headroom required to solve the reliability problems.

Table 4 identifies the incremental headroom calculated by the Sponsoring Utilities, as needed, and the incremental headroom provided by the proposed AOC Projects.

**Table 4 - Incremental Headroom Need and Headroom Provided by Proposed AOC Projects**

| Area of Concern/Companies | Generator Pocket | Incremental Capacity Headroom | |
|---|---|---|---|
| | | Expected Needs* (MW) | Amount Provided by AOC Projects (MW) |
| Northern NY - National Grid & NYSEG | X2 & X3 | 1,080 | 1,150 |
| Capital Porter Rotterdam - National Grid | Y1 | 280 | 360 |
| Capital North Catskill-Coxsackie - Central Hudson | Y2 | 15 | 43 |
| Southern Tier - NYSEG & RG&E | Z1 | 1,283 | 1,876 |
| TOTALS > | | 2,658 | 3,429 |
| *As proposed by the Sponsoring Utilities and accepted by the Commission, Capacity Headroom needs for Regions X2&3, Y1, and Y2 are No Curtailment needs and Region Z1 is the Limited Curtailment need. | | | |

3. Development of Local Transmission Solutions

Having identified the reliability violations and the limiting elements, the Sponsoring Utilities then designed and tested solutions that would provide enough capacity to meet the Near-Term CLCPA Need. As directed by the Phase 2 Order, the Sponsoring Utilities identified solutions for both a Limited Curtailment option and the No Curtailment option. The No Curtailment option produced solutions designed to "correct for existing deliverability constraints" caused by the modeled

generation operating at levels up to 100% of the nameplate rating.[40] The Limited Curtailment option corrected the constraints resulting from the same generation operating at the 70% level. To put it another way, the upgrades identified for the Limited Curtailment option were designed to facilitate delivery of 70% of the assumed generation capacity while the No Curtailment option upgrades support delivery of up to 100% of that capacity.

As required by the Phase 2 Order, the Sponsoring Utilities' solutions were developed using the Commission's approved method for calculating Capacity and Energy Headroom. The Sponsoring Utilities calculated and submitted the per unit costs of creating the necessary headroom for both the No Curtailment and Limited Curtailment options. It is important to note that the Sponsoring Utilities' use of a presumed 70% utilization in the Limited Curtailment option was not intended to denote that the upgrades proposed under this scenario would result in curtailing renewable generation by 30%. In actual operations, all renewable generators are not likely to be generating at full output simultaneously for a number of reasons, including the daily and annual weather pattern variations that impact the amount of energy that these intermittent resources produce and equipment outages. This diversity between simultaneously available renewable outputs tends to reduce the actual level of curtailment experienced in real time. Additionally, we note that the study methodology for calculating headroom is based upon the worst-case and most restrictive conditions. In actuality, these worst-case conditions only occur for a portion of the year.

Nonetheless, the Petition points out that under the 70% Limited Curtailment option, some renewable output would still be

[40] Id., p. 15.

curtailed.[41] In contrast, as explained in the Appendix, the upgrades associated with the No Curtailment Option would assure full deliverability for the modeled generation based on the study assumptions used. Notably, each of the existing systems in the four AOC regions currently provides a certain, though not sufficient, level of deliverability for the existing and expected renewables (i.e., renewable curtailments will occur, but not unconditionally). Thus, the incremental headroom provided by the upgrades is not necessarily required to equal the renewables needs, as stated on Table 1, provided the resulting deliverability needs are met.

Based on our review of the Petition, the Commission finds that the Sponsoring Utilities' solutions were developed using the Commission's approved Headroom method, and properly computed the Capacity and Energy Headroom, including their per unit costs within each Area of Concern, for both the No Curtailment and Limited Curtailment options.[42] The Commission thus finds that the Sponsoring Utilities' approach to developing solutions to the Near-Term CLCPA Need complies with the requirements of the Phase 2 Order, and that the two scenarios reported provide a reasonable basis for comparing the benefits and cost-effectiveness of the proposed upgrades.

4. Evaluation of Proposed AOC Projects

The Commission's review of the upgrades proposed in the Petition is summarized in Table 5 below. As detailed in the Appendix, the Commission approves the upgrades associated with the 100% dispatch scenario (i.e., the No Curtailment Option), except with respect to the proposed projects in the Southern Tier Region, where the Commission finds that the Limited Curtailment Option is appropriate. As discussed in more detail in the

41 Ibid.
42 Id., p. 40.

Appendix and as summarized in Table 5, the Commission accepts the Sponsoring Utilities' analysis of the proposed curtailment options (i.e., Limited Curtailment versus No Curtailment) and approves the 62 projects proposed by the Sponsoring Utilities, with modifications.

The AOC Projects proposed in the Petition consist mainly of transmission line and substation rebuilds and upgrades, and are intended to mitigate deliverability violations caused by thermal overloads and low voltage violations, which would otherwise lead to curtailment of renewable generator outputs. Overall, the Commission authorizes a total expenditure on AOC Projects of $4.382 billion, which amounts to $33 million less than originally proposed in the Petition. To meet the deliverability needs of existing and expected renewables - which in some cases will provide a certain level of surplus headroom for longer term needs - the AOC Projects are expected to add a total of 3,429 MW of Capacity Headroom by 2030 with some of the projects coming into service as early as 2024. The per unit costs for these regional improvements in headroom range from $0.37 million per MW to $1.80 million per MW, with an overall average of $1.28 million/MW.

**Table 5: Approved CLCPA AOC Project Options**

| Region/ Companies | Study Dispatch | Renew-able Output (Dis-patch) (MW) | Surplus (Deficient) Capacity Headroom with Dispatched Amount* (MW) | Accepted Cost $millions | Incremental Headroom (AOC Projects) | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Capacity Headroom | | Energy Headroom | |
| | | | | | MW | $million/ MW | Annual GWh | $/MWh |
| Northern NY (X2&3) - National Grid & NYSEG | 100% | 1,404 | 70 | $2,071.7 | 1,150 | $1.80 | 13,106 | $3.95 |
| Capital Porter Rotterdam (Y1) - National Grid | 100% | 760 | 80 | $81.3 | 360 | $0.23 | 3,960 | $0.52 |
| Capital North Catskill-Coxsackie (Y2) - Central Hudson** | 100% | 110 | 28 | $15.7 | 43 | $0.37 | 424 | $0.93 |
| Southern Tier (Z1) - NYSEG & RG&E*** | 70% | 1,433 | 593 | $2,212.4 | 1,876 | $1.18 | 12,842 | $4.31 |
| TOTALS > | | 3,707 | 771 | $4,381.1 | 3,429 | $1.28 | 30,332 | $3.61 |

* Surplus or Deficient Capacity Headroom is the amount of Capacity Headroom remaining with the Dispatched Renewables already on-line.

** Capital Region Y2 Renewable Generation Dispatch above and associated Headroom results only pertain to the North Catskill-Coxsackie 69 kV system, which was found to be restricting for expected renewable output.

*** The Southern Tier Cost is a $33.3 million reduction of the Companies' original proposed AOC cost of $2,245.7 million (no change in number of projects).

The Commission notes that many of the entities that provided comments in response to the Petition agree that significant transmission upgrades are necessary to support both existing and anticipated renewable generation. For example, as noted above, ACENY, Boralex, EDFR, and Steuben County IDA each urges the Commission to take prompt action to approve the projects proposed in the Petition based on the need to unlock current and future renewable generation. The Commission agrees with these commenters that infrastructure upgrades in the Areas of Concern are necessary to support both existing and anticipated

renewable generation. However, a key issue is predicting how much investment is required to address the problem when the future progress of generation development cannot be perfectly predicted. In other words, when there is a difference in cost, the Commission must consider whether to fund infrastructure to meet the No Curtailment Option or the Limited Curtailment Option.

The Appendix lays out details comparing the costs and benefits of the projects proposed for the No Curtailment and Limited Curtailment alternatives for each area. We also take into consideration the long-term projection for generation development submitted with the Petition and the additional updates discussed above, which show that the pool of generation projects that would qualify as being in advanced development today is considerably larger than the amount assumed in the Sponsoring Utilities' models. In summary, the Commission approves the upgrades needed to resolve all curtailments in the Northern New York and the Capital regions, and the upgrades identified for the Limited Curtailment Option for the Southern Tier area.

Our approval of projects in the Northern New York Region (X2 and X3) rests primarily on the certainty of considerable future generation development in these areas. As explained in the Appendix, investing to meet the No Curtailment option is appropriate even though that option has a higher per unit cost because the proposed upgrades would not only provide greater headroom to serve the assumed Near-Term need but would also support this region's Long-Term renewable development potential. We note that the updated projection for renewable generation in this region (as shown on Table 3 above) is over twice the amount assumed for the studies and significantly higher than the Sponsoring Utilities' projection for the long-term need. This evidence of continuing high developer interest in these

regions provides reassurance that the risk of overbuilding in the near-term here is low. Where a high level of future generation development is more certain, we can be reasonably confident that the higher level of investment is likely to be necessary. For these reasons, we approve the proposed AOC Projects for the Northern New York Region (X2 and X3).[43]

In the case of the Capital (Porter-Rotterdam) Region (Y1) and the Capital (North Catskill-Coxsackie Region (Y2), the Commission approves the No Curtailment option because the proposed projects are the same under both scenarios and there is no cost difference to evaluate. The same investment will provide sufficient headroom under both No Curtailment and Limited Curtailment options and will support future needs.

Last, with respect to the proposed upgrades in the Southern Tier Region (Z1), we find that the Limited Curtailment option is reasonable and appropriate for several reasons. First, as demonstrated in the Appendix, this option has the lowest per unit cost of incremental headroom. Second, the upgrades provide a sizeable surplus of headroom above the Near-Term CLCPA Need and thus should accommodate additional renewable development, depending on future generation siting locations. In contrast to the Northern New York areas, the updated generation growth projection for this region does not significantly exceed the Long-Term potential identified in the Petition, and thus the No Curtailment Option would present a higher risk of over building. In addition, the projects proposed for this option have a lower

[43] We also note that the No Curtailment Option provides greater flexibility for interconnection of renewables and greater improvement in reliability, safety, and resiliency as compared to the Limited Curtailment Option. While this is not the basis for our decision here, we note that it supports the reasonableness of this investment choice.

execution risk, which helps assure completion by 2030, and are scalable to help accommodate future development needs.

Notably, while concurring with the need for the proposed AOC Projects, several commenters raised concerns with respect to both the speed of transforming the grid to comply with the CLCPA's renewables mandates and the focus of the Petition on local transmission upgrades. For example, ACENY and EDFR commented that the upgrade schedule should be accelerated. We concur that there is a need for prompt action but find that the Sponsoring Utilities' completion schedules are already aggressive. The Sponsoring Utilities have proposed to undertake a complex portfolio of projects for completion by the mandated 2030 deadline. Given our experience with transmission development, the Commission believes that the schedule associated with the AOC Projects approved here represents the most expeditious pathway that is feasible.

ACENY also requests that the Sponsoring Utilities be required to identify additional upgrades to eliminate expected curtailments even after AOC upgrades are built. The Commission will not impose such a requirement here. The Coordinated Grid Planning Process is intended to identify additional upgrades needed going forward.[44] ACENY and Boralex commented that National Grid should consult with stakeholders again to optimize upgrades proposed for the Northern NY Region. We note that National Grid has consulted with stakeholders, along with the other Sponsoring Utilities, and we expect such consultations to continue within the Coordinated Grid Planning Process.

Several entities, including Boralex, recommend that the Commission declare a Public Policy Transmission Need (PPTN) in the Northern NY and/or the Southern Tier Regions authorizing the

[44] Case 20-E-0197, Coordinated Grid Planning Process Proposal (filed December 27, 2022, as updated January 5, 2023).

NYISO to use its Public Policy Transmission Planning Process to solicit and evaluate bulk alternatives against the proposed transmission projects. While we note that at least one bulk alternative was considered, we do not believe a PPTN finding with respect to these regions is appropriate at this time. Proposals for public policy transmission needs have been submitted in the NYISO's ongoing planning process, which the Commission will act on in due course.[45] Furthermore, as noted above, the Commission expects that the Coordinated Grid Planning Process will re-evaluate these areas of the State in the future and provide recommendations on the need for local and bulk transmission solutions.

Transource and WATT each commented that the Petition insufficiently evaluated and adopted advanced transmission technologies and grid enhancing technologies in considering potential AOC Projects. We disagree with this assertion and believe the Sponsoring Utilities complied with existing directives, properly considered advanced technologies and GETs, adopted them where effective, and rejected instances in which they were shown to be infeasible or inferior compared to the proposed AOC Projects.

For their part, LIPA and MI commented that the proposed AOC Projects should not be undertaken until they are actually needed. We believe the evidence of need is compelling, especially given the time frames for transmission development and construction. These parties also comment that the data provided for the proposed projects and the subsequent review of those projects should be similar to that of a rate case. The Commission does not share this concern. The data provided by the

[45] The Commission is considering the proposed Public Policy Transmission Needs submitted by the NYISO on November 7, 2022 in Case 22-E-0633.

Sponsoring Utilities, including the cost estimates, is as detailed and refined as rate case submittals. For example, the Petition includes detailed descriptions of the existing system, renewable needs, assumptions and approaches used in the associated study, and detailed descriptions and rationales for the proposed AOC Projects. Additionally, the Technical Assessment of the projects in the Appendix is consistent with the approach to similar evaluations in the rate case context.

For all of the reasons identified above, the Commission finds that the AOC Projects, as modified in Table 5 above, are necessary to address the Near-Term CLCPA Need.

Ratepayer Impacts

This Order is being issued by the Commission pursuant to the requirement under Section 7(3) of the Accelerated Renewables Act to identify "local transmission upgrades that ... are necessary or appropriate to achieve the CLCPA [renewables] targets" under "a prioritized schedule upon which each such upgrade shall be accomplished." Having found that the projects at issue are justified, it remains incumbent on the Commission to maintain transparency with respect to the potential cost impacts of the AOC Projects on ratepayers. However, we would be remiss if we did not also consider the costs to ratepayers should we fail to take action to address the transmission constraints in the Areas of Concern associated with delivering renewable energy to load.

1. Rate Impacts Associated with Costs of AOC Projects

By this Order, we are authorizing construction of 62 AOC Projects. We estimate the construction cost of the authorized AOC Projects at approximately $4.38 billion, based on the Sponsoring Utilities' submittals. However, given the stage of development of the projects, the Sponsoring Utilities indicate that their construction cost estimates range in accuracy from

minus 25% to plus 50%, meaning actual costs to construct the projects may range from $3.3 billion to $6.6 billion. The full impact of the AOC Project costs will be borne by ratepayers in the future as the projects come into service. We estimate the annual revenue requirement of these projects, once all components are operational, to be between $657 million and $1.315 billion per year. These estimates assume that the first-year revenue requirement will be 20% of the construction cost.

Since the AOC Projects consist of transmission plant upgrades with long service lives, the revenue requirements associated with the AOC Projects will decrease slowly over time as the assets are depreciated. The revenue requirements will be recovered through supply rates administered by the NYISO. The NYISO forecasts 149,020 GWh of energy sales for the calendar year 2030 in the New York Control Area.[46] Assuming similar state-wide energy consumption, the revenue requirement associated with the AOC Projects is estimated to increase energy costs by 5.9 mills per kWh. Using the Companies' range of construction cost estimates, energy cost increases are estimated to be between 4.4 and 8.8 mills per kWh. These estimates are likely aggressive over a longer term given that energy sales levels are forecasted to rise due to the State's heating and transportation sector electrification efforts under the CLCPA.[47]

With these caveats, Table 6 below shows the estimated impacts, in dollars annually, of the AOC Projects for typical customers assuming the above noted energy price increase estimates. Table 7 below shows the estimated ratepayer impact,

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[46] Source: NYISO 2022 Load & Capacity Data Report, p. 23. https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf/cd2fb218-fd1e-8428-7f19-df3e0cf4df3e

[47] Id. The NYISO forecasts over a 20% increase in energy sales across the State between 2030 and 2040 and over a 30% increase between 2030 and 2050.

as a percentage, of the dollar increases depicted in Table 6 above for each of the major electric utilities. The percentage increases shown in Table 7 are based on 2021 typical total bills, with the exception of NYSEG and RG&E Industrial High Load Factor (HLF) customers, which is based on 2019 data – the most recent data available for these utilities.

**Table 6: Estimated Annual Dollar Impact for Typical Customers**

| | Residential 600 kWh | Commercial 50 kw–35% LF | Industrial 2,000 kW-50% LF | Industrial HLF 2,000 kW-90% LF |
|---|---|---|---|---|
| **Statewide** | | | | |
| $4.38B Estimate | $42 | $889 | $50,813 | $91,463 |
| Range | $32—64 | $667—1,334 | $38,109—76,219 | $68,597—137,194 |

**Table 7: Estimated Total Bill Impacts on % Basis**

| | Residential 600 kWh | Commercial 50 kw–35% LF | Industrial 2,000 kW-50% LF | Industrial HLF 2,000 kW-90% LF |
|---|---|---|---|---|
| **CHG&E** | | | | |
| $4.38B Estimate | 3.1% | 4.4% | 6.0% | 7.6% |
| Range | 2.3—4.6% | 3.3—6.6% | 4.5—9.0% | $5.7—11.3% |
| **Con Edison** | | | | |
| $4.38B Estimate | 2.2% | 2.4% | 3.0% | 3.8% |
| Range | 1.7—3.3% | 1.8—3.6% | 2.3—4.5% | 2.9—5.8% |
| **NIMO** | | | | |
| $4.38B Estimate | 3.8% | 4.9% | 6.4% | 8.2% |
| Range | 2.9—5.8% | 3.7—7.4% | 4.8—9.6% | 6.1—12.3% |
| **NYSEG** | | | | |
| $4.38B Estimate | 4.4% | 5.4% | 7.2% | 10.9% |
| Range | 3.3—6.6% | 4.1—8.2% | 5.4—10.9% | 8.2—16.32% |
| **O&R** | | | | |
| $4.38B Estimate | 2.8% | 3.5% | 5.1% | 8.9% |
| Range | 2.1—4.2% | 2.7—5.3% | 3.9—7.4% | 6.7—13.4% |
| **RG&E** | | | | |
| $4.38B Estimate | 4.2% | 3.9% | 5.9% | 9.0% |
| Range | 3.1—6.2% | 2.9—5.9% | 4.5—8.9% | 6.8—13.5% |

There is no question that the costs of the AOC Projects approved here will be borne by electric ratepayers through increased bills somewhere in the range of the estimates provided in the tables above. However, these investments in local transmission are necessary to comply with the CLCPA and the Accelerated Renewables Act. As discussed in detail below, we also conclude that the problem of extensive curtailments imposes

significant costs on ratepayers that likely increase as the State procures more renewable generation resources to ensure compliance with the 70% renewables by 2030 requirement under PSL §66-p(2)(a).

2. Impacts Related to Failing to Address Local Transmission Constraints

The failure to address transmission constraints does not come without cost. Indeed, features of the wholesale markets administered by the NYISO are based on the fact that the transmission grid is not designed to guarantee deliverability of all energy inputs across the entire system.[48] The structure of NYSERDA's REC procurement program currently imposes the risk of curtailment due to transmission congestion on generation developers and thus indirectly on ratepayers who fund the RECs that they earn.

This arises because generators finance projects based on their expected wholesale market revenues and RECs (i.e., their two sources of cash flow). When the risk of curtailment due to transmission system limitations is high, generation developers must assume their volume of energy and REC sales will be reduced. Therefore, to ensure adequate overall compensation for the projects, generation developers will raise their REC bid prices above the level that might be economical if curtailment was not a risk. When the curtailment impacts are uncertain, as they are today in the AOC, bidders must offset that curtailment risk by

[48] "Transmission congestion limits the economic transfer of energy between generation resources and demand, creates inefficient generation commitment and dispatch, causes generation curtailment, and increases the cost of electricity." NYISO Economic Planning Process Manual at 16 (October 2021). The NYISO markets recognize Transmission Congestion Contracts as a hedge against the costs of congestion. https://www.nyiso.com/documents/20142/3037451/10-TCC.pdf/cee949d1-f332-b6fd-1ec0-0e4257862118.

incorporating risk premiums into their strike prices, which in turn raises the price of RECs borne by ratepayers. We note that ratepayers pay this congestion-influenced price for the full term of each REC contract, which is 20 years.

While renewable generation developers may factor a base level of curtailment into their solicitation bids, curtailment risk is not static. Rather, curtailment risk increases as more resources locate in congested areas and decreases as transmission improvements alleviate congestion. If congestion is not addressed, the risk premium included in future bids will only increase, with continuing upward pressure on REC prices as additional generation is developed in the constrained areas. Further, projects under contract that did not accurately estimate their curtailment risk may not be financeable. As ACENY emphasizes in its comments, until transmission constraints are addressed through approval of the required upgrades, "Tier 1 REC procurements will begin to see increased bid prices to account for the risk of basis and curtailment impacts resulting from a constrained transmission system, and/or in some cases the inability of some projects to commence construction .... The Commission's swift approval is crucial to the continued development and construction of renewable energy projects and the compliance with the CLCPA."[49]

The Commission recognizes that ratepayers will bear the costs of transmission system limitations through the REC procurement program. While we do not have precise tools to measure the potential increase in cost that would flow in this way, we anticipate that program costs for RECs for renewable generation located in the Areas of Concern could increase significantly – potentially by several billion dollars – above

[49] Comments of ACENY (filed May 31, 2022), p. 2.

what might be expected if bids did not have to include this risk premium.

We recognize that ratepayers also pay the cost of eliminating congestion when we approve transmission solutions. Since the burden falls on ratepayers either way, our concern is to ensure that our choice is cost-effective. Here, faced with balancing generation and transmission costs, under legislatively-based renewable energy mandates, we find that addressing the congestion by investing in transmission infrastructure is likely the better choice from the ratepayer perspective. This investment will maximize the public investment already made in renewable generation by increasing the amount of renewable energy that can be delivered and will also make the NYSERDA procurement program more competitive in the future, by largely eliminating curtailment risk premiums. Together, these factors will reduce the overall cost of the generation procurements required to achieve CLCPA goals.

Cost Recovery Associated with Projects

Finally, the Sponsoring Utilities request that the Commission approve deferral for future recovery of incremental operating expenses and related taxes associated with investments, return on capital investment (including initial and ongoing cost of removal), and depreciation associated with the AOC Projects, where such costs are not recovered regionally through a NYISO Tariff or through an existing rate plan. The Sponsoring Utilities explain that approval of such deferrals would enable them to recover such amounts in future rate filings and permit projects to be implemented on a timely basis should there be a delay in obtaining the necessary regulatory approvals of the Joint Utilities' proposed CSRA.

As explained above, this Commission accepted the CSRA filing, as modified on April 20, 2022, pursuant to which the

costs of the approved AOC Projects will be allocated and recovered under the utilities' CSRA and the NYISO's Rate Schedule 19, after the Sponsoring Utilities have made the requisite filings with the FERC. This Commission's acceptance of the CSRA and Allocation Mechanism and the FERC's approval of Rate Schedule 19 obviate the need to provide for the requested deferral. Notably, the request in the Petition for the Commission to approve the deferral for future recovery of incremental operating expenses and related taxes was made prior to either this Commission or the FERC approving the CSRA. With the CSRA having been approved, and there now being no need for a deferral of costs, the request is denied.

The revenue requirements associated with the approved AOC Projects will be recovered as specified in the CSRA and Rate Schedule 19 of the NYISO OATT. Pursuant to the CSRA, the Sponsoring Utilities are obligated to apply the State Commission-authorized return on equity and capital structure in its revenue requirement filings before the FERC. The CSRA also specifies that each of the Sponsoring Utilities is required to submit an initial formula rate and annual formula rate updates. Accordingly, the Sponsoring Utilities shall use the return on equity and capital structure specified in their most recent Commission-approved rate plans to determine the revenue requirement in their respective filings with the FERC.

To ensure the FERC process is transparent, the Commission directs the Sponsoring Utilities to file, in this proceeding, copies any of their submissions to the FERC related to the AOC Projects approved in this proceeding. Additionally, consistent with the Phase 1 Order, the Sponsoring Utilities are directed to file status reports on the AOC Projects on January 1st and July 1st of each year, beginning on July 1, 2023. The reports shall include a description of each AOC Project, the

progress made on the project since the last report, the in-service date, the budgeted and actual cost of the project to date, with an explanation of any variances exceeding 10%, and an explanation of any changes to the schedule or project scope arising since the prior reporting period. The report shall also specify the actual headroom benefits associated with each in-service project or set of projects.

## CONCLUSION

The Commission finds that the Sponsoring Utilities complied with the directions given in the Phase 2 Order concerning the identification of transmission upgrades to address congestion in the Areas of Concern. Further, the Commission approves the proposed AOC Projects, with the modifications summarized in Table 5 above, and authorizes the Sponsoring Utilities to seek cost recovery for those projects consistent with the requirements of the May 12, 2022 Order Accepting Compliance Filings issued in this proceeding.

The Commission orders:

1. The projects proposed in the Petition, filed on March 8, 2022, by Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation are hereby approved, as discussed in Table 5 and the body of this Order.

2. Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation are hereby authorized to seek cost recovery at the Federal Energy Regulatory Commission pursuant to the Cost Sharing and Recovery Agreement accepted by the Public Service Commission

on May 12, 2022, with respect to the projects approved in Ordering Clause No. 1, and subject to the terms and conditions discussed in the body of this Order.

3. Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation shall file semi-annual status reports on January 1 and July 1 each year, as discussed in the body of this Order.

4. Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation shall file, for informational purposes, copies of its Federal Energy Regulatory Commission submissions related to the Areas of Concern projects in this proceeding, as discussed in the body of this Order.

5. This proceeding is continued.

By the Commission,

(SIGNED) MICHELLE L. PHILLIPS
Secretary

Achieving the mandates of the Climate Leadership and Community Protection Act (CLCPA) and the Accelerated Renewable Energy Growth and Community Benefit Act ("Accelerated Renewables Act") will require major investments in transmission and distribution infrastructure, in addition to investments in renewable generation to ensure the system of the future serves New Yorkers in a reliable and cost-effective manner. The Commission has been focused on upgrades to local transmission facilities that are deemed needed to support New York's clean energy goals for 2030. The Commission is also charged with addressing the need for additional bulk transmission related to offshore wind integration. For the longer term, the Commission is undertaking a Coordinated Grid Planning Process to identify the grid investments needed to meet the State's clean energy mandates and ensure the Commission and the utilities are equipped to respond to the system needs in a timely manner.

The issues that came before us in the matter today are difficult. If it were purely still a market-based generation market, transmission investment would be undertaken by the developers. But since the State has largely taken over resource decisions and focused on the primary objective of meeting the State's clean energy goals without considering the full ramifications, the Commission is unwisely leaning more towards ratepayers picking up the ever-increasing tab directly.

The fundamental question for me is how the most cost-effective solutions rise to the top when the Commission is pre-ordaining the utility plans and expenditures and doing so outside the rate case and without a well-established tried and true process to rely on. If we get it wrong, it can be extremely detrimental to the ratepayers. Moreover, we must establish now a responsible checks and balances approach that incorporates and encourages oversight by an active and engaged Commission with a

focus on giving proper regulatory guardrails and framework for policy implementation.

There is no dispute that the current significant costs of over four billion dollars to be recovered by the utilities from the ratepayers is only a preliminary estimated number. In fact, it is not disputed that the final costs are unknown but could be more than 50 percent higher. Socializing billions of dollars in this manner should be a major concern for all consumers and will very likely stress the disadvantaged communities that we and the CLCPA seek to help. The underlying Order states that "[h]aving found that the projects at issue are justified, it remains incumbent on the Commission to maintain transparency with respect to the potential cost impacts of the [Areas of Concern] AOC projects on ratepayers." The Commission is right, it is incumbent on us, as a Commission to be transparent on potential cost impacts. However, the Commission and the State are not being transparent enough on the true actual cost impacts of the State energy policy goals. Today, we properly admitted that the cost estimates are unknown. We should be more transparent in getting under the hood on the proper modeling and forecasting that is needed NOW for all future costs related to these projects and other CLCPA related ones. Moreover, the Order, without any detailed analysis, expressly looks at this as a we must do this action today because we must consider "the costs to ratepayers should we fail to take action to address the transmission constraints in the Areas of Concern associated with delivering renewable energy to load". That limited way to view this matter is misplaced. No one is suggesting we "do nothing". In fact, there are parties to the proceeding who offered alternative mechanisms to how we might undertake a different approach. The item that came before the Commission should have more thoroughly flushed out other viable

options for us to examine and determine what is responsible for us to consider and perhaps come to consensus on finding a better next steps process. We already know that we will have to revisit in the near future the transmission system needs in the Areas of Concern. We are missing an opportunity to address such crucial issues more responsibly in the Coordinated Grid Planning Process and other Commission dockets pending. We must figure out a better regulatory structure, have more fiscal accountability and implement due diligence through prudent policy review actions that will positively inform and shape our future decision making and oversight.

In the Order, it notes, that Staff will monitor and scrutinize the companies' expenditures and undertake such scrutiny like that in a rate case review and may participate in the Federal Energy Regulatory Commission (FERC) proceedings to ensure the incurred costs are reasonable and prudent. This is not enough to give regulatory certainty and accountability to the process. There is nothing laying out the clear detailed review process the Commission expects in these matters. We need to be mindful that we, as a Commission, through this Order and the related Accelerated Renewables Act Orders are not giving clear direction on what we consider reasonable and prudent costs and the realistic timeframe we expect to see these projects in place. In fact, it is an open question on at least one pending FERC proceeding on cost overruns and uncertainty surrounds a separate unrelated request to NYSERDA to renegotiate contracts. The Commission as a body must give clearer, formal direction and policy guidance on these matters that ensures confidence in the regulatory and related contractual bid award processes.

We must strive as a Commission not to become a body that is simply a "check the box" on legislative mandates. We do have a fiduciary obligation to ensure we are meeting all our

legislative and regulatory responsibilities including safe, reliable, and affordable service. We have discretion to responsibly implement legislative mandates and to openly address those negative consequences of the legislation, however well-intentioned, and seek solutions to addressing them.

We are creating an unsustainable system where consumers and ratepayers assume greater and greater risks going forward with minimal guarantees. Moreover, we aren't even setting up a realistic process that is ensuring the timing of all this is possible.

Based on a full review of the record, I am dissenting as the record is insufficient in demonstrating that this action should be taken today. There may very well be more measured ways to establish a forward-looking process on transmission and grid planning that can be a part of the ongoing clean energy review we must undertake to fulfill our mission under the Public Service Law and other State imposed mandates. We have an obligation to ensure our actions are helping to guarantee that what we are doing for New York in the energy transition will not result in lessened reliability and clearly address now what the actual final cost impacts will be to homeowners and businesses. In short, this action today does not serve the public need, is not consistent with the long-term plans to improve reliability and transmission capabilities, and thus, will not properly help to accommodate future responsible expansion of the clean energy grid.

In conclusion, I respectfully dissent.

**TECHNICAL ASSESSMENT**

Headroom

The fundamental objective for the Areas of Concern (AOC) is to develop and construct local transmission upgrades to reduce congestion and, therefore, improve deliverability for existing and expected renewable generators in these areas by increasing "headroom."[50] Headroom represents the ability of the power system to deliver additional energy output from generators to load under a specific set of circumstances. Increases in headroom generally result in decreased levels of generator curtailment, though not necessarily total elimination of curtailments. Headroom may vary seasonally and over the course of the day due to changes in system configurations, load levels, generation outputs, and power flows. A generator's potential output will be curtailed to the extent that it exceeds the prevailing headroom capability.

"Existing headroom" describes the amount of generation output that can be delivered to load by the existing power system facilities. Alternately, "incremental headroom" describes the additional amount of generation output that a proposed power system upgrade can deliver to load. Notably, headroom computations are based upon the specific study assumptions used (including levels and locations of renewable generators) and may vary based upon actual conditions and configurations.

The Sponsoring Utilities computed both Capacity Headroom and Energy Headroom. "Capacity Headroom" reflects the capability of the power system to deliver a certain level of renewable energy generation output to load at an instant in time under a specific set of circumstances and is typically measured in megawatts (MW). In the AOC analyses, Capacity Headroom was

[50] Phase 2 Order, pp. 34-39.

defined by the most restrictive scenario. Thus, if headroom for peak load, shoulder load, and light load was found to be 150 MW, 110 MW and 90 MW respectively, the Capacity Headroom would be 90 MW (i.e., the most restrictive level).

"Energy Headroom" reflects the capability of the power system to deliver a specific level of renewable resource energy output over a span of time and is typically measured in annual megawatt-hours (MWh/yr). Energy Headroom is typically calculated using a weighted average of headroom values for several load levels based on the annual duration of those load levels. For example, if headroom values for peak, shoulder and light loads were calculated as 150 MW, 110 MW, and 90 MW, respectively and those load levels occurred for 1,800 hours, 4,460 hours, and 1,800 hours; respectively over a year, then Energy Headroom would be calculated as 986 GWh annually[51].

Notably, Capacity Headroom is conservative, but gives the assurance that the designated level of renewables will be deliverable during all hours. Energy Headroom, on the other hand, is less stringent and can indicate that a certain level of renewable generation above the Capacity Headroom level can be delivered during some, but not all, hours of the year.

Given that the power system is an intricate network of parallel path transmission circuits interconnecting with continually changing loads and generators at various locations, the computation of available headroom is a complex process. In contrast, simple examples for computing headroom with one local load, one renewable generator and one transmission line are illustrated on Figures 3 and 4. In these examples, Headroom equals (Local Load) plus (Transmission Transfer Capability) minus (Generator Available Output).

[51] 986 GWh/yr = (150 MW x 1,800 hrs + 110 MW x 4,460 hrs + 90 MW x 1,800 hrs) x (1 GW/1,000 MW).

Figure 3 illustrates negative headroom representing insufficient deliverability for the existing generator. Though the generator has an available output of 90 MW, its output is curtailed by 30 MW, or down to 60 MW because after serving the 20 MW of local load, the transmission line can only accommodate 40 MW of flow to the outside system; otherwise, it would thermally overload. Any flow above 40 MW on the transmission line would be defined as a deliverability violation. The headroom in this example would be negative 30 MW.

**Fig. 3**
**Negative Headroom (Insufficient Deliverability) with Existing Transmission**

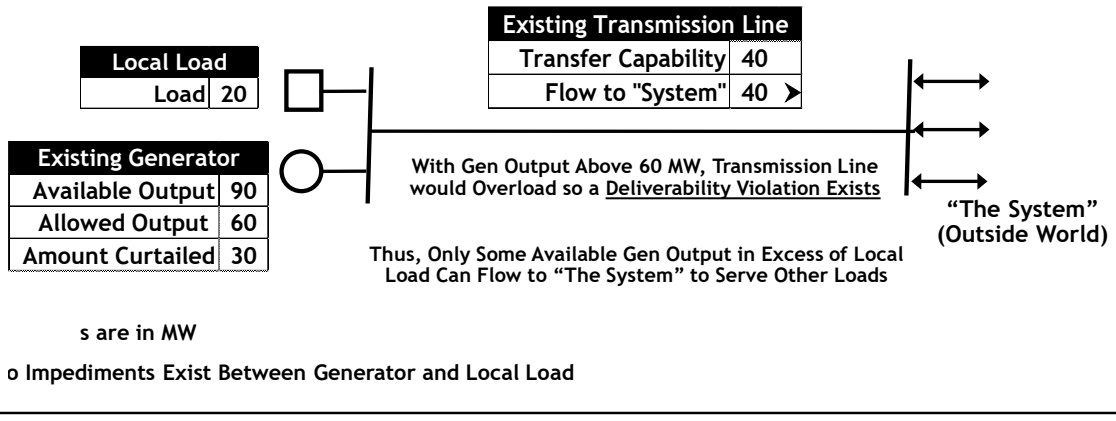
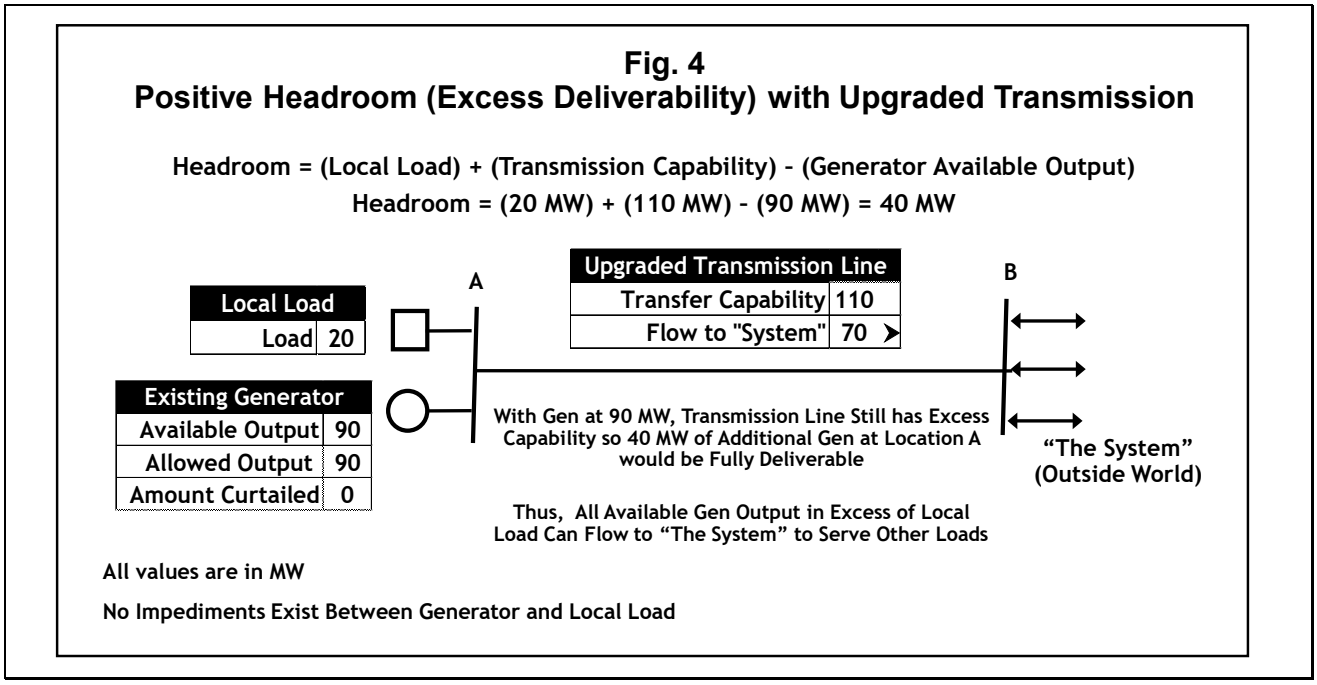



Figure 4 illustrates positive headroom resulting from a transmission upgrade that increases transmission transfer from 40 MW capability to 110 MW. Even after allowing the existing generator at 90 MW output to be fully deliverable, an additional 40 MW of generation could be added at Location A and be fully deliverable as well. Thus, positive headroom represents "excess deliverability" that can accommodate some new renewable

generators being added in addition to providing full deliverability for existing generators.




Study Assumptions and Approaches

The Sponsoring Utilities analyzed four Area of Concern planning regions comprised of Northern NY Region X2 and X3 (National Grid and NYSEG), Capital (Porter-Rotterdam) Region Y1 (National Grid), Capital (North Catskill-Coxsackie) Region Y2 (Central Hudson), and Southern Tier Region Z1 (NYSEG and RG&E) using a consistent set of assumptions and study approaches. Each modeled the electric power system with anticipated CLCPA Phase 1 projects in service and with virtually no fossil generation on-line in the respective planning regions. They composed several scenarios generally with expected levels of renewable generators dispatched[52] to 70%and 100% of their nameplate ratings for Peak Load, Shoulder Load, and Light Load conditions. For these

[52] "Dispatch" is the level of output expected from a generator e.g., a 100 MW generator dispatched to 100 percent of nameplate would output the full 100 MW, while a 100 MW generator dispatched to 70 percent of nameplate would output 70 MW).

combination scenarios, they performed power-flow studies under N-0 conditions (with all transmission facilities in service) and N-1 contingencies (following the loss or outage of one element or component of transmission facilities such as the loss of one transmission line or transformer). With the anticipated level of renewables on-line, these studies identified deliverability violations (i.e., transmission constraints[53]) that would result in curtailment[54] of those renewables.

The 70% of nameplate renewable generation dispatch was described by the Sponsoring Utilities as the "Limited Curtailment" option in which some diversity in the output of renewables was assumed so maximum output from each renewable generation source would not be coincident, but the Sponsoring Utilities acknowledged that this option could lead to a certain level of curtailed renewable output. The 100% renewable dispatch was described by the Sponsoring Utilities as the "No Curtailment" option in which no diversity in the output of renewables was assumed, meaning output from all renewables would be coincident at full nameplate amounts.

The Sponsoring Utilities' identification of deliverability violations under both the Limited Curtailment and No Curtailment options provided an indication of what transmission facilities needed to be upgraded to eliminate renewable curtailments dispatched to 70% or 100 of nameplate. This led to the Sponsoring Utilities developing and proposing

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[53] Transmission constraints are specific transmission facility elements that thermally overload and/or experience low voltage violations that require restrictions in energy transfers on those facilities.

[54] Curtailment is the restriction of generators to produce their full capable energy output due to limited power system delivery capability to transfer that energy to loads. In the case of renewable resources, such as wind and solar power, curtailment results in the loss of that energy unless it can be stored.

specific AOC Projects to coincide with each planning scenario studied to provide sufficient headroom to meet the deliverability requirements of the renewable generators modeled.

The Sponsoring Utilities performed headroom evaluations of each Area of Concern planning region without, and then with, the proposed AOC Projects in service (for the Limited Curtailment and No Curtailment portfolio, with renewables dispatched to 70 percent and 100 percent of nameplate, respectively) to determine the "base level" of headroom (without the AOC Projects in-service) and the incremental headroom provided by the AOC Projects. A negative "base level" headroom would indicate that the power system would be constrained and could not fully deliver the expected level of renewable output. A positive headroom with AOC Projects in service would indicate that the expected level of renewable output would be deliverable, and a certain level of additional renewable output would be deliverable as well.

The Sponsoring Utilities provided cost estimates for their proposed system upgrades in the Petition based on somewhat detailed project scopes which are intended to result in accuracy confidence levels of +50%/-25% compared to the original cost estimate. The scheduled in-service dates range from 2024 to 2030.

Assessment of Study Assumptions and Approaches

We find the Sponsoring Utilities' AOC study assumptions, overall approach, results (particularly the headroom determinations), development of AOC Projects, and overall documentation in the Petition to be comprehensive, reasonable, rational, and consistent between planning regions.

The Sponsoring Utilities complied with the Commission's requirement to consult with the NYISO, neighboring utilities and renewable resource developers to help develop accurate and

consistent models and methods.[55] The Sponsoring Utilities' computation of deliverability violations and headroom aligns with the Commission's requirements for determining headroom.[56] Additionally, the large number and variety of cases modeled for each of the planning regions lends credibility to the representation of the transmission system studied and conclusions reached by the Sponsoring Utilities.

In developing their AOC transmission projects, the Sponsoring Utilities evaluated alternatives and incorporated them into their proposals as appropriate. Project scope detail and cost estimate accuracy for their AOC Projects are "rate-case quality" submittals. Overall, we accept the Sponsoring Utilities' study approach and findings. We find them to be reasonable and realistic with one exception in the Southern Tier Region, to which we make a modification.

Assessments of Individual Planning Region Proposals

Northern NY Regions X2 and X3 – National Grid and NYSEG

The Northern NY Area of Concern (renewable generation pockets X2 and X3) coincides with the National Grid Watertown/Oswego/Porter Planning Region and consists primarily of the 115 kV transmission network located in Franklin, Jefferson, Lewis, Oneida, Oswego, and St. Lawrence Counties. The Watertown/Oswego/Porter region is a generation export region with six transmission paths via which power can be transferred to the rest of the state: Malone – Willis, Alcoa – Moses, Lighthouse Hill – South Oswego, Lighthouse Hill – Clay, Boonville – Porter, and Boonville – Rome – Oneida.

National Grid assessed renewable deliverability for the Northern NY Area of Concern, modeling a total of 1,404 MW of renewables (80 MW existing plus an additional 1,324 MW of

[55] Phase 2 Order, p. 19.
[56] Id., p. 50.

renewables with an "Advanced Stage of Development," which includes renewables that have advanced to Stage 6 or beyond in the NYISO Interconnection Queue or have been contracted by NYSERDA). Approximately 200 MW of existing local hydro generation were also included in the study cases. NYSERDA's 2021 REC awards were not included in the study cases because they were not yet awarded at the time the study was performed.

The Phase 1 projects proposed by National Grid for the Watertown/Oswego/Porter Planning Region were previously authorized for development by the Commission.[57] These projects (Coffeen – Black River 115 kV terminal upgrades and Lighthouse Hill – Clay 115 kV Clearance Limits) were developed by National Grid to address reliability and asset conditions issues, add headroom, and lay the groundwork for Phase 2 projects that will further reduce renewable curtailment and increase Capacity Headroom. The Phase 1 projects authorized for development are expected to increase Capacity Headroom by 30 MW from negative 650 MW to negative 620 MW with renewable generation dispatched to 70% of nameplate capacity and by 100 MW from negative 1,180 MW to negative 1,080 MW with renewable generation dispatched to 100% of nameplate capacity. Similarly, Energy Headroom will increase with approved Phase 1 projects by 306 GWh/yr from negative 5,518 GWh/yr to negative 5,212 GWh/yr for 70% renewable dispatch and by 524 GWh/yr from negative 9,881 GWh/yr to negative 9,357 GWh/yr for 100% renewable dispatch.

National Grid conducted a deliverability assessment with these anticipated Phase 1 projects in service for Peak, Shoulder, and Light load conditions under two expected renewable output levels: 70% and 100% of nameplate capacity (i.e., 983 MW

[57] Case 20-E-0197, Order Authorizing Development of Phase 1 Transmission Projects and Cost Recovery Measures (issued July 14, 2022).

and 1,404 MW, respectively). Deliverability violations (i.e., transmission constraints which would limit the amount of available renewable output that could be delivered to load) were defined as facilities exceeding their Normal summer thermal rating with all transmission facilities in service (N-0 conditions) or their Long-Term Emergency (LTE) summer thermal rating with outages of one facility element (N-1 contingencies), or voltages below 95% of nominal values for either N-0 conditions or N-1 contingencies.

National Grid identified numerous deliverability violations for both the 70% and 100% dispatch scenarios under both N-0 conditions and N-1 contingencies. The worst deliverability violations occurred on the Lighthouse Hill – Clay, Black River – Lighthouse Hill, Taylorville – Boonville, and Black River – Taylorville 115 kV circuits, exceeding 200% and 300% of the circuits' LTE ratings under N-1 contingencies for 70% and 100% renewable dispatch, respectively. National Grid also identified voltage issues in the region, including the potential for widespread voltage collapse under certain N-1 contingencies with 100% renewable dispatch.

To address post-Phase 1 deliverability violations in the Watertown/Oswego/Porter Planning Region, National Grid developed two different levels of system upgrades – a Limited Curtailment Option and a No Curtailment Option. The No Curtailment Option represents transmission projects designed to resolve deliverability constraints for an assumed generation output of 100% of nameplate capacity for the 1,404 MW of existing and expected generation included in National Grid's Northern NY Area of Concern analysis. Conversely, the Limited Curtailment Option represents transmission projects designed to resolve deliverability constraints for 70% of nameplate capacity (i.e., 983 MW of the 1,404 MW of renewable generation modeled within the

Area of Concern). The Limited Curtailment Option is comprised of 16 transmission projects with an estimated cost of $1,520.5 million, while the No Curtailment Option consists of 28 transmission projects with an estimated cost of $2,071.8 million. All proposed transmission projects included in the Limited Curtailment Option are also included in the No Curtailment Option. The Limited Curtailment Option increases Capacity Headroom by 900 MW from negative 620 MW to 280 MW for 70% renewable dispatch. Similarly, the No Curtailment Option increases Capacity Headroom by 1,150 MW from negative 1,080 MW to 70 MW for 100% renewable dispatch. These increases in Capacity Headroom correspond to transmission project costs of $1.69 million per MW and $1.80 million per MW for the Limited Curtailment and No Curtailment Options, respectively.

In its analysis, National Grid studied facilities owned by the New York Power Authority (NYPA) and NYSEG adjacent to the National Grid system and considered if upgrades to the NYPA or NYSEG systems could address issues identified on the National Grid system. As a result, the NYSEG Willis – Malone 115 kV Line Full Rebuild project is included in both the Limited Curtailment and No Curtailment Options to resolve deliverability constraints identified on the National Grid system in the Northern NY Area of Concern.

At the time the Northern NY Area of Concern renewable deliverability assessment was conducted, there were 1,339 MW of proposed renewable generation in the NYISO Interconnection Queue beyond the 1,404 MW of modeled renewable generation. National Grid determined that the 280 MW of Capacity Headroom provided by the Limited Curtailment Option would only provide capability for 30 percent of that additional renewable generation, assuming it was dispatched to 70% of nameplate capacity. Thus, the Limited Curtailment Option would not provide enough capability to support

Long-Term Development Potential for the region. Conversely, National Grid found that the No Curtailment Option would provide sufficient headroom for the additional renewable generation in the NYISO Interconnection Queue in the Northern NY region and thereby support the region's Long-Term Development Potential. Despite its higher costs, National Grid recommended the No Curtailment Option, citing several rationale, including: (1) it would provide the largest incremental amount of headroom, (2) it provides sufficient headroom capability to support Long-Term Development Potential in the region, (3) it would provide the capability to support increased customer demand due to electrification and future DER interconnections, (4) it would provide flexibility for where planned and future large-scale renewable generation could cost-effectively interconnect, and (5) it would enhance the safety, reliability, and resiliency of the local transmission system.

We agree with National Grid's assessment that the Limited Curtailment Option is insufficient to support the Long-Term Development Potential of the Northern NY Area of Concern. As of December 2022, Operational and NYSERDA-contracted renewable generation in the North Country region exceed 1,700 MW, and more than 1,300 MW of additional uncontracted advanced stage renewables in the NYISO Interconnection Queue propose to interconnect in the region, indicating overall renewable potential of over 3,000 MW. Therefore, despite higher costs, we approve the No Curtailment Option.

As part of its renewable deliverability assessment, National Grid considered alternative solutions, including bulk transmission and advanced technologies[58] such as power flow

[58] In the Phase 1 Order, the Commission recognized certain technologies as sufficiently well developed to warrant requiring the Utilities to consider them in preparing Phase 1

controllers, advanced conductors, energy storage, and Dynamic Line Ratings (DLR). Power flow control in the form of Phase Angle Regulators (PAR) and DLR were included in some of National Grid's proposed transmission projects. However, in other cases, National Grid concluded that advanced technologies were not effective or viable to resolve deliverability violations. In particular, National Grid determined that the use of advanced conductors would not be cost-effective and that a hybrid transmission and storage option would likely be more costly than the transmission-only solution.

ACENY submitted public comments suggesting that National Grid consider utilizing power flow controllers to replace the proposed South Oswego – Lighthouse Hill 115-kV Line Upgrade.[59] However, National Grid has already considered and rejected power flow controllers as an alternative for that transmission project. National Grid has proposed power flow controllers for two of the six transmission paths via which power can be transferred from the Northern NY Area of Concern to the rest of the state and determined that additional power flow control on the Lighthouse Hill – South Oswego would increase loading on the three remaining paths without power flow control and negatively impact future headroom. We do not agree with ACENY's suggestion that National Grid be required to further consider power flow controllers between South Oswego and Lighthouse Hill.

National Grid also considered a bulk alternative that would build a 345-kV backbone across the Northern NY region and

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upgrade proposals. Phase 1 Order, pp. 18-19. Those technologies were discussed in Section III.B of the Initial Report on the Power Grid Study filed in Case 20-E-0197 on January 19, 2021. The Commission gave the Utilities a similar directive in the Phase 2 Order. Phase 2 Order, p. 36.

[59] Comments of ACENY (filed May 31, 2022), pp. 3, 10-11.

determined that the 345-kV projects would have higher execution risk and provide fewer supporting benefits. Concerns identified by National Grid include: (1) a new 345-kV backbone would require new right-of-way and additional property for substations, adding complexity, cost, and time that would jeopardize the ability to complete the upgrades by 2030; and (2) N-1 contingencies of the 345-kV backbone would result in similar deliverability violations as those observed under N-0 conditions in the renewable deliverability assessment.

As detailed on Table 6, we approve the 28 proposed transmission projects that comprise National Grid's No Curtailment Option. The total estimated cost of the approved projects is $2,071.8 million. The Lighthouse Hill – Clay 115 kV line upgrades would replace the Lighthouse Hill – Clay 115 kV Clearance Limits Phase 1 project authorized for development by the Commission on July 14, 2022, providing an offset of $5.9 million to overall costs for National Grid's Phase 1 and Area of Concern transmission projects. [60] The approved transmission projects will also avoid the need for $4.3 million in asset refurbishment projects through 2029.

For several of the proposed transmission projects, National Grid recommended rebuilding existing double circuits as two single circuits in order to increase headroom and address a critical voltage issue. In its renewable deliverability assessment, National Grid identified double circuit outages (i.e., N-1 contingencies involving the loss of both circuits on double circuit structures) as leading to the most severe thermal overloads of up to 475% of LTE and widespread voltage collapse. We approve National Grid's proposal to rebuild the Black River –

[60] The Lighthouse Hill - Clay 115kV Phase 1 project was authorized for development in the Order Authorizing Development of Phase 1 Transmission Projects and Cost Recovery Measures (issued July 14, 2022).

Middle Rd – Lighthouse Hill, Taylorville – Boonville, Lighthouse Hill – Clay, Black River – North Carthage – Taylorville, and Boonville – Porter double circuits as two single circuits, noting that rebuilding existing double circuits as two single circuits eliminates the need to secure the system for the outage of both circuits on the double circuit structures.

In conducting its renewable deliverability assessment, National Grid identified system protection issues that limit the ability to increase the ratings of existing circuits in the Northern NY Area of Concern. To address these issues, National Grid proposed the addition of synchronous condensers at Taylorville and Coffeen and the expansion of Middle Rd Station to split a three-terminal line. We determined that while these upgrades do not directly increase headroom, system protection is critical to the overall ability to reliably increase headroom in the region. Therefore, we approve the addition of synchronous condensers at Taylorville and Coffeen and the expansion of Middle Rd Station.

While considerations of reliability and resiliency are not explicitly required in the CLCPA Phase 2 Order, we note that eight of eleven 115 kV circuits proposed for rebuild in the Northern NY Region as two single circuits are over 90 years old.[61] Thus, the resulting replaced facilities will improve both reliability and resiliency of the system.

In summary, as detailed on Table 6, we find the No Curtailment Option to be the preferred approach for the Northern NY Region. We approve all 28 of the proposed transmission projects at an estimated cost of $2,071.8 million. Table 7 indicates this recommended option is expected to provide 1,150 MW of incremental Capacity Headroom at a cost of $1.80 million/MW

[61] Response by National Grid to DPS Information Request 2.

and 13,106 GWh/yr of incremental Energy Headroom at a cost of $3.95/MWh (based on 40-year project lives).

**Table 8 - Northern NY (X2 & X3) CLCPA AOC Projects (Sheet 1 of 3)**

| D | Proposed Project | In Serv Date | Age (Yrs) | New ROW Feet | Art VII? | Estimated Total Costs thru 2030 ($millions) | | | Deliverability Violation Addressed | Rationale for Acceptance or Rejection |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Company Proposal | Accept | Reject | | |
| WO3 | Black River – Middle Rd - Lighthouse Hill 115 kV Full Rebuild as two Single Ckt 795 ACSR Lines (35.4 mi. each) | 2029 | 98 | TBD | Likely | 276.8 | 276.8 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO4 | Taylorville – Boonville 115 kV Full Rebuild as two Single Ckt 795 ACSR Lines (34 mi. each) | 2029 | 102 | TBD | Likely | 253.9 | 253.9 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO5 | Coffeen – Black River 115 kV Line Full Rebuild with 795 ACSR (7.5 mi.) | 2028 | 63 | TBD | Unlikely | 48.0 | 48.0 | 0.0 | Line Thermal Overload for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO6 | Lighthouse Hill – Clay 115 kV Line Full Rebuild as two Single Ckt 795 ACSR Lines (26.1 mi. each) | 2028 | 109 | TBD | Likely | 233.1 | 233.1 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO7 | Coffeen – Lyme 115 kV Line Full Rebuild with 795 ACSR (7.4 mi.) | 2027 | 60 | TBD | Unlikely | 47.8 | 47.8 | 0.0 | Line Thermal Overload for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO8A | North Carthage – Taylorville 115 kV Line Full Rebuild as two Single Ckt 795 ACSR Lines (12.0 mi. each) | 2028 | 97 | TBD | Likely | 112.1 | 112.1 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO8B | Black River – North Carthage 115 kV Line Full Rebuild as two Single Ckt 795 ACSR Lines (14.0 mi. each) | 2028 | 97 | TBD | Likely | 95.2 | 95.2 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO9 | South Oswego – Lighthouse Hill 115 kV Line Full Rebuild with 795 ACSR of Double Ckt (25.0 mi. each for a total of 50.0 ckt miles) and Single Ckt (1.2 mi.) | 2029 | 94 | TBD | Likely | 222.2 | 222.2 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO10 | Boonville – Porter 115 kV Line Full Rebuild as two Single Ckt 795 ACSR Lines (26.0 mi. each) | 2028 | 99 | TBD | Likely | 229.4 | 229.4 | 0.0 | Line Thermal Overload for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO11 | Colton – Nicholville 115 kV Line Full Rebuild as Single Ckt 795 ACSR Lines (18.3 mi.) | 2029 | 90 | TBD | Likely | 72.6 | 72.6 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO12 | Willis – Malone 115 kV Line Full Rebuild as Single Ckt 795 ACSR Lines (11.1 mi.) - **NYSEG PROJECT** | 2029 | -- | TBD | Likely | 39.0 | 39.0 | 0.0 | Line Thermal Overload for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |

**Table Continued …**

**Table 8 - Northern NY (X2 & X3) CLCPA AOC Projects (Sheet 2 of 3)**

| ID | Proposed Project | In Serv Date | Age (Yrs) | New ROW Feet | Art VII? | Estimated Total Costs thru 2030 ($millions) | | | Deliverability Violation Addressed | Rationale for Acceptance or Rejection |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Company Proposal | Accept | Reject | | |
| WO13 | Taylorville 115 kV Substation - Rebuild 115/23 kV Substation on new greenfield with BAAH 115 kV, 2 - 115 kV 150 MVAr Synchronous Condensers, 1 - 115/23 kV 33 MVA LTC Transformer, and 6 - 23 kV Vacuum Ckt Breakers | 2028 | Varies | TBD | Possible | 159.0 | 159.0 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency; Also System Protection Issue | ACCEPT - Adds Headroom by Addressing Overloads, and Required for System Protection |
| WO14 | Alcoa 115 kV Substation - Upgrade Terminal Connection Equipment and Upgrade 115 kV Bus Conductors | 2024 | Varies | TBD | Unlikely | 0.6 | 0.6 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO15 | East Watertown 115 kV Substation - Upgrade Disconnects and Upgrade Takeoffs with 2 - 1272 AAC Conductors | 2024 | Varies | TBD | Unlikely | 1.1 | 1.1 | 0.0 | Line Thermal Overload for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO17 | Coffeen 115 kV Substation - Install 2 - 115 kV 150 MVAr Synchronous Condensers including new Bus Sections | 2028 | Varies | TBD | Unlikely | 106.9 | 106.9 | 0.0 | System Protection Issue | ACCEPT - Required for System Protection |
| WO18 | Middle Road 115 kV Substation - Convert to a Six Breaker Ring-Bus | 2026 | NA | TBD | Possible | 26.3 | 26.3 | 0.0 | System Protection Issue | ACCEPT - Required for System Protection |
| WO19 | Bremen 115 kV Substation - Upgrade 115 kV Disconnects and Upgrade Takeoffs with 2 - 1272 AAC Conductors | 2028 | Varies | TBD | Possible | 1.3 | 1.3 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO20 | Colton 115 kV Substation - Upgrade Disconnects and Terminal Equipment | 2025 | Varies | TBD | Unlikely | 0.5 | 0.5 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO21 | North Carthage 115 kV Substation - Upgrade 115 kV Breakers and Disconnects and Upgrade Takeoffs with 2 - 1272 AAC Conductors | 2026 | Varies | TBD | Possible | 2.7 | 2.7 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO22 | Dennison 115 kV Substation - Upgrade Disconnects and Upgrade Takeoffs with 2000 AL | 2024 | Varies | TBD | Unlikely | 0.4 | 0.4 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO23 | Clay 115 kV Substation - Add 115 kV Position, also Replace 6 - 115 kV Breakers and 14 Disconnects, and Replace Bus Sections with 2-1272 AAC Conductor | 2028 | Varies | TBD | Possible | 5.0 | 5.0 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |

**Table Continued …**

**Table 8 - Northern NY (X2 & X3) CLCPA AOC Projects (Sheet 3 of 3)**

| ID | Proposed Project | In Serv Date | Age (Yrs) | New ROW Feet | Art VII? | Estimated Total Costs thru 2030 ($millions) | | | Deliverability Violation Addressed | Rationale for Acceptance or Rejection |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Company Proposal | Accept | Reject | | |
| WO24 | Maiden Lane 115 kV Substation - Install new BAAH Substation connecting 2 - Ckts to South Oswego, 2 Ckts to Lighthouse Hill, 1 Ckt to Nine Mile Point and 1 Ckt to Fitzpatrick; also Adding 2 - 115 kV 50 MVAr Two-Stage Capacitors and 2 Sets of Three 115 kV Reactors | 2029 | New | TBD | Possible | 24.2 | 24.2 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Addresses outage limitations and reduces scope of South Oswego – Lighthouse Hill 115 kV line rebuild |
| WO25 | East Ave 115 kV Substation - Install New Four Breaker Ring-Bus 115 kV Substation connecting 1 - Ckt to South Oswego, 1 Ckt to Lighthouse Hill, and 2 Ckts to Indeck | 2027 | New | TBD | Possible | 16.3 | 16.3 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Addresses outage limitations and reduces scope of South Oswego – Lighthouse Hill 115 kV line rebuild |
| WO26 | Coffeen-Middle Road 115 kV Line Full Rebuild with 795 ACSR of Double Ckt (2.0 mi. each for a total of 4.0 ckt miles) and Single Ckt (7.5 mi.) | 2029 | 98 | TBD | Unlikely | 55.1 | 55.1 | 0.0 | Line Thermal Overload for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO27 | Boonville 115 kV Substation - Install 2 - 115 kV 200 MVA phase angle regulators (PARs) with 4 new 115 kV Breakers on the Boonville-Rome 115 kV Lines #3 & #4 | 2028 | Varies | TBD | Possible | 31.2 | 31.2 | 0.0 | Line Thermal Overload for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO28 | Colton–McIntyre #8 115 kV Line - Install Dynamic Line Rating (DLR) monitors (includes 5 years of LineVision support service) | 2024 | New | TBD | Unlikely | 3.2 | 3.2 | 0.0 | Line Thermal Overload for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO29 | Black River 115 kV Substation - Replace 115 kV Breakers and Disconnects, Add 2nd Bus Tie Breaker, and Upgrade Takeoffs with 2 - 1272 AAC Conductors | 2027 | Varies | TBD | Possible | 5.6 | 5.6 | 0.0 | Low Voltage Violation for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Low Voltage Violation |
| WO30 | South Oswego 115 kV Substation - Replace 2 - 115 kV Breakers and 4 Disconnects; also Upgrade Takeoffs with 2 - 1272 AAC Conductors | 2027 | Varies | TBD | Possible | 2.2 | 2.2 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| WO | **Total Northern NY (X2 & X3) >** | | | | | **2,071.7** | **2,071.7** | **0.0** | | |

| Table 9 - CLCPA AOC Headroom Results<br>Northern NY X2 & X3 Region | | | |
|---|---|---|---|
| Input | Cost of AOC Projects ($millions)> | $2,071.7 | |
| | Renewables Modeled (Nameplate in MW) > | 1,404 | |
| | Level of Renewable Dispatch (% of Nameplate) > | 100% | |
| Results | | Before AOC | After AOC |
| | Capacity Headroom (MW) | (1,080) | 70 |
| | Incremental Capacity Headroom (MW) | | 1,150 |
| | Per Unit Cost of Incremental Capacity Headroom from AOC Projects ($million/MW) | | $ 1.80 |
| | Energy Headroom (GWh) | (9,357) | 3,749 |
| | Incremental Energy Headroom (GWh) | | 13,106 |
| | Per Unit Cost of Incremental Energy Headroom over 40 Years from AOC Projects ($/MWh) | | $ 3.95 |
| Headroom results presume renewables are already on-line at 100% of Nameplate | | | |

Capital Region Y1 (Porter-Rotterdam) – National Grid

The Porter-Rotterdam Planning Region consists of the area centered in the Mohawk Valley from Little Falls to Schenectady. The Phase 1 projects proposed by National Grid for the Porter-Rotterdam Planning Region were authorized by the Commission.[62] Those Phase 1 projects (Rebuild of 127 miles of Inghams-Rotterdam 115 kV circuits, Meco and Marshville 115/69 kV Substation upgrades, and installation of a new Saltsman Road 115 kV Switching Station) were developed by National Grid to address reliability and asset condition issues, add headroom, and provide a foundation from which to provide additional headroom through completion of an AOC project.

Using the assumptions that its Phase 1 projects were in place and 760 MW of expected renewable generators were on-line in the Porter-Rotterdam Planning Region (Y1), National Grid performed deliverability violation analyses with the expected

[62] Case 20-E-0197, Order Authorizing Development of Phase 1 Transmission Projects and Cost Recovery Measures (issued July 14, 2022).

renewable generation at both 70% and 100% of nameplate ratings using peak, shoulder and light load scenarios. No deliverability violations were identified for the 70% and 100% dispatches with all facilities in service (N-0 condition). However, many deliverability violations were identified for both the 70% and 100% dispatch scenarios following the loss of one element (N-1 contingency) with the worst overloads for both occurring during light load periods. For the 70% dispatch, this translates to 532 MW of available output being curtailed by 110 MW thereby allowing only 422 MW to be delivered during worst case conditions (other periods and conditions would be less restrictive). Likewise, for the 100% dispatch, it translates to 760 MW of available output being curtailed by 290 MW thereby allowing only 470 MW to be delivered during worst case conditions. Notwithstanding the worst-case curtailments following the completion of Phase 1 projects, the Capacity Headroom was nevertheless improved with Phase 1 compared to the existing system for the 70% dispatch level by 180 MW from negative 120 MW to negative 60 MW, and for the 100% dispatch case by 160 MW from negative 440 MW to negative 280 MW. Alternately, the Energy Headroom was improved with Phase 1 for the 70% dispatch by 902 GWh/yr from negative 854 GWh/yr to plus 48 GWh/yr and for the 100% dispatch by 1,142 GWh/yr from negative 3,218 GWh to negative 2,076 GWh/yr.

As described on Table 10, to address the post-Phase 1 deliverability violations in the Porter-Rotterdam Region, National Grid proposed the Marshville 345/115 kV Substation as an AOC Project. This is comprised of a new 345 kV 4-Bay Breaker and a Half (BAAH) Substation, looping in and out of the existing Porter-Rotterdam 230 kV Lines 30 and 31 (to be converted to 345 kV as the Edic-Princetown AC Transmission Segment A project before construction of the Marshville 345/115 kV Substation), two 345/115 kV 448 MVA Transformers, and looping St Johnsville-

Marshville 115 kV Line 11 and Clinton-Porter 115 kV Line 12 in and out of the new Marshville Substation. This project, which provides an "on-ramp" for renewables from the 115 kV system to the bulk system is estimated to cost $81.3 million with an in-service date of 2028. This proposed AOC project is the same for the 70% Limited Curtailment case and the 100% No Curtailment case, and therefore provides sufficient incremental headroom for both.

Completion of the proposed AOC Marshville 345/115 kV Substation is expected to increase the Capacity Headroom compared to completion of just Phase 1 for the 70% dispatch level by 220 MW from negative 60 MW to plus 160 MW, and for the 100% dispatch case by 360 MW from negative 280 MW to plus 80 MW. Alternately, the Energy Headroom is expected to improve with AOC (compared to post-Phase 1) for the 70% dispatch by 3,459 GWh/yr from negative 48 GWh/yr to plus 3,507 GWh/yr, and for the 100% dispatch by 3,960 GWh/yr from negative 2,076 GWh/yr to plus 1,884 GWh/yr. This indicates that curtailments for the assumed 760 MW level of renewables would not occur (under the study assumptions), and that a certain higher level of renewables could be added in the region. In terms of per unit costs for the 100% dispatch case this project is estimated to provide Capacity Headroom at a cost of $0.23 million/MW and Energy Headroom at a cost of $0.51/MWh (based on a 40-year project life).

Notably, National Grid evaluated the system with its proposed AOC project in-service, but without its Phase 1 projects in-service. This analysis indicated that renewable curtailments would generally be over 1,000 MW and, in certain cases, over 2,000 MW, thereby reaffirming the need for the Phase 1 projects to be in place to work in unison with the AOC project in increasing headroom.

In proposing its AOC project, National Grid developed and evaluated several alternatives. The alternatives included further reinforcement of the 115 kV system, a 345/115 kV on-ramp at another location, power flow control devices, advanced technology conductors, dynamic line rating (DLR), and energy storage. Compared to the proposed AOC project, National Grid determined that each of the alternatives considered was more expensive and less effective.

As detailed on Tables 10 and 11, we approve National Grid's proposed Porter-Rotterdam AOC project consisting of the construction and integration of the Marshville 345/115 kV Substation at an estimated cost of $83.1 million. The same project was proposed for both the Limited Curtailment 70% renewable dispatch option and the No Curtailment 100% renewable dispatch option. Table 10 indicates that this recommended option is expected to provide 360 MW of incremental Capacity Headroom at a cost of $0.23 million/MW and 3,960 GWh/yr of incremental Energy Headroom at a cost of $0.52/MWh.

**Table 10 - Capital (Porter-Rotterdam) Y1 CLCPA AOC 2a Project**

| ID | Proposed Project | In Serv Date | Age (Yrs) | New ROW Feet | Art VII? | Estimated Total Costs thru 2030 ($millions) | | | Deliverability Violation Addressed | Rationale for Acceptance or Rejection |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Company Proposal | Accept | Reject | | |
| R4 | Marshville 345/115 kV Substation - New 345 kV 4-Bay Breaker and a Half (BAAH) Substation, looping in and out of the existing Porter-Rotterdam 230 kV Lines 30 and 31 (to be converted to 345 kV as the Edic-Princetown AC Transmission Segment A project before construction of Marshville), two 345/115 kV 448 MVA Transformers, and looping in and out of St Johnsville-Marshville 115 kV Line 11 and Clinton Porter 115 kV Line 12. | 2028 | NEW | 200 | Unknown | 81.3 | 81.3 | 0.0 | Several 115 kV Line Thermal Overloads for N-1 Contingency (both 70% & 100% Dispatches) | ACCEPT - Adds Headroom by Addressing Overloads (Solution is the same for both 70% and 100% dispatches) |
| Y1 | **TOTAL CAPITAL Y1 >>>** | | | | | **81.3** | **81.3** | **0.0** | | |

| Table 11 - CLCPA AOC Headroom Results<br>Capital (Porter-Rotterdam) Y1 Region | | | |
|---|---|---|---|
| Input | Cost of AOC Project ($millions)> | $83.1 | |
| | Renewables Modeled (Nameplate in MW) > | 760 | |
| | Level of Renewable Dispatch (% of Nameplate) > | 100% | |
| Results | | Before AOC | After AOC |
| | Capacity Headroom (MW) | (280) | 80 |
| | Incremental Capacity Headroom (MW) | | 360 |
| | Per Unit Cost of Incremental Capacity Headroom from AOC ($million/MW) | | $ 0.23 |
| | Energy Headroom (GWh) | (2,076) | 1,884 |
| | Incremental Energy Headroom (GWh) | | 3,960 |
| | Per Unit Cost of Incremental Energy Headroom over 40 Years from AOC ($/MWh) | | $ 0.52 |
| Headroom results presume renewables are already on-line at 100% of Nameplate | | | |

Capital Region Y2 (North Catskill-Coxsackie) - Central Hudson Gas & Electric

Central Hudson performed deliverability violation analyses with expected Phase 1 projects in service with anticipated renewable generation dispatched at both 70% and 100% of their nameplate ratings in peak, shoulder, and light load scenarios. For these cases, no deliverability violations, and therefore no renewable curtailments, were identified for the 70% dispatch scenarios. However, deliverability violations for expected renewables at 100% dispatch were identified for the 69 kV system in the vicinity of Coxsackie and on two 115 kV circuits. With 110 MW of renewable output injected into the Coxsackie area, deliverability violations were identified on the North Catskill–Coxsackie 69 kV Line (in the northern portion of its service territory on the western side of the Hudson River Valley) for the 100% renewable dispatch. Central Hudson's headroom test for 70% and 100% renewable dispatch on the existing system estimated that Capacity Headroom was 18 MW and negative 15 MW, respectively, indicating that renewable generation dispatched

to 70% of nameplate would not be curtailed, but renewables dispatched to 100% would be curtailed.

To address curtailments with 100% renewable dispatch due to a deliverability violation on the North Catskill-Coxsackie 69 kV Line, Central Hudson proposed an AOC rebuild of this 8.6 mile line replacing 336 ACSR conductor with 1033 ACSR conductor and built to 115 kV standards but continued to operate at 69 kV initially. This rebuild is estimated to cost $15.7 million ($1.4 million more than a rebuild to 69 kV standards) with an in-service date of 2029.

Completion of the proposed AOC North Catskill-Coxsackie 69 kV Line rebuild would increase the estimated Capacity Headroom for 70% dispatch level by 55 MW from 18 MW to 73 MW, and for 100% dispatch by 43 MW from negative 15 MW to plus 28 MW. Alternately, the Energy Headroom would improve for the 70% dispatch by 484 GWh/yr from 230 GWh/yr to 714 GWh/yr, and for the 100% dispatch by 424 GWh/yr from negative 85 GWh/yr to 339 GWh/yr. This indicates that curtailments for the assumed 110 MW level of renewables near Coxsackie with the proposed AOC upgrade would not occur for a dispatch at 100% of nameplate (under the study assumptions), and that a certain level of additional renewables could be located in that region as well. In terms of per unit costs for the 100% dispatch case, this project is estimated to provide Capacity Headroom at a cost of $0.37 million/MW and Energy Headroom at a cost of $0.93/MWh over a 40-year life.

Central Hudson indicated that the rebuilt North Catskill-Coxsackie 69 kV Line could be subsequently converted to 115 kV at an estimated additional cost of $8.0 million to provide additional headroom, if needed.

Additionally, N-1 deliverability violations were identified for the 100% dispatch during peak load on two 115 kV

circuits. However, Central Hudson determined that these violations could be mitigated by dispatching the output down pre-contingency from the non-renewable fueled Danskammer generating plant to no more than 410 MW, a reduction of up to 32 MW, considering that Danskammer's maximum output is 442 MW.

Central Hudson did not evaluate alternatives specific to the North Catskill-Coxsackie 69 kV rebuild but reports that it is currently engaging in a program to evaluate transmission alternatives including advanced technologies such as energy storage, high temperature conductors, and methods to manage grid constraints.

The proposed AOC project of the North Catskill-Coxsackie Line 69 kV rebuild will increase Capacity Headroom by 43 MW from negative 15 MW to plus 28 MW with 110 MW renewables in the Coxsackie area dispatched to 100%. Thus, no curtailment risk is anticipated for the expected level of renewables following completion of this project.[63]

As detailed on Tables 12 and 13, we approve the North Catskill-Coxsackie 69 kV rebuild at a cost of $15.7 million because it would add sufficient incremental Capacity Headroom (43 MW) at a cost $0.37 million/MW and Energy Headroom at a cost of $0.93/MWh (over 40 years) to prevent curtailment of expected renewables at 100% dispatch and provide headroom for a certain level of additional renewables as well. Central Hudson indicates that if renewable generation development exceeds the expected level, the rebuilt line could be converted to 115 kV at a cost of $8 million to provide additional headroom.

[63] Central Hudson provided corrections and clarifications in its response to DPS Information Request 1.

| Table 12 - Capital (N Catskill-Coxsackie) Y2 CLCPA AOC Project | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| ID | Proposed Project | In Serv Date | Age (Yrs) | New ROW Feet | Art VII? | Estimated Total Costs thru 2030 ($millions) | | | Deliverability Violation Addressed | Rationale for Acceptance or Rejection |
| | | | | | | Company Proposal | Accept | Reject | | |
| Y2 | Rebuild North Catskill-Coxsackie line from 336 ACSR to 1033 ACSR to 115 kV standards (8.6 mi.) and operate initially at 69 kV - Increases Thermal Ratings by more than Double | 2029 | ? | 0 to 50 | No | 15.7 | 15.7 | 0.0 | Line Thermal Overload for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| Y2 | **TOTAL CAPITAL Y2 >>>** | | | | | **15.7** | **15.7** | **0.0** | | |

| Table 13 - CLCPA AOC Headroom Results<br>Capital (North Catskill-Coxsackie) Y2 Region | | | |
|---|---|---|---|
| Input | Cost of AOC Project ($millions)> | $15.7 | |
| | Renewables Modeled (Nameplate in MW) > | 110 | |
| | Level of Renewable Dispatch (% of Nameplate) > | 100% | |
| Results | | Before AOC | After AOC |
| | Capacity Headroom (MW) | (15) | 28 |
| | Incremental Capacity Headroom (MW) | | 43 |
| | Per Unit Cost of Incremental Capacity Headroom from AOC Project ($million/MW) | | $ 0.37 |
| | Energy Headroom (GWh) | (85) | 339 |
| | Incremental Energy Headroom (GWh) | | 424 |
| | Per Unit Cost of Incremental Energy Headroom over 40 Years from AOC Projects ($/MWh) | | $ 0.93 |
| Headroom results presume renewables are already on-line at 100% of Nameplate | | | |

Southern Tier Region Z1 – NYSEG and RG&E

The NYSEG-RG&E Southern Tier Planning Region (Area of Concern Zone Z1) is a large rural, semi-rural, and small city area in New York State centered around the City of Hornell and Village of Bath, lying southeast of Buffalo, south of Rochester, and west of both Ithaca and Binghamton. Electrically, a 230 kV backbone path traverses the region extending from Stolle Road Substation (near East Aurora) approximately 125 miles to the Watercure Substation (near Elmira) where it connects with the 345

kV bulk system. This 230 kV path connects with 115 kV circuits at the Meyer, Stoney Ridge, and Hillside 230/115 kV Substations. This region also has two 115 kV west-to-east paths in parallel with the 230 kV path serving local load.

NYSEG and RG&E estimated that total Near-Term solar and wind renewable needs as indicated on Table 1 amounted to 1,944 MW (535 MW existing plus 1,409 of additional "Advanced Stage of Development" renewables, which includes renewables that have advanced beyond Stage 6 of the NYISO Interconnection Queue or have been contracted by NYSERDA but excludes Energy Storage). NYSEG and RG&E modeled 2,047 MW[64] and 1,433 MW of these renewables at anticipated locations for the 100% No Curtailment and 70% Limited Curtailment cases respectively. These were studied against three load levels: Summer Peak of 527 MW, Shoulder load of 358 MW (69% of Peak), and Light Load of 209 MW (40% of Peak).[65]

NYSEG and RG&E conducted deliverability assessments with the expected renewables and anticipated NYSEG Phase 1 projects in service for the three load levels with all transmission facilities in-service (N-0 conditions) and with outages of one facility element (N-1 contingencies). Deliverability violations were defined as facilities exceeding their Normal or Long-Term Emergency (LTE) summer thermal rating

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[64] Within the 2,047 MW of renewables, the model included 103 MW of Energy Storage which is technically not a renewable per se (rather than requiring headroom, Energy Storage generally serves to provide headroom by charging when renewable output is available to reduce the likelihood of renewable curtailments and discharging energy when renewable output is less available). Coincidently, the Updated Near-Term Need for the Southern Tier (as shown on Table 3) is 2,053 MW, which is virtually the same as the amount modeled. We view the results as valid, particularly with respect to the determination of incremental headroom provided by the AOC Projects.

[65] Additional study assumptions are included in the response by NYSEG and RG&E to DPS Information Request 1.

for N-0 conditions and N-1 contingencies respectively or voltages below 95% of nominal values for either N-0 conditions or N-1 contingencies. For 70% dispatch (i.e., 1,433 MW of renewable output which equaled 70% of the assumed 2,047 MW nameplate capacity), NYSEG and RG&E indicated for the N-0 condition that three 230 kV lines, ten 115 kV lines, and one 34.5 kV line were thermally overloaded. Additionally, for the N-1 contingency three 230 kV lines, one 230/115 kV transformer, fifteen 115 kV lines and four 34.5 kV lines were thermally overloaded, while nine 115 kV substation buses had low voltage reliability criteria violations. These issues represent deliverability violations (i.e., transmission restrictions which would limit the amount of available renewable output that could be delivered to load) that translated into a Capacity Headroom for the post-Phase 1 system of negative 1,283 MW. This indicated a large level of renewable curtailments would occur given that 1,3613 MW of renewable output was assumed to be available. Under worst case conditions, approximately only 150 MW of the 1,361 MW would be deliverable (i.e., 1,361 MW - 1,283 MW = 150 MW).[66]

Based on their deliverability assessments, NYSEG and RG&E developed and evaluated the relative advantages of four different levels of system upgrades to address deliverability violations and provide incremental headroom: (1) Rebuild Existing for Limited Curtailment (i.e., provide sufficient incremental headroom so renewables dispatched to 70% of nameplate would not be curtailed), (2) Rebuild Existing for No Curtailment (i.e., provide sufficient incremental headroom so renewables dispatched to 100% of nameplate would not be curtailed), (3) Expand with New (345 kV transmission) and Upgrade Existing for Limited

[66] Attachment 1 to the response provided by NYSEG and RG&E to DPS Information Request 2 lists deliverability violations identified in the Southern Tier study.

Curtailment, and (4) Expand with New and Upgrade Existing for No Curtailment.

Of the four levels of upgrades, NYSEG and RG&E recommended the Rebuild Existing for Limited Curtailment Upgrade. Though not providing the highest incremental amount of headroom, the rationale provided by NYSEG and RG&E for this selection was its other relative advantages, including: (a) lowest lifetime costs, (b) lowest Capacity Headroom per unit cost ($/MW), (c) lowest execution complexity allowing fastest implementation (e.g., with respect to ROW acquisition, outages, Article VII, etc.), (d) least incremental footprint and environment impact, (e) better for existing infrastructure reliability and resiliency enhancement, and (f) more scalable to further add incremental headroom as needed and where needed.

We accept the proposal by NYSEG and RG&E to pursue the Rebuild Existing for Limited Curtailment Upgrade approach, particularly because this option provided a relatively large surplus of Capacity Headroom amounting to 593 MW above the Limited Curtailment needs, as indicated in both Tables 5 and 15. Accordingly, we evaluated the attributes of the 70% Limited Curtailment option in more detail.

To address the identified deliverability violations (for the Rebuild Existing for Limited Curtailment Upgrade), NYSEG and RG&E proposed 32 AOC Projects costing an estimated $2,245.7 million and comprised of line rebuilds of 63 miles of 230 kV, 197 miles of 115 kV, and 27 miles of 34.5 kV; 4 - 115 kV capacitors and 3 – 115 kV STATCOMs or SVCs for voltage support; 1 – 115 kV power flow control device; 1 – 345/115 kV transformer; 1 - 230/115 kV transformer; 1 – 230 kV substation rebuild; 2 – 115 kV substation rebuilds; 3 – 115/34.5 kV – distribution substation rebuilds; and minor upgrades at nine 115 kV substations.

To compute headroom, NYSEG and RG&E increased or decreased renewable output to the point at which power flow just caused a reliability thermal or voltage violation (i.e., the level of renewable output above which curtailment risk would occur). Using this method, NYSEG and RG&E determined the absolute value of headroom with no renewable output on the system, and the surplus or deficiency in headroom (i.e., incremental headroom) with the expected renewables dispatched to 70% of nameplate. For its proposed portfolio of AOC Projects, NYSEG and RG&E indicated that Capacity Headroom would increase by 1,876 MW from the post-Phase 1 level of negative 1,283 MW to the post-AOC level of 593 MW. Similarly, NYSEG and RG&E indicated that Energy Headroom would increase by 12,842 GWh/yr from the post-Phase 1 level of negative 5,856 GWh/yr to the post-AOC level of 6,986 GWh/yr. This would transform the Southern Tier Region from one that would experience significant curtailment risk to one that would experience virtually no curtailment risk for the expected renewables dispatched simultaneously at 70% of nameplate. Furthermore, it would provide virtually no curtailment for renewables dispatched a certain level above the 70% dispatch.

We reviewed and evaluated each of the 32 proposed AOC Southern Tier projects with the intent of determining whether each should be: (a) fully accepted as contributing to the AOC objective by mitigating a deliverability thermal or voltage violation thereby contributing to incremental headroom, or (b) rejected in whole or in part because all or a portion of the proposed project was not shown to contribute to incremental headroom. Table 14 includes detailed descriptions of each of the

AOC Projects proposed by NYSEG and RG&E, along with rationale for acceptance or rejection.[67]

Based upon each proposed AOC project's ability to contribute to incremental headroom, we approve the following:

1) Rebuild of 230 kV Lines 67, 68, 69, and 72 (total of 63 miles) to mitigate thermal overloads.
2) Rebuild of 115 kV Lines 906, 934, 935, 953, 963, 965, 968, 978, 711, 712, 722, 723, and 724(total of 184 miles) to mitigate thermal overloads.
3) Upgrade of Stoney Ridge 230/115 kV Substation with larger 230/115 kV transformer.
4) Upgrade Hillside 230/115/34.5 kV Substation which is intertwined with line upgrades contributing to increased headroom.
5) Upgrade Watercure 345/230/115 kV Substation to address thermal overloads and provide the main West to East connection to the 345 kV Bulk Power System for Southern Tier renewables.
6) Upgrade of Eel Pot 115 kV Substation adding 115 kV capacitor and STATCOM or SVC for voltage support.
7) Upgrade of Greenidge 115 kV Substation adding 115 kV capacitor for voltage support.
8) Upgrade of Bennett 115 kV Substation adding power flow control device to prevent thermal overloads on a 115 kV Line 932.

[67] NYSEG and RG&E provided clarifications to cost estimates in response to DPS Information Request 4. NYSEG and RG&E provided expected annual expenditures for each proposed AOC project for the Southern Tier in response to DPS Information Request 5. NYSEG and RG&E provided additional scope and justification details and clarifications for proposed AOC projects in the Southern Tier in response to DPS Information Requests 6 and 7.

9) Upgrade Bath 115/34.5 kV Substation 115 kV facilities, including addition of a 115 kV STATCOM or SVC for voltage support and relocation of 115/34.5 kV transformer; but reject rebuild of the remaining 34.5 kV and distribution facilities (reducing the cost by $28.1 million) because they were not shown to contribute to incremental headroom.[68]
10) Replace structures on 115 kV Line 932 (13 miles) to assure headroom increase is not impaired by limitations on this line caused by clearance issues but reduce cost estimate by $5.2 million due to the limited nature of this upgrade (the proposed cost and cost range for this partial rebuild was in excess of the cost estimate for a full rebuild with new structures, conductor and right-of-way).[69] Accordingly, this project's estimated cost should be limited to $2.0 million per mile.
11) Rebuild Montour Falls 115/34.5 kV Substation, which is intertwined with line upgrades contributing to increased headroom, mitigate low voltage violations and relocate out of flood plain.
12) Rebuild Hickling 115/34.5 kV, which is intertwined with line upgrades contributing to increased headroom and relocate out of flood plain.
13) Rebuild 34.5 kV Lines 539, 546, 542, and 565 (total of 27 miles) to mitigate thermal overloads.[70]
14) Perform minor upgrades of Caton Ave, Flat St, Moraine, Ridge Rd, Spencer Hill, Station 128, Sullivan Park, West

[68] Response by NYSEG and RG&E to DPS Information Request 3.

[69] NYSEG and RG&E provided additional details about this project in response to DPS Information Request 9.

[70] NYSEG and RG&E provided additional details on the proposed 34.5 kV rebuilds in its response to DPS Information Request 8.

Erie Ave, and Yawger Rd 115 kV Substations to mitigate thermal overloads.

While considerations of reliability and resiliency are not explicitly required in the CLCPA Phase 2 Order, we note that four substations proposed for rebuild in the Southern Tier are at least 93 years old (one is 80 years old). Additionally, seven circuits proposed for rebuild are at least 70 years old and another ten circuits are between 50 and 70 years old. Thus, the rebuilt facilities will improve both reliability and resiliency of the system.

The project scope detail and cost estimate accuracy for the proposed projects are "rate-case quality" submittals with confidence levels of +50%/-25% such that the cost estimates and construction schedules for their scopes of work are reasonable for capital investments that are proposed well in advance of project-specific engineering. Thus, we find the presented project cost estimates to be acceptable for the purposes of the AOC proposals by NYSEG and RG&E.

In developing its project proposals, NYSEG also evaluated alternative solutions, which included slight variations of its proposed projects, advanced technology options, and/or non-wires alternative solutions, including power flow control devices, high temperature conductors, and expanded line ratings. In some instances, NYSEG proposed advanced technology options for its AOC solutions; however, in other cases, NYSEG concluded that advanced technologies were not effective or viable for the specific circumstances considered and the level of incremental headroom needed.

In summary, NYSEG and RG&E proposed 32 AOC Projects (estimated cost of $2,245.7 million) after identifying deliverability violations (i.e., transmission restrictions which

would limit the amount of available renewable output that could be delivered to load).

As indicated on Tables 14 and 15 below, we essentially approve all 32 projects proposed, with the exceptions that the accepted cost estimate for one project was reduced and the project scope for another was reduced. This resulted in an estimated expenditure for Southern Tier AOC Projects of $2,212.4 million; a reduction of $33.3 million compared to the $2,245.7 million proposed by NYSEG and RG&E. As shown on Table 15, for expected renewables dispatched to 70% of nameplate, the approved projects are anticipated to increase Capacity Headroom in the Southern Tier Region by 1,876 MW from the post-Phase 1 level of negative 1,283 MW to the post-AOC level of 593 MW at a cost of $1.18 million/MW. Additionally, the projects are expected to increase annual Energy Headroom by 12,842 GWh from negative 5,856 GWh to 6,986 GWh at a cost of $4.31/MWh (over 40 years).

**Table 14 - Southern Tier (Z1) CLCPA AOC Projects (Sheet 1 of 5)**

| ID | Proposed Project | In Serv Date | Age (Yrs) | New ROW Feet | Art VII? | Estimated Total Costs thru 2030 ($millions) | | | 70% Limited Curtailment Deliverability Violation Addressed | Rationale for Acceptance or Rejection |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Company Proposal | Accept | Reject | | |
| Z01 | Stolle Rd - High Sheldon 230 kV Line **67** - Rebuild w/bundled 1192 ACSR (11 mi.) - 2.6 miles from Dbl to Single Ckt | 2029 | 66 | 0 to 150 | Yes | 93.0 | 93.0 | 0.0 | Line at Thermal Overload for N-1 Contingency | ACCEPT - Makes headroom improvement more robust for the 230 kV backbone by eliminating a potential restriction depending on actual load and renewable development. |
| Z02 | Canandaigua-Stoney Ridge 230 kV Line **68** - Rebuild w/bundled 1192 ACSR (24 mi.) | 2029 | 59 | 0 | Yes | 181.8 | 181.8 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads. |
| Z03 | **Stoney Ridge** 230/115 kV Substation - Replace 230/115 kV 224 MVA Transformer Bank 1 with 448 MVA Transformer. | 2024 | 13 | ? | No | 16.9 | 16.9 | 0.0 | Transformer Thermal Overload and Low Voltage Violation at 3 Substations for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads & Voltage Violations. |
| Z04 | Stoney Ridge-Hillside 230 kV Line **72** - Rebuild w/2156 ACSR (27 mi.) | 2030 | 60 | 160 | Yes | 224.4 | 224.4 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads. |
| Z05 | Hillside-Watercure 230 kV Line **69** - Rebuild w/2156 ACSR from Dbl Ckt to Separate Single Ckt (1.3 to 3 mi.) - Higher relative costs reflects challenging terrain thru congested neighborhood and need for new ROW as per Response by NYSEG and RG&E to DPS Information Request 4 | 2029 | 50 | 150 | ? | 34.7 | 34.7 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| Z06 | **Hillside** 230/115/34.5 kV Substation - Decommission 115 kV Buswork and 2 115/34.5 kV Transformers Banks 1 & 2; Reroute 115 kV Lines to new 115 kV at Watercure Substation (at least 1.3 miles); Replace 2 230 kV Breakers; Ground 115 kV side of 230 kV Transformers; Add 34.5 kV Breaker to provide separate breakers for 230/115/34.5 kV Transformer Banks 3 and 4. (Response by NYSEG and RG&E to DPS Information Request 7) | 2024 | 80 | ? | ? | 10.2 | 10.2 | 0.0 | Intertwined with several 230 kV and 115 kV rebuilds that will increase Headroom (Response by NYSEG and RG&E to DPS Information Request 7) | ACCEPT - Intertwined with Line Rebuilds that will Add Headroom by Addressing Overloads |

**Table Continued …**

**Table 14 - Southern Tier (Z1) CLCPA AOC Projects (Sheet 2 of 5)**

| ID | Proposed Project | In Serv Date | Age (Yrs) | New ROW Feet | Art VII? | Estimated Total Costs thru 2030 ($millions) | | | 70% Limited Curtailment Deliverability Violation Addressed | Rationale for Acceptance or Rejection |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Company Proposal | Accept | Reject | | |
| Z07 | **Watercure** 345/230/115 kV Substation - Add 345 kV Bay to existing 2-Bay BAAH; Add 115 kV 3-Bay BAAH; Reroute Hillside 115 kV lines to Watercure new 115 kV BAAH; Add new 345/115 kV three winding 448 MVA transformer. to connect new 115 kV BAAH and 345 kV BAAH expansion, Relocate 115 kV Lines 978, 960, 962 & 963 Hillside (Response by NYSEG and RG&E to DPS Information Request 7) | 2027 | 54 | ? | ? | 138.3 | 138.3 | 0.0 | Line Thermal Overload for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads in Conjunction with 230 kV and 115 kV Line Rebuilds. This substation will provide the main West to East connection to the 345 kV Bulk Power System for Southern Tier Renewables |
| Z08 | Meyer-South Perry (115) 115 kV Line **934** - Rebuild w/795 ACSR (19 mi.) - converting 2 miles to single circuit from 230 kV line 87 | 2029 | 80 | 100 | Yes | 89.4 | 89.4 | 0.0 | Line Thermal Overload for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| Z09 | RG&E Sta 128-RG&E Sta 82 115 kV Line **906** - Rebuild w/1590 ACSR (30 mi.) - RG&E Line | 2030 | 56 | 100 | Yes | 156.8 | 156.8 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| Z10 | Meyer-Eel Pot 115 kV Line **724** - Rebuild w/1590 ACSR (15 mi.) | 2029 | 71 | 100 | Yes | 63.8 | 63.8 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| Z11 | **Eelpot** 115/34.5 kV Substation - Add 115 kV breaker to convert ring bus from 4 to 5 positions, add 50 MVAr Capacitor and +150/-100 MVAr STATCOM or SVC, and 115 kV Terminal Work | 2025 | 48 | ? | No | 76.7 | 76.7 | 0.0 | Low Voltage Violation at 2 115 kV Substations for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Voltage Violations |
| Z12 | Eel Pot-Flat Street 115 kV Line **722** - Rebuild w/1590 ACSR (23 mi.) | 2030 | 71 | 100 | Yes | 114.2 | 114.2 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| Z13 | Flat Street-Greenidge 115 kV Line **968** - Rebuild w/1590 ACSR (5 mi.) | 2026 | 71 | 100 | Yes | 18.5 | 18.5 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |

**Table Continued …**

**Table 14 - Southern Tier (Z1) CLCPA AOC Projects (Sheet 3 of 5)**

| ID | Proposed Project | In Serv Date | Age (Yrs) | New ROW Feet | Art VII? | Estimated Total Costs thru 2030 ($millions) | | | 70% Limited Curtailment Deliverability Violation Addressed | Rationale for Acceptance or Rejection |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Company Proposal | Accept | Reject | | |
| Z14 | **Greenidge** 115 kV Substation - Add 115 kV Breaker and Terminal Work for Line 968, and 30 MVAr Capacitor with new 115 kV Breaker | 2024 | 74 | No | No | 17.2 | 17.2 | 0.0 | Line Thermal Overload for N-0 and Low Voltage Violation at 1 115 kV Substation for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads & Voltage Violations |
| Z15 | **Montour Falls** 115/34.5 kV Substation - Rebuild in new location out of flood plain as 4-Bay AIS BAAH 115 kV with 2 115 kV 30 MVAr Capacitors ($83.3 M), Add 2-115/34.5 kV 50 MVA Transformers to replace 1-33 MVA, 34.5 kV GIS Straight Bus with Tie Breaker, and 12.5 kV GIS Straight Bus (Converted from 8.3 kV) ($52.7 M) (Response by NYSEG and RG&E to DPS Information Requests 6 and 7) | 2027 | 93 | Yes - New Location | No | 135.9 | 135.9 | 0.0 | 115 kV Line Thermal Overload for N-0; Low Voltage Violation at 1 115 kV Substation for N-1 Contingency - 115/34.5 kV and Distribution are intertwined due to relocation | ACCEPT - Adds Headroom by Addressing Overloads and Low Voltage Violations; also relocates substation out of flood plain |
| Z16 | Montour Falls to Ridge Rd Tap to Hillside 115 kV Line **963** - Rebuild Montour Falls to Ridge Rd Tap w/1590 ACSR (8 mi.) and from Ridge Rd to Hillside w/1192 ACSR (8 mi.) - Note: 115 kV Line 963 is doubled circuited with 115 kV Line 978 which is proposed to be rebuilt also. Note 963 is 3-way tap with a segment also going from Ridge Rd Tap to Yawger | 2029 | 78 | 100 | Yes | 74.6 | 74.6 | 0.0 | Line Thermal Overload for N-0 and N-1 Contingency. | ACCEPT - Adds Headroom by Addressing Overloads |
| Z17 | Montour Falls to Ridge Road to Hillside 115 kV Line **978** - Rebuild Montour Falls to Ridge Rd w/1590 ACSR (8 mi.) and from Ridge Rd to Hillside w/1192 ACSR (8 mi.) - Note: Line 978 is doubled circuited with 115 kV Line 963 which is proposed to be rebuilt also. Rebuilding Lines 978 & 963 as 2 single ckts would cost $70.5 M + $71.0 M = $141.5 M bu ROW will be difand 2 Single Ckts will not add noticeable benefits (Response by NYSEG and RG&E to DPS Information Request 6). | 2029 | 78 | 100 | Yes | 74.6 | 74.6 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |

**Table Continued ...**

**Table 14 - Southern Tier (Z1) CLCPA AOC Projects (Sheet 4 of 5)**

| ID | Proposed Project | In Serv Date | Age (Yrs) | New ROW Feet | Art VII? | Estimated Total Costs thru 2030 ($millions) | | | 70% Limited Curtailment Deliverability Violation Addressed | Rationale for Acceptance or Rejection |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Company Proposal | Accept | Reject | | |
| Z18 | Bennett-Palimeter 115 kV Line **932** Structure replacements (13 mi.) in preparation for SmartValve Power Flow Control Device at Bennett Substation (proposed cost is +200%/-50%) – Response by NYSEG and RG&E to DPS Information Request - 4 indicates correct cost is $33.0 million. | 2029 | 57 | 0 | Yes | 33.0 | 27.8 | 5.2 | Some Clearances may be Deficient Thereby Reducing Circuit's Thermal Rating Below Presumed Level | PARTIALLY ACCEPT - This is Needed to Return Line Capability to Presumed Rating to Assure Headroom Increases - But cost should be limited to $2.0 million per mile (+50%/-25%) |
| Z19 | **Bennett** 115/34.5 kV Substation - Rebuild & Expand 115 kV Bus (new generator interconnection position), SmartValve - Power Flow Control Device, and Terminal Work for Line 725 - in flood plain but no relocation proposed due to limited scope | 2025 | 94 | 0 | No | 25.7 | 25.7 | 0.0 | Low Voltage Violation at 1 Substation for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| Z20 | Bennett-Spencer Hill 115 kV Line **953** - Rebuild w/2156 ACSR (5 mi.) | 2026 | 36 | 0 | Yes | 18.1 | 18.1 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| Z21 | Spencer Hill-Bath 115 kV Line **723** - Rebuild w/bundled 795 ACSR (15 mi.) | 2029 | 36 | 0 | Yes | 75.9 | 75.9 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| Z22 | **Bath** 115/34.5 kV Substation - Rebuild as 3-Bay AIS BAAH 115 kV with +150/-100 MVAr STATCOM or SVC ($114.0 M), 2-115/34.5 kV 50 MVA Transformers, 34.5 kV GIS Straight Bus with Tie Breaker, 34.5/12.5 kV 14 MVA LTC Transformer, and 12.5 kV GIS Straight Bus ($28.1 M) but need to relocate 115/34.5 Transformers for 115 kV work | 2025 | 94 | 0 | No | 142.1 | 114.0 | 28.1 | Low Voltage Violation at 2 115 kV Substations for N-1 Contingency; No indication of violations for 115/34.5 kV and below | ACCEPT - 115 Work & 115/34.5 Transformer Relocations to address Voltage Violation - REJECT 34.5 kV and lower voltage work as not needed to provide incremental headroom |
| Z23 | Bath-Montour Falls 115 kV Line **965** - Rebuild w/bundled 795 ACSR (22 mi.) | 2029 | 51 | 0 | Yes | 116.1 | 116.1 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| Z24 | Stoney Ridge-Sullivan Park 115 kV Line **712** - Rebuild w/2156 ACSR from Dbl Ckt to Single Ckt (6 mi.) | 2026 | 11 | 50 | No | 23.7 | 23.7 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |

**Table Continued ...**

**Table 14 - Southern Tier (Z1) CLCPA AOC Projects (Sheet 5 of 5)**

| ID | Proposed Project | In Serv Date | Age (Yrs) | New ROW Feet | Art VII? | Estimated Total Costs thru 2030 ($millions) | | | 70% Limited Curtailment Deliverability Violation Addressed | Rationale for Acceptance or Rejection |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Company Proposal | Accept | Reject | | |
| Z25 | Sullivan Park-West Erie Ave 115 kV Line **711** - Rebuild w/2156 ACSR from Dbl Ckt to Single Ckt (3 mi.) | 2026 | 11 | 50 | No | 11.1 | 11.1 | 0.0 | Line Thermal Overload for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| Z26 | West End Ave-Hickling 115 kV Line **935** - Rebuild w/2156 ACSR (9 mi.) | 2026 | 53 | 0 | No | 31.5 | 31.5 | 0.0 | Line Thermal Overload for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| Z27 | **Hickling** 115/34.5 kV Substation - Rebuild in new location out of flood plain as 3-Bay AIS BAAH 115 kV ($72.1 M), 2-115/34.5 kV 50 MVA Transformers, 34.5 kV GIS Straight Bus with Tie Breaker, and 12.5 kV GIS Straight Bus ($62.2 M) - cost breakdowns are approximate (Response by NYSEG and RG&E to DPS Information Requests 6 and 7) | 2027 | 94 | Yes - New Location | No | 134.3 | 134.3 | 0.0 | Substation buswork Line 964 Thermal Overload for N-1 Contingency; 115/34.5 kV and Distribution are intertwined due to relocation | ACCEPT - Adds Headroom by Addressing Overloads; also moves substation out of flood plain |
| Z28 | Marshall-Marsh Hill 34.5 kV Line **539** - Partially Rebuild w/477 ACSR (2 mi. of 13 mi.) | 2026 | 58 | 25 | No | 8.2 | 8.2 | 0.0 | Line Thermal Overload for N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| Z29 | Marsh Hill-Troupsville-Woodhull 34.5 kV Line **546** - Rebuild Marsh Hill to Troupsburg to Marsh Hill w/477 ACSR (8 mi.) and Partially Rebuild Troupsville to Woodhull w477 ACSR (3 of 8 mi.) | 2026 | 56 to 63 | 0 to 100 | No | 42.8 | 42.8 | 0.0 | Line Thermal Overload for both N-0 and N-1 Contingency | ACCEPT - Adds Headroom by Addressing Overloads |
| Z30 | Meyer-Wayland 34.5 kV Line **565** - Rebuild w/477 ACSR (8 mi.) | 2026 | 96 | 0 to 100 | No | 31.0 | 31.0 | 0.0 | Overload (in Appendix A page 16) | ACCEPT - Adds Headroom by Addressing Overloads |
| Z31 | Wayland-Atlanta 34.5 kV Line **542** - Rebuild w/477 ACSR (6 mi.) | 2026 | 45 | 0 | No | 21.8 | 21.8 | 0.0 | Overload (in Appendix A page 15) | ACCEPT - Adds Headroom by Addressing Overloads |
| Z32 | **Various 115 kV Substations** - Minor upgrades at Caton Ave, Flat St, Moraine, Ridge Rd, Spencer Hill, Station 128, Sullivan Park, West Erie Ave, and Yawger Rd 115 kV Substations (Switch, Breaker, Bus Upgrades) | 2030 | Varies | No | No | 9.2 | 9.2 | 0.0 | Line Thermal Overload for N-1 Contingencies | ACCEPT - Adds Headroom by Addressing Various Overloads |
| | Adjustment for Rounding Error > | | | | | 0.2 | 0.2 | 0.0 | | |
| | **TOTAL SOUTHERN TIER Z1 >>>** | | | | | **2245.7** | **2212.4** | **33.3** | | |

| **Table 15 - CLCPA AOC Headroom Results<br>Southern Tier (Z1) Region** | | | |
|---|---|---|---|
| Input | Proposed Cost of AOC Project ($millions)> | $2,245.7 | |
| | Approved Cost of AOC Project ($millions)> | $2,212.4 | |
| | Renewables Modeled in Study (Nameplate in MW) > | 2,047 | |
| | Level of Renewable Dispatch (% of Nameplate) > | 70% | |
| Results | | Before AOC | After AOC |
| | Capacity Headroom (MW) | (1,283) | 593 |
| | Incremental Capacity Headroom (MW) | | 1,876 |
| | Per Unit Cost of Incremental Capacity Headroom from AOC Projects ($million/MW) | | $ 1.18 |
| | Energy Headroom (GWh) | (5,856) | 6,986 |
| | Incremental Energy Headroom (GWh) | | 12,842 |
| | Per Unit Cost of Incremental Energy Headroom over 40 Years from AOC Projects ($/MWh) | | $ 4.31 |
| Headroom results presume renewables are already on-line at 70% of Nameplate | | | |

# Exhibit 2

# April 19, 2024, NYPSC Order Authorizing Applicants to Seek FERC Authorization to Utilize 100% CWIP Incentive

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on April 18, 2024

COMMISSIONERS PRESENT:

Rory M. Christian, Chair
James S. Alesi
David J. Valesky
John B. Maggiore
Uchenna S. Bright
Denise M. Sheehan, recusing

CASE 20-E-0197 - Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act.

ORDER ADDRESSING RATEMAKING FOR AREAS OF CONCERN TRANSMISSION UPGRADES

(Issued and Effective April 19, 2024)

BY THE COMMISSION:

## INTRODUCTION

On October 17, 2023, New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E) (together, the Companies) filed a petition (Petition) requesting approval from the Public Service Commission (Commission) to seek authorization from the Federal Energy Regulatory Commission (FERC) to utilize 100 percent Construction Work in Progress (CWIP) in rate base for certain local

transmission projects.[1] Through this Order, the Commission approves the Petition, as discussed below.

## BACKGROUND

In the September 2021 Order on Local Transmission and Distribution Planning Process and Phase 2 Project Proposals, the Commission sought the development of a portfolio of projects (Phase 2 Projects) to enable achievement of the clean energy goals established in the Climate Leadership and Community Protection Act (CLCPA).[2] The Commission also identified a preference for a voluntary statewide participant funding agreement to recover the costs of Phase 2 Projects.[3]

In January 2022, the Joint Utilities filed a proposed Cost Sharing and Recovery Agreement (CSRA) and a proposed cost allocation mechanism in compliance with the Phase 2 Order.[4] In April 2022, the Joint Utilities submitted a revised CSRA and the Commission subsequently accepted the compliance filings in the May 2022 Order.[5] Under the CSRA, cost recovery for Phase 2

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[1] The Companies filed a petition on October 13, 2023, which was revised by the Companies on October 17, 2023 to include a signature that the Companies indicate was inadvertently left off the original filing.

[2] Case 20-E-0197, Order on Local Transmission and Distribution Planning Process and Phase 2 Project Proposals (issued September 9, 2021) (Phase 2 Order), p. 49. The CLCPA was enacted as Chapter 106 of the Laws of 2019 (codified, in part, in Public Service Law §66-p).

[3] Phase 2 Order, pp. 30-31.

[4] The Joint Utilities include Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

[5] Case 20-E-0197, Order Accepting Compliance Filings (issued May 12, 2022) (May 2022 Order).

projects that are approved for development by this Commission must also be approved by FERC to implement statewide cost allocation.

In August 2022, FERC accepted the CSRA and related cost allocation filings.[6] Pursuant to the approved CSRA, the Joint Utilities are allowed to recover project costs, including the cost of financing construction using the Allowance for Funds Used During Construction (AFUDC), from the in-service date of a project until the end of its useful life.[7] Recovery of costs during construction (i.e., CWIP) is only recoverable if approved by the Commission and FERC.[8]

On February 16, 2023, the Commission approved the upgrade projects proposed by the Companies for their local transmission systems in the Areas of Concern (AOC).[9] The upgrades proposed by the Companies were designed to address transmission deficiencies in areas that are already experiencing curtailments of renewable generation or where developer interest exceeds the capability of the local transmission system.

## THE PETITION

In their Petition, the Companies indicate that they are in the midst of an unprecedented level of capital investment in transmission to meet the clean energy targets established in

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[6] FERC Docket Nos. ER22-2152, et al., Order Accepting Proposed Cost Sharing and Recovery Agreement, Rate Schedule, Tariff Revisions, and Certificates of Concurrence (issued August 19, 2022).

[7] CSRA, p. 10.

[8] Ibid.

[9] Case 20-E-0197, Order Approving Phase 2 Areas of Concern Transmission Upgrades (issued February 16, 2023) (AOC Order). The Areas of Concern are identified on page 5 of the AOC Order.

legislation and directed by the Commission.[10] The Companies note that the approved AOC upgrades include several large projects with long development and construction schedules that will require a rapid pace of investment. The Companies explain that traditional ratemaking treatment does not provide for cost recovery of the AFUDC until the projects enter commercial operation. The Companies further explain that they will spend more than $1 billion in capital expenditures over the next few years for facilities that are not yet in service and are not generating any cash flow under the traditional AFUDC approach.

According to the Companies, their cash flows and credit metrics are already under pressure and the substantial investments required to develop the approved projects will exacerbate the pressure and put the Companies' investment grade credit ratings at risk if AFUDC is utilized for all of the planned transmission upgrades. The Companies provide a table depicting cash flows and debt ratios spanning 2018-2022 in comparison with its New York State utility peers, noting that the Companies have recently fallen below the expected range for investment grade ratings and that ratings agencies have referred to NYSEG's financial metrics as extremely weak and being amongst the lowest in the industry.[11]

The Companies assert that allowing 100 percent CWIP in rate base would benefit customers by avoiding the accumulation of large AFUDC balances that would be compounded in rates over the life of the investments. The Companies estimate that capital costs would be reduced by $195 million through the use

[10] The CLCPA was enacted on July 18, 2019, and the Accelerated Renewable Energy Growth and Community Benefit Act (Accelerated Renewables Act) was enacted on April 3, 2020. The Companies note that the CLCPA sets targets for New York State to reduce carbon emissions from the electricity sector.

[11] Petition, pp. 6-7.

of CWIP in place of AFUDC. The savings would result from the avoidance of incurring carrying costs that are recovered through depreciation over the life of the assets. In addition, the Companies state that further savings of $79 million would be realized from a lower return due to the lower rate base and an additional $23 million in savings would occur from the reduced collection of associated income and gross receipts taxes. In total, the Companies indicate that the savings to customers through the utilization of CWIP would amount to nearly $298 million.[12]

In the Petition, the Companies explain that the use of CWIP will enable them to obtain favorable financing for the Phase 2 transmission upgrades and better position them to avoid a debt ratings downgrade. According to the Companies, such a downgrade would extend beyond Phase 2 projects to increase debt financing costs for the Companies broadly and thus result in higher costs to customers of the Companies.

The Companies submit that there is ample precedent for allowing CWIP to be utilized for large transmission projects in New York State. The Petition includes a discussion of several examples of recent transmission investments for which the Commission supported or did not oppose the use of CWIP before FERC.[13]

The Companies indicate that if they are authorized to utilize CWIP, they will implement accounting controls to ensure that they do not accrue any AFUDC for the Phase 2 projects during any period when CWIP is in effect. The Companies state

[12] Petition, pp. 11-13.

[13] The Companies point to the New York Energy Solution project (FERC Docket No. ER15-572), Segment A of the Edic to Pleasant Valley transmission solution (FERC Docket No. EL19-88), and Smart Path Connect (FERC Docket Nos. ER23-973 and ER23-974).

that they have created program accounting codes in their accounting systems such that all new capital orders for the Phase 2 projects would be tagged with the unique program code and assigned an interest profile that prohibits the calculation of AFUDC on the capital assets.

## NOTICE OF PROPOSED RULE MAKING

A Notice of Proposed Rule Making was published in the State Register, in accordance with the State Administrative Procedure Act (SAPA) §202(1), on December 6, 2023 [SAPA No. 20-E-0197SP18] regarding the revised petition filed on October 17, 2023, by the Companies. The time for submission of comments in response to the notice expired on February 5, 2024. No comments were received.

## LEGAL AUTHORITY

The Accelerated Renewables Act directs the Commission and Department of Public Service to take action to ensure that renewable energy can be efficiently and cost-effectively injected into the State's transmission and distribution system for delivery to regions of the state where it is needed.[14] The Accelerated Renewables Act further requires the Commission to develop plans that "provide for the timely development of local transmission and distribution upgrades" by the state's regulated utilities and LIPA.[15]

In addition, the Public Service Law (PSL) provides the Commission with broad authority to direct actions to ensure that energy supplies and transmission resources are adequate to meet demand in a manner that is protective of the environment. In

[14] Accelerated Renewables Act §7(2).

[15] Accelerated Renewables Act §7(3).

particular, PSL §4(1) expressly imbues the Commission with "all powers necessary or proper to enable [the Commission] to carry out the purposes of [the PSL]" which include, without limitation, the provision of safe and adequate service at just and reasonable rates,[16] environmental stewardship, and the conservation of resources.[17] Further, PSL §5(1) provides that the "jurisdiction, supervision, powers and duties" of the Commission extend to the "manufacture, conveying, transportation, sale or distribution of … electricity." Under PSL §5(2), the Commission is required to "encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources."

Additionally, PSL §65(1) grants the Commission authority to ensure that "every electric corporation and every municipality shall furnish and provide such service, instrumentalities and facilities as shall be safe and adequate and, in all respects, just and reasonable." The Commission has further authority under PSL §66(5) to prescribe the "safe, efficient and adequate property, equipment and appliances thereafter to be used, maintained and operated for the security and accommodation of the public" whenever the Commission

[16] See Int'l Ry. Co. v. Pub. Serv. Comm'n, 264 A.D. 506, 510 (1942).

[17] PSL §5(2); see also Consolidated Edison Co. of N.Y., Inc. v. Pub. Serv. Comm'n, 47 N.Y.2d 94 (1979) (overturned on other grounds) (describing the broad delegation of authority to the Commission and the Legislature's unqualified recognition of the importance of environmental stewardship and resource conservation in amending the PSL to include §5).

determines that the utility's existing equipment is "unsafe, inefficient or inadequate." Moreover, PSL §66(2) provides that the Commission shall "examine or investigate the methods employed by ... persons, corporations and municipalities in manufacturing, distributing and supplying ... electricity ... and have power to order such reasonable improvements as will best promote the public interest, preserve the public health and protect those using such ... electricity." The actions taken in this Order fall within the scope of this authority.

## DISCUSSION

Both AFUDC and CWIP provide regulated utilities with compensation for financing costs incurred to construct new facilities. The AFUDC approach provides for recovery after the infrastructure is in service by adding the accumulated carrying costs to capital expenditures for inclusion in gross plant in service. Conversely, including CWIP in rate base provides for recovery during construction, in advance of the projects being placed in service. While both mechanisms are intended to provide compensation for financing costs, each mechanism presents different advantages and disadvantages. AFUDC provides for recovery over the life of the asset, thereby aligning funding with the customers that benefit from the asset, but increases gross plant in service by financing costs and results in higher revenue requirement over the life of the asset. CWIP requires customers to fund projects that are not yet being used, but results in a lower revenue requirement over the life of the asset.

The Companies are currently operating under a three-year electric and gas rate plan which was adopted by the

Commission on October 12, 2023.[18] The 2023 Rate Order incorporates a return on equity of 9.2 percent and a common equity ratio of 48 percent for both Companies. Currently, both NYSEG and RG&E have a long-term credit rating of "Baa1" from Moody's Investors Services (Moody's) with a "Stable" outlook.[19] NYSEG and RG&E have an issuer credit rating of "A-" from S&P Global Ratings (S&P) with a "Stable" outlook.[20] The immediate parent company of both utilities, Avangrid Inc., is rated "Baa2" by Moody's and "BBB+" by S&P.[21]

Both S&P and Moody's consider a company's credit worthiness when determining their ratings. While each rating agency utilizes a number of different factors in its analysis, their reports often specifically refer to the ability of companies to maintain these metrics within a specified range as a large determinant as to whether a company may be upgraded or downgraded. For S&P, two of those core metrics are the funds from operations (FFO) to debt ratio and the debt to earnings before interest, taxes, depreciation, and amortization (EBITDA) ratio. The FFO/debt ratios for NYSEG and RG&E were within S&P's "A-" range of 13 to 23, with ratios of 14.1 and 16.0,

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[18] Cases 22-E-0317 et al., Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service, Order Adopting Joint Proposal (issued October 12, 2023) (2023 Rate Order).

[19] Moody's Investors Service Credit Opinion, New York State Electric and Gas Corporation, January 19, 2024. Moody's Investors Service Credit Opinion, Rochester Gas & Electric Corporation, January 19, 2024.

[20] S&P Global Ratings, New York State Electric & Gas Corp., September 11, 2023. S&P Global Ratings, Rochester Gas & Electric Corp., September 12, 2023.

[21] Moody's Investors Service Credit Opinion, Avangrid, Inc., March 8, 2024. S&P Global Ratings, Avangrid Inc., December 13, 2023.

respectively, as of December 31, 2022.[22] However, the debt to EBITDA ratios for NYSEG and RG&E are 6.1 and 5.5 respectively.[23] These ratios are higher than the S&P "A-" rating ratios range of 3.5 to 4.5, and the ratings are therefore an indication that this metric is weaker than the metrics of other companies with similar risk and ratings.[24]

Similarly, one of the core metrics that Moody's focuses on is the Companies' cash flow from operations before changes in working capital (CFO-Pre WC) to debt metric. This metric was at -2.2 percent and 4.0 percent, for NYSEG and RG&E, respectively, as of September 2023.[25] This is below the 14 percent that Moody's indicates is the bottom of the "Baa" range for both Companies.[26] As the Companies indicate in the Petition, the 2023 Rate Order is expected to significantly improve the Companies' metrics. While the most recent S&P analysis predates the 2023 Rate Order, Moody's most recent analysis agrees that the current rate settlement will improve the financial metrics of both Companies.[27]

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[22] S&P Corporate Rating Methodology, November 19, 2013. S&P Global Ratings, New York State Electric & Gas Corp., September 11, 2023. S&P Global Ratings, Rochester Gas & Electric Corp., September 12, 2023.

[23] S&P Global Ratings, New York State Electric & Gas Corp., September 11, 2023. S&P Global Ratings, Rochester Gas & Electric Corp., September 12, 2023.

[24] S&P Corporate Rating Methodology, November 19, 2013.

[25] Moody's Investors Service Credit Opinion, New York State Electric and Gas Corporation, January 19, 2024. Moody's Investors Service Credit Opinion, Rochester Gas & Electric Corporation, January 19, 2024.

[26] Moody's Rating Methodology for Regulated Electric and Gas Utilities, June 23, 2017.

[27] Moody's Investors Service Credit Opinion, New York State Electric and Gas Corporation, January 19, 2024. Moody's Investors Service Credit Opinion, Rochester Gas & Electric Corporation, January 19, 2024.

Were the Companies to be downgraded by either rating agency, the result would be an increased cost of debt for ratepayers. This higher cost of debt would not only apply to the portion of debt the Companies will need to issue for construction of the Phase 2 Projects, but also to debt issued by the Companies for any other long-term projects that require funding with external debt as well as replacement of any maturing debt that would occur.

As the Companies discuss in their Petition, the annual investment in the Phase 1 and Phase 2 transmission projects for NYSEG alone will total over $1.1 billion for the next three years. These are largely long-term projects for which the Companies will have to raise a substantial amount of capital upfront before the projects go into service and generate any revenues. While some of that capital will be in the form of equity and internally generated funds, in order to maintain an appropriate capital structure, the Companies will also need to fund these projects with debt issuances. With the debt portion of some of their core credit metrics increasing, without a corresponding increase in cash flow, the Companies would face a period where their core metrics would be pressured, all else being equal.

The Companies are requesting approval to recover the cost of CWIP to mitigate pressure on cash flows, which will reduce the future financing cost burdens on ratepayers. Allowing the Companies to recover the cost of CWIP as these projects proceed will improve their cash flow positions. Keeping the core credits metrics in line with their current ratings will also reduce the likelihood that the Companies will face a credit rating downgrade and subsequent increased interest costs.

Financial Impacts to Customers

The Companies forecast capital expenditures, exclusive of carrying charges, of approximately $2.133 billion ($1.994 billion at NYSEG and $149 million at RG&E) to construct the AOC projects. We find that the Companies appropriately estimated AFUDC of the AOC Projects. The Companies used the FERC methodology to determine the AFUDC rate coupled with the Companies' capital expenditure forecast to determine a forecasted allowance for the projects.[28] This resulted in AFUDC of approximately $195 million ($179 million at NYSEG and $17 million at RG&E). Adding these carrying charges to the construction costs would increase gross plant in service to approximately $2.329 billion ($2.163 billion at NYSEG and $166 million at RG&E).

The Companies included estimated savings of allowing for CWIP in rate base, as compared to AFUDC, to be $298 million ($270 million for NYSEG and $28 million for RG&E) over the life of the assets. The savings are comprised of lower:

1. Depreciation expenses of $195 million ($179 million for NYSEG and $17 million for RG&E);
2. Return costs of $79 million ($71 million for NYSEG and $9 million for RG&E); and,
3. Tax obligations of $23 million ($21 million for NYSEG and $3 million for RG&E).

The assumptions underlying these estimates are reasonable as the Companies used the capital structure, including cost of debt and equity, from the 2023 Rate Order.

Tables 2 and 3 in the Petition compare the estimated return, depreciation, and associated taxes of the AOC Projects using CWIP and AFUDC for NYSEG and RG&E, respectively, on a

[28] 18 C.F.R. §101.

nominal, real, and present value (PV) basis. The estimated savings of $298 million, on a nominal basis, is nearly five percent of the return, depreciation, and associated taxes of the projects. The PV basis estimates show CWIP in rate base to be approximately 1.5 percent costlier than AFUDC. However, this estimate does not consider that the cost of debt may be higher under the AFUDC rate treatment mechanism compared to CWIP in rate base.

Controls

The Companies propose to tag capital orders for the Phase 2 Projects with a unique program code in their SAP accounting systems to prevent double recovery of capitalization costs. We will require the Companies to file, on a semi-annual basis, a report detailing the capital costs incurred for the tagged projects. The report is to provide verification that gross plant does not include AFUDC for these projects. The reports are to be filed by January 1 and July 1 of each year until all projects are in service. Any upgrades made after the projects' initial in-service date will follow the financing cost recovery mechanism, as agreed to in the CSRA.

## CONCLUSION

The Commission previously authorized the Companies to develop specific projects to unbottle renewable generation in the Areas of Concern. Unlike other transmission and distribution investments, the Companies cannot abandon these projects without our consent. Given the magnitude of the savings expected to be realized by electric customers across the state and the financial risk to the Companies' creditworthiness metrics, the Commission authorizes the Companies to seek FERC

approval to utilize CWIP in rate base for these transmission upgrades.[29]

The Commission orders:

1. New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation are authorized to seek Construction Work in Progress in rate base for the Areas of Concern Projects at the Federal Energy Regulatory Commission, as discussed in the body of this Order.

2. New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation shall file semi-annual reports detailing the capital costs incurred for the Areas of Concern Projects by January 1 and July 1 of each year, as described in the body of this Order.

3. In the Secretary's sole discretion, the deadlines set forth in this Order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least three days prior to the affected deadline.

[29] Pursuant to CLCPA §7(2), we note that our approval of the request to seek FERC authorization to include CWIP for these projects is consistent with and will not interfere with the attainment of the statewide greenhouse gas emissions limits, as these projects are designed to unbottle renewable generation and our decision here only pertains to cost recovery for the projects. Similarly, in line with CLCPA §7(3), we further note that our approval will not disproportionately burden disadvantaged communities, as this decision only concerns cost recovery and will provide cost savings to electric customers across the state.

4. This proceeding is continued.

By the Commission,

(SIGNED) MICHELLE L. PHILLIPS
Secretary

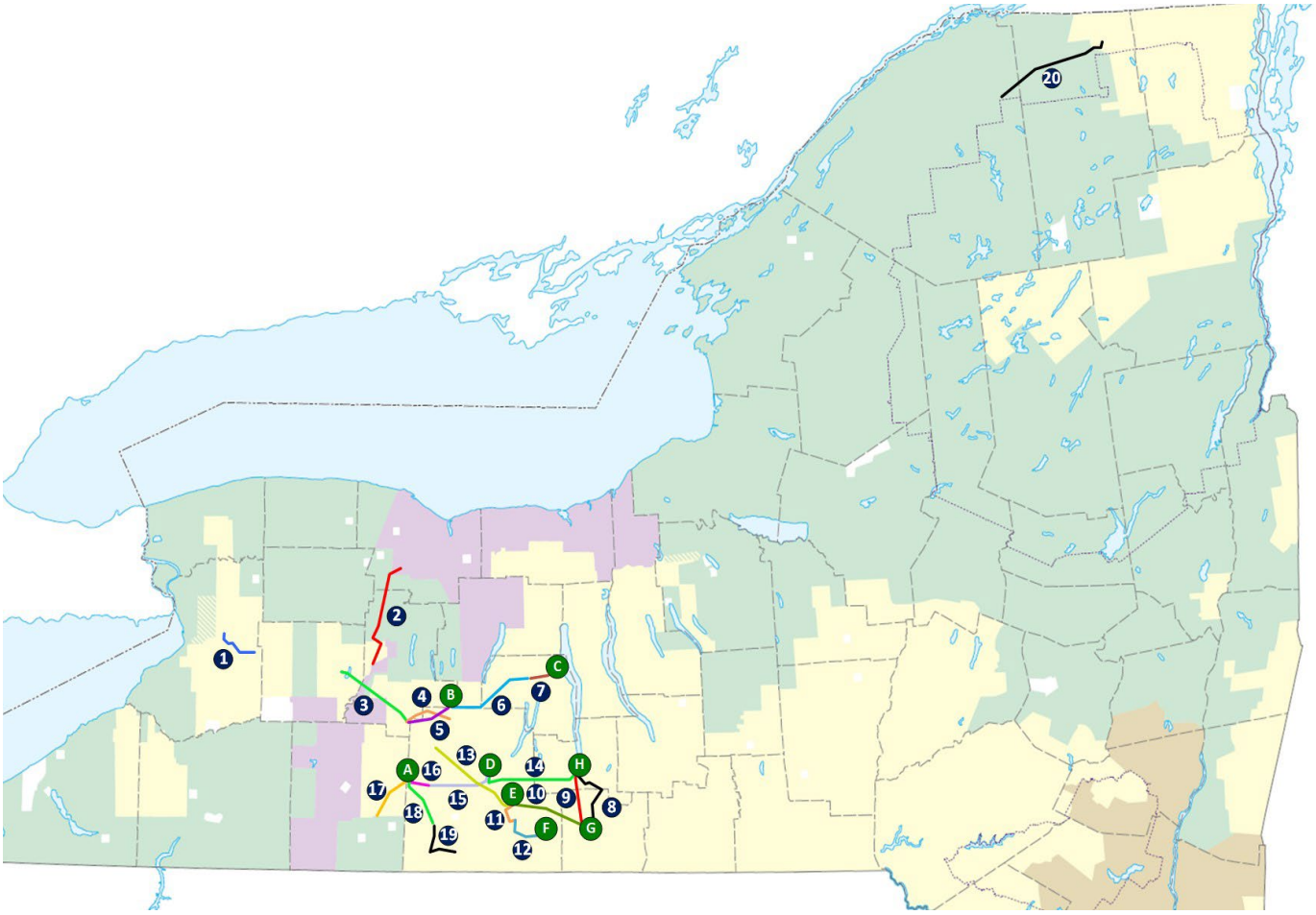
# Exhibit 3

# Map and Description of Applicants' Phase 2 Projects

**Exhibit 3**
**To Direct Testimony of Alan Trotta**

This exhibit contains a map and descriptions of the Phase 2 Projects. Unless otherwise noted, details on existing assets and Phase 2 Projects are from NYSEG and RG&E's (Southern Tier Area of Concern) section of Attachment B to the joint petition for approval of projects filed by NYSEG and RG&E along with Central Hudson Gas & Electric Corporation and National Grid on March 8, 2022.[1] Conceptual engineering and the preparation of siting filings are currently underway, and adjustments to the project may be necessary in response to the outcome of this detailed design and siting work.

**Figure 1: Map of Phase 2 Projects**




[1] Case 20-E-0197 March 8, 2022 Petition of Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation; Identifying Are of Concern Needs and Recommended Solutions.

## Project List[2][3]

## I. Transmission Line Projects[4]

**1. NYSEG 230 kV Line 67 Full Rebuild (Z01):** Line 67 is a 230 kV transmission line that is 11.3 miles long and runs from Stolle Road Substation to High Sheldon Substation. Line 67 is on double circuit lattice towers with 345 kV Line 29 for 2.6 miles near Stolle Road Substation. The conductor is 68 years old, and the average pole age is 68 years old. The conductor is nearing the end of its useful life and there are numerous structures in need of replacement. Overloads[5]: Limited Curtailment: 16% overloaded; No Curtailment: 77% overloaded.

As a result of aging infrastructure, known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 67 with larger capacity conductors. Due to right of way ("ROW") congestion near Stolle Road Substation and anticipated outage restrictions, it is assumed that Line 67 will be constructed with single circuit structures on new ROW near Stolle Road Substation. An initial assessment indicates that 150 feet of new ROW will be required for about 2.6 miles, or 54 acres. Under the project scope, line 29 will remain on the existing double circuit towers. This project will require an Article VII[6] permitting submission.

**Current Project Cost Estimate (+50%/-25%):** $93.05 Million
**In-Service:** 2029

**2. RG&E 115 kV Line 906 Full Rebuild (Z09):** Line 906 is a 115 kV transmission line that is 29.7 miles long and runs from Station 82 to the ARS Tap. The existing conductor is 48

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[2] References in parentheses are project numbers from the Phase 2 Order; Technical Appendix Pages 37 – 42 and Page 16 (NYSEG 115 kV Line 910 Full Rebuild).

[3] Projects cost estimates and in-service dates are from NYSEG/RG&E's December 22, 2023 semi-annual Phase 2 project status report: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={C029938C-0000-C43B-8BC8-C0A44B2238B5}

[4] Indicated by blue numbers in Figure 1, above.

[5] Pursuant to direction in the NYPSC's September 9, 2021 Order in Case 20-E-0197 that: "*The utility proposals should fully eliminate the curtailment risk for the Near-Term CLCPA Need and potentially enable additional headroom availability beyond the Near-Term CLCPA Need. The second option should eliminate most, but not all, of the curtailment risk for the Near-Term CLCPA Need*.", NYSEG and RG&E proposed project portfolios that addressed 100% of curtailments ("No Curtailment") and most, but not all curtailments ("Limited Curtailment"). The Limited Curtailment project portfolio was recommended by NYSEG and RG&E and approved in the Phase 2 Order. The overloads shown are for modeling of the Limited Curtailment (70% renewable generation dispatch) and No Curtailment (100% renewable generation dispatch) scenarios prior to adding the Phase 2 Projects. *See* Technical Assessment appendix to the Phase 2 Order for details on modeling assumptions and methodology.

[6] New York Public Service Law, Chapter 48, Article VII, Siting of Major Utility Transmission Facilities. Available at https://www.nysenate.gov/legislation/laws/PBS/A7.

years old, and the average pole age is 58 years old. There are structures that need replacing. Overloads: Limited Curtailment: 60% overloaded; No Curtailment: 123% overloaded.

As a result of known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 906 with larger capacity conductors. This transmission line has pole rights[7] only, with no ROW for the rebuild. An initial assessment indicates that 100 feet of new ROW will be required for this rebuild, or 359 acres. This project will require an Article VII permitting submission.

**Current Project Cost Estimate (+50%/-25%):** $156.81 Million
**In-Service:** 2030

**3. NYSEG 115 kV Line 934 Full Rebuild (Z08):** Line 934 is a 115 kV transmission line that is 19.6 miles long and runs from Meyer Substation to the South Perry Substation. Line 934 is double circuit with 230 kV Line 87 for two miles through Letchworth State Park. The conductor is 83 years old, and the average pole age is 82 years old. The conductor is past its useful life and there are numerous National Electric Safety Code ("NESC") clearance issues. Overloads: Limited Curtailment: 138% overloaded; No Curtailment: 154% overloaded.

As a result of aging infrastructure, known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 934 on an offset with larger capacity conductors. Line 934 will be rebuilt as single circuit monopole structures through Letchworth State Park. Record drawings indicate the ROW varies extensively. An initial assessment indicates that to allow for at least 100 feet of ROW in all locations, 48 acres of land will be required. This project will require an Article VII permitting submission.

**Current Project Cost Estimate (+50%/-25%):** $89.39 Million
**In-Service:** 2030

**4. NYSEG 34.5 kV Lines 565 & 542 Full Rebuilds (Z30 and Z31):** Line 565 is a 34.5 kV transmission line that is 8.1 miles long and runs from Meyer Substation to Wayland Substation. Line 565 is double circuit with 34.5 kV Line 534 for about 1.4 miles. The conductor is 98 years old, and the average pole age is 68 years old. The conductor is past its useful life and numerous structures need to be replaced. The line is overloaded for both the Limited and No Curtailment scenarios.

[7] As explained further in the Testimony of James Yeske, A pole right easement will generally provide the right to install and operate the pole in a fixed location. Such easement would include the right to repair a broken pole, attach conductors, etc., but generally does not provide a fixed ROW width or vegetation or expansion rights. Attach. B at p. 6-7.

As a result of aging infrastructure, known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 565 with larger capacity conductors. The ROW varies extensively. An initial assessment indicates that to ensure at least 100 feet of ROW in all locations, 37 acres of land will be required.

**Current Project Cost Estimate (+50%/-25%):** $30.97 Million
**In-Service:** 2027

Line 542 is a 34.5 kV transmission line that is 6.4 miles long and runs from Atlanta Substation to Wayland Substation. Line 542 is double circuit with 34.5 kV Line 544 for about 0.7 miles. The existing conductor is 33 years old, and the average pole age is 47 years old. The line is overloaded for both the Limited and No Curtailment scenarios.

As a result of the deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 542 with larger capacity conductors. Where Line 542 is currently on double circuit structures with Line 544, Line 542 will be rebuilt with new single circuit structures. Line 544 will be left on the existing double circuit structures. An initial assessment indicates that the ROW will be expanded by 50 feet for about 0.7 miles, or four acres.

**Current Project Cost Estimate (+50%/-25%):** $21.84 Million
**In-Service:** 2027

**5. NYSEG 115 kV Line 724 Full Rebuild (Z10):** Line 724 is a 115 kV transmission line that is 15.1 miles long and runs from Eelpot Substation to Meyer Substation. The existing conductor is 73 years old, and the average pole age is 63 years old. The conductor is past its useful life and there are NESC clearance issues. Overloads: Limited Curtailment: 90% overloaded; No Curtailment: 144% overloaded.

As a result of aging infrastructure, known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 724 with larger capacity conductors. This transmission line has pole rights only and no ROW. An initial assessment indicates that 100 feet of new ROW will be required for this rebuild, or 183 acres. This project will require an Article VII permitting submission.

**Current Project Cost Estimate (+50%/-25%):** $63.83 Million
**In-Service:** 2030

**6. NYSEG 115 kV Line 722 Full Rebuild (Z12):** Line 722 is a 115 kV transmission line that is 23.2 miles long and runs from Flat Street Substation to Eel Pot Substation. The existing conductor is 73 years old, and the average pole age is 56 years old. The conductor is past its useful life and there are 28 NESC clearance issues. Overloads: Limited Curtailment: 103% overloaded; No Curtailment: 162% overloaded.

As a result of aging infrastructure, known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 722 with larger capacity conductors. This transmission line has pole rights only and no ROW. An initial assessment indicates that 100 feet of new ROW will be required for this rebuild, or 281 acres. This project will require an Article VII permitting submission.

**Current Project Cost Estimate (+50%/-25%):** $114.17 Million
**In-Service:** 2030

**7. NYSEG 115 kV Line 968 Full Rebuild (Z13):** Line 968 is a 115 kV transmission line that is 5.3 miles long and runs from Greenidge Substation to Flat Street Substation. The existing conductor is 73 years old, and the average pole age is 55 years old. The conductor is past its useful life and there are numerous structures in need of replacement and NESC clearance issues. Overloads: Limited Curtailment: 98% overloaded; No Curtailment: 157% overloaded.

As a result of aging infrastructure, known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 968 with larger capacity conductors. This transmission line has pole rights only and no ROW. An initial assessment indicates that 100 feet of new ROW will be required for this rebuild, or 64 acres.

**Current Project Cost Estimate (+50%/-25%):** $18.48 Million
**In-Service:** 2027

**8. NYSEG 115 kV Line 978 Full Rebuild (Z17):** One section of the 115 kV Line 978 is 9.5 miles long and runs from Montour Falls Substation to Ridge Road Substation. The existing conductor is 80 years old, and the average pole age is 67 years old. This section of Line 978 is double circuit with 115 kV Line 963. The second section of the 115 kV Line 978 is 6.7 miles long and runs from Ridge Road Substation to Hillside Substation. The existing conductor is 76 years old, and the average pole age is 67 years old. This section of Line 978 is double circuit with 115 kV Line 963. The conductor is past its useful life and there are NESC clearance issues. Overloads: Limited Curtailment: 53% overloaded; No Curtailment: 91% overloaded.

As a result of aging infrastructure, known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild double circuit Line 978/963 with larger capacity conductors. This double circuit transmission line has pole rights only and no ROW. An initial assessment indicates that 100 feet of new ROW will be required for this rebuild. The allocation of land to be acquired under the Line 978 scope of work is 98 acres. This project will require an Article VII permitting submission.

**Current Project Cost Estimate (+50%/-25%):** $74.61 Million
**In-Service:** 2030

**9. NYSEG 115 kV Line 963 Rebuild (Z16):** One section of the 115 kV Line 963 is 9.5 miles long and runs from Montour Falls Substation to Ridge Road Substation. The existing conductor is 80 years old, and the average pole age is 66 years old. This section of Line 963 is double circuit with 115 kV Line 978. The second section of the 115 kV Line 963 is 6.7 miles long and runs from Ridge Road Substation to Hillside Substation. The existing conductor is 79 years old, and the average pole age is 66 years old. This section of Line 963 is double circuit with 115 kV Line 978. The last section of the 115 kV Line 963 is 4.9 miles long and runs from Ridge Road Substation to Yawger Substation. The existing conductor is 76 years old and the average pole age is 66 years old. The conductor is past its useful life and there are numerous NESC clearance issues. Overloads: Limited Curtailment: 63% overloaded; No Curtailment: 108% overloaded.

As a result of aging infrastructure, known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild the double circuit Line 963/978 with larger capacity conductors. This double circuit transmission line has pole rights only and no ROW. An initial assessment indicates that 100 feet of new ROW will be required for this rebuild. The allocation of land to be acquired under the Line 963 scope of work is 98 acres. This project will require an Article VII permitting submission.

**Current Project Cost Estimate (+50%/-25%):** $74.61 Million
**In-Service:** 2030

**10. NYSEG 230 kV Line 72 & 69 Full Rebuilds (Z04 and Z05):** Line 72 is a 230 kV transmission line that is 26.9 miles long and runs from Hillside Substation to Stoney Ridge Substation. Line 72 is on double circuit lattice towers with 230 kV Line 69 for 0.8 miles near Hillside Substation. The existing conductor is 62 years old, and the average pole age is 62 years old. Numerous structures need replacement. Overloads: Limited Curtailment: 29% overloaded; No Curtailment: 55% overloaded.

As a result of known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 72 with larger capacity conductors. Due to ROW congestion near Hillside Substation and anticipated outage restrictions, Line 72 will be rebuilt on new ROW using single circuit structures near Hillside Substation. An initial assessment indicates that 160 feet of new ROW will be required for about two miles, or 39 acres. This project will require an Article VII permitting submission.

**Current Project Cost Estimate (+50%/-25%):** $224.4 Million
**In-Service:** 2030

Line 69 is a 230 kV transmission line that is 1.3 miles long and runs from Hillside Substation to Watercure Substation. Line 69 is on double circuit lattice towers with 230 kV Line 72 for 0.8 miles near Hillside Substation. The existing conductor is 57 years old, and the average pole age is 52 years old. Overloads: Limited Curtailment: 22% overloaded; No Curtailment: 24% overloaded.

As a result of known asset condition needs and deliverability overloads requiring larger capacity conductors, the initial recommended solution was to rebuild Line 69 on an offset. However, due to ROW congestion near Hillside Substation and anticipated outage restrictions, Line 69 will be rebuilt on new ROW using single circuit structures with larger capacity conductors. An initial assessment indicates that 150 feet of new ROW will be required for about three miles, or 54 acres.

**Current Project Cost Estimate (+50%/-25%):** $34.71 Million
**In-Service:** 2030

**11. NYSEG 115 kV Line 712 & 711 Full Overhead Rebuilds; Underground cable remains (Z24 and Z25):** Line 712 is a 115 kV transmission line that is 6.3 miles long and runs from Sullivan Park Substation to Stoney Ridge Substation. Line 712 is double circuit with 34.5 kV Line 561 for approximately 2.5 miles near Sullivan Park Substation. This transmission line was rebuilt in 2011, so today all assets are 13 years old. Overloads: Limited Curtailment: 23% overloaded; No Curtailment: 53% overloaded.

As a result of the deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 712 with larger capacity conductors. Where Line 712 is currently on double circuit structures with Line 561, Line 712 will be rebuilt with new single circuit structures. Line 561 will be left on the existing double circuit structures. An initial assessment indicates that the ROW will be expanded by 50 feet for about 2.5 miles, or 15 acres.

**Current Project Cost Estimate (+50%/-25%):** $23.68 Million
**In-Service:** 2026

Line 711 is a 115 kV transmission line that is 2.6 miles long and runs from Sullivan Park Substation to West Erie Substation. Line 711 is double circuit with 34.5 kV Line 561 for approximately one mile near Sullivan Park Substation. This transmission line was rebuilt in 2011, so today all assets are 13 years old. The deliverability overloads require larger capacity conductors (and one structure replacement due to condition). Overloads: Limited Curtailment: 20% overloaded; No Curtailment: 50% overloaded.

The solution is to rebuild Line 711 with larger capacity conductors. Where Line 711 is currently on double circuit structures with Line 561, Line 711 will be rebuilt with new single circuit structures. Line 561 will be left on the existing double circuit structures. An initial assessment indicates that the ROW will be expanded by 50 feet for about one mile, or six acres.

**Current Project Cost Estimate (+50%/-25%):** $11.1 Million
**In-Service:** 2026

**12. NYSEG 115 kV Line 935 Full Rebuild (Z26):** Line 935 is a 115 kV transmission line that is 8.6 miles long and runs from Hickling Substation to West Erie Avenue Substation. The existing conductor is 55 years old, and the average pole age is also 55 years old. Overloads: Limited Curtailment: 6% overloaded; No Curtailment: 34% overloaded.

As a result of known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 935 with larger capacity conductors. No new ROW is anticipated for this solution.

**Current Project Cost Estimate (+50%/-25%):** $31.55 Million
**In-Service:** 2027

**13. NYSEG 230 kV Line 68 Full Rebuild (Z02):** Line 68 is a 230 kV transmission line that is 24.0 miles long and runs from Canandaigua Substation to Avoca Substation to Stoney Ridge Substation. The existing conductor is 61 years old, and the average pole age is 56 years old. Overloads: Limited Curtailment: 48% overloaded; No Curtailment: 84% overloaded.

As a result of known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 68 with larger capacity conductors. No new ROW is anticipated for this solution. This project will require an Article VII permitting submission.

**Current Project Cost Estimate (+50%/-25%):** $181.85 Million
**In-Service:** 2030

**14. NYSEG 115 kV Line 965 Full Rebuild (Z23):** Line 965 is a 115 kV transmission line that is 22.0 miles long and runs from Montour Falls Substation to Bath Substation. The existing conductor is 53 years old, and the average pole age is 34 years old. Several structures need to be replaced. Overloads: Limited Curtailment: 64% overloaded; No Curtailment: 131% overloaded.

As a result of known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 965 with larger capacity conductors. No new ROW is anticipated for this solution. This project will require an Article VII permitting submission.

**Current Project Cost Estimate (+50%/-25%):** $116.11 Million
**In-Service:** 2030

**15. NYSEG 115 kV Line 723 Full Rebuild (Z21):** Line 723 is a 115 kV transmission line that is 15.4 miles long and runs from Spencer Hill Substation to Bath Substation. The existing conductor is 37 years old and the average pole age is 38 years old. Overloads: Limited Curtailment: 76% overloaded; No Curtailment: 113% overloaded.

As a result of known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 723 with larger capacity conductors. No new ROW is anticipated for this solution. This project will require an Article VII permitting submission.

**Current Project Cost Estimate (+50%/-25%):** $75.86 Million
**In-Service:** 2030

**16. NYSEG 115 kV Line 953 Full Rebuild (Z20):** Line 953 is a 115 kV transmission line that is 5.0 miles long and runs from Bath Substation to Bennett Substation. The existing conductor is 36 years old, and the average pole age is 38 years old. Overloads: Limited Curtailment: 58% overloaded; No Curtailment: 86% overloaded.

As a result of deliverability overloads requiring larger capacity conductors, the solution is to rebuild Line 953 with larger capacity conductors. No new ROW is anticipated for this solution.

**Current Project Cost Estimate (+50%/-25%):** $18.09 Million
**In-Service:** 2027

**17. NYSEG 115 kV Line 932 Structure Replacements (Z18)**: Line 932 is part of a 115 kV transmission line that is 46.7 miles long and runs from the Bennett Substation (NYSEG) to Homer Hill Substation (National Grid). There are an additional four intermediate stations along the line: Palimeter (NYSEG), Andover (National Grid), Wellsville (National Grid), and Nile (National Grid). The NYSEG section of this transmission line is named Line 932 and is 12.8 miles long. NYSEG Line 932 runs from the Bennett Substation to Palimeter Substation to the National Grid demarcation point. The conductor is 55 years old, and the average pole age is 59 years old. Several structures need to be replaced. Under both curtailment conditions, this transmission line is overloaded.

To resolve constraints, a power flow control device will be placed on the NYSEG Line 932 terminal at Bennett Substation to eliminate the thermal overload. As a result of the known and unknown asset condition needs, in-kind structure replacements will be required on the NYSEG section of this transmission line prior to installing the smart valve. No new ROW is anticipated for this solution. This project may require an Article VII permitting submission.

**Current Project Cost Estimate (+50%/-25%):** $33.05 Million
**In-Service:** 2030

**18. NYSEG 34.5 kV Line 539 Partial Rebuild (Z28):** Line 539 is a 12.9-mile, 34.5 kV line that runs from Bennett Substation to Marsh Hill Substation, with Canisteo Substation and Marshall Substation in between. The relevant section is the 1.9-mile section between Marshall and Marsh Hill, which has an existing conductor age of 60 years old and an average pole age of 52 years. This section of the line is overloaded under both curtailment scenarios.

As a result of known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild the 1.9-mile segment of Line 539 between Marshall and Marsh Hill with larger capacity conductors. It is anticipated that 25 feet of additional ROW would be required for about two miles, or six acres.

**Current Project Cost Estimate (+50%/-25%):** $8.2 Million
**In-Service:** 2027

**19. NYSEG 34.5 kV Line 546 Partial Rebuild (Z29):** One section of the 34.5 kV Line 546 is 4.0 miles long and runs from Marsh Hill Substation to Jasper Substation. The existing conductor is 73 years old, and the average pole age is 58 years old. The second section of the 34.5 kV Line 546 is 4.2 miles long and runs from Jasper Substation to Troupsburg Substation. The existing conductor is 73 years old and the average pole age is 58 years old. The last section of the 34.5 kV Line 546 is 7.6 miles long and runs from Troupsburg Substation to Woodhull

Substation. The existing conductor is 65 years old, and the average pole age is 58 years old. The conductors are past their useful lives. The line is overloaded under both curtailment scenarios.

As a result of aging infrastructure, known asset condition needs and deliverability overloads requiring larger capacity conductors, the solution is to rebuild about 10.9 miles (out of 15.7 miles) of Line 546 with larger capacity conductors. The ROW varies extensively. An initial assessment indicates that to ensure at least 100 feet of ROW in all locations, 39 acres of land will be required.

**Current Project Cost Estimate (+50%/-25%):** $42.75 Million
**In-Service:** 2027

**20. NYSEG 115 kV Line 910 Full Rebuild (WO12):** This project was proposed by Niagara Mohawk Power Corporation d/b/a National Grid. Line 910 is an 11.1 mile, 115 kV line that runs from Willis to Malone. The line is overloaded under both curtailment scenarios.

The line will be fully rebuilt with larger capacity conductors.

**Current Project Cost Estimate (+50%/-25%):** $39 Million
**In-Service:** 2030

## II. Substation Projects[8]

### A. Bennett 115/34.5 kV Substation Expansion and Upgrades and Power Flow Device (Z19):

Bennett is an existing 115/34.5/12.5 kV substation located in NYSEG's Hornell division in the city of Hornellsville. The station was built in 1928. The substation's 115 kV is configured in a straight bus configuration with one (1) 56 MVA 115/34.5 kV transformer built in 1973 and one (1) 33 MVA 115/34.5 kV transformer built in 1950, and interconnects a total of three (3) existing NYSEG 115 kV lines. The two 115/34.5 kV transformer banks do not currently operate in parallel due to their size and resulting impedance differences. The station also has two (2) new generator interconnections planned that require the existing 115 kV bus to be expanded. The #1 and #2 transformer banks should be replaced as a part of any substation upgrade that would require them to be relocated or de-energized.

The Bennett Substation upgrades and power flow device solution includes the replacement of the 115 kV Line 953 & 725 terminal equipment as well a new dead-end structure and bus work on

[8] Indicated by green letters in Figure 1, above.

Line 953. It also includes the installation of a 0.05pu SmartValve power flow control device on the 115 kV Line 932. As a result of space and outage constraints this Line 932 power flow control device must be in a new location approximately 0.5 miles west of the substation.

**Current Project Cost Estimate (+50%/-25%):** $25.7 Million
**In-Service:** 2028

**B. Eelpot 115 kV Substation Expansion (Z11):** Eel Pot is an existing 115/34.5 kV substation located in the NYSEG Hornell division in the city of Cohocton. The station was built in 1974. The substation's 115 kV is configured as a 2-bay breaker-and-a-half that is configured as a ring bus with two (2) 56 MVA 115/34.5 kV transformers and interconnects a total of two (2) existing NYSEG 115 kV lines. The substation's 34.5 kV is configured as a straight bus and connects two (2) existing NYSEG 34.5 kV lines. There are plans for a generation interconnection on the 34.5 kV bus.

The Eelpot substation expansion project includes the installation of a new a +100/-100 MVAR dynamic VAR compensation unit (STATCOM or SVC). The design will convert the existing 115 kV four position ring bus to a five-position ring bus by adding a new 115 kV breaker and three switches. The new +100/-100 MVAR dynamic VAR compensation unit (STATCOM or SVC) will be installed in this new 115 kV ring bus position.[9]

**Current Project Cost Estimate (+50%/-25%):** $76.66 Million
**In-Service:** 2028

**C. Greenidge 115 kV Substation Upgrades (Z14):** Greenidge is an existing 115/34.5 kV substation located in the NYSEG Geneva division in the city of Dresden. The station was built in 1948 along with the Greenridge Power Plant. The substation's 115 kV is configured as a double bus with a tie breaker configuration with one (1) NYSEG owned 115/34.5 kV transformer and interconnects a total of four (4) existing NYSEG 115 kV lines. The Greenridge Powerplant currently has two main connection points; one (1) is on the 115 kV bus with a dedicated breaker and the other is on the 34.5 kV bus with a dedicated breaker. The substation's 34.5 kV is configured as a straight bus with three (3) existing NYSEG 34.5 kV lines and one generator connection. It was determined that seven (7) out of twelve (12) breakers at the station require replacement due to poor condition.

[9] Dynamic VAR compensation unit has been changed from +100/-50 MVAR to +100/-100. A 50 MVAR capacitor bank has also been removed from the scope.

The upgrades include the addition of a cap bank at the Greenidge substation along with the replacement of the dead-end structure and terminal equipment on the 115 kV line 968. This solution consists of one (1) new 115 kV circuit breaker for Line 968, Line 968 terminal work, and a new 30 MVAR capacitor bank.

**Current Project Cost Estimate (+50%/-25%):** $17.24 Million
**In-Service:** 2026

D. **Bath 115/34.5 kV Substation Rebuild (Z22):** Bath is an existing 115/34.5/12.5 kV substation located in the NYSEG Elmira division in the city of Bath. The station was built in 1928. The substation's 115 kV elements are configured in a straight bus configuration with two (2) 56 MVA 115/34.5 kV transformers and interconnects a total of two (2) existing NYSEG 115 kV lines. The substation's 34.5 kV is configured as a straight bus with a tie breaker which includes one (1) 34.5/12.5 kV transformer and interconnects four (4) existing NYSEG 34.5 kV lines, as well as a customer interconnection. The 2.5 MVA 34.5/12.5 kV transformer feeds a 12.5 kV bus, which feeds a single 12.5 kV circuit. Half of the breakers at the substation need to be replaced due to poor health. All transformers should be replaced as a part of any substation upgrade that would require them to be relocated or de-energized.

As a result of the physical and outage limitations of the existing substation, the deliverability needs, and existing asset condition needs, NYSEG determined that a full rebuild of the substation would be necessary. NYSEG proposed that the 115 kV portion of the station be expanded to a 3 Bay Breaker-and-a-half (BAAH) as well as the addition of a +150/-100 MVAR dynamic VAR compensation unit (STATCOM or SVC). As a result of the physical and outage limitations of the existing substation, the deliverability needs, and existing asset condition needs, NYSEG determined that a full rebuild of the substation would be necessary. The proposed rebuild consists of a 115 kV three-bay breaker-and-a-half (BAAH) air insulated substation (AIS) with two (2) new 115/34.5 kV 50 MVA transformers, a +150/-100 MVAR dynamic VAR compensation unit (STATCOM or SVC), a new 34.5 kV Gas insulated Switchgear (GIS) straight bus with a tie breaker. The design would also include a new 34.5/12.5 kV 14 MVA transformer with LTC and the 12.5 kV will utilize a GIS straight bus design. The (+50%/-25%) cost estimate for the proposed solution was $142.1 Million.

In the Phase 2 Order, the NYPSC determined that the 34.5 kV and lower voltage work would not create headroom and approved a reduced project scope that includes the 115 kV work and relocation of the 115/34.5 kV transformers. The NYPSC estimated that the scope reduction would reduce the project cost by $28 Million. The project scope is thus the scope proposed to the NYPSC with removal of the 34.5 kV and lower work consistent with the Phase 2 Order. The

current scope also includes changes to the transformer size from 50 to 56 MVA, and the dynamic VAR compensation device from +150/-100 MVAR to +150/-150 MVAR.

**Current Project Cost Estimate (+50%/-25%):** $114 Million
**In-Service:** 2028

**E. Stoney Ridge Transformer Replacement (Z03):** Stoney Ridge is an existing 345/230 kV substation located in the NYSEG Elmira division in the city of Campbell. The station was built in 2009. The substation's 230 kV is configured as a 3-breaker ring bus that interconnects a total of two (2) existing NYSEG 230 kV lines and one (1) 230/115/34.5 kV transformer. The substation's 115 kV is configured as a straight bus with only one (1) 115 kV line terminating into a 115 kV bay position. The line and transformer share a single 115 kV breaker. The 34.5 kV side of the transformer goes to station service and has a breaker.

The increased power flow requires the replacement of the existing 230/115/34.5 kV transformer Bank 1 one (1) new larger 448 MVA 230/115/34.5 kV transformer.

**Current Project Cost Estimate (+50%/-25%):** $36.5 Million
**In-Service:** 2028

**F. Hickling 115/34.5 kV Substation Rebuild (Z27):** Hickling is an existing 115/34.5/12 kV substation located in the NYSEG Elmira division in the city of Corning. The station was built in 1948. The substation's 115 kV is configured as a straight bus with two (2) 115/34.5 kV transformers and interconnects a total of three (3) existing NYSEG 115 kV lines. The substation's 34.5 kV is configured as a straight bus with one (1) 34.5/12 kV transformer and connects five (5) existing NYSEG 34.5 kV lines. The 34.5/12 kV transformer feeds a 12 kV bus, which connects to two (2) 12 kV circuits. The Hickling Substation borders the Chenango river and currently has portions of the substation yard within the 100 year flood plain. The substation cannot be accessed in the event of a flood. The majority of the breakers are in need of replacement due to poor health, and all of the 115 kV transformers are greater than 70 years old. A full rebuild outside of the flood plain is needed.

Due to overloads, Hickling substation requires the replacement of the 115 kV bus work for Lines 958, 935 and 964. As a result of the physical and outage limitations of the existing substation, the deliverability needs, and the existing asset condition needs, NYSEG determined a full rebuild of the substation would be necessary. The project is a full substation rebuild at a new location approximately 1 mile to the south outside of the flood zone. The 115 kV will be configured as a three-bay breaker-and-a-half (BAAH) air insulated substation (AIS) design with two (2) new 115/34.5 kV 50 MVA transformers with dedicated low side breakers, a new 34.5 kV GIS straight bus with a tie breaker as well as a new 12.5 kV GIS. The 12.5 kV will include a new 14.5 MVA

34.5/12.5 kV transformer with LTC and the 12.5 kV will be configured as a straight bus. This solution alternative was selected as it addresses all known needs at the station.

**Current Project Cost Estimate (+50%/-25%):** $134.29 Million
**In-Service:** 2028

**G. Watercure 345/230/115 kV Substation Expansion / Hillside 115 kV retirement (Z06 and Z07):**

Hillside is an existing 230/115/34.5 kV substation located in the NYSEG Elmira division in the city of Elmira. The station was built in 1942. The substation's 230 kV is configured as a straight bus with two (2) 230/115/34.5 kV transformer banks and interconnects a total of two (2) existing 230 kV lines. The substation's 115 kV is configured as a straight bus with two (2) 115/34.5 kV transformers and interconnects a total of four (4) existing NYSEG 115 kV lines. The substation's 34.5 kV is configured as a double bus with a tie breaker with one (1) 34.5 kV ground transformer and connects seven (7) existing NYSEG 34.5 kV lines. Several 115 kV and 34.5 kV breakers are in poor health and in need of replacement and the existing 115/34.5 kV transformers date back to 1968 and 1969 and should be replaced as part of any solution.

As a result of the physical and outage limitations of the existing substation, the deliverability needs, and the existing asset condition needs, NYSEG determined a full rebuild of the substation would be necessary. The substation's 115 kV yard will be decommissioned with re-routing of the existing 115 kV lines to a new 115 kV 3 bay breaker-and-a-half at the Watercure Road substation approximately 1 mile to the east. The existing Hillside substation will also require replacing one (1) set of 230 kV breakers CT's and connecting the 230/115/34.5 kV power transformer Bank #3 tertiary to the 34.5 kV bus.

**Current Project Cost Estimate (+50%/-25%):** $10.17 Million
**In-Service:** 2029

Watercure Road is an existing 345/230 kV substation located in the NYSEG Elmira division in the city of Elmira. The station was built in 1968. The substation's 345 kV is configured as a two-bay breaker-and-a-half bus that interconnects a total of two (2) existing 345 kV lines. The 230 kV is also configured as a two-bay breaker-and-a-half bus that interconnects a total of two (2) existing NYSEG 230 kV lines. There are two (2) 230/115/34.5 kV transformer banks, operated in parallel with 345/230 kV transformation.

The Watercure Road substation expansion is coupled with the decommissioning of the Hillside substation 115 kV yard and re-routing the existing 115 kV lines to a new 115 kV 3 bay breaker-and-a-half at Watercure Road. This solution also requires the addition of a new 345 kV bay at the

Watercure Road substation as well as a new 345/115 448 MVA power transformer. New Site grading and the relocation of the 4 existing 115 kV lines (L978, L960, L962 & L963) currently at Hillside will be required as a part of this solution.

**Current Project Cost Estimate (+50%/-25%):** $138.3 Million
**In-Service:** 2028

**H. Montour Falls 115/34.5 kV Substation Rebuild (Z15):** Montour Falls is an existing 115/34.5/8.3 kV substation located in the NYSEG Elmira division in the city of Montour Falls. The station was built in 1929. The substation's 115 kV is configured as a double straight bus with a tie breaker with one (1) 115/34.5 kV transformer bank and interconnects a total of six (6) existing NYSEG 115kV lines. The substation's 34.5 kV is configured as a straight bus with one (1) 34.5/8.3 kV transformer bank and connects four (4) existing NYSEG 34.5 kV lines. The 34.5/8.3 kV transformer feeds an 8.3 kV bus, which connects to two (2) 8.3 kV circuits. Most of the breakers need to be replaced due to poor health as do the 115/34.5 kV transformer bank. The station is also in the 100 year floodplain. Considering the asset condition needs and floodplain location, the solution is a full rebuild at a new location.

The replacement of the 115 kV main bus is required due to thermal overloads. The project is a full substation rebuild as a 115 kV four-bay breaker-and-a-half (BAAH) air insulated substation (AIS) design with two (2) new 115/34.5 kV 50 MVA transformers, two (2) new 115 kV 30 MVAR capacitor banks, a new 34.5 kV GIS straight bus, well as a 12.5 kV GIS straight bus (operated at 8.3 kV). The existing 34.5/12.4/8.3 kV transformer will be relocated and reused.

**Current Project Cost Estimate (+50%/-25%):** $135.94 Million
**In-Service:** 2029

**I. Minor Substation Upgrades *(not shown on map)* (Z32):** Multiple 115 kV Substations - Minor upgrades at Caton Ave, Flat St, Moraine, Ridge Rd, Spencer Hill, Station 128, Sullivan Park, West Erie Ave, and Yawger Rd 115 kV Substations (Switch, Breaker, Bus Upgrades)

**Current Project Cost Estimate (+50%/-25%):** $9.3 Million
**In-Service:** 2030

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **New York State Electric & Gas Corporation** | ) | **Docket Nos. ER24-___-000** |
| **New York Independent System Operator, Inc.** | ) | |
| **Rochester Gas and Electric Corporation** | ) | **ER24-___-000** |
| **New York Independent System Operator, Inc.** | ) | |

## VERIFICATION

I, Alan Trotta, verify under penalty of perjury that I have read the testimony, know the contents thereof, and that the facts and representations set forth therein are true to the best of my knowledge, information and belief.

Alan Trotta

Dated: May 1, 2024