STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

PETITION OF
NIAGARA MOHAWK POWER CORPORATION D/B/A NATIONAL GRID
FOR COST RECOVERY OF PHASE 1 LOCAL TRANSMISSION PROJECTS

Niagara Mohawk Power Corporation
d/b/a National Grid

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I. Introduction

Pursuant to the Public Service Commission's ("Commission") "Order on Phase 1 Local Transmission and Distribution Project Proposals" issued and effective February 11, 2021 ("Phase 1 Order") in Case 20-E-0197, Niagara Mohawk Power Corporation d/b/a National Grid ("Company" or "Niagara Mohawk") is pleased to present the 2030 CLCPA Regional Transmission Plan ("2030 Regional Plan") along with the Company's recommended transmission solutions designed to mitigate the effects of climate change and in support of New York State's efforts to decarbonize the electric grid.[1] By this petition, the Company requests that the Commission (i) find that the Company should continue to pursue the development of Phase 1 transmission solutions presented in the Company's 2030 Regional Plan because the plan is in compliance with recently enacted legislation and Commission orders that are intended to achieve the State's renewable energy targets under the Climate Leadership and Community Protection Act ("CLCPA")[2]; (ii) approve deferral of carrying charges[3] associated with certain Phase 1 transmission solutions that

[1] It is important to note that the entire portfolio of Phase 1 and Phase 2 transmission solutions in the 2030 Regional Plan are intended to support the planned renewable generation growth in Upstate New York necessary to meet the State's 2030 renewable energy goals.
[2] Chapter 106 of the laws of 2019.
[3] Carrying charges consist of return on investment, depreciation expense, and operating expense associated with an investment. *See* Phase 1 Order at 14.

were not reflected in the Company's currently pending rate case[4] but that nevertheless could be placed in service during the rate plan period covered by that rate case ("Initial Phase 1 Projects"), as well as a tariff surcharge ("Phase 1 Facility Surcharge") to provide recovery of the deferred costs; and (iii) approve deferral of operating expense associated with investments, return on capital investment (including cost of removal), and depreciation associated with the Phase 1 transmission solutions not recovered through a surcharge or existing rate plan ("Subsequent Phase 1 Projects"), for future recovery as part of the Company's next rate filing so projects can be implemented on a timely basis.[5]

II. <u>Background</u>

Enacted in July 2019, the CLCPA established the following renewable energy targets for New York State to curb the adverse climate impacts attributable to carbon emission: (i) 70 percent of electricity is produced from renewable sources by 2030 (70 x 30); and (ii) 100 percent reduction in greenhouse gas emissions from the electricity sector by 2040 (100 x 40).[6] To help achieve these CLCPA targets, the Accelerated Renewable Energy Growth and Community Benefit Act[7] ("AREGCBA" or the "Act") was signed into law on April 3, 2020. Among other things, Section 7 of the AREGCBA directs Department of Public Service Staff ("Staff"), in consultation with other parties, to undertake a comprehensive study to identify "distribution upgrades, local transmission

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[4] Case 20-E-0380, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service ("2020 Rate Case").

[5] The instant petition concerns solutions to CLCPA Phase 1 transmission issues only. CLCPA Phase 1 distribution issues are addressed with projects included in the Company's 2020 Rate Case and do not require a separate petition.

[6] CLCPA § 1(12)(d).

[7] Chapter 58 (Part JJJ) of the laws of 2020. Among other things, the Act directs the Commission to commence two proceedings to advance projects needed to meet the goals of the CLCPA: one proceeding is to focus on establishing "a distribution and local transmission capital plan" for each utility; and, the second planning proceeding mandated under the Act relates to upgrades on the "bulk transmission" needs to meet CLCPA. Act §7(3) and (4).

upgrades and bulk transmission investments that are necessary or appropriate to facilitate the timely achievement of CLCPA targets."[8] Accordingly, the Commission initiated the instant proceeding to implement the mandates of AREGCBA.[9] As directed by the Initiating Order, the Joint Utilities[10] identified distribution and local transmission projects that support the CLCPA goal of 70 x 30 and submitted their proposed system upgrades in the November 2, 2020 Utility Transmission and Distribution Investment Working Group Report ("Utilities' Report"). Subsequently, on January 19, 2021, Staff filed its "Initial Report on the Power Grid Study" ("Power Grid Study"), which included review of and general support for the Joint Utilities' recommendations as well as several other study components.

On February 11, 2021, the Commission issued the Phase 1 Order, finding that the Phase 1 projects presented in the Utilities' Report represent important opportunities to support CLCPA objectives, and directed that the utilities proceed with the development of the Phase 1 projects that have been incorporated into the utilities' capital planning processes and rate plans and to include any additional Phase 1 transmission solutions that support the CLCPA goals in the utility's next rate filing. Recognizing that relying strictly on rate case cycles for cost recovery of Phase 1 transmission solutions could delay implementation of such projects and therefore jeopardize achieving the CLCPA targets, the Commission indicated that utilities would be allowed to petition the Commission separately for authority to recover carrying costs and expenses associated with Phase 1 transmission solutions that are not included in their current rate filing or rate plan.[11]

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[8] Act, at 7(2).
[9] Case 20-E-0197, "Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act" (issued and effective May 14, 2020) ("Initiating Order").
[10] Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., New York State Electric and Gas Corporation, Rochester Gas and Electric Corporation, Central Hudson Gas & Electric Corporation, Long Island Power Authority, and Niagara Mohawk Power Corporation d/b/a National Grid.
[11] Phase 1 Order at 15. As the Commission noted, petitions for Phase 1 project cost recovery outside the context of a rate case are expected to be short-term mechanisms until such time as utilities are able to effectively incorporate CLCPA considerations into their capital planning processes and rate plans.

Consistent with the Utilities' Report, the Phase 1 Order defines Phase 1 projects as those that are immediately actionable, satisfy traditional reliability, safety and compliance planning needs but can also address bottlenecks or constraints that limit the delivery of renewable energy within a utility's system.[12] The Phase 1 Order explained that the Commission addressed Phase 1 proposals first because these projects contribute to CLCPA goals and can be implemented in the near-term, which is critical to the timely achievement of the 70 x 30 CLCPA targets. The Commission also directed that Phase 1 projects should be funded by the ratepayers of the utility proposing the project. The Phase 1 Order noted that existing cost recovery mechanisms are appropriate to fund Phase 1 projects because these projects satisfy local reliability and other planning needs in addition to enabling renewable energy deliverability.[13]

III. Overview of 2030 Regional Transmission Plan

Niagara Mohawk's electric service territory encompasses approximately 25,000 square miles, serving more than 450 upstate cities and towns and approximately 1.65 million customers. The Company's transmission system is comprised of over 6,000 circuit miles of transmission lines and more than 200 transmission substations. According to the New York Independent System Operator ("NYISO") interconnection queue, 1,964MW of wind and 3,934MW of solar generation are proposing to connect to the Company's system. In addition, 2,867MW of the generation in queue has received contract support from New York State Energy Research and Development Authority ("NYSERDA") in response to past Renewable Energy Standard Tier 1 solicitations.[14]

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[12] Phase 1 Order at 5.
[13] *Id.*, at 13.
[14] See https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility/Solicitations-for-Long-term-Contracts for additional details on contract awards.

While renewable generation developers' interest in connecting to Niagara Mohawk's system is encouraging, this represents approximately half of the generation capacity expected to interconnect to the Company's system to meet 70X30 targets. In addition, the NYISO reports that in the last five years, an additional 3,696MW of solar and wind generation proposing to connect into the Company's local system has withdrawn from its interconnection queue. Based on the Company's interconnection assessments and other planning studies, the growth in renewable capacity is being inhibited by the lack of low cost, congestion free interconnection points among other issues (*e.g.*, siting concerns). To address these system shortcomings, the Company developed its 2030 Regional Plan, which consists of both Phase 1 and Phase 2 transmission projects that, in the aggregate, serve as a robust solution that benefit the production of clean, affordable electricity. Given the amount of renewable generation required in Upstate New York to effectively decarbonize New York's electric grid, and because generation development typically out paces transmission, a delay or absence in executing transmission system upgrades will risk attainment of the CLCPA goals and ensuing economic benefits in Upstate New York. The 2030 Regional Plan discussed in Appendix B hereto represents timely solutions to excessive renewable energy curtailments or "bottling", which leads to the undesirable effect of chilling generation investments, increasing energy prices, and continuing to rely on the generation commitment and dispatch of fossil fueled resources. The 2030 Regional Plan not only supports New York's clean energy 2030 goals, but it is also foundational to the State's 2040 goals.

Each of the Company's Phase 1 solutions were designed after assessing existing reliability-based transmission projects – those projects already requiring upgrades to address condition issues, enhance storm resiliency, or improve operational performance – to minimize the cost to unbottle renewable energy. Existing reliability-based projects were assessed based on their ability to improve renewable energy deliverability as designed or improve deliverability if redesigned.

Those redesigned reliability projects that improve energy deliverability with material project cost increases are being proposed as Phase 1 transmission solutions and are the subject of this petition.[15] A summary of the existing asset condition, planned replacement, and age is provided in Appendix A.

The portfolio of Phase 1 transmission solutions the Company proposes to develop also includes the deployment of several Grid Enhancing Technologies ("GETs") that cost effectively increase transmission capability or "headroom." Further, the 2030 Regional Plan reflects Staff's recommendations in the Power Grid Study that the Company postpone development of solutions for one area originally identified as a Phase 1 transmission solution in the Utilities' Report until Phase 2.[16]

A Commission determination that the Company should continue to pursue the Phase 1 transmission solutions presented here is necessary for the Company to advance the timely development of the transmission assets to keep pace with NYSERDA facilitated renewable generation deployment and realize New York's renewable energy targets.[17] Commission approval of this petition will also give renewable developers confidence when and where generation projects can interconnect to avoid significant energy curtailments, which in turn will enable increased renewable generation participation in the energy markets and open the door to improved renewable generation utilization with fewer interconnections in the State.

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[15] Transmission projects that address reliability and improve renewable energy deliverability are referred to by the Company as Multi Valued Transmission or "MVT".

[16] Power Grid Study, Page A-2, Figure A-1: Phase 1 Local Transmission Projects – National Grid.

[17] *"Additional transmission capability is necessary to alleviate constraints and maximize the potential contribution of [] renewable resources to meet electric demand and achieve public policy goals."* (emphasis added) Power Trends 2021, New York's Clean Energy Grid of the Future, the New York ISO Annual Grid and Markets Report, accessed at: https://www.nyiso.com/documents/20142/2223020/2021-Power-Trends-Report.pdf/471a65f8-4f3a-59f9-4f8c-3d9f2754d7de (last accessed August 16, 2021).

Based on the several years' worth of work necessary to engineer, permit, construct, and commission transmission assets by the need date of 2030, the Company seeks Commission approval of this petition. Commission approval of the instant petition will enable the Company to aggressively pursue development and execution of its Phase 1 transmission solutions described in Appendix B and address the transmission capability limitations that could impede renewable energy development. In addition, Commission approval of the Phase 1 transmission solution will allow for frequent stakeholder review of the Company's Phase 1 project status. As directed by the Phase 1 Order, the Company will file semi-annual reports detailing the status of funded Phase 1 transmission solutions, the estimated in-service date, the associated CLCPA benefits, the budgeted and actual cost of the project to date, with an explanation of any variances exceeding ten percent, and an explanation of any changes to the schedule or project scope arising since the prior reporting period.[18]

IV. <u>Benefits of the Company's Proposed Phase 1 Transmission Solutions</u>

The Company's Phase 1 transmission solutions will address the transmission bottlenecks that limit delivery of upstate renewable energy to the bulk system. These projects also address one or more additional planning considerations such as reliability, resilience, or increased system capacity for the benefits of its customers (*See* Appendix A). In general, the Company's Phase 1 transmission solutions are considered no- to low-regrets MVT investments because they either address near to midterm transmission issues or accelerate the upgrade of transmission assets that are future candidates for a reliability-based upgrade. Details regarding CLCPA benefits including review of project alternatives, the efficacy of planned reliability project to improve energy

[18] Phase 1 Order at 17, 20.

deliverability in areas of high renewable generation developer interest, and a description of the study assumptions and methodologies can be found in Appendix B.

The Company's Phase 1 investments also provide storm resiliency and community benefits. Upgrading the existing transmission in remote portions of the State will greatly reduce the impacts from low frequency high impact storms and provide for an operationally flexible grid needed to accommodate additional CLCPA requirements, which could result in load growth expected from electrification in the heating and transportation sectors. In addition to the CLCPA and reliability benefits, transmission investments will also support local economies and increase employment opportunities. Transmission investments, like other large infrastructure projects, will help boost the local economy and create new jobs through local spending on construction-related services. Local economies realize an increase in short-term economic growth in proportion to approximately a third of the cost of transmission investment.[19]

A. Reliability Benefits

The Company's Phase 1 transmission solutions targets assets that provide reliability or benefits other than CLCPA in order to ensure customer value.[20] The Company's primary mission is the safe and reliable delivery of electricity to customers and the transmission of electricity to support regional electricity markets. To that end, the Company continually monitors asset and system conditions to ensure continued safe and reliable service. The Company evaluates asset condition to determine which assets should be replaced before their performance negatively impacts the provision of safe and adequate service. The physical elements of Niagara Mohawk's transmission facilities can have a service life ranging up to 100 years. While engineering analyses

[19] https://wiresgroup.com/wp-content/uploads/2020/06/2018-01-08-London-Economics-Intl-How-Does-Electric-Transmission-Benefit-You.pdf "How Does Electric Transmission Benefit You? Identifying and Measuring the Life-Cycle Benefits of Infrastructure Investments" January 8, 2018, page 9.

[20] Alternative wires projects such as GETs were used if i) they provided similar CLCPA benefits as a wire solution and ii) reliability needs were not in the near term.

can identify older assets that are serviceable, overhead line assets experience declining reliability as the effects of environmental, mechanical, and electrical degradation with age. Asset degradation can unknowingly result in assets failing to meet original design standards and fall short of present-day design criteria. In the absence of a costly and detailed condition assessments, the relative age of a circuit can provide some insight into how close the circuit may be to an end of life refurbishment or replacement or was built to an obsolete standard (*See* Appendix A).

B. <u>Resilience Benefits</u>

In addition to addressing deteriorating infrastructure that fails to maintain its original design strength or is experiencing chronic failure, the Company's Phase 1 transmission solutions also will provide enhanced system resiliency by meeting or exceeding todays engineering design standards (*e.g.*, exceeding National Electric Safety Criteria (NESC) for ice loading). The Phase 1 investments will bring existing circuits up to structural standards or improve their design to mitigate the impact of severe storms. For example, there currently exists areas where tens of thousands of customers can be interrupted by an outage of lines that the Company is considering rebuilding due to their condition and the number of customers at risk from low frequency high impact storm.

By making modifications to the original project meant to address traditional system needs of providing safe reliable service, the proposed Phase 1 investments can also unbottle locally produced renewable energy. The Company estimates that a single 24-hour outage of a community of tens of thousands of customers could have an adverse economic impact of approximately $30M.

C. <u>CLCPA Benefits</u>

Beyond addressing local system reliability needs, the Company's Phase 1 transmission solutions will also perform several critical functions necessary to facilitate CLCPA goals. The *Regional Congestion Assessment* included in the analysis in Appendix B (Test 1) is intended to;

1) identify existing system limitations in a planning region based on a 2030 load and renewable generation assumption, based off of the NYISO interconnection queue and areas of known generator developer interests; and 2) eliminate all identified congestion within the region with transmission-based solutions. If the identified congestion is not addressed, then additional generation development may be pursued in other parts of the State where the interconnection costs or project development costs (*e.g.*, land use cost) are likely higher than they are in Upstate New York. Yet, even if such additional generation could be cost effectively sited, such facilities would likely still experience curtailment as curtailment-free interconnection locations across upstate are becoming exhausted. The lack of transmission capability would result in renewable generation becoming less and less deliverable and thus less and less cost effective.

It is important to note that the transmission solutions being proposed are not meant to fully unconstrain the deliverability of the generator's nameplate capacity under all system conditions. Under Niagara Mohawk's testing, wind resources, primarily located in Western, Central and Northern NY, varied between 0 percent of nameplate up to 75 percent of nameplate and solar resources, located primarily in Central, Northern and Eastern NY were dispatched between 0 percent of nameplate up to 70 percent of nameplate. Neither wind nor solar resources were modeled at 100 percent of nameplate. The Company's renewable energy dispatch assumptions targeted NYISO hourly renewable generation output information from its CARIS 70x30 scenario where dispatches typically occurred for 100 hours or more in a year. For example, a dispatch scenario model by the Company was wind generation greater than or equal to 30 percent of nameplate concurrent with solar generation output greater than or equal to 27 percent. This dispatch occurred in the CARIS 70x30 scenario for 802 hours. Another example of the many scenarios studied by the Company was wind generation at 15 percent of nameplate and solar generation at 52 percent of nameplate. The dispatch at or above this level occurred in the CARIS 70x30 scenario for 457 hours.

Table 1 below provides a breakdown of the distribution of renewable resources assumed to be connecting to the Company's system by 2030. These renewable generation assumptions serve as a foundation to the 2030 Regional Plan. As Table 1 shows, Niagara Mohawk's CLCPA transmission investments will facilitate the delivery of over 10 GW of renewable capacity across seven generator pockets that are forming within its service area.

Table 1: 2030 CLCPA renewable generator assumptions (nameplate capacity).

Zone/Type	Total LBW	Total UPV	National Grid LBW Allocation		National Grid UPV Allocation	
	MW	MW	MW	%	MW	%
A	2,286	4,432	2,088	91%	793	18%
B	314	505	314	100%	118	23%
C	2,411	2,765	455	18%	1,102	36%
D	1,762	0	103	6%	0	0%
E	2,000	1,747	1,545	77%	1,360	78%
F		3,592			2,433	68%
G		2,032			0	0%
H						
I						
J						
K		77			0	0%
Total	**8,773**	**15,150**	**4,505**	**51%**	**5,706**	**38%**

LBW = Land-based wind. UPV = Utility-scale photo voltaic solar.

The 2030 Regional Plan also identifies ideal interconnection points for the existing network, as well as how the system is improved by the Company's proposed transmission solutions. This information, together with the scope and schedules for the planned projects gives renewable developers increased clarity regarding suitable interconnection points. It also provides developers the opportunity to consider future interconnection locations that they may have previously considered to be infeasible due to transmission system limitations. This added transparency should allow developers to submit the most cost-effective bids possible.

D. **Other Benefits**

1. Economic Development in Rural Communities

Many of New York's upstate communities are struggling to attract investment. The Company's transmission investments act as a catalyst for direct and indirect community economic benefits. The proposed transmission investments not only replace hundreds of miles of aged transmission assets but also provide numerous spin-off economic benefits in proximity to many upstate rural communities, most of which have been identified as disadvantage communities.[21]

Given the tremendous demand for transmission construction jobs in support of CLCPA, the Company is actively marketing its transmission investment plan with national construction firms to encourage them to locate in New York. In addition, CLCPA transmission investments will enable the growth of renewable generation development along its path as seen in Table 1, above. New generation entering into Payment In Lieu of Taxes (PILOT) agreements and the Commission's recently approved Host Community Benefit Program[22] will provide enduring *direct* economic benefits to participating communities as well.

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[21] See https://www.nyserda.ny.gov/ny/disadvantaged-communities#_blank.

[22] Case 20-E-0249, Order Adopting a Host Community Benefit Program (issued and effective February 11, 2021). Under this program, applicable solar and wind projects would provide payments to the town(s) or city(ies) within which the generator is located. Residential electric utility customers residing in a Host Community would receive an annual bill credit for each of the first ten years that the Facility operates in that community. Should more than one generating facility be in a given Host Community, residential electric utility customers would receive an annual bill credit for each facility. The New York State Energy Research and Development Authority shall ensure that all TIER 1 Renewable Energy Credit contracts entered into after April 3, 2020, with a Major Renewable Energy Facility appropriately reflects the obligations of the Host Community Benefit Program established in this Order, including the payment, annually for a period of ten years, of Program Fees in the amount of $500 per MW nameplate capacity for applicable solar projects and $1,000 per MW nameplate capacity for applicable wind projects to fund the Host Community Benefit Program.

The overall economic benefits attributed to the development of transmission and generation investments include.

- **Direct benefits** – During the construction period, the main driving force of economic benefits come from construction activities and project spending on labor and material that directly boost the local economy and create new jobs.
- **Indirect benefits** – Construction activities will drive up demand for supporting goods and services and indirectly boost sales in relevant sectors, such as manufacturing and transportation.
- **Induced benefits** – Workers and professionals that are hired to construct the transmission project will spend (part) of their salaries on consumer goods and services, such as housing, healthcare, and food, thus creating induced benefits for the local economy across a wide range of sectors.[23]

Focusing just on short term benefits, local communities can realize economic gains of up to one third of the cost of transmission in the form of local gross domestic product.[24] This ignores additional benefits accrued across the lifecycle of the transmission asset such as energy cost savings, improved air quality, and preventing energy supply interruptions which can be especially harmful for a community's commercial and industrial sectors whose production may be forced to be suspended during such events.

2. Energy Cost Savings

The Company's Phase 1 investment plan eliminates local transmission system constraints that would otherwise prevent renewable resources, from reaching the bulk power system (345 kV system) and ultimately serving downstream load. Through the Company's Phase 1 investments, renewable energy will be deliverable to the bulk power system and able to serve those that contribute to the NYSERDA payment's for the generation which would otherwise be served by high cost, high emissions, fossil fuel power plants. The Phase 1 transmission solutions also offer

[23] *See* https://wiresgroup.com/wp-content/uploads/2020/06/2018-01-08-London-Economics-Intl-How-Does-Electric-Transmission-Benefit-You.pdf "How Does Electric Transmission Benefit You? Identifying and Measuring the Life-Cycle Benefits of Infrastructure Investments," January 8, 2018.
[24] *Id.*, at 8.

short to midterm market benefits to customers. These market savings are achieved primarily by reducing energy curtailments from economical variable cost generation (*i.e.*, renewable generation) and bring more zero variable cost energy to market.

V. **<u>Phase 1 Components of the Company's 2030 Regional Plan Should Progress Immediately to Meet CLCPA Goals</u>**

All the Company's Phase 1 transmission solutions satisfy one or more of the Commission's Phase 1 project characteristics requirements as enumerated in the Phase 1 Order and noted below. The Phase 1 Order generally identifies the following as a characteristics of Phase 1 projects:

1. Circuit rebuilds with larger current carrying conductors.

2. Circuit rebuilds at higher operating voltages (*e.g.*, from 69 kV to 115 kV) to transmit higher levels of energy on the same conductors.

3. Replacement of existing transformers with higher capability transformers.

4. Reconfigurations and additions of new circuits or substation transformers to increase overall transfer capability.

5. Addition or capability upgrades of Phase Angle Regulators (PARs) or series reactors each of which help control and balance flows on the power system to make more effective use of the system and increase overall system transfer capability.

6. Replacement and upgrade of existing "weak-link" equipment (notably in substations) which currently serve as "choke-points" to restrict overall transfer capability.[25]

Moreover, the Phase 1 transmission solutions proposed by the Company are consistent with the Commission's previously reviewed and approved scope of work presented in the Utilities' Report.[26] However, the 2030 Regional Plan presented herein has been adjusted from the Company's Phase 1 project plan contained in the Utilities' Report in recognition of recommendations contained in the Power Grid Study and the Phase 1 Order. Specifically, a

[25] Phase 1 Order at 12-13.
[26] *See* the Company's plan beginning on page 158 of the Utilities' Report.

planned 69 kV asset condition refurbishment project included in the 2020 Rate Case has been redesigned to 115kV and has been incorporated as a Phase 1 transmission solution in the 2030 Regional Plan. The 2030 Regional Plan has also been revised to accelerate deployment of GETs, and at the recommendation of Staff, moves one project from Phase 1 into Phase 2.[27] These updates to the 2030 Regional Plan increased the total regional headroom for approximately the same overall cost estimate of Phase 1 transmission solutions from what the Company provided in the Utilities' Report.[28]

Table 2, below, provides a high-level overview of the Phase 1 projects in its 2030 Regional Plan. More details on project scope, cost and system benefits are provided in Appendix B.

Table 2: High-Level Summary of the Phase 1 Components of 2030 Regional Plan

Project Name (Nov 2 Utilities' Report)	Region	Associated Projects	Proposed I/S Date	+50%-25% Estimated Cost ($000)[29]
Homer Hill – Bennett 115kV Terminal Upgrades	Southwest	Andover Station Upgrades Nile Hill Switch Station Upgrades Nile Station Upgrades	11/2022* 11/2022* 10/2022*	$1,501
Dunkirk – Falconer 115kV Line Upgrades	Southwest	Dunkirk to Laona Lines 161/162 Rebuild	6/2026	$43,954
Laona – Moon – Falconer Dynamic Line Ratings	Southwest	Laona to Falconer Dynamic Line Rating	10/2023*	$5,640
Batavia – Golah 115kV Line Upgrade	Genesee	Southeast Batavia - Golah Line 119 Rebuild Mumford Station Upgrades North Leroy Station Upgrades North Leroy 04 Station Upgrades	10/2028 4/2024* 8/2023* 5/2023*	$99,376

[27] The Power Grid Study noted that nearly all of the Company's Phase 1 transmission solutions provide clear and tangible benefits and should be approved. In the Power Grid Study, Brattle noted, "We find that all nine projects [proposed by National Grid] are beneficial towards meeting the state's 70x30 CLCPA goals and recommend that immediate approval be considered for eight of the nine projects." Consistent with Brattle's recommendation, the Company proposes to delay the development of projects associated with the Capital/Northeast region until Phase 2.

[28] The original Phase 1 Project costs proposed by National Grid in the Utilities' Report totaled $708M after being reduced by what is committed for in the pending 2020 Rate Case.

[29] This estimate is based on current project maturities, with all cost project estimates at +50%/-25%.

Lockport – Mortimer 115kV Smart Valve System	Genesee	Lockport 115kV Smart Valve System	7/2025	$47,107
Mortimer – Golah 109 Conversion to 115kV	Genesee	Mortimer Station Upgrades Golah Station Upgrades	7/2025 12/2025	$27,362
Clarks Corners – Oneida 115kV Terminal Upgrades	East of Syracuse	Fenner Wind Station Upgrades Delphi Station Upgrades Cortland Station Upgrades Tilden Station Upgrades Tilden - Cortland Line 18 Clearance Limits	8/2024* 5/2023* 11/2024* 11/2023* 11/2023*	$7,769
Lighthouse Hill – Clay 115kV Clearance Limits	Watertown/Oswego/ Porter	Lighthouse Hill - Clay Line 7 Clearance Limits	8/2023*	$5,868
Coffeen – Black River 115kV Terminal Upgrades	Watertown/Oswego/ Porter	Coffeen Station Upgrades	12/2023*	$233
Inghams – Rotterdam 115kV Line Upgrades	Porter - Rotterdam	Inghams/Rotterdam Circuit Rebuild Rotterdam Station Upgrades Stoner Station Upgrades Clinton Station Upgrades	9/2029 7/2023* 3/2023* 5/2023*	$455,267
Meco Station Upgrade	Porter – Rotterdam	Meco Station Upgrade	7/2025	$11,847
Marshville Station Upgrade	Porter – Rotterdam	Marshville Station Upgrade	5/2024*	$6,312
Churchtown– Pleasant Valley 115kV Upgrades	Albany South	Churchtown - Pleasant Valley Section Rebuild	1/2025*	$6,708
Total				$718,945

* *denotes Initial Phase 1 Projects*

Expediting deployment of the Company's Phase 1 transmission solutions is essential to satisfy the State's renewable energy target. The Company needs to commit substantial resources to support proper planning, staging, and execution of the large volume of CLCPA transmission solutions required to meet the targeted in-service date of 2030 in addition to other mandatory and reliability-based projects. Work on these projects cannot be put on hold until the Company's next rate case cycle if it is to support the development of upstate renewable energy necessary to achieve the State's renewable energy goals. Specifically, the Company expects to spend approximately $38 million on Phase 1 projects that will be placed in-service during the term of the pending Joint Proposal in the 2020 Rate Case (*i.e.*, Initial Phase 1 Projects) and approximately $109 million from

FY22 through FY25[30] in preliminary engineering, capital investments, and associated operating expenses to progress those Phase 1 transmission solutions not identified as Initial Phase 1 Projects (*i.e.*, Subsequent Phase 1 Projects). A Commission determination that the Company should continue to pursue Subsequent Phase 1 Projects as identified in this petition will enable the Company to prioritize these projects in its long-term capital planning process and support inclusion of these projects in future rate cases as non-discretionary projects.

A delay until the next rate case to develop Initial Phase 1 Projects or Subsequent Phase 1 Projects will almost certainly delay the in-service date for these projects well beyond 2030, continue to frustrate upstate renewable generation developers, and delay attainment of additional reliability and short-term economic benefits.

VI. <u>The Company Has Satisfied the Investment Criteria of the Phase 1 Order for Seeking Funding to Develop the Initial Phase 1 Projects and Subsequent Phase 1 Projects</u>

When seeking funding for projects either in a rate filing or by petition, the Phase 1 Order requires utilities to submit, at a minimum, information concerning:

(1) existing system attributes.

(2) existing and forecast local loads, generation, and headroom.

(3) other planned projects.

(4) details on the proposed projects; and

(5) viable alternative projects, to permit meaningful review of the Phase 1 projects.[31]

Below is an overview of the five investment criteria requirements identified above as applied to the 2030 Regional Plan. A more detailed response to the Commission's five

[30] FY is the Company's Fiscal Year, which runs from April1 to March 31 of the subsequent calendar year. Thus, FY25 is April 1, 2024 – March 31, 2025.
[31] Phase 1 Order at 16.

requirements is contained in the each of the regional plans in Appendix B. Based on the information provided herein and in Appendix B, the Company submits that it has satisfied the investment criteria requirements of the Phase 1 Order and asks the Commission to find that the Phase 1 transmission solutions presented in the Company's 2030 Regional Plan advance achieving the State's CLCPA targets, comply with recently enacted legislation, and that the Company should continue development of those projects so they can be implemented on a timely basis.

It is important to note that the information summarized below and included in Appendix B is in the context of the Company's entire portfolio of CLCPA transmission solutions – both Phase 1 and Phase 2 transmission solutions. While the Company is seeking cost recovery through a surcharge mechanism only for the Initial Phase 1 Projects[32] in this petition, it is nonetheless providing information on a portfolio-level so the Commission can evaluate the Company's 2030 Regional Plan in its entirety, including the associated development cost, capital investments and operating expenses for all Phase 1 transmission solutions. For the avoidance of doubt, while the 2030 Regional Plan consists of a coordinated set of Phase 1 and 2 projects, and the proposed Phase 2 projects are included in Appendix B for information only, and the Company is not requesting a Commission finding with respect to the Phase 2 projects at this time.

A. <u>Existing electric system</u>

There are seven planning regions reviewed in the Company's 2030 Regional Plan:

a. Southwest Renewables Pocket

b. Genesee Renewables Pocket

c. East of Syracuse Renewables Pocket

[32] Except for the *Initial Phase 1 Projects*, the Company is not proposing to recover Phase 1 transmission solutions costs, including operating expenses, until they are placed in-service and as part of future rate filings.

d. Watertown/Oswego/Porter Renewables Pocket

e. Porter-Rotterdam Renewables Pocket

f. Capital/Northeast Renewables Pocket

g. Albany South Renewables Pocket

Project drawings, region maps, and the description of the existing system can be found in Appendix B.

B. Existing and forecast local loads, generation, and transfer capability

The Company studied various light, shoulder, and heavy load levels as assumed in the NYISO RNA 70 x 30 study. For each region, the Company assessed the local system's ability to transfer renewable energy out of the pocket to the surrounding bulk and local systems under different system conditions. The details regarding study conditions, methodology, and results can be found in the plans for each region in Appendix B. Imports from and exports to all regions external to New York were set to 0 MW except for Hydro Quebec, which was modeled at either 1110 MW or 535 MW of imports.

Table 3: Generation Study Assumptions

Planning Region	Light Load	Existing Fossil Generation Turned Off	Existing Renewables	NYISO Interconnection Queue	70x30 Study Assumptions
Southwest Renewable Pocket	210MW	88MW	LBW: 310MW	LBW: 924MW UPV: 608MW	LBW: 1845MW UPV: 879MW
Genesee Renewable Pocket	130MW	66MW	NA	LBW: 200MW UPV: 590MW	LBW: 308MW UPV: 119MW
East of Syracuse Renewable Pocket	60MW	64MW	LBW: 30MW	LBW: 73MW UPV: 340MW	LBW: 328MW UPV: 553MW
Watertown/Oswego/ Porter Renewable Pocket	260MW	256MW	LBW: 80MW H: 200MW	LBW: 508MW UPV: 1339MW	LBW: 1258MW UPV: 518MW
Porter-Rotterdam Renewable Pocket	150MW	NA	LBW: 74MW H: 20MW	UPV: 730MW	LBW: 74MW UPV: 1645MW

Capital/Northeast Renewable Pocket	710MW	1200MW	H: 170MW	UPV: 320MW	UPV: 487MW
Albany South Renewable Pocket	60MW	509MW	NA	UPV: 390MW	UPV: 1572MW
Total	1580MW	2183MW	LBW: 494MW H: 390MW	LBW: 1705MW UPV: 6022MW	LBW: 3813MW UPV: 5773MW

LBW: Land Based Wind H: Hydro Electric UPV: Utility Scale Photovoltaic

C. Other currently planned transmission projects

Appendix B provides a description of transmission projects contained in the Company's current capital plans that could materially affect generation deliverability in each of the planning regions. The Company reviewed existing planned projects to determine if rescoping these projects would improve system headroom. As part of its analysis and project selection, the Company consulted adjacent transmission owners and included all significant and known projects in adjacent service territories in its analysis. It also included the Western New York and AC Public Policy Transmission Projects in all base cases and completed a sensitivity analysis on the Northern New York Priority Transmission Project.

D. Details of the proposed projects, contribution toward CLCPA goals justification for prioritization

Table 4, below, summarizes the capital investment (including cost of removal ("COR")) and operating cost estimates, incremental ROW requirements, and improvements to the import/export capability (headroom) of each region. In many cases, not only did the ideal capacity headroom in a region increase, but the availability for resources to connect to alternative locations also increased.

Table 4: Summary of CLCPA Project Information for Phase 1

Planning Region	Phase 1 Capital and COR Cost Estimate ($000)	Phase 1 Operating Cost Estimate ($000)[33]	Phase 1 Incremental ROW Required	Existing Capacity Headroom (MW)	Phase 1 Capacity Headroom after Ø-1 projects (MW)	Phase 2 Capacity Headroom after Ø-2 projects (MW)
Southwest Renewable Pocket	$43,180	$7,915	Possible	550	740	740
Genesee Renewable Pocket	$167,403	$6,443	Possible	790	1210	1210
East of Syracuse Renewable Pocket	$5,998	$1,771	Unlikely	660	770	770
Watertown/Oswego/ Porter Renewable Pocket	$3,782	$2,318	Unlikely	720	800	1860
Porter-Rotterdam Renewable Pocket	$458,645	$14,782	Possible	440	540	1330
Capital/Northeast Renewable Pocket	NA	NA	NA	710	710	770
Albany South Renewable Pocket	$5,725	$984	Unlikely	710	940	1440
Totals	$684,733	$34,213		4,580	5,710	8,120

For the analysis of capacity headroom, the Company used the Straw Proposal for Conducting Headroom Assessments.[34] Headroom is an indicator of how much generation an area could support. Headroom is not the total nameplate capability of generation that could be connected in an area. Instead, it is the maximum simultaneous output from all area renewables before transmission system limits would require the generation to be curtailed. As upgrades or

[33] This estimate is based on current project maturities, with all cost project estimates at +50%/-25%.
[34] Case 20-E-0197, Staff Straw Proposal for Conducting Headroom Assessments (March 16, 2021).

reinforcements are made to the transmission system, the area headroom increases. The headroom increase is one gauge of how helpful a project would be in meeting the State's climate goals.

E. Viable alternative projects and approaches

A detailed assessment of alternatives for each regional plan is provided in Appendix B. In aggregate, the complete Phase 1 portfolio of transmission solutions unbottle 1,130 MW of existing and planned upstate renewable generation interconnecting to the Company's system.

As described in greater detail in Appendix B, the Company assessed its system to determine the transmission capability needs and performed a comprehensive evaluation to determine if the generator pockets export capacity could be increased with non-wires alternatives such as GETs. While the Company identified several non-wires alternatives that it is proposing as part of its Phase 1 investment plan, not all non-wires solution will be economical or viable due to the magnitude of estimated congestion and existing system reliability needs. For example, the Company examined the feasibility of using only utility scale energy storage to defer the transmission solutions. But because the Company's Phase 1 transmission solutions are mostly MVT (*e.g.*, 4/0 copper from the 1920's requiring replacement of both conductor and structures due to its degraded condition), it was determined that storage would not be a sufficient or viable solution at this time. The large system capability shortfalls identified in the Company's 2030 Regional Plan that contribute to the formation of generator pockets are best addressed through optimizing system utilization with GETs or by modifying reliability-based projects to increase overall local transmission capability. However, after the transmission upgrades are built, electric storage and other GETs should be strongly considered as a "fine tuning" congestion management tool to maximize the utilization of the new transmission system and thus maximize renewable energy deliverability.

Below is a high-level summary of the Company's assessment of additional alternatives to the rebuild option. Further detail on existing system conditions, 2030 system needs, and alternatives assessment can be found in Appendix A and B.

- **Advanced Conductors:** The use of advanced conductors, which have higher allowed operation temperature due to the material used, can provide economic alternatives to traditional wire, provided the existing structures can accommodate higher wire tensions. The Company is not recommending advanced conductors in any of its Phase 1 transmission solutions due to the expectation that the maximum high temperature conductor size that could be supported on the existing 89+ year old structures would not sufficiently address the identified overloads. The need to address the age of the structures also makes the use of the more expensive high temperature conductor a poor choice for an economic alternative. The incremental cost of selecting a sufficiently large ACSR conductor is small compared to the cost of using the advanced conductor when all structures are being planned for replacement due to age, condition, or structural capability.
- **DLR:** Dynamic Line Ratings can increase the rating of existing circuits without any conductor replacements. However, DLR in most cases does not provide enough of an increase to address the identified overloads within many of the pockets. Niagara Mohawk has identified one region, the Southwest, where DLR is the proposed Phase 1 solution.
- **Power Electronic Devices**: Alternatives that used power flow controllers were viable in a limited number of cases. For these types of devices (Series Reactors or Capacitors, Phase Angle Regulators, Static Synchronous Series Compensators (SSSC)) to be effective, an alternative underutilized parallel path must be available to shift power

onto. No underutilized parallel paths exist in many of the areas, especially for the limiting contingency conditions that were identified. The Company proposes to use SSSC in the Genesee region as a Phase 1 project to address generation curtailment and SSSC is being considered South of Albany as a Phase 2 project.

- **New 345 kV Solutions:** While the following is specific to the Watertown/Oswego/Porter regional pocket, the concepts hold true in other portions of the system.
    - The number and location of the existing 115kV lines are critical to providing a reliable supply to load in the area. None of the existing 115kV circuits could feasibly be removed to make way for a 345kV circuit. The Company rarely has vacant right of way, with the energized 115kV lines occupying generally all available corridor width. Thus, to add a new 345kV circuit or circuits into a region it would be necessary to procure new right of way.
    - Assuming the 345kV backbone would run parallel with the 115kV system would require approximately 75 miles of new right of way (across the Watertown/Oswego/Porter pocket). The availability and cost of the required right of way is highly uncertain which would add complexity, cost and time to any option that required substantial new right of way.
    - In the analyses done for this study, overloads were found when all lines are in service. If a 345kV backbone is added, an outage of this backbone would result in the same existing system N-0 overloads, only now occurring for an N-1 outage of the 345kV circuit. To address these overloads without rebuilding the 115kV circuits it would be necessary to build two 345kV circuits.

- Nearly all circuits that are proposed to be rebuilt were put into service between 1913 and 1928, making them 93 to 108 years old. The Company's 10-year plan already includes refurbishment work on several of these circuits. By rebuilding these circuits, future age and condition driven needs will be addressed. An option that builds a 345kV backbone without rebuilding the 115kV system will not address asset condition needs.
- Providing a 345kV line into this area, without connecting the 345kV circuit to the existing 115kV system would force generation to connect at 345kV, or force generators to build long lines from their facility to a 345/115kV collector station. Either case would result in high interconnection cost and complexity, especially for small to medium sized generators.

As highlighted above, the Company has taken a regional approach to renewable energy deliverability. This approach identified the most efficient and cost-effective transmission reinforcements that support the achievement of the State goals and satisfies the Commissions Phase 1 project characteristics. The 2030 Regional Plan in Appendix B fully complies with the Commissions information and assessment requirements. To sufficiently plan, stage, and deliver the projects in the 2030 Regional Plan, the Company must continue to fund the engineering and development of the complete portfolio of Phase 1 transmission solutions for the next three years and until such time they can be incorporated as part of the capital plan in future Niagara Mohawk rate cases.

Therefore, the Company requests that the Commission find the Phase 1 transmission solutions presented in the Company's 2030 Regional Plan are investments that advance achieving the State's renewable energy targets under the CLCPA and asks the Commission to (i) find that the Company should continue to pursue the Phase 1 transmission solutions presented in the

Company's 2030 Regional Plan because they help achieve the State's renewable energy targets under the CLCPA; (ii) approve deferral of carrying charges associated with the Initial Phase 1 Projects and the Phase 1 Facility Surcharge to recover such deferred costs; and (iii) approve deferral of operating expense associated with investments, return on capital investment (including cost of removal), and depreciation associated with the Subsequent Phase 1 Projects for future recovery as part of the Company's next rate filing so projects can be implemented on a timely basis.

VII. <u>The Company Seeks Commission Approval of its Proposed Tariff Amendment; "Phase 1 Facility Surcharge"</u>

In accordance with the Phase 1 Order, the Company proposes to implement a surcharge mechanism to recover carrying charges including depreciation expense and operating expenses associated with a subset of Phase 1 transmission solutions that are anticipated to go into service prior to the end of the rate plan period under the 2020 Rate Case – the Initial Phase 1 Projects. While the Initial Phase 1 Projects are immediately actionable and consist of relatively minor station and line upgrades, they are necessary to support attainment of the full benefit of the 2030 Regional Plan and improve the Company's ability to manage its resources and system outage needs.

Recovery of the Initial Phase 1 Projects carrying charges would be pursuant to a separate surcharge created exclusively for this purpose. Appendix C sets forth the proposed tariff amendments to facilitate recovery of the Initial Phase 1 Projects, or the Phase 1 Facility Surcharge.[35] Specifically, the Company asks the Commission to approve the proposed tariff amendment in Appendix C to recover the carrying charges of the Initial Phase 1 Projects. As discussed below, the Company believes it has satisfied the investment criteria requirements listed

[35] As indicated above, the proposed surcharge is intended to be temporary until such time as the cost of CLCPA-driven investments can be reflected in base rates.

in the Phase 1 Order as described above. Commission approval of these Initial Phase 1 Projects is, therefore, appropriate and necessary to enable these projects to be placed in-service prior the Company's next rate filing and not delay deployment of subsequent Phase 1 transmission solutions.

A. Initial Phase 1 Projects Requiring Immediate Approval and Development

The Initial Phase 1 Projects consist of 19 projects that could be placed in service prior to the Company's next rate case. All 19 projects provide benefits to renewable resources by modestly increasing headroom initially, but ultimately work in combination with other CLCPA transmission solutions to contribute to the more significant increases in headroom within the entire region. Importantly, immediate implementation of Initial Phase 1 Projects would enable the effective sequencing of the development, engineering, and construction, including required outages, of the other projects in the 2030 Regional Plan.

The Phase 1 transmission solutions, including the Initial Phase 1 Projects, were not identified in time to be included in the 2020 Rate Case, and waiting until the next rate case would put the delivery of the portfolio of transmission CLCPA projects needed by 2030 at risk. Accordingly, the Company requests authority to defer the following for any portion of the projects placed in-service prior to the start of the next rate plan:

1) All operating costs associated with capital work since inception of the project;
2) Return on cost of removal since inception of the project until the project is in service;
3) Return on the projects' net plant investments (*i.e.*, gross plant less depreciation reserve) once the project is in service; and
4) Depreciation expense.

Further, the Company proposes to recover those charges from ratepayers that have traditionally funded its transmission investments.

These deferred costs will be recovered through the proposed Phase 1 Facility Surcharge on a two-month lag following the end of the fiscal year. Cost for individual projects will not be surcharged until the fiscal year subsequent to the year the project is in service. Recovery of any deferred amounts for projects not in service prior to the next rate case will be addressed in that case.

Table 5, below, lists the Initial Phase 1 Projects that are (i) not included in the 2020 Rate Case and (ii) planned to go into service prior to the start of the Company's next rate filing cycle. The total cost for these projects is estimated to be $38 million.[36]

Table 5: Initial Phase 1 Projects for Immediate Approval and Initiation

Project ID	Project	Project Description	Region	In-Service Date	Estimated Cost ($000)
AS1	LN13 Churchtown - Pleasant Valley - Blue Stores Tap 115kV	This project is for the rebuild of 2.12 miles from Str 265 to Blue Stores Substation. This includes replacing 24 wood structures, the existing 397.5 ACSR with 2-795 ACSR 26/7 "Drake" conductor and existing shieldwire with 1-3/8" steel and install 1-OPGW.	Albany south	25-Jan	$6,708
R3	Clinton	Replace 115kV Disconnects SW1588, SW8177, SW8199, and SW1288 and replace the existing conductors between SW1588 and SW1288 and their respective 115kV take-off structures.	Porter-Rotterdam	23-May	$707
R2	Marshville	This project is for the rebuild of the 115kV side of Marshville Station. This includes replacing two 115kV:69kV autotransformers, MOD6199, MOD6299, SW1188, SW1199, SW1288, and SW1299, and associated relaying.	Porter-Rotterdam	24-May	$6,312
R3	Rotterdam Sub	This project is for the replacement of SW1288, SW1299, SW1088, and SW1299.	Porter-Rotterdam	23-Jul	$631
R3	Stoner	Replace 115kV Disconnects SW988, SW912, and SW1288 and replace the existing conductors between the SW988 and SW1288 and the 115kV line terminations.	Porter-Rotterdam	23-Mar	$695
WO2	Coffeen	Replace existing conductors to 2-1192 ACSR in R50 breaker bay. Adjust bushing CT ratios on R50 to 800:5, and for R30 change ratios to 400:5	Watertown Oswego Porter	23-Dec	$233
S1	Cortland	Replace existing conductors with 1192 ACSR in Line #1, Line #3, and Line #18 breaker bays. Adjust bushing CT ratios on R10 to	East of Syracuse	24-Nov	$1,363

[36] This estimate is based on current project maturities, with all cost project estimates at +50%/-25%.

		1000:5, and for R30 and R180 change ratios to 800:5.			
S1	Delphi	Replace existing conductors between 115kV disconnects SW33 and SW34 and their respective take-off structures.	East of Syracuse	23-May	$72
S1	Fenner	Replace existing 795 ACSR conductors with 1192 ACSR in the R30 and R80 breaker bays.	East of Syracuse	24-Aug	$121
WO2	LHH – Clay	Install fifteen (15) nonstandard double circuit wood monopole structures to remediate clearance issues on 15 spans	Watertown Oswego Porter	23-Aug	$5,868
S1	Tilden	Replace existing conductors with 1192 ACSR in the R180 breaker bay. Adjust breaker CT ratio to 800/5.	East of Syracuse	23-Nov	$63
S1	Tilden – Cortland	Replace fourteen (14) wood H-Frame suspension structures and with single circuit steel H-Frame structures and one (1) wood three pole suspension structure with a steel three pole suspension structure to remediate clearance issues on 8 spans.	East of Syracuse	23-Nov	$6,150
SW1	Andover	Adjust CT tap from 400:5 on the free-standing inter-company metering CT to 800:5	Southwest	22-Nov	$54
SW3	Laona-Falconer Dynamic Line Rating	This project is to install eight (8) Smart wires dynamic line rating devices on the Laona - Moon Rd LN173 and Moon Rd - Falconer LN175. This project includes the work to modify the EMS system to utilize ratings.	Southwest	23-Oct	$5,640
G1	Mumford	Replace 115kV Disconnects SW401, SW402, SW404, and SW405 and replace portions of the existing 115kV 2" AL bus.	Genesee	24-Apr	$972
SW1	Nile Station	Upgrade existing copper conductors with 795ACSR between SW660 and SW676. Note: SW676 is located approximately 50ft outside of the station.	Southwest	22-Oct	$619
SW1	Nile Hill Switch	Replace switch structure 693 with a new switching structure and replace approximately 900 circuit ft of conductor between SW663 and SW664	Southwest	22-Nov	$829
G1	North Leroy 04	Replace 115kV Disconnects SW26, SW27, SW200, and SW300 and replace the existing conductors between the SW26 and SW27 and the 115kV take-off structures.	Genesee	23-May	$762
G1	North Leroy	Replace 115kV disconnects SW28 and SW29 and replace the existing conductors between the 115kV disconnects and the take-off structures.	Genesee	23-Aug	$412
	Total				$38,211

1. <u>Phase 1 Facility Surcharge</u>

The Company requests authority to recover, through a monthly Phase 1 Facility Surcharge, a carrying charge that includes expenses associated with capital work, a return on cost of removal, both since inception of the project in addition to a return on the net plant investments (*i.e.*, gross plant less depreciation reserve) placed in-service, and depreciation expense associated with the Initial Phase 1 Projects. The carrying charge should be based on the pre-tax weighted average cost of capital ("WACC") at approved rates in place at the time (*i.e.*, under the WACC approved in the 2020 Rate Case). The net utility plant balances and depreciation expense being recovered through the surcharge mechanism will be excluded from actual reporting used in the Net Utility Plant and Depreciation tracker mechanism to avoid any double recovery of these costs. In Niagara Mohawk's next rate filing, these projects will be included in the net plant and depreciation forecast.

The estimated revenue requirement including the carrying charge on the net plant balances, depreciation expense, and operating expense of the Initial Phase 1 Projects to be recovered through the Phase 1 Facility Surcharge mechanism are shown below in Table 6 for illustrative purposes.

Table 6: Illustrative Revenue Requirement for the Initial Phase 1 Projects

Niagara Mohawk Power Corporation d/b/a National Grid
Case 20-E-0197
Initial Phase 1 Projects Not in 2020-E-0380 Rate Case but Estimated to be In Service by 3/31/25
Summary of Estimated Revenue Requirement Impact to be Recovered in Phase 1 Facility Surcharge
(000)

	Revenue Requirement Impact (000)			
Initial Phase 1 Projects Not in 2020-E-0380 Rate Case	FY22	FY23	FY24	FY25
Transmission Line Projects				
LN13 Churchtown - Pleasant Valley - Blue Stores Tap 115kV	$ -	$ -	$ -	$ 1,265
Lighthouse Hill-Clay	-	-	2,493	347
Tilden-Cortland LN18 Clearance Limits	-	-	1,984	423
Laona-Falconer Dynamic Line Rating	-	-	456	513
Transmission Substation Projects				
Marshville Station 299 Tran/Thermo upgrade	-	-	-	351
Rotterdam No. 20 Sub.-115 kV line upgrades: Stoner #12 & Meco #10	-	-	32	64
Coffeen Station	-	-	12	24
Fenner Wind Farm Upgrade Conductors Thermo Upgrades	-	-	-	6
Tilden	-	-	3	6
Andover Station	-	3	6	5
Nile Upgrade Conductors Thermo Upgrades	-	32	64	62
North Leroy Station Thermo upgrades	-	-	20	40
Nile Switch - Wire Replacement	-	88	78	77
Transmission Upgrades to Distribution Substation Projects				
Clinton Road Station 366 115KV Thermo Upgrades	-	-	41	68
Stoner Station	-	33	67	66
Cortland Station	-	-	-	67
Delphi Thermo upgrades	-	-	3	7
Mumford Station 50 Thermo upgrades	-	-	-	56
North Leroy 4	-	-	42	73
Total Estimated Revenue Requirement Subject to Phase 1 Facility Surcharge	$ -	$ 156	$ 5,300	$ 3,521

Based on the information summarized above and detailed in Appendix B, the Company believes it has satisfied the requirements of the Phase 1 Order and that the Commission should approve the Phase 1 Facility Surcharge recovery mechanism for the carrying costs, depreciation expense, and expenses associated with construction of Initial Phase 1 Projects not included in the Company's 2020 Rate Case.

VIII. Considerations for Phase 2 Projects

Addressing the transmission limitations by 2030 in several of the most transmission constrained, but also most desirable renewable generation locations, will require advancement of Phase 2 projects. As noted above and described in Appendix B, the Company provides the Commission the necessary information regarding its Phase 2 projects as part of its 2030 Regional Plan. The provided information regarding Phase 2 projects is consistent with the information requirements included in the Phase 1 Order. This information is included in this petition so that stakeholders and the Commission have a complete view of the network capacity upgrades needed to meet the 2030 objectives of the CLCPA. Phase 2 projects were included in just four of the seven renewable pockets. The increased capacity headroom in these pockets due solely to Phase 2 projects totals to 2410 MW.

The Company continues to refine the design and execution plan of its Phase 2 transmission solutions so that projects are not unduly delayed or disrupted to the detriment of meeting the CLCPA goals. The Company will consider the potential need and benefits of its Phase 2 projects in accordance with the Commission's "Order on Local Transmission and Distribution Planning Process and Phase 2 Project Proposals" issued and effective September 9, 2021 in the instant proceeding and currently plans to submit its qualified projects, along with the other utilities Phase 2 projects, on or before January 1, 2023.

IX. Conclusion

The need to mitigate climate change is of paramount importance to the Company and the wellbeing of its customers. Decarbonizing the electric system is essential to mitigating to most severe effects of climate change and meeting State policy goals. The Company therefore submits its 2030 Regional Transmission Plan to serve as a robust clean energy solution that benefits the production of clean affordable electricity by mitigating excessive renewable energy curtailments. The 2030 Regional Transmission Plan not only supports the CLCPA clean energy 2030 goals by addressing system limitations within the Company's upstate transmission network, but it is foundational to the State's clean energy future and consistent with recently enacted legislation.

The Company's staged approach to deploying transmission solutions provides upstate renewable generation deliverability benefits in the timeframe required by current or planned renewable generation and helps the Company levelize its resource management and system outage needs. With the Commission's approval of the 2030 Regional Transmission Plan, the Company stands the best chance at providing cost certainty to customers, identifying the most promising locations for renewable generation development, benefiting local community economies, and informing future NYSERDA renewable generation solicitations. Commission approval of the Company's proposed surcharge cost recovery mechanism for the Initial Phase 1 Projects via the Phase 1 Facility Surcharge will provide an essential first step required for the Company to meet these objectives.

Based on the foregoing, Niagara Mohawk respectfully requests that the Commission (i) find that the Company should continue to pursue the Phase 1 transmission solutions presented in the Company's 2030 Regional Plan because they help achieve the State's renewable energy targets under the CLCPA; (ii) approve deferral of carrying charges associated with the Initial Phase 1 Projects, namely those Phase 1 transmission solutions that were not reflected in the Company's currently pending rate case but that nevertheless could be placed in service during the term of the pending Joint Proposal in the 2020 Rate Case, as well as the Phase 1 Facility Surcharge to provide recovery of the deferred costs; and (iii) approve deferral for future recovery of operating expense associated with investments, return on capital investment (including cost of removal), and depreciation associated with the Subsequent Phase 1 Projects, namely those solutions not recovered through a surcharge or existing rate plan, as part of the Company's next rate filing so projects can be implemented on a timely basis.

Appendix A

Existing Asset Assessment, Generator Interest, Phase 1 Headroom & Execution Risk

Region	Average Age per Circuit Mile	Reliability need (load at risk & asset issues being addressed)	Gen In NYISO Queue	Gen Withdrawn (Total over last 5 years)	Phase 1 Solutions: Cost (CAPEX) and Schedule (Ready for load RFL)	Capacity Headroom Post Phase 1 unless noted	Overall Solution need High Medium Low	Execution: Risk of 2030 goal
Genesee Generator Pocket	96 years	Circuits at end of life. Significant near-term asset condition issues *	200MW wind 590MW solar 31MW storage	475MW	Const. Start: Feb 2023 RFL: Oct 2028 $151M	420 MW	High Generator Interest High relative asset condition concerns	High Execution Risk. Projects need to progress ASAP to address reliability needs and meet 2030 in service date
Southwest Generator Pocket	99 year	Circuits approaching end of life.	924MW wind 608MW solar 370MW storage	420MW	Const. Start: Sept 2022 RFL: June 2026 $39M	190 MW	High Generator Interest	Low Execution Risk All Phase 1. Five miles of

							Assets approaching end of life	line rebuild, DLR, and station upgrades.
Syracuse Generation Pocket	NA Minor station upgrades and targeted structure replacement	Replace 14 wooden structures due to design/clearance deficiency	73MW wind 340MW solar	80 MW	Const. Start: Apr 2023 RFL: Nov 2024 $6M	110 MW	Medium Generator Interest Assets design issues exist.	Low Execution Risk Station upgrades
Watertown Porter Oswego Generator Pocket	NA Minor station upgrades and targeted structure replacement	Install 15 mid span structures due to design/clearance deficiency	508MW wind 1,339MW solar 20MW storage	974 MW	Const. Start: Apr 2023 RFL: Dec 2023 $4M	80MW 1100MW**	High Generator Interest Assets design issues exist.	High Execution Risk for Phase 2. Phase 1 station upgrades enabling projects for Phase 2. Projects need to progress ASAP to meet Phase 2 in service dates.
Inghams Rotterdam Generator Pocket	93 years	At end of life. Significant near-term asset condition issues *	730MW solar	360MW	Const. Start: Jan 2023 RFL: Sept 2029 $425M	100MW 790MW**	High Generator Interest	High Execution Risk for Phase 2. Phase 1 enabling station rebuild in Phase 2. Projects need

							High relative asset condition concerns.	to progress ASAP address several reliability issues and to meet Phase 2 in service dates.
Albany South Generator Pocket	89 years	Approaching. End of life.	390MW solar 120MW storage	400 MW	Const. Start: Feb 2024 RFL: Jan 2025 $6 M	230MW 730MW**	High Generator Interest Assets approaching end of life	Low Execution Risk
North East Generator Pocket	NA	NA	NA	NA	NA	NA	NA	This generator pocket has no Phase 1 enabling projects and is all Phase 2.

*Reliability based projects planned in the current rate case will be upgraded to support CLCPA

** Headroom post Phase 1 and Phase 2 in-service.

Appendix B

2030 CLCPA Regional Transmission Plan

nationalgrid

Niagara Mohawk 2030 CLCPA Regional Transmission Plan

August 2021

Table of Contents:

2030 CLCPA Regional Transmission Plan

System Planning Overview

Simulating a build-out of the New York electric system that shifts the energy supply away from the current generation locations and alters existing dispatch profiles to future behind-the-meter generation and large-scale intermittent renewable generation in quantities large enough to meet future load results in a dramatically different flow of energy across New York. To deliver on New York's CLCPA goals, electric system plans also need to include studies under heavy, shoulder and light load that focus on creating a system that can deliver renewable energy out of the local system without the need for curtailing the renewable generation energy outputs. These changes to electric flow patterns across the local networks create overloads and voltage issues in unexpected locations. Historically, planning studies focused on transmission security, where a peak day load was studied assuming fossil-fueled generation was available and able to be dispatched to ensure system security. The goal of the peak load studies was to ensure enough generation was available to meet peak demand after system operators' actions to reduce generation to avoid overloading transmission lines. Variations on these traditional reliability studies will continue to be important for meeting renewable energy goals.

To deliver on the CLCPA's goal of 70% renewable energy by 2030 (70x30), the 2030 CLCPA Regional Transmission Plan focuses on creating a system that can deliver renewable energy from the local transmission system to the local load and to the bulk transmission system without the need for curtailing generation from renewables. This plan will also lay the foundation for achieving the State's goals for further renewable integration necessary to achieve an emission-free grid by 2040 and to reliably serve new electrification loads that will be necessary to achieve the 85% economy-wide carbon emission reduction by 2050.

While this effort represents an important first step, the Company's plan will continue to evolve as plans for generator interconnection locations and sizes mature. The Company may need to take appropriate steps to address newly identified system constraints as they occur, through either additional Phase 1 or Phase 2 projects.

System Planning Problem Statement

To mitigate the impact of generation curtailments and provide additional cost-effective interconnection points for renewable generation, the lack of transmission capability must be timely addressed. The first step in addressing existing and future curtailments is to understand and quantify existing system capability relative to the expected buildout of renewable generation required to comply with the State's CLCPA mandates. The next step is to identify cost effective solutions that mitigate excessive curtailments due to existing system limitations. Prior system planning studies that assessed the 70x30 mandate identified the potential for significant transmission limit violations that would lead to curtailment. These curtailments would interfere with the full utilization of renewable energy needed to meet the 70x30 objective. The Utilities' Report[1] reaffirmed that renewable curtailment due to the local system constraints is likely.

In a system that lacks available transmission capacity, one of two options must be pursued: (i) more renewable generation capacity must be built in close proximity to load and be equivalent to the amount of energy that would have otherwise been used if the transmission capacity existed; or (ii) more transmission capability must be added in close proximity to the generation to make it deliverable to customers. Due to renewable generation geospatial needs, most new large-scale renewable generation must be built in areas distant from load centers. However, the local transmission system in these remote locations is ill-equipped to support the efficient development of large-scale renewable generation, as traditionally the system was built to serve low levels of demand. To resolve this situation, either the proposed renewable generation does not get built, resulting in a system maintained by a fleet of fossil generators, or the new renewable generation is forced to connect to weak transmission and be curtailed. Under traditional planning objectives, so long as transmission system limits are honored and peak load is served, there is no need for utilities to upgrade their transmission systems, even though renewable energy curtailments may significantly increase as generation competes for scarce transmission capacity. Today, system planners and policy makers see this approach as highly inefficient, and it may even frustrate the New York's goals to decarbonize the grid.

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

In support of a more integrated generation and transmission planning approach, and in recognition of the fact that developing a renewable generation project typically requires less time than do developing transmission system capacity upgrades, the Company's 2030 CLCPA Regional Transmission Plan identifies areas of known merchant generator developer interest (generator clusters or pockets) and calculates the amount of energy that would be curtailed (bottled) to honor transmission limits. Once curtailment is identified, solutions to local transmission system capacity limitations are created, assessed, and appropriately sized to deliver the given amount of renewable generation in a given generation pocket. The Company's planning methods are summarized below and are explained in greater detail in individual reliability planning region assessments.

Study Methodology and Assumptions

The study that served as the basis for the Company's 2030 CLCPA Regional Transmission Plan, as well as for the analysis contained in the Utilities' Report, is based upon the study cases established and used by the NYISO for the 2020 RNA 70 x 30 CLCPA Scenario. The proposed renewable buildout used in those cases came from the 70 x 30 scenario in the NYISO's 2019 Congestion Assessment and Resource Integration Study (CARIS). The selected three cases are the starting point for the 70x30 scenario studies were: (i) Day Peak Load of 30,000 MW; (ii) Shoulder Load of 21,500 MW; and (iii) Light Load of 12,500 MW. The load is modeled based on the 2020 Gold Book forecast for 2030. On a more granular level, the load is modeled and distributed within regions based on the same NYISO 2020 RNA case distribution.

Starting from the 70 x 30 scenario peak load, shoulder load, and light load cases created by the NYISO, the Company built sensitivity cases examining different renewable dispatch conditions. All study cases used by the Company assumed no fossil generation was operating in NYISO Zones A (West) through F (Capital) and one of the upstate nuclear plants was assumed retired. In each case, Land Based Wind (LBW) and Utility Scale Photovoltaic (UPV) generation was dispatched to various levels. In the Company's testing, LBW, primarily located in Western, Central and Northern NY, was varied between 0 percent of nameplate up to 75 percent of nameplate. UPV, located in most areas, was dispatched between 0 percent of nameplate up to 70 percent of nameplate. All dispatches modeled by Niagara Mohawk were consistent with the CARIS 70 x 30 generation output levels assumed to be achieved for 100 hours or more. For example, a dispatch scenario model by the Company was LBW at 30 percent of nameplate concurrent with UPV output at 27 percent. A dispatch at or above these levels occurred in the CARIS 70 x 30 scenario for 802 hours in the given year.

Once the study cases were finalized, the Company performed steady state testing in accordance with Transmission Group Procedure 28 (TGP28), National Grid's Transmission Planning Criteria. Simulations were performed to assess the system response with all elements in-service (N-0) as well as for N-1 outage conditions. These N-1 tests included loss of a circuit, transformer, generator, or shunt device as well as breakers opening without a fault, bus outages, faults with a breaker failure and double circuit tower outages. The system response to these N-1 outages was considered acceptable when all local transmission facilities are loaded below 100 percent of their Long-Term Emergency (LTE) rating. For pre-contingency conditions, loading is considered acceptable when all local facilities are loaded below 100 percent of their Normal (continuous) rating. The summer ratings were used in all cases. Acceptable post-contingency system voltages on the 115kV and 69kV system are between 90 percent of nominal and 105 percent of nominal and acceptable pre-contingency voltages were between 95 percent of nominal and 105 percent of nominal.

Two types of tests were performed on the existing and proposed transmission system to assess the amount of capability that could be used for renewable generation. The first test, Test 1 - 2030 Regional Congestion Assessment, was performed to assess the effects the 2030 CLCPA mandates have on reliability and to identify and resolve renewable generation curtailments. The second test, Test 2 - Capacity Headroom Test, measured the change in "Capacity Headroom" consistent with Staff's Straw Proposal for Conducting Headroom Assessments.

Under Test 1, all overloads that would develop if renewable generation was not curtailed were identified and then a security dispatch identified the minimal amount of generation curtailments necessary to correct all thermal overloads, without consideration of generator market bid behavior.

Under Test 2, an optimization program determined which one or more of the existing 115kV switching stations are optimal locations for generation to connect and the maximum amount of generation could connect to that location. The optimized dispatch keeps all transmission elements in the pocket within acceptable loading for any N-0 or N-1 condition. Unlike Test 1, Test 2 does not distinguish between the type of generation, only estimates the maximum capability for simultaneous output from generation within the local network.

The two tests identified the local transmission system elements that constrain renewable generation. The results of Test 1 were primarily used to identify the constraints, with the results of Test 2 confirming that the identified elements were constraining and helping to indicate whether any other elements would become constraining for varying dispatches. With the overloads and voltage issues identified, solutions were then developed for each renewable pocket that would provide the biggest benefit to customers. Test 1 and Test 2 were repeated on the cases with the solutions added to determine if any remaining constraints existed and to assess the effectiveness of the solutions.

In addition, the Company collaborated with neighboring utilities and upgrades to the neighboring utility systems were considered as potential solutions to CLCPA system needs on National Grid’s networks prior to establishing the Company’s Phase 1 transmission investment plan. The Company’s CLCPA Phase 1 transmission investment considerations also recognize renewable generator developers’ interest in a planning region to validate generator interest assumptions and the likelihood of a developing generator pockets.

Grid Enhancing Technologies (GETs)

For each planning region, the Company compared the proposed projects to viable alternatives, including GETs such as dynamic line ratings (DLR), high current – low sag composite core conductors, and other advanced transmission technologies.

The Company identified economic GET projects to enhance regional unbottling in several regions. By adding a Smart Valve device in addition to a planned rebuild of the #119 line in the Genesee Pocket, 17 to 56 miles (depending on generation interconnection points) of double circuit rebuilds was avoided. By deploying DLR in the Southwest Pocket, the Company was able to avoid fully rebuilding nearly 30 miles of double circuit transmission on the Laona-Moon-Falconer circuits. A discussion of those comparisons and the benefits of the recommended suite of projects are included in this report.

In addition, there could be an opportunity to use battery storage for any observed residual congestion once transmission and generation projects enter service. However, due to magnitude of the overloads, the benefits to addressing aging infrastructure, and the current useful life of storage, the Company recommends deploying storage solutions at such time that tangible system congestion is observed. At that point, the useful life of storage will support the system needs for a longer period of time and the ideal location for storage can be better determined. Additionally, as the installed costs of storage continue to decline, deferring installation makes its future application more economic.

Individual Regional Transmission Plans

Southwest Region
Transmission and Renewable Generation Assessment

August 1, 2021

This review was undertaken to determine if portions of the local 115kV system in the Southwest region would prevent the delivery of existing and proposed renewable generation. The Company examined multiple generation dispatches for three different base case load scenarios; light load, shoulder load and heavy load. Upon identifying that the existing local transmission system would create constraints on renewable generation, several solutions were considered.

The conclusion of this analysis is that limiting station connections should be upgraded on the Homer Hill – Bennett circuit, a 4.8-mile section of the Dunkirk – Laona circuits should be rebuilt and Grid Enhancing Technology (GET) should be installed (i.e. pilot the use of a Dynamic Line Rating system) on the Laona – Falconer circuits. The combination of these projects was found to address many of the constraints on renewable generation, reducing curtailment from 340MW to 20MW. Separately a headroom test was performed where the optimal location and size of generation was identified before and after the proposed reinforcements. This test found that the projects increased headroom by about 190MW.

This region contains only Phase 1 projects.

<u>Existing System Overview</u>

The Southwest Region is a two circuit 115kV loop (Southwest Loop), extending from Gardenville to Dunkirk to Falconer to Homer Hill to Five Mile to Arcade to Gardenville (see Figure 1). The Southwest Loop is connected to the 230kV system at Dunkirk and to the 345kV system at Five Mile.

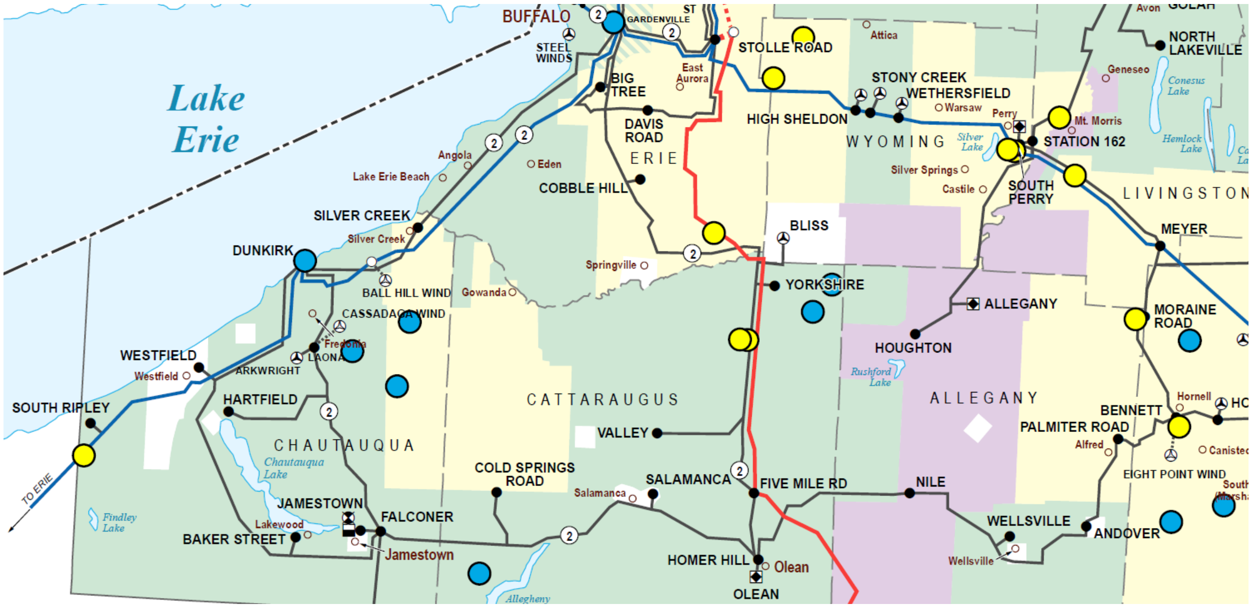
The area has one connection to the Avangrid system. A 63-mile-long line connects from the National Grid Homer Hill station to the Avangrid Bennett Station (See Figure 2). The long length and resulting high impedance of this circuit prevents large power transfer between these two terminals. There is significant developer interest in interconnecting to both the National Grid and Avangrid owned portions of this circuit and to the Avangrid system in the Bennett area. To review the potential impact that Avangrid connected generation in the Bennett area could have on National Grid's Southwest region, this study modeled wind or solar generation in other portions of Western NY and throughout the Avangrid system in Central NY. These study assumptions and results were discussed with Avangrid.

In all analysis, National Grid monitored facilities adjacent to this area that were owned by Avangrid. All recommendations were developed considering if upgrades to the Avangrid system could address issues on the National Grid system. The Company has collaborated with neighboring utilities and all recommended upgrades were shared with other transmission owners and their comments were considered before finalizing plans.

[redacted]

[redacted]

Figure 2. Southwest Region Transmission Map



While age is not always an indicator of condition, in the absence of condition assessments, the relative age of a circuit can provide some insight into how close the circuit may be to end of life refurbishment or replacement. Table 1 is a list of area circuits with the age of the oldest components.

Table 1: Transmission Circuit Age

Circuit	Year	Age	Mileage
Gardenville - Dunkirk #141	1920	101	44.9
Gardenville - Dunkirk #142	1920	101	44.9
Arcade - Five Mile #167	1922	99	25.5
Dunkirk - Laona #161	1922	99	10.5
Dunkirk - Laona #162	1922	99	10.5
Five Mile - Homer Hill #169	1922	99	7.4
Five Mile - Homer Hill #170	1922	99	7.4
Gardenville - Arcade #151	1922	99	34.9
Gardenville - Five Mile #152	1922	99	58.5
Laona - Moon Road #172	1922	99	9.8
Laona - Moon Road #173	1922	99	9.8
Moon Road - Falconer #175	1922	99	14.2
Moon Road - Falconer #176	1922	99	14.2
Falconer - Homer Hill #153	1927	94	42.7
Falconer - Homer Hill #154	1927	94	42.7
Andover - Bennett #157-932	1954	67	43.8
Homer Hill - Andover #157	1954	67	18.7
Dunkirk - Falconer #160	1967	54	53.7

Reliability and Condition Driven Transmission Projects

All transmission projects identified as firm in the NYISO 2020 Gold Book were include in the study cases. Generally, projects are only listed in the Gold Book if they result in a modification to the system; such as a change in rating, change in impedance, or a change in system or station configuration. National Grid has other transmission projects in the medium to long term horizon. These projects are generally condition based projects. The following describes all major projects in the region, including some projects that are not expected to have an impact on the system. These projects were assessed as either having; a benefit to CLCPA as designed, a benefit to CLCPA if the project design was revised, or no benefit to CLCPA if revised. Those revised projects that have CLCPA benefits and lead to a significant increase in project cost are proposed as Phase 1 and Phase 2 projects.

Dunkirk – Falconer Reactor Replacement – The Dunkirk – Laona – Moon – Falconer circuits have reactors installed in series with the line at the New Rd Switch Structure between Dunkirk and Laona. The reactors help manage the flow on the Dunkirk – Laona – Moon – Falconer circuits by pushing power flow on the longer, but higher rated circuit that connects directly between Dunkirk and Falconer. These series reactors are nearing the end of their expected life. Prior to replacing them with new series reactors at the same location, studies were done to determine if the addition of Laona and Moon station changed the need or ideal location. Studies determined that the reactors are still required during periods of no generation, but that the ideal location is heavily dependent on the location of generation. Given the uncertainty of future generation interconnections and ability of the Company to readily connect a reactor at a different station, the Company has determined that the reactors should remain at their current location for the near term.

Gardenville – Dunkirk 141/142 Northern and Southern Rebuild – The scope of this project is a complete replacement of all structures and conductor on the Gardenville – Dunkirk 141 and 142 circuits. The project will result in an increase in the thermal limit of the overall circuit and a small change to the circuit impedance. This project was included in the study base cases. The Northern section is currently being permitted through Article VII and is included in Niagara Mohawk's rate case.

Gardenville – Five Mile refurbishment – The National Grid 10-year plan includes funding for refurbishment work on the Gardenville – Five Mile, Gardenville – Arcade and Arcade – Five Mile circuits. At this time the expectation is that this project will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. The study included a desktop assessment of a scenario where the rating of this circuit was increased, but the expanded project scope did not result in any identified system capacity benefits. An increase in the rating of these circuits, which would be achieved by a complete rebuild, would result in additional flexibility for the placement of new generation in the headroom test. However, a rebuild of these circuits is not recommended at this time. During the development of the project, an option to rebuild with lines will be considered further.

Dunkirk – Falconer 160 refurbishment – The National Grid 10-year plan includes funding for refurbishment work on the Dunkirk – Falconer 160 circuit. At this time the expectation is that this project will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. The study included a desktop assessment of a scenario where the rating of this circuit was increased, but the expanded project scope did not result in any identified system capacity benefits.

Falconer – Homer Hill 153/154 refurbishment – The National Grid 10-year plan includes funding for refurbishment work on the Falconer – Homer Hill 153/154 circuits. At this time the expectation is that this project will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. The study included a desktop assessment of a scenario where the rating of this circuit was increased, but the expanded project scope did not result in any identified system capacity benefits.

Local Design Criteria

For purposes of this study, National Grid performed steady state testing in accordance with its Transmission Group Procedure 28 (TGP28), *National Grid Transmission Planning Criteria*. Simulations were performed to assess the system response with all elements in service (N-0) as well as for N-1 outage conditions. These N-1 tests included loss of a circuit, transformer, generator or shunt device as well as breakers opening without a fault, bus outages, faults with a breaker failure and double circuit tower outages. All testing was limited to steady state for N-0 and N-1 conditions.

The system response to these N-1 outages is generally considered acceptable when all local facilities are loaded below 100 percent of their Long-Term Emergency (LTE) rating. For pre-contingency conditions, loading is considered acceptable when all local facilities are loaded below 100 percent of their Normal (continuous) rating. The summer ratings are used in all cases. Acceptable post-contingency system voltages on the 115kV and 69kV system are between 90 percent of nominal and 105 percent of nominal and acceptable pre-contingency voltages are between 95 percent of nominal and 105 percent of nominal.

All solutions are required to meet the full set of local and regional Planning Criteria to ensure that the reliability of the planned system is not compromised. These criteria include dynamic, short circuit and expanded steady state requirements. Additional testing will be required for some proposed Phase 2 solutions to ensure that they are designed to conform with and adhere to all applicable North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), New York State Reliability Council ("NYSRC") Reliability Rules, as well as applicable National Grid specifications, procedures, and guidelines.

Test 1: 2030 Regional Congestion Assessment - Methodology and Assumptions

The Regional Congestion Assessment (Test 1) is meant to; 1) identify existing local system congestion in a planning region based on the 2030 load and generation input assumptions and 2) eliminate all identified congestion within the region through system upgrades.

This study is based upon the database established and used by the NYISO for the 2020 Reliability Needs Assessment (RNA) 70x30 CLCPA Scenario using generation buildout assumptions from the Congestion Assessment and Resource Integration Study (CARIS) 70x30 scenario. The three cases selected as the starting point for the 70x30 scenario studies were: (i) Day Peak Load of 30,000 MW; (ii) Shoulder Load of 21,500 MW; and (iii) Light Load of 12,500 MW. The load is modeled based on the 2020 Gold Book forecast for 2030, with the load distributed within the regions based on the same 2020 RNA cases.

Starting from the 70x30 scenario peak load, shoulder load, and light load cases created by the NYISO, National Grid built sensitivity cases examining different renewable dispatch conditions. These dispatch scenarios were communicated with neighboring utilities for their consideration and use in their study work. While developing the case dispatches, monitoring and correcting overloads and voltage limitations on the 345kV and 230kV systems was considered out of scope for this assessment of the local system performance.

All study cases used by National Grid assumed no fossil generation was operating in NYISO Zone A (West) through F (Capital) and assumed that nuclear generators at Nine Mile 1, Nine Mile 2, and Fitzpatrick were all in service at maximum output and Ginna was assumed to be out of service. For the ties from New York to the external areas, no import or export was allowed from New York to PJM (across the free-flowing ties), New England or Ontario.

Hydro generation at Gilboa was set to maximum generation in the peak and shoulder cases and set to pumping in light load cases. In all cases, the Moses generation was set to maximum output. At the Niagara/Lewiston facility, Niagara was set to 2160MW, evenly distributed across the thirteen machines and Lewiston was set to either 240MW of generation or 360MW of pumping load depending on the case. Run of river hydro generation was set to typical seasonal values. The import of Hydro generation from Hydro Quebec was set to either 1110MW or 535MW. No hydro generation was imported to Dennison from the Cedars generation.

The above assumptions were modeled in each case, and Land Based Wind (LBW) and Utility Scale Photovoltaic (UPV) generation was then dispatched to various levels. In the National Grid testing, LBW, primarily located in Western, Central and Northern NY, was varied between 0 percent of nameplate up to 75 percent of nameplate and UPV, located primarily in Central, Northern and Eastern NY was dispatched between 0 percent of nameplate up to 70 percent of nameplate. Neither wind nor solar resources were modeled at 100 percent of nameplate.

The NYISO zonal data of hourly load, LBW output, and the UPV output from its CARIS 70x30 scenario was also reviewed for consistency with National Grid modeling assumptions. All dispatches modeled by National Grid were consistent with the NYISO CARIS 70x30 generation output levels assumed to be achieved for 100 hours or more. For example, a dispatch scenario model by National Grid was LBW greater than or equal to 30 percent of nameplate concurrent with UPV output greater than or equal to 27 percent. This dispatch occurred in the CARIS 70x30 scenario for 802 hours. Another example of the many scenarios studied by National Grid was LBW at 15 percent of nameplate and UPV at 52 percent of nameplate. The dispatch of these renewables at or above this level occurring in the CARIS 70x30 scenario for 457 hours.

For the National Grid assessment, no assumptions were made for the generation mix in New York City or Long Island, including no specific assumptions for offshore wind, as the generation mix downstate does not have any impact on the result of testing within National Grid’s service territory. However, for simplicity of developing the scenario cases, it was assumed that the flow across the UPNY – CONED interface would not exceed 7000MW.

Test 1: 2030 Regional Congestion Assessment - Modeled Existing and Proposed Generation

Three large wind generation plants are already or soon to be in commercial operation; 100WM connected to National Grid’s system at Arcade, 80MW connected at Laona and 130MW is under construction at Moon.

Past reliability studies of this area have shown that generation additions or removals at Gardenville and in the system north of Gardenville do not have an impact on the 115kV southwest system. To confirm that throughflow created by generation north of Gardenville is not material, this study examined two dispatches of Niagara/Lewiston and modeled wind or solar generation in other portions of Western NY. The study assumed that the interchange with Ontario would be neither importing or exporting by keeping it fixed at 0MW and that the interchange with Pennsylvania across the free-flowing upstate ties would be fixed at 0MW.

As of 1/31/2021, the NYISO interconnection queue includes 924MW of wind, 608MW of solar and 370MW of storage proposing to connect to the area's local system. The projects are summarized in table 2 and 3. These summary tables include generation connecting to the 230kV system in the Dunkirk and South Ripley area. For normal and contingency conditions, a large amount of this 230kV connected generation can flow into the 115kV Southwest Loop.

In the last 5 years an additional 420MW of generation proposing to connect into this area has withdrawn from the NYISO queue. While some of these projects may have withdrawn due to siting or financing issues, it is believed that some projects have withdrawn due to insufficient transmission capability.

Additionally, generation in the Avangrid system east of Bennett that is in operation, in the NYISO queue or was assumed to develop as part of the CARIS 70x30 scenario was modeled. This includes large wind and solar facilities connected to the 230kV system between Stolle and Oakdale as well as interconnections directly to the local 115kV system. These resources were included in the study cases but are not summarized in the tables 2 and 3 below. When dispatching study cases, the resources in the Avangrid system were treated the same and dispatched to the same percent of nameplate as resources connected to the National Grid local system.

Table 2: Generation in the NYISO Interconnection Queue

Queue	MW	Type	Interconnection Point
0422	101	W	Bennett 115kV
0466	132	W	Falconer - Homer Hill 115kV
0505	100	W	Dunkirk - Gardenville 230kV
0519	291	W	Bennett 115kV
0814	300	W	Dunkirk Substation 230kV
0666	20	S	Arcade - Five Mile 115kV
0667	20	S	Arcade - Five Mile 115kV
0783	270	S	South Ripley Substation 230kV
0954	158	S	South Ripley - Dunkirk 230 kV
1043	20	S	Dunkirk - Falconer 115kV
1096	100	S	Homer Hill - Bennett 115 kV
1098	20	S	Dunkirk - Gardenville 115kV
0595	100	ES	Five Mile Rd Substation 115kV
0809	240	ES	South Ripley Substation 230kV
1014	20	ES	South Ripley Substation 230kV
1106	10	ES	Homer Hill - Bennett 115 kV

Table 3: 2019 CARIS Generation Additions Necessary to Meet the 70x30 Mandate

Bus	Type	MW	Interconnection Point
Bennett	S	45	Bennett 115kV
Machias	S	117	Arcade - Five Mile 115kV
S Ripley 230kV	S	523	South Ripley Substation 230kV
Arcade	W	199	Arcade - Five Mile 115kV
Bennett	W	741	Bennett 115kV
Dunkirk 230kV	W	494	Dunkirk Substation 230kV
Falconer	W	130	Falconer 115kV
Laona	W	156	Dunkirk - Falconer 115kV
Moon	W	125	Dunkirk - Falconer 115kV

As previously stated, generator representation (e.g. type, size and location for new renewables) used in this assessment was based on the 2019 CARIS 70x30 sensitivity case. The CARIS 70X30 case modeled 1845MW of new and proposed wind and 879MW of new and proposed solar in the Southwest region (See Table 3). Figure 2 shows geographically where new resources were added, with each yellow dot representing a new solar generator location and each blue dot representing a new wind generator location.

The base cases assume 905MW of wind between Dunkirk (230kV and 115kV) and Falconer. Between Arcade and Five Mile, 117MW of solar and 199MW of wind was assumed. At Bennett, 741MW of wind and 45MW of solar was modeled.

Test 1: 2030 Regional Congestion Assessment - Proposed Distributed Energy Resources

In addition to the generation proposed in the NYISO queue, Distributed Energy Resources (DER) have also proposed to connect to National Grid's distribution system. The DER queue for the region contains over 150MW of proposed DER, the majority of which is solar with a few small wind generators. The stations where the largest amount of solar DER is proposed is summarized in Table 4. While the DER was not explicitly modeled in the base cases, the proposed locations are similar to the locations used to model the new resources (Table 3) needed to meet the 70x30 mandate. Because energy produced from DER may make its way from the distribution system to the transmission system through the existing transmission stations modeled in this study, DER is expected to have a similar impact as the generation directly connected to the transmission system and would benefit from the same projects identified as necessary to unbottle the region.

Table 4: Generation in the DER Interconnection Queue

Station	MW
Baker	18
Berry	28
Dugan	29
Machias	13
Roberts	13
Valley	32
W Olean	16

There is also approximately 200MW of solar generation that is proposing to connect directly to 34.5kV circuits throughout the area. This includes 45MW ultimately feeding into a radial 115kV line connected to Andover and 20MW on the Dunkirk – Hartfield circuit feeding back to the transmission system at Dunkirk or Moon. While this DER was not explicitly modeled in the base cases, the proposed locations are similar to the locations used to model the new resources (Table 3) needed to meet the 70x30 mandate.

Test 1: 2030 Regional Congestion Assessment - Study Results (System Bottlenecks)

Based on the study base cases, two areas of congestion were identified that would constrain the output of generation (generation pocket). The flow on the Dunkirk – Laona circuits was found to be at 206% of LTE in the shoulder load case with Lewiston hydro pumping and wind dispatched to 75% of nameplate. In the same case the Laona – Moon loading was 134% of LTE and the Moon – Falconer loading was 125% of LTE. Dunkirk – Laona is limited by 4.8 miles of 4/0 ACSR conductor, Laona – Moon is limited by 9.6 miles of 4/0 ACSR, Moon – Falconer is limited by 14.2 miles of 4/0 ACSR. The worst contingency loading generally occurs for loss of one line overloading the parallel line or a double circuit tower outage that takes out both circuits, pushing all connected wind generation toward either [redacted].

[redacted] The National Grid section of the line was only overloaded in the shoulder load case with the wind dispatched to 75% of nameplate. [redacted] It was observed that many of the overloaded sections of the circuit are first limited by station equipment. However, correction of the station equipment limits would not fully eliminate the overloads. Once the station equipment limits are addressed, the limit becomes 18 miles of 4/0 ACSR and 32 miles of 336 MCM ACSR.

To address these two overload conditions in the shoulder case with wind dispatched to 75% of nameplate, 205MW had to be curtailed at Bennett and 165MW had to be curtailed at Laona and Moon.

Table 5: Test 1 Southwest Facility Overloads

Facility	Worst Case Overload (% LTE)
Dunkirk - Laona 161	206
Dunkirk - Laona 162	206
Andover - Bennett 932	186
Laona - Moon 172	134
Homer Hill - Andover 157	133
Laona - Moon 173	130
Moon - Falconer 176	125
Moon - Falconer 175	124
Arcade - Five Mile 167	92
Gardenville - Arcade 151	91

Test 2: Capacity Headroom Test - Methodology and Results

To further determine the areas that could cause congestion, a Capacity Headroom test was performed. According to the DPS Headroom Test whitepaper (Case 20-E-0197), Capacity Headroom uses the lowest identified optimal transfer value observed in a heavy, light and shoulder load case. This test was done using the Optimal Transfer feature in TARA. Unlike Test 1 where the location of the generation was based on generation identified by the NYISO in the 70X30 CARIS case, Test 2 involves assigning possible locations for generation to interconnect, then having the program determine which one or more of the sites is an optimal location and how much generation could connect. The optimized dispatch keeps all transmission elements in the pocket within acceptable loading for any N-0 or N-1 condition. The analysis does not distinguish between the type of generation, only estimates the capability for simultaneous output from generation within the local network.

Under Test 2, base cases are initialized with no solar or wind generation in service. Including no solar or wind generation in upstream or downstream locations or on the bulk power system. All other load, hydro and nuclear generation and system topology assumptions made in the Test 1 base case were held constant. For Test 2, it was assumed that generation could only be added to the existing 115kV switching stations in the region. The impact of adding generation to the middle of a line, which is likely not an optimal electric location, will not be captured. One of the limitations of this test is that the model can add a relatively large amount of generation into one site, ignoring or reducing the other options. To provide a more realistic indication of the headroom provided, a limit of 500MW was placed on all 115kV switch stations.

For this region, the selected 115kV buses were Dunkirk, Laona, Moon, Falconer, Homer Hill, Andover, Five Mile and Arcade.

The amount and location of generation for each study base case is summarized in Table 6. The program identified several bottlenecks. The test identified the same binding elements as found in the 2030 Regional Congestion Assessment (Test 1); Homer Hill – Bennett and Dunkirk – Laona – Moon – Falconer. Also identified were the Dunkirk 230/115kV transformers and the Gardenville – Arcade and Gardenville – Five Mile circuits. The most limiting case for this region was the light load case.

Table 6: Existing System Capacity Headroom (MW)

	Dunkirk	Laona	Moon	Falconer	Homer Hill	Andover	Five Mile	Arcade	Total
Heavy Load	250	100	50	0	0	20	300	90	810
Heavy Load w/Pumping	240	10	160	0	20	20	300	60	810
Light Load	270	100	0	0	0	0	30	150	550
Light Load w/Pumping	190	10	170	0	0	0	160	150	680
Shoulder Load	250	100	0	0	0	0	230	150	730
Shoulder Load w/Pumping	200	10	150	0	0	10	360	110	840

Note that in some cases the program placed more generation at Laona and in other cases it placed more generation at Moon. In sensitivity testing, if the program was only allowed to place generation at one of the two locations, the area total was not significantly impacted. The large difference shown in the Table 6 is the result of the program trying to optimize the area to maximize the total output without considering minimum or maximum project sizes.

Because National Grid has previously considered changes to the location of the series reactors on the Dunkirk – Laona – Moon – Falconer circuits, a sensitivity was tested to see if the recommended location should be changed. For this test the RNA/CARIS shoulder load base case with wind dispatched to 75% was tested to see how the overloads were impacted and the light load headroom case was tested to see how the area headroom was impacted. While the system was less sensitive to reactor locations under the 2030 CARIS assumptions, the reactors must remain in service between Dunkirk and Falconer to address overload conditions during periods of little to no generation. Based on these sensitivity tests, no definitive advantages are observed that would suggest the reactors be installed in a specific location. Because of the uncertainty of future generation interconnections and ability of the Company to readily connect a reactor at a different station if the need arises, the Company has determined that the reactor should remain at its present location.

Regional Transmission Plan: Recommended System Upgrades

Based on both the RNA/CARIS testing and the headroom tests, increasing the rating of the Homer Hill – Andover circuit would provide benefits. However, addressing the 50 miles of limiting 4/0 ACSR and 336 MCM ACSR conductor by rebuilding the Homer Hill- Andover line is not recommended due to timing, cost relative to benefits and numerous unknown factors. Some sections of this line are limited by terminal equipment, which is recommended to be upgraded to maximize the circuit rating. [redacted] Discussion with Avangrid confirmed that they are investigating this condition. National Grid will continue to work with Avangrid and monitor the area generation interconnections to determine if any additional upgrades are warranted between Homer Hill and Bennett, beyond replacement of the simple station connections.

In the initial testing and the screening studies, the 4.8-mile section of 4/0 ACSR on the Dunkirk – Laona circuit was found to be heavily overloaded. Rebuilding this portion of the circuit is recommended to address these overloads. The location of the upgrades is shown in Figure 3.

As discussed in the following Project Benefits section, after the completion of the above projects additional constraints still exist on the system, primarily on the Laona – Moon – Falconer circuits. But the remaining constraint on resources does not warrant a complete rebuild of the two 24-mile-long circuits. Instead National Grid recommends that a Dynamic Line Rating (DLR) System be installed on these circuits as a near term solution.

Included in the Power Grid Study was a discussion of the benefits of a DLR system. Utilities that have installed these systems have found increased ratings compared to static ratings of 30%-70% with the average increase over the year of 20-30%.[2]The report noted that higher transfer capabilities (e.g., due to higher wind speeds) can be highly correlated with renewable generation levels (e.g., from local onshore wind). As this region has existing wind generation, with more wind generation potentially being added, the area is more likely to benefit from a DLR system.

The headroom tests found an additional constraint, that when corrected could provide regional benefits. When trying to add generation to the Gardenville – Arcade – Five Mile portion of the system, overloads on the area circuits were encountered. The headroom in this area can be increased by expanding Arcade station. The station was fully constructed to connect to only one of the Gardenville –

[2] the Initial Report on the New York Power Grid Study, dated January 19, 2021 (the “Power Grid Study”), at p. 45

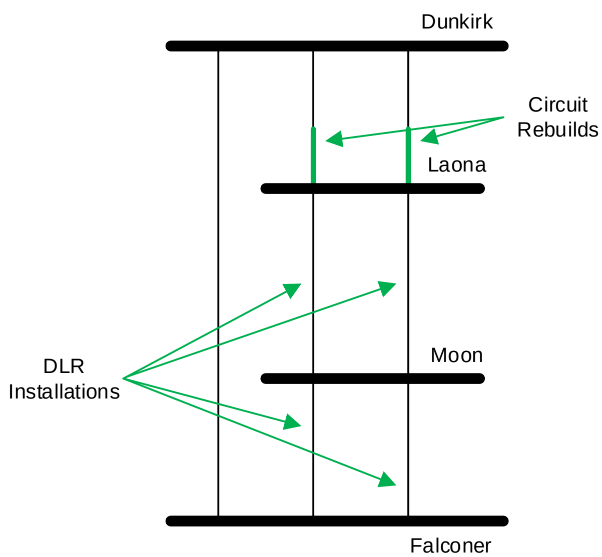
Five Mile circuits. But the station was designed to be expandable to connect to both Gardenville – Five Mile circuits. If Arcade station was expanded to connect to both lines, the headroom for generation to connect into this portion of the system would increase. Because the CARIS/RNA cases did not identify the need for this upgrade and because the latest review of the interconnection queue does not show sufficient resources to warrant this upgrade, reconfiguring the Arcade station is not recommended at this time. National Grid will continue to monitor this area to determine when this upgrade becomes appropriate.

Table 7: Regional Project Plan Summary*

Project ID	Project Name	Phase	Project Description
SW1	Homer Hill – Bennett 115kV Terminal Upgrades	Phase 1	Address all limiting 115kV terminal equipment at various stations between Homer Hill and Bennett
SW2	Dunkirk – Laona 115kV Line Upgrades	Phase 1	115kV Upgrade: sections of Dunkirk-Laona
SW3	Laona – Moon – Falconer Dynamic Ratings	Phase 1	Add a Dynamic Line Rating System to the Laona – Moon – Falconer Circuits

*No Phase 2 projects are proposed for this area

Figure 3: Dunkirk – Falconer System Upgrades



Regional Transmission Plan: Project Benefits

In the 2030 Regional Congestion Assessment (Test 1) and the Capacity Headroom test (Test 2), benefits are estimated with the Homer Hill – Bennett upgrade and the Dunkirk – Laona upgrade and assuming the DLR system allows a 40% increase in circuit rating. With these upgrades, only 20MW of constrained generation was observed. The Homer Hill – Bennett circuit was the remaining limiting element and not the Dunkirk – Laona – Moon – Falconer circuits.

Table 8: Project Congestion Benefits

System Configuration	Constraint (MW)
Existing System	370
All Phase 1 Projects Complete	20
All Phase 2 Projects Complete	20

The Capacity Headroom test shows that additional generation can be optimally added once associated system upgrades are completed. The Southwest Region solutions allowed for an increase in the amount of headroom (Test 2) at Laona and Moon, or more generally the system between Dunkirk and Falconer, but reduced the amount of generation that could otherwise be connected at Dunkirk. Overall, the projects resulted in a 190MW increase in the light load case when the DLR allowed a 40% increase above the static ratings. But more importantly the amount of generation that can connect between Laona and Moon, an area of generation interest, increased from 100MW to 270MW.

Table 9: System Headroom, with Circuit Rebuild and Terminal Upgrades, 40% DLR

	Dunkirk	Laona	Moon	Falconer	Homer Hill	Andover	Five Mile	Arcade	Total
Heavy Load	160	140	170	0	0	50	370	70	960
Heavy Load w/Pumping	170	140	170	0	0	70	270	60	880
Light Load	160	140	130	0	0	30	130	150	740
Light Load w/Pumping	140	140	150	0	0	30	200	150	810
Shoulder Load	140	140	160	0	0	40	260	140	880
Shoulder Load w/Pumping	120	140	170	0	0	40	360	100	930

Regional Transmission Plan: Project Alternatives

Alternatives considered to the recommended solution were:

Rebuild 35 miles of double circuit construction on the Dunkirk – Laona – Moon – Falconer circuits – This option was rejected due to the limited benefits, timing, and cost. The recommended solution to rebuild 4.8 miles of line was found to provide just 30 MWs less headroom relative to rebuilding the entire line.

Rebuild 50 miles of the Homer Hill – Bennett circuits. This option was rejected due to the large scope and lack of asset condition drivers. It is also expected that once the circuit is rebuilt and generation connects into the area or directly onto the circuit that this generation would create additional problems on the Avangrid system around Bennett. As a stand-alone project, due to limitations in the Bennett area, this rebuild was determined to have limited benefits.

Series Reactors on Homer Hill – Bennett– Due to the long length of this circuit, marginally acceptable voltage is found at stations in the middle of the line. The addition of a rector to the circuit would further weaken the voltage.

Phase Angle Regulators or SSSC – A PAR or SSSC on the Homer Hill - Bennett circuit would push more power into the Avangrid system worsening overloads towards Bennett. These devices could be reconsidered if Avangrid makes upgrades to their system. PAR or SSSC were considered on the Dunkirk – Laona – Moon – Falconer circuits, but because the system is always secured to prevent overloads on all possible circuits for all possible outages, a location and setting of the PAR or SSSC could not be found that provided more headroom than the recommended solution.

The use of advanced conductors, which have higher allowed operation temperature due to the material used in the conductor core, were not recommended in this area due to the expectation that the maximum high temperature conductor size that could be supported on the existing structures would not sufficiently address the identified overloads. The need to address the age of the structures also makes the use of the more expensive high temperature conductor uneconomic. For when all structures are planned for replacement due to age or condition, the incremental cost of selecting a sufficiently large ACSR conductor is small compared to the cost of using the advanced conductor.

Regional Transmission Plan: Project Details

The Southwest pocket includes three Phase 1 projects and no Phase 2 projects. The Homer Hill – Bennett 115kV Terminal upgrade project is comprised of three individual project deliverables.

The tables below provide specific Phase 1 project details. It is important to note the information provided is based on current estimates and will continue to improve in accuracy as the project engineering design and execution matures.

Table 10: Phase 1 Project Description

Project ID	Project Title	Scope	Additional ROW Required
SW2	Dunkirk – Laona 115kV Line Upgrades	This project will rebuild 4.9 miles of the Dunkirk – Laona T1090 #161 and T1100 #162 from New Road Switching Station to Laona Substation. This will require the removal of eleven (11) wood structures, ten (10) monopole structures, Twelve (12) lattice towers, and twenty-nine (29) suspension flex towers. These will be replaced with four (4) single circuit steel H-Frame dead-end structures, forty-two (42) double circuit light duty steel monopole structures, eight (8) double circuit steel dead-end monopole structures, and three (3) single circuit steel dead-end monopoles. The existing 4/0 ACSR “Penguin” will be replaced with two (2) bundled 795 ACSR 26/7 “Drake” conductor and existing shield wire will be replaced with one (1) 3/8” steel and install one (1) OPGW. This project will include the replacement of six (6) structures with steel H-Frame structures on the #73/#74 Gardenville-Dunkirk 230kV lines at the point of crossing.	Possible
SW1	Andover Sta - LN 157 THERMAL UPGRADE	This project, which is part of the Homer Hill – Bennett 115kV terminal upgrade project will adjust the free-standing CT tap from 400:5A to 800:5A and reconfigure the line 157 inter-company billing meter for the Andover-Bennett (NYSEG) line 932.	No
SW1	Nile Station - 115kV THERMAL UPGRADE	This project, which is part of the Homer Hill – Bennett 115kV terminal upgrade project will replace the upper and lower 115kV copper bus between SW660 and SW676 with new 795 ACSR conductors. Brass fittings may be required at aluminum to copper transitions. New bus insulators may be required to support the new conductors.	No
SW1	Nile Hill Switch - 115kV THERMAL UPGRADE	This project, which is part of the Homer Hill – Bennett 115kV terminal upgrade project will replace switch structure 693 with a new switching structure and 2000-amp switch and replace approximately 900 circuit feet of the existing 336 ASCR conductor with 795 ACSR 26/7 “Drake” conductor between deadend Str 288 and Str 292	No
SW3	Laona to Falconer - DLR	This project will install eight (8) dynamic line rating monitors from LineVision on the Laona - Moon Rd LN173 and Moon Rd - Falconer LN175 including any work required for access. This project will also include the modifications required to integrate the line ratings into EMS.	No

Table 11: Phase 1 Estimated Construction Milestones

	Dunkirk – Laona	Andover Sta	Nile Sta	Nile Hill Sta	Laona – Falconer DLR
Final Engineering Complete	3-Jul-25	11-Jul-22	25-Jul-22	25-Aug-22	15-May-23
Construction Start	1-Sep-25	7-Sep-22	23-Aug-22	23-Sep-22	13-Jun-23
Ready for Load	1-Sep-25	6-Oct-22	21-Sep-22	24-Oct-22	12-Jul-23

Table 12: Phase 1 Estimated Project Spend Profile

Dunkirk-Laona

SW2	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	-	240	411	411	21,336	9,427	-	-	-	-	31,825
Opex	-	-	-	-	5,366	2,300	-	-	-	-	7,666
Removal	-	-	-	-	3,124	1,339	-	-	-	-	4,463
Total	-	240	411	411	29,826	13,065	-	-	-	-	**43,954**

Andover

SW1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	1	52	-	-	-	-	-	-	-	-	54
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	-	-	-	-	-	-	-	-	-	-
Total	1	52	-	-	-	-	-	-	-	-	54

Nile

SW1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	1	605	-	-	-	-	-	-	-	-	606
Opex	-	0	-	-	-	-	-	-	-	-	0
Removal	-	13	-	-	-	-	-	-	-	-	13

Total	1	617	-	-	-	-	-	-	-	-	619

Nile Hill

SW1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	-	668	4	-	-	-	-	-	-	-	672
Opex	-	49	-	-	-	-	-	-	-	-	49
Removal	-	109	-	-	-	-	-	-	-	-	109
Total	-	825	4	-	-	-	-	-	-	-	829

DLR

SW3	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	31	125	2,644	-	-	-	-	-	-	-	2,800
Opex	-	-	200	-	-	-	-	-	-	-	200
Removal	-	-	-	-	-	-	-	-	-	-	-
Total	31	125	2,844	-	-	-	-	-	-	-	3,000

Genesee Region
Transmission and Renewable Generation Assessment
August 1, 2021

This review was undertaken to determine if portions of the local 115kV and 69kV system in the Genesee region would prevent the delivery of existing and proposed renewable generation. The Company examined multiple generation dispatches for three different base case load scenarios; light load, shoulder load and heavy load. Upon identifying that the existing local transmission system would create constraints on renewable generation, several solutions were considered.

The conclusion of this analysis is that an existing condition driven project on the Southeast Batavia – Golah #119 (C060217) should be expanded to a full line rebuild, the Mortimer – Golah 69kV line 109 should be converted to 115kV operation and Grid Enhancing Technology (GET) should be added (i.e. Static Synchronous Series Compensator (SSSC) system) to each of the Lockport – Mortimer circuits. The SSSC allows System Operators to control the flow on the Lockport – Mortimer circuits and increase utilization of the Lockport – Batavia – Golah circuits. The combination of these projects was found to address the constraints on renewable generation and take advantage of Grid Enhancing Technology. These projects were found to address all the constraints on renewable generation, reducing curtailments from 110MW to 0 MWs. Separately a headroom test was performed where the optimal location and size of generation was identified before and after the proposed reinforcements. This headroom test found that the projects increased headroom by about 420MW.

This region contains only Phase 1 projects.

Existing System Overview

The Genesee Region is bordered by Lockport Station at the west end and Mortimer Station at the east end, see Figure 1. Three 115kV circuits connect directly from Lockport to Mortimer. Three 115kV circuits connect from Lockport to Batavia with one circuit between Batavia and Southeast Batavia, one circuit between Southeast Batavia and Golah and one 115kV and one 69kV circuit between Golah and Mortimer. There is also a radial load serving circuit connected to Golah.

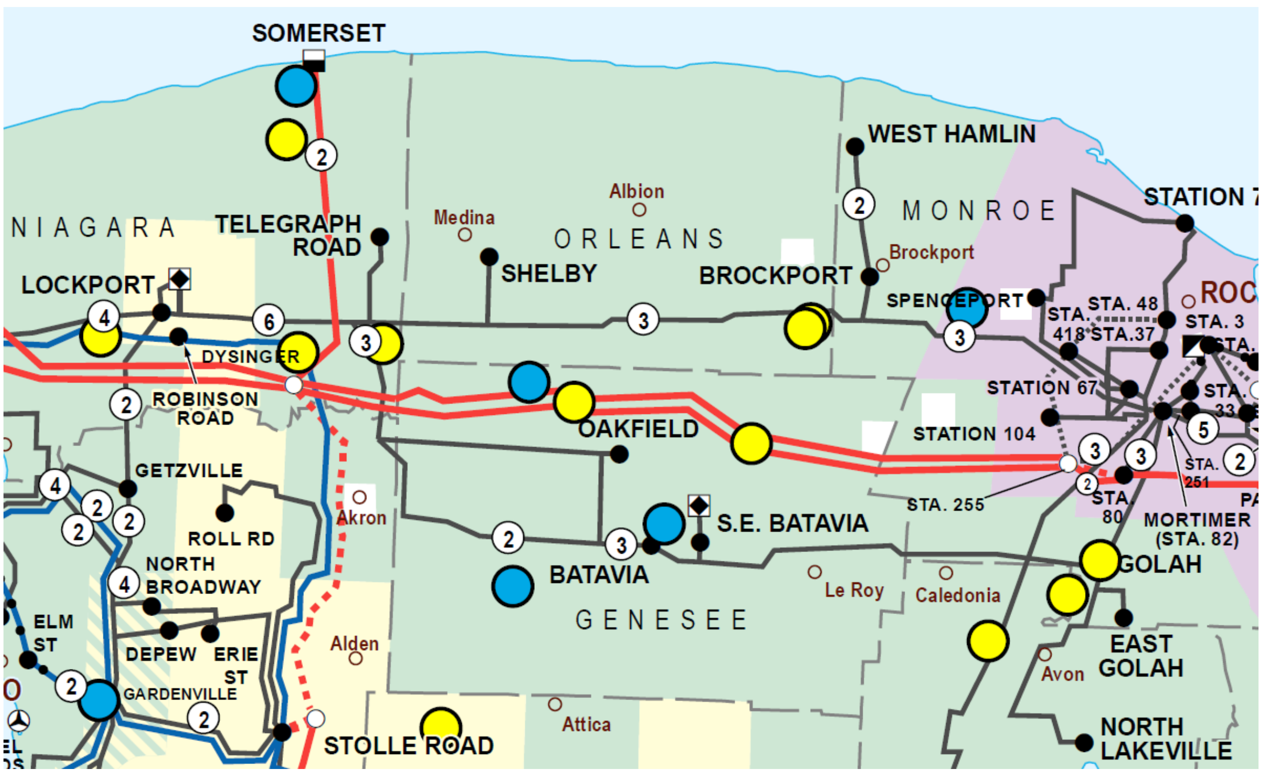
In parallel with this 115kV system are two 345kV circuits that start at Niagara in western NY and end at Clay station in the Syracuse area. These two 345kV circuits connect to the Avangrid Henrietta Station 255 and the Avangrid Station 80, which is near to and electrically tightly connected to Mortimer Station.[3] Also, in parallel with the 115kV system are two National Grid 34.5kV networks, one primarily served from the Lockport – Mortimer circuits with the other primarily served from the Lockport – Batavia – Golah – Mortimer circuits.

In all analysis National Grid monitored facilities adjacent to this area that were owned by Avangrid. All recommendations were developed considering if upgrades to the Avangrid system could address issues on the National Grid system. The Company has collaborated with neighboring utilities and all recommended upgrades were shared with other Transmission Owners and their comments were considered before finalizing plans.

[3] Mortimer is referred to as Station 82 by Avangrid

[redacted]

Figure 2. Genesee Region Transmission Map



While age is not always an indicator of condition, in the absence of condition assessments, the relative age of a circuit can provide some insight into how close the circuit may be to end of life refurbishment or replacement. Table 1 is a list of area circuits with the age of the oldest components.

Table 1: Transmission Circuit Age

Circuit	Year	Age	Mileage
Lockport - Batavia #112	1907	114	33.8
Lockport - Mortimer #113	1922	99	55.9
Mortimer - Golah #109	1924	97	10.3
Batavia - Southeast Batavia #117	1925	96	3.1
Southeast Batavia - Golah #119	1925	96	27.7
Lockport - Batavia #108	1931	90	35.8
Mortimer - Golah #110	1950	71	9.6
Lockport - Mortimer #114	1952	69	55.7
Lockport - Batavia #107	1967	54	35.8
Golah - North Lakeville #116	1973	48	13.9
Lockport - Mortimer #111	2011	10	56.2

Planned Reliability and Condition Driven Transmission Projects

All transmission projects identified as firm in the NYISO 2020 Gold Book were include in the study cases. Generally, projects are only listed in the Gold Book if they result in a modification to the system; such as a change in rating, change in impedance, or a change in system or station configuration. National Grid has other transmission projects in the medium to long term horizon. These projects are generally condition based projects. The following describes all major projects in the region, including some projects that are not expected to have an impact on the system. These projects were assessed as either having; a benefit to CLCPA as designed, a benefit to CLCPA if the project design was revised, or no benefit to CLCPA if revised. Those revised projects that have CLCPA benefits and lead to a significant increase in project cost are proposed as Phase 1 and Phase 2 project.

Rochester Airport Cable refurbishment – This project is addressing the condition of a 0.39-mile section of pipe type cable that forms a series part of the 111, 113 and 114 circuits. Due to the condition of the cables, the project proposes to drain the oil and clean the pipes and then use the pipes to install new solid dielectric cable. A goal of the project has been to maximize the rating of the cable section, as the cables are the thermal limit for each of the circuits. The preliminary design ratings for the cables were incorporated into the study base cases. The study included a desktop assessment of a scenario where the rating of this circuit was increased. Rating increases may result in increased system capacity or increased flexibility for optimally locating generation in the headroom test. However, higher ratings cannot be achieved without drastically changing the project scope. This project is under construction and expected to be completed in 2022. Thus, this project will not be revised from the current plan and is not a Phase 1 or Phase 2 project.

Lockport Station Refurbishment – At Lockport, many of the existing station components are planned for replacement. These replacements will not result in any changes to the station configuration and will not impact the thermal rating of any circuits. No changes to the study base cases were required. The study included a desktop assessment of a scenario where the configuration of the station was modified, but the expanded project scope did not result in any identified system capacity benefits.

Golah Station Reconfiguration – The Golah 115kV station is planned to be reconfigured from a single straight bus to a two-bus section straight bus by the addition of a bus tie breaker. This planned change was included as a base case assumption in the study. The study included a desktop assessment of a scenario where the configuration of the station was modified, but the expanded project scope did not result in any identified system capacity benefits. As discussed later in this document, it was found that converting the Mortimer – Golah 69kV line 109 to 115kV operation did have CLCPA benefits and is recommended as a Phase 1 project. This plan to convert 109 to 115kV operation requires substantial modification of the Golah station. Because of the extent of the required modifications, the existing Golah project will be replaced with a new Phase 1 project at Golah.

Lockport – Batavia 112 Rebuild – The scope of this project is a complete replacement of approximately 20 miles of this 34-mile-long circuit. The project will not result in an increase in the thermal limit of the overall circuit due to thermally limiting conductor in the last 14 miles. The study included a desktop assessment of a scenario where the project scope was increased to include the last 14 miles, but the expanded project scope did not result in any identified system capacity benefits.

Southeast Batavia – Golah 119 refurbishment – This project is addressing the condition of the Southeast Batavia – Golah 119 115kV circuit. At this time the scope includes replacement of a significant number of structures, but the expectation is that the work will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. The study included an assessment of a scenario where the rating of this circuit was increased. As discussed later in this document, an increased scope, combined with other projects was found to have capacity benefits. This project will be replaced with a Phase 1 project.

Lockport – Batavia 107 and 108 refurbishment – The National Grid 10-year plan includes funding for refurbishment work on the Lockport – Batavia 107 and 108 115kV circuits. At this time the expectation is that this project will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. The study included a desktop assessment of a scenario where the rating of this circuit was increased, but the expanded project scope did not result in any identified system capacity benefits.

Mortimer – Golah 109 and 110 refurbishment – The National Grid 10-year plan includes funding for refurbishment work on the Mortimer – Golah 110 115kV circuit and the Mortimer – Golah 109 69kV circuit. Originally this project would not result in a rating increase or an impedance change and thus no changes to the study base cases were required. However, it was recently determined that a more cost-effective solution that addressed the condition of both circuits and future demand growth is to completely rebuild the 110 circuit and the 109 circuit with line 109 being rebuilt to 115kV standards. In light of this new information the CLCPA base case was revised. The base case included an assessment of a scenario where the rating of these circuits was further increased. This scenario proved to provide additional CLCPA benefits. While the new project scope does have additional capacity benefits which help to unbottle proposed renewable generation in the area, this change in scope does not materially increase cost and is not a Phase 1 or Phase 2 project.

Local Design Criteria

For purposes of this study, National Grid performed steady state testing in accordance with its Transmission Group Procedure 28 (TGP28), *National Grid Transmission Planning Criteria*. Simulations were performed to assess the system response with all elements in service (N-0) as well as for N-1 outage conditions. These N-1 tests included loss of a circuit, transformer, generator or shunt device as well as breakers opening without a fault, bus outages, faults with a breaker failure and double circuit tower outages. All testing was limited to steady state for N-0 and N-1 conditions.

The system response to these N-1 outages is generally considered acceptable when all local facilities are loaded below 100 percent of their Long-Term Emergency (LTE) rating. For pre-contingency conditions, loading is considered acceptable when all local facilities are loaded below 100 percent of their Normal (continuous) rating. The summer ratings are used in all cases. Acceptable post-contingency system voltages on the 115kV and 69kV system are between 90 percent of nominal and 105 percent of nominal and acceptable pre-contingency voltages are between 95 percent of nominal and 105 percent of nominal.

All solutions are required to meet the full set of local and regional Planning Criteria to ensure that the reliability of the planned system is not compromised. These criteria include dynamic, short circuit and expanded steady state requirements. Additional testing will be required for some proposed Phase 2 solutions to ensure that they are designed to conform with and adhere to all applicable North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), New York State Reliability Council ("NYSRC") Reliability Rules, as well as applicable National Grid specifications, procedures, and guidelines.

Test 1: 2030 Regional Congestion Assessment - Methodology and Assumptions

The Regional Congestion Assessment (Test 1) is meant to; 1) identify existing local system congestion in a planning region based on the 2030 load and generation input assumptions and 2) eliminate all identified congestion within the region through system upgrades.

This study is based upon the database established and used by the NYISO for the 2020 Reliability Needs Assessment (RNA) 70x30 CLCPA Scenario using generation buildout assumptions from the Congestion Assessment and Resource Integration Study (CARIS) 70x30 scenario. The three cases selected as the starting point for the 70x30 scenario studies were: (i) Day Peak Load of 30,000 MW; (ii) Shoulder Load of 21,500 MW; and (iii) Light Load of 12,500 MW. The load is modeled based on the 2020 Gold Book forecast for 2030, with the load distributed within the regions based on the same 2020 RNA cases.

Starting from the 70x30 scenario peak load, shoulder load, and light load cases created by the NYISO, National Grid built sensitivity cases examining different renewable dispatch conditions. These dispatch scenarios were communicated with neighboring utilities for their consideration and use in their study work. While developing the case dispatches, monitoring and correcting overloads and voltage limitations on the 345kV and 230kV systems was considered out of scope for this assessment of the local system performance.

All study cases used by National Grid assumed no fossil generation was operating in NYISO Zone A (West) through F (Capital) and assumed that nuclear generators at Nine Mile 1, Nine Mile 2, and Fitzpatrick were all in service at maximum output and Ginna was assumed to be out of service. For the ties from New York to the external areas, no import or export was allowed from New York to PJM (across the free-flowing ties), New England or Ontario.

Hydro generation at Gilboa was set to maximum generation in the peak and shoulder cases and set to pumping in light load cases. In all cases, the Moses generation was set to maximum output. At the

Niagara/Lewiston facility, Niagara was set to 2160MW, evenly distributed across the thirteen machines and Lewiston was set to either 240MW of generation or 360MW of pumping load depending on the case. Run of river hydro generation was set to typical seasonal values. The import of Hydro generation from Hydro Quebec was set to either 1110MW or 535MW. No hydro generation was imported to Dennison from the Cedars generation.

The above assumptions were modeled in each case, and Land Based Wind (LBW) and Utility Scale Photovoltaic (UPV) generation was then dispatched to various levels. In the National Grid testing, LBW, primarily located in Western, Central and Northern NY, was varied between 0 percent of nameplate up to 75 percent of nameplate and UPV, located primarily in Central, Northern and Eastern NY was dispatched between 0 percent of nameplate up to 70 percent of nameplate. Neither wind nor solar resources were modeled at 100 percent of nameplate.

The NYISO zonal data of hourly load, LBW output, and the UPV output from its CARIS 70x30 scenario was also reviewed for consistency with National Grid modeling assumptions. All dispatches modeled by National Grid were consistent with the NYISO CARIS 70x30 generation output levels assumed to be achieved for 100 hours or more. For example, a dispatch scenario model by National Grid was LBW greater than or equal to 30 percent of nameplate concurrent with UPV output greater than or equal to 27 percent. This dispatch occurred in the CARIS 70x30 scenario for 802 hours. Another example of the many scenarios studied by National Grid was LBW at 15 percent of nameplate and UPV at 52 percent of nameplate. The dispatch at or above this level occurred in the CARIS 70x30 scenario for 457 hours.

For the National Grid assessment, no assumptions were made for the generation mix in New York City or Long Island, including no specific assumptions for offshore wind, as the generation mix downstate does not have any impact on the result of testing within National Grid's service territory. However, for simplicity of developing the scenario cases, it was assumed that the flow across the UPNY – CONED interface would not exceed 7000MW.

Test 1: 2030 Regional Congestion Assessment - Modeled Existing and Proposed Generation

As of 1/31/2021, the NYISO interconnection queue includes 200MW of wind, 590MW of solar and 31MW of storage proposing to connect to the local system. The projects are summarized in Table 2.

In the last 5 years an additional 475MW of generation proposing to connect into this area has withdrawn from the NYISO queue. While some of these projects may have withdrawn due to siting or financing issues, it is believed that some projects have withdrawn due to insufficient transmission capability.

Table 2: Generation in the NYISO Interconnection Queue

Queue	MW	Type	Interconnection Point
0571	200	W	Lockport - Mortimer 115kV
0710	180	S	Golah Substation 115kV
0862	20	S	Lockport - Mortimer 115kV
0879	20	S	Lockport - Mortimer 115kV
0932	20	S	Caledonia - Golah 34.5 kV
0950	200	S	Lockport - Mortimer 115kV
0995	130	S	Lockport - Batavia 115kV
1051	20	S	Batavia - Golah 115kV
0947	11	ES	North Lakeville 34.5kV
1104	20	ES	Brockport Station 34.5 kV

Table 3: 2019 CARIS Generation Additions Necessary to Meet the 70x30 Mandate

Bus	MW	Type	Interconnection Point
OAKFLDTP	77	W	Lockport - Batavia 115kV
SWDN-113	192	W	Lockport - Mortimer 115kV
BATAVIA1	19	W	Batavia Substation 115kV
NAKR-107	19	W	Lockport - Batavia 115kV
GOLAH115	99	S	Golah Substation 115kV
SWDN-113	20	S	Lockport - Mortimer 115kV

As previously stated, generator representation (e.g. type, size and location for new renewables) used in this assessment was based on the 2019 CARIS 70x30 sensitivity case. These cases modeled 308MW of wind and 119MW of solar in the region (see Table 3). Figure 2 shows geographically where new resources were added, with each yellow dot representing a new solar generator location and each blue dot representing a new wind generator location.

It should be noted that compared to the resources proposed in the NYISO queue, the 2019 CARIS assumptions under assumed the amount of utility scale solar and DER. The largest differences between the queue and the study cases are approximately 100MW of solar at Golah and 200MW of solar on the Lockport – Mortimer circuits. This additional generation in the queue could contribute to higher loading on the circuits that were identified as overloaded in this study.

Several of the projects added to the cases were added to existing tap buses. When a line outage or contingencies occur, these tap buses are usually disconnected. No changes were made to the contingency definitions to reflect the addition of this generation. It was assumed that the contingencies would result in the generation tripping, same as the load. New three breaker ring generation interconnections could change this contingency but were not modeled. The change in contingency could increase the amount of congestion identified by this testing. This is especially true for the generators at SWDN (192MW wind, 20MW solar) OAKFLD (77MW wind) and NAKR-107 (19MW wind).

The base cases assume 192MW of wind and 20MW of solar connected on the Lockport – Mortimer circuits and assume 115MW of wind and 99MW of solar connected between Lockport, Batavia, Golah and Mortimer.

Test 1: 2030 Regional Congestion Assessment - Proposed Distributed Energy Resources

In addition to the generation proposed in the NYISO queue, Distributed Energy Resources (DER) have also proposed to connect to National Grid's distribution system. The DER queue for the region contains over 250MW of proposed generation and is almost entirely solar. The stations where the largest amount of solar DER is proposed is summarized in Table 4. While the DER was not explicitly modeled in the base cases, the proposed locations are similar to the proposed locations used to model the new resources (Table 3) needed to meet the 70x30 mandate. Because energy produced from DER may make its way from the distribution system to the transmission system through the existing transmission stations modeled in this study, DER is expected to have a similar impact as the generation directly connected to the transmission system and would benefit from the same projects identified as necessary to unbottle the region.

Table 4: Generation in the DER Interconnection Queue

Station	MW
Batavia	35
Brockport	15
East Batavia	31
East Golah	26
Knapp Rd	44
Mumford	14
Shelby	17
West Hamlin	41

Test 1: 2030 Regional Congestion Assessment - Study Results (System Bottlenecks)

Based on the study base cases, two areas of congestion were identified that would constrain the output of generation (generation pocket).

[redacted] The pre-contingency flow is also at 100% of the normal rating of the new Rochester Airport cable section. An overload was found in all peak, shoulder and light load cases when wind was dispatched to 45% of nameplate or higher and likely due to the CARIS assumption that a 192MW wind project would directly interconnect to this circuit. As the NYISO queue includes a 200MW wind project, 260MW of utility scale solar projects and over 70MW of DER solar proposing to connect to the Lockport – Mortimer circuits, there is a high likelihood that this overload would develop and be more severe than this study found. It should also be noted that depending on the interconnection arrangement, it is possible that this generation would create a similar overload on the Lockport – Mortimer #114 circuit, which is on the same towers as line #113 and has the same overhead and underground conductor rating as line #113.

Starting from a case with the wind generation dispatched to 75% of nameplate and no solar generation in service, as much as 110MW of generation had to be curtailed to bring to loading on the circuit to within limits.

Secondary to the Lockport – Mortimer overloads, it was found that the Southeast Batavia – Golah circuit was loaded to 91% of normal and 95% of LTE. This loading did not result in any generation curtailment but is notable as this portion of the system is at its maximum. The limiting element on this circuit is 15.9 miles of 397.5 MCM ACSR conductor.

Table 5: Test 1 Genesee Facility Overloads

Facility	Worst Case Overload (% LTE)
Lockport - Mortimer 113	140
Southeast Batavia - Golah 119	93

Test 2: Capacity Headroom Test - Methodology and Results

To further determine the areas that could cause congestion, a Capacity Headroom test was performed. According to the DPS Headroom Test whitepaper (Case 20-E-0197), Capacity Headroom uses the lowest identified optimal transfer value observed in a heavy, light and shoulder load case. This test was done using the Optimal Transfer feature in TARA. Unlike Test 1 where the location of the generation was based on generation identified by the NYISO in the 70X30 CARIS case, Test 2 involves assigning possible locations for generation to interconnect, then having the program determine which one or more of the sites is an optimal location and how much generation could connect. The optimized dispatch keeps all transmission elements in the pocket within acceptable loading for any N-0 or N-1 condition. The analysis does not distinguish between the type of generation, only estimates the capability for simultaneous output from generation within the local network.

Under Test 2, base cases are initialized with no solar or wind generation in service. Including no solar or wind generation in upstream or downstream locations or on the bulk power system. All other load, hydro and nuclear generation and system topology assumptions made in the Test 1 base case were held constant. For Test 2, it was assumed that generation could only be added to the existing 115kV switching stations in the region. The impact of adding generation to the middle of a line, which is likely not an electrically optimal location, will not be captured. One of the limitations of this test is that the model can add a relatively large amount of generation into one site, ignoring or reducing the other options. To provide a more realistic indication of the headroom provided, a limit of 500MW was placed on all 115kV switch stations.

For this region, the selected 115kV buses were Lockport, Batavia and Golah.

The amount and location of generation for each study base case is summarized in Table 6. The program identified three bottlenecks; Lockport – Mortimer #113 and #114, Southeast Batavia – Golah #119 and Mortimer – Golah #110, even with line 110 rebuilt. Note that the program found higher levels of unconstrained generation was possible when Niagara/Lewiston was pumping, as the pumping would reduce the region throughflow. Higher load levels also result in lower throughflow. The binding case for this region was the light load case without hydro pumping.

Table 6: Existing System Capacity Headroom (MW)

	Lockport	Batavia	Golah	Total
Heavy Load	500	290	190	980
Heavy Load w/Pumping	500	310	190	1000
Light Load	450	200	140	790
Light Load w/Pumping	500	210	140	850
Shoulder Load	500	250	170	920
Shoulder Load w/Pumping	500	270	170	940

For the Lockport – Mortimer constraint, the headroom test found that the most limiting section of the lines was the Lockport end. This differed from the Test 1 Congestion Assessment in that the Congestion Assessment found the constraint to be at the Mortimer end of the circuits. This difference points to the sensitivity of the generation interconnection point. As the generation is moved from the Mortimer end (2030 Regional Congestion Assessment assumption; Test 1) to the Lockport end (Capacity Headroom test assumption; Test 2), more of the circuits or different portions of the circuits could be overloaded. A project that targets just one portion of these lines for an upgrade may not provide the needed capacity based on where the projects connect.

The headroom test also found that the rebuilt Mortimer – Golah circuit was still limiting the area capability. This can be attributed to the generation the program was attempting to connect to Golah and Batavia. Note: the total generation in the interconnection queue between Batavia and Golah is 350MW compared to the 214MW assumed in the CARIS/RNA study cases.

<u>Regional Transmission Plan: Recommended System Upgrades</u>

The condition driven projects are focused on the Lockport – Batavia – Golah – Mortimer portion of the system where some of the capacity limits have been identified. However, capacity concerns were also identified on the Lockport – Mortimer circuits where no condition driven projects are proposed.

To address the Lockport – Mortimer overloads, it is proposed to use GET devices such as SmartValve (Static Series Synchronous Compensators) to push power off the Lockport – Mortimer circuits and onto the Lockport – Batavia – Golah – Mortimer circuits, utilizing capacity created by the condition driven projects on those lines. To maximize the capacity increase on the Lockport – Batavia – Golah – Mortimer path, the scope of current condition driven project on the Southeast Batavia – Golah circuit will be expanded to replace all 397.5 MCM ACSR conductor with two conductor per phase 795 ACSR.

To further increase capacity in the Batavia – Golah area it is recommended that the Mortimer – Golah 69kV line 109, which is already planned to be built to 115kV standards, be fully converted to 115kV operation. To complete this conversion to 115kV operation, it is necessary to add 115kV breaker positions at Mortimer and Golah as well as reconfigure the 69kV and 34.5kV supplies at Golah. This substantial modification of Golah station will need to replace already planned work at Golah, with the original project scope incorporated into the new Golah station project. The conversion of 109 to 115kV operation has the added resiliency benefit of creating a third 115kV supply into the Batavia – Mortimer pocket [redacted]. The number of customers that would be interrupted for [redacted] makes this one of the top three largest resiliency risks in all of the National Grid service territory. The elimination of the [redacted] risk will also reduce construction time and cost of the 119 rebuild project, also recommended in this study, by facilitating the required outages and eliminating the need to have a short outage recall time.

While series reactors could be sized to address the overloads identified in the study, it may not be possible to identify a reactor size that can sufficiently manage the power flow for all generation, load and transfer conditions without impacting area voltages. PAR would provide the control needed to manage the power flow for all hours and system conditions, but expansion of the Lockport station would be required to add the devices and the breakers, switches, protection and control equipment. The SSSC provides a modular design that results in the power flow being controllable.

Table 7: Regional Project Plan Summary*

Project ID	Project Name	Phase	Project Description
G1	Batavia – Golah 115kV Line Upgrade	Phase 1	115kV Upgrade: sections of Batavia – Golah
G2	Lockport – Mortimer 115kV Smart Valve System	Phase 1	115kV Upgrade: Add Smart Valve system to Lockport – Mortimer lines
G3	Mortimer – Golah 109 Conversion to 115kV	Phase 1	Convert Mortimer – Golah 69kV line 109 to 115kV operation

*No Phase 2 projects are proposed for this area

[redacted]

<u>Regional Transmission Plan: Project Benefits</u>

With the 119 line rebuild completed, 109 converted to 115kV operation and the SSSC added to the Lockport – Mortimer circuits, it was no longer necessary to curtail 110MW in the 2030 Regional Congestion Assessment (Test 1).

Table 8: Project Congestion Benefits

System Configuration	Constraint (MW)
Existing System	110
All Phase 1 Projects Complete	0
All Phase 2 Projects Complete	NA

The Capacity Headroom test (Test 2) shows that additional generation can be optimally added to the system once these projects are completed. Overall the projects resulted in a 4202MW increase in capacity headroom. Note that because the headroom test is only given three possible locations, each with a 500MW limit, the program is achieving near maximum headroom capability for this area.

Table 9: System Capacity Headroom Post Project

	Lockport	Batavia	Golah	Total
Heavy Load	500	360	480	1340
Heavy Load w/Pumping	500	360	500	1360
Light Load	500	350	360	1210
Light Load w/Pumping	500	350	390	1240
Shoulder Load	500	360	420	1280
Shoulder Load w/Pumping	500	350	450	1300

Regional Transmission Plan: Project Alternatives

Alternatives considered to the recommended solution were:

Rebuild 17 miles of the 113/114 circuits – This option was rejected due to the cost and the project having no condition-based drivers. In addition, rebuilding only a section of the 113/114 circuits would not provide any flexibility for generator interconnection location on the Lockport – Mortimer circuits. For example, if a generator proposed to interconnect just east of Lockport, the required rebuild would increase beyond the 17 circuit miles.

Build an expanded Interconnection Station – This option would expand the greenfield generator interconnection stations proposed by developers connecting to the Lockport – Mortimer circuits to include two or all three of the Lockport – Mortimer circuits. By expanding the interconnection to include additional circuits, the hope was that the loading on any one circuit could be reduced. This option was rejected as studies showed that this expanded station resulted in increased post-contingency flows on the Lockport – Mortimer 113 and 114 circuits, requiring more curtailment.

Series Reactors – Instead of using the SSSC, series reactors could be installed on each of the Lockport – Mortimer circuits. This option was rejected due to the difficultly selecting reactor sizes that would address system constraints for different loads levels, generation interconnections and system transfers while not impacting area voltages.

Phase Angle Regulators – Instead of using the SSSC, a PAR could be installed on each of the Lockport – Mortimer circuits. These three PARs can be operated in a similar manner to the SSSC. National Grid continues to review if this option would be a cost-effective alternative to the SSSC.

The use of advanced conductors, which have higher allowed operation temperature due to the material used in the conductor core, were not recommended in this area due to the expectation that the maximum high temperature conductor size that could be supported on the existing structures would not sufficiently address the identified overloads. The need to address the age of the structures also makes the use of the more expensive high temperature conductor uneconomic. For when all structures are planned for replacement due to age or condition, the incremental cost of selecting a sufficiently large ACSR conductor is a small compared to the cost of using the advanced conductor.

Regional Transmission Plan: Project Details

The Genesee pocket includes three Phase 1 projects and no Phase 2 projects. The Batavia – Golah 115kV Line Upgrade project is comprised of four individual project deliverables. The Mortimer – Golah 109 Conversion to 115kV project is comprised of two individual project deliverables.

The tables below provide specific Phase 1 project details. It is important to note the information provided is based on current estimates and will continue to improve in accuracy as the project engineering design and execution matures.

Table 10: Phase 1 Project Description

Project ID	Project Title	Scope	Additional ROW Required
G1	SE Batavia – Golah 119 Rebuild	This project is for the full rebuild of 15.9 miles of the SE Batavia - Golah LN119 from Str 107 to Golah Substation. This required the removal of 155 wood pole structures and the installation of one hundred and twenty eight (128) steel pole davit arm suspension structures, one (1) steel pole davit arm r- suspension structure; one (1) steel pole 1-pole suspension structure, nine (9) steel monopole structures; install 12 steel davit arm de structures; and install four (4) steel pole h-frame de structures, the existing 397.5 ACSR "Chickadee" with 2-795 ACSR 26/7 “Drake” conductor and existing shieldwire with one (1) 3/8” steel and install one (1) OPGW.	Possible
G1	North Leroy 04 - 115kV THERMAL UPGRADE	This project, which is part of the SE Batavia – Golah 115kV Line 119 upgrade project, will replace the existing 115kV motor operated disconnects SW26 and SW27 with new 2000A motor operated disconnects. The supervisory control for SW26 will be retained. The existing 115kV manually operated disconnects SW200 and SW300 will also be replaced with new 2000A gang-operated disconnects. The existing 397.5 ACSR conductors between disconnects SW26 and SW27 and their respective takeoff structures will be replaced with new 1192 ACSR conductors (two (2) per phase)	No
G1	North Leroy - 115kV THERMAL UPGRADE	This project, which is part of the SE Batavia – Golah 115kV Line 119 upgrade project, will replace the existing motor operated disconnects SW28 and SW29 with new 2000A motor operated disconnects. The supervisory control for SW29 will be retained. The existing 397.5 ACSR conductors between the new disconnects and their respective line terminations will be replaced with new 1192 ACSR conductors (two (2) per phase). This will require the modification of the existing 115kV structure for support of the new disconnect switches and new insulators. The existing insulators will be replaced with new insulators for support of the transmission line tap new conductors.	No
G1	Mumford - 115kV	This project, which is part of the SE Batavia – Golah 115kV Line 119 upgrade project, will replace the existing 115kV motor operated	No

	THERMAL UPGRADE	disconnects SW401 and SW405 with new 2000A motor operated disconnects. The supervisory control for both units will be retained. The existing 115kV manually operated disconnects SW402 and SW404 will also be replaced with new 2000A gang-operated disconnects on new galvanized steel 115KV disconnect switch structures. The existing 2” AL bus tube between disconnects SW401 and SW405 and their respective takeoff structures will be replaced with new 3.5” AL bus tube. The existing 3.50” AL bus tube will need to be replaced for both the upper and lower buses to accommodate the new structures spacing and connection points while meeting proper phase spacing along the 115kV bus. This will require two (2) galvanized steel 115KV bus support structures and new 795ACSR to make the drops from the new upper buses to the lower bus.	
G3	Mortimer Station Upgrades	This project is for the 115kV rebuild of Golah station and upgrade of the LN109 bay from 69kV to 115kV. This will require the expansion of Golah substation including new gradings, ground grid and fencing. The existing TR3 transformer 69kV:34.5kV 7.5/9.375MVA will be removed and one new 69kV:34.5kV 30/40/50 MVA w/LTC TR1 installed. The 115:69kV 33.6/44.8/56MVA LTC transformer at Mortimer substation or a spare will be installed. One (1)115kV SF6 2000A tie breaker between disconnect switches SW259 and SW261 will be installed. Existing 115kV 1200-amp R246 breaker will be replaced with One (1) 115kV, 2000A, 40kA SF6 circuit breaker. The five (5) existing 1200amp disconnect switches SW245, SW247, SW259, SW261 and SW37 will be replaced with new gang operated 115kV 2000A disconnect switches. The mobile capacitor bank will be replaced with one (1) new permanent 115kV 40MVar capacitor bank, one (1) new 115kV SF6 2000A capacitor bank synchronous close circuit breaker, and one (1) new 115kV 2000A capacitor bank gang operated disconnect switch. The existing surge arrestors on the 115kV bus A will be replaced with three new 120kV 98 MCOV rated surge arresters and install three (3) new 120kV 98MCOV surge arresters on 115kV bus B. The existing PTs on the 115kV bus A will be replaced with three new oil filled 69kV:115/69v PTs and three new oil filled 69kV:115/69v PTs will be installed on bus B. A new 24ft by 32ft control encloser will be installed. The existing obsolete electromechanical relays will be replaced with digital relaying for the Line, transformer, and bus protection.	No
G3	Golah Station Rebuild	This project will rebuild the LN109 bay at Mortimer from 69kV to 115kV. The 115:69kV 33.6/44.8/56MVA LTC transformer, 69kV UG cable/duct, 69kV breaker NR214 and associated relaying will be removed. Approximately 250ft of new three-phase 115kV 4-inch AL bus tubing with nine (9) bus support structures and foundations will be Installed as a low-profile bus from the 109-bay connection to	No

		disconnect switch 172 on the north bus. The existing 3000amp GCB R174 will be relocated to the 109 bay and reused for line protection. One (1) new 115kV CCVT will be installed for line 109 auto-reclosing and synch check.	
G2	Lockport Smart Valves	This project will install Static Synchronous Series Compensators (SSSC), also known as Smart Valve System on the Lockport to Mortimer LN111, LN113, and LN114. This will require the expansion of the Lockport substation yard to the south east by approximately 230 ft by 270 ft including site grading, new grounding grid, and fencing. Each line will require six (6) Smart Valves model#10-1800 installed for a total of Eighteen (18). These will be installed on platforms with one hundred and sixty-two (162) 115 kV support insulators, six (6) 115 kV upright mounted group operated disconnect switches, and three (3) 115 kV invert mounted group operated disconnect switches. For the transmission line connects three (3), 115 kV A frame structures and three (3), 115 kV H frame structures will be installed.	No

Table 11: Phase 1 Estimated Construction Milestones

	SE Batavia – Golah 119 Rebuild	N Leroy 04 Sta	N Leroy Sta	Mumford Sta	Mortimer Station Upgrades	Golah Station Rebuild	Lockport Smart Valves
Final Engineering Complete	1-Feb-26	16-Nov-22	19-Jul-22	15-Feb-23	20-Sep-24	18-Dec-23	9-Nov-23
Construction Start	1-Jul-26	15-Dec-22	17-Aug-22	14-Apr-23	19-Nov-24	14-Mar-24	6-Feb-24
Ready for Load	1-Jul-28	13-Feb-23	15-Sep-22	9-Oct-23	16-Jan-25	4-Jun-24	3-May-24

Table 12: Phase 1 Estimated Project Spend Profile

SE Batavia – Golah 119 Rebuild

G1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	105	316	316	316	1,178	28,804	37,438	8,872	-	-	77,347
Opex	-	-	-	-	17	2,421	3,212	791	-	-	6,441
Removal	-	-	-	-	-	5,041	6,721	1,680	-	-	13,442
Total	105	316	316	316	1,194	36,266	47,372	11,343	-		**97,230**

N Leroy 04 Sta

G1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	-	507	168	-	-	-	-	-	-	-	676
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	58	29	-	-	-	-	-	-	-	86
Total	-	565	197	-	-	-	-	-	-	-	**762**

N Leroy Sta

G1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	13	302	5	-	-	-	-	-	-	-	320
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	92	-	-	-	-	-	-	-	-	92
Total	13	393	5	-	-	-	-	-	-	-	412

Mumford Sta

G1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	23	55	766	23	-	-	-	-	-	-	868
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	-	104	-	-	-	-	-	-	-	104
Total	23	55	871	23	-	-	-	-	-	-	972

Mortimer Station Upgrades

G3	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	-	-	29	1,176	881	-	-	-	-	-	2,086
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	-	-	232	464	-	-	-	-	-	696
Total	-	-	29	1,408	166	-	-	-	-	-	**2,782**

Golah Station Rebuild

G3	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	248	297	7,199	7,362	4,585	74	-	-	-	-	19,765
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	-	-	755	680	-	-	-	-	-	1,435
Total	248	297	7,199	8,117	5,264	74	-	-	-	-	**21,200**

Lockport Smart Valves

G2	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	142	3,890	10,533	7,655	50	-	-	-	-	-	22,270
Opex	-	-	-	2,312	-	-	-	-	-	-	2,312
Removal	-	-	-	-	-	-	-	-	-	-	-
Total	142	3,890	10,533	9,968	50	-	-	-	-	-	**24,582**

East of Syracuse Region
Transmission and Renewable Generation Assessment

August 1, 2021

This review was undertaken to determine if portions of the local 115kV system south and east of Syracuse would prevent the delivery of existing and proposed renewable generation. The Company examined multiple different generation dispatches for three different base case load scenarios; light load, shoulder load and heavy load. Upon identifying that the existing local transmission system would create constraints on renewable generation, solutions were considered.

The conclusion of this analysis is that limiting station connections should be upgraded on the circuits between Clarks Corners and Oneida and between Tilden and Cortland. These projects were found to address all the constraints on renewable generation, reducing curtailments from 90MW to 0 MWs. Separately a headroom test was performed where the optimal location and size of generation was identified before and after the proposed reinforcements. This headroom test found that the projects increased headroom by about 110MW in the most limiting case.

This region contains only Phase 1 projects.

<u>Existing System Overview</u>

The East of Syracuse Region is mainly defined by multiple single 115kV circuits in series from Clarks Corners to Cortland to Fenner to Oneida. From Oneida several circuits head east to Porter and Rome and several circuits head west to Teall (in Syracuse). Cortland also has a circuit that heads north to Tilden (See Figure 1).

In all analysis National Grid monitored facilities adjacent to this area that were owned by Avangrid. All recommendations were developed considering if upgrades to the Avangrid system could address issues on the National Grid system. The Company has collaborated with neighboring utilities and all recommended upgrades were shared with other Transmission Owners and their comments were considered before finalizing plans.

Figure 1: East of Syracuse Single Line

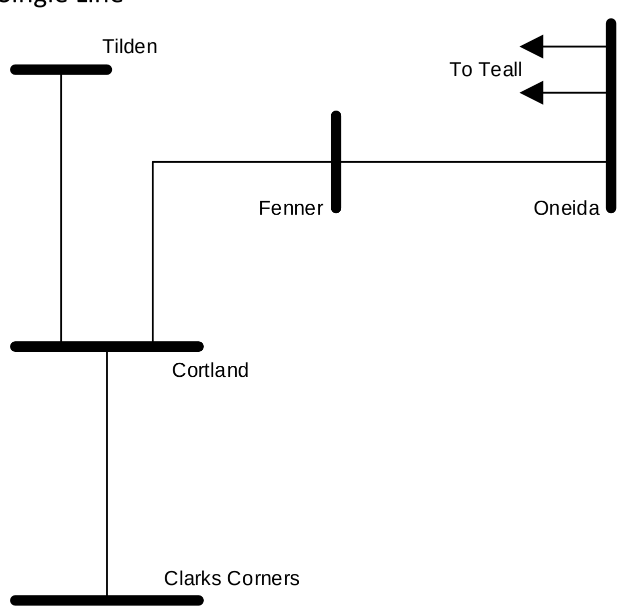
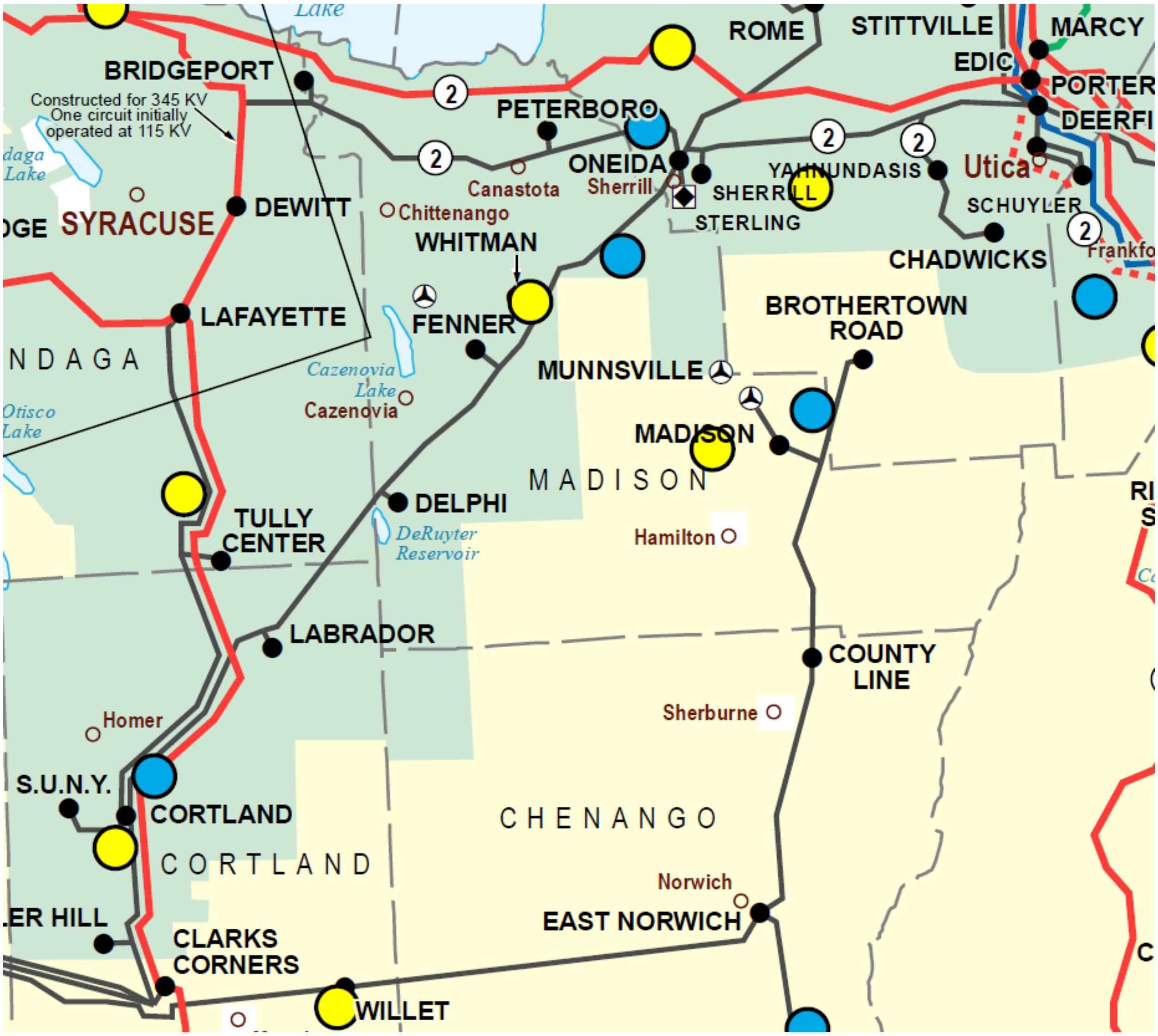


Figure 2. East of Syracuse Transmission Map



While age is not always an indicator of condition, in the absence of condition assessments, the relative age of a circuit can provide some insight into how close the circuit may be to end of life refurbishment or replacement. Table 1 is a list of area circuits with the age of the oldest components.

Table 1: Transmission Circuit Age

Circuit	Year	Age	Mileage
Teall - Oneida #2	1925	96	28.9
Teall - Oneida #5	1925	96	28.9
Cortland - Clarks Corners #1-716	1928	93	10.6
Tilden - Cortland #18	1970	51	35.1
SUNY Cortland - Cortland #2	1972	49	5.9
Fenner - Cortland #3	1976	45	34.5
Oneida - Fenner #8	1976	45	11.1

Planned Reliability and Condition Driven Projects

All transmission projects identified as firm in the NYISO 2020 Gold Book were include in the study cases. Generally, projects are only listed in the Gold Book if they result in a modification to the system; such as a change in rating, change in impedance, or a change in system or station configuration. National Grid has other transmission projects in the medium to long term horizon. These projects are generally condition based projects. The following describes all major projects in the region, including some projects that are not expected to have an impact on the system. These projects were assessed as either having; a benefit to CLCPA as designed, a benefit to CLCPA if the project design was revised, or no benefit to CLCPA if revised. Those revised projects that have CLCPA benefits and lead to a significant increase in project cost are proposed as Phase 1 and Phase 2 project.

Oneida Station Rebuild – The National Grid 10-year plan includes funding for refurbishment work at Oneida. The project scope includes changing the station to a breaker and a half arrangement. The new arrangement and replacement of several thermally limiting components were reflected in the study. The rating increase associated with the replacement of thermally limiting components does provide CLCPA benefits. However, this project does not need to be revised from the current plan and is not a Phase 1 or Phase 2 project.

Tilden Station Rebuild – The National Grid 10-year plan includes funding for refurbishment work at Tilden station. At this time the expectation is that this project will not result in a change to the station configuration or any rating increases and thus no changes to the study base cases were required. The study included a desktop assessment of a scenario where the configuration of the station was modified, but the expanded project scope did not result in any identified system capacity benefits.

Yahnundasis Station Rebuild – The National Grid 10-year plan includes funding for refurbishment work at Yahnundasis. At this time the expectation is that this project will not result in a change to the station configuration or any rating increases and thus no changes to the study base cases were required. The study included a desktop assessment of a scenario where the configuration of the station was modified, but the expanded project scope did not result in any identified system capacity benefits.

Local Design Criteria

For purposes of this study, National Grid performed steady state testing in accordance with its Transmission Group Procedure 28 (TGP28), *National Grid Transmission Planning Criteria*. Simulations were performed to assess the system response with all elements in service (N-0) as well as for N-1 outage conditions. These N-1 tests included loss of a circuit, transformer, generator or shunt device as well as breakers opening without a fault, bus outages, faults with a breaker failure and double circuit tower outages. All testing was limited to steady state for N-0 and N-1 conditions.

The system response to these N-1 outages is generally considered acceptable when all local facilities are loaded below 100 percent of their Long-Term Emergency (LTE) rating. For pre-contingency conditions, loading is considered acceptable when all local facilities are loaded below 100 percent of their Normal (continuous) rating. The summer ratings are used in all cases. Acceptable post-contingency system voltages on the 115kV and 69kV system are between 90 percent of nominal and 105 percent of nominal and acceptable pre-contingency voltages are between 95 percent of nominal and 105 percent of nominal.

All solutions are required to meet the full set of local and regional Planning Criteria to ensure that the reliability of the planned system is not compromised. These criteria include dynamic, short circuit and expanded steady state requirements. Additional testing will be required for some proposed Phase 2 solutions to ensure that they are designed to conform with and adhere to all applicable North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), New York State Reliability Council ("NYSRC") Reliability Rules, as well as applicable National Grid specifications, procedures, and guidelines.

Test 1: 2030 Regional Congestion Assessment - Methodology and Assumptions

The Regional Congestion Assessment (Test 1) is meant to; 1) identify existing local system congestion in a planning region based on the 2030 load and generation input assumptions and 2) eliminate all identified congestion within the region through system upgrades.

This study is based upon the database established and used by the NYISO for the 2020 Reliability Needs Assessment (RNA) 70x30 CLCPA Scenario using generation buildout assumptions from the Congestion Assessment and Resource Integration Study (CARIS) 70x30 scenario. The three cases selected as the starting point for the 70x30 scenario studies were: (i) Day Peak Load of 30,000 MW; (ii) Shoulder Load of 21,500 MW; and (iii) Light Load of 12,500 MW. The load is modeled based on the 2020 Gold Book forecast for 2030, with the load distributed within the regions based on the same 2020 RNA cases.

Starting from the 70x30 scenario peak load, shoulder load, and light load cases created by the NYISO, National Grid built sensitivity cases examining different renewable dispatch conditions. These dispatch scenarios were communicated with neighboring utilities for their consideration and use in their study work. While developing the case dispatches, monitoring and correcting overloads and voltage limitations on the 345kV and 230kV systems was considered out of scope for this assessment of the local system performance.

All study cases used by National Grid assumed no fossil generation was operating in NYISO Zones A (West) through F (Capital) and assumed that nuclear generators at Nine Mile 1, Nine Mile 2, and Fitzpatrick were all in service at maximum output and Ginna was assumed to be out of service. For the ties from New York to the external areas, no import or export was allowed from New York to PJM (across the free-flowing ties), New England or Ontario.

Hydro generation at Gilboa was set to maximum generation in the peak and shoulder cases and set to pumping in light load cases. In all cases, the Moses generation was set to maximum output. At the Niagara/Lewiston facility, Niagara was set to 2160MW, evenly distributed across the thirteen machines and Lewiston was set to either 240MW of generation or 360MW of pumping load depending on the case. Run of river hydro generation was set to typical seasonal values. The import of Hydro generation from Hydro Quebec was set to either 1110MW or 535MW. No hydro generation was imported to Dennison from the Cedars generation.

The above assumptions were modeled in each case, and Land Based Wind (LBW) and Utility Scale Photovoltaic (UPV) generation was then dispatched to various levels. In the National Grid testing, LBW, primarily located in Western, Central and Northern NY, was varied between 0 percent of nameplate up to 75 percent of nameplate and UPV, located primarily in Central, Northern and Eastern NY was dispatched between 0 percent of nameplate up to 70 percent of nameplate. Neither wind nor solar resources were modeled at 100 percent of nameplate.

The NYISO zonal data of hourly load, LBW output, and the UPV output from its CARIS 70x30 scenario was also reviewed for consistency with National Grid modeling assumptions. All dispatches modeled by National Grid were consistent with the NYISO CARIS 70x30 generation output levels assumed to be achieved for 100 hours or more. For example, a dispatch scenario model by National Grid was LBW greater than or equal to 30 percent of nameplate concurrent with UPV output greater than or equal to 27 percent. This dispatch occurred in the CARIS 70x30 scenario for 802 hours. Another example of the many scenarios studied by National Grid was LBW at 15 percent of nameplate and UPV at 52 percent of nameplate. The dispatch at or above this level occurred in the CARIS 70x30 scenario for 457 hours.

For the National Grid assessment, no assumptions were made for the generation mix in New York City or Long Island, including no specific assumptions for offshore wind, as the generation mix downstate does not have any impact on the result of testing within National Grid's service territory. However, for simplicity of developing the scenario cases, it was assumed that the flow across the UPNY – CONED interface would not exceed 7000MW.

Test 1: 2030 Regional Congestion Assessment - Modeled Existing and Proposed Generation

A 30MW wind generator is connected at the Fenner station.

As of 1/31/2021, the NYISO interconnection queue includes 73MW of wind and 340MW of solar proposing to connect to the area's local system. The projects are summarized in Table 2.

In the last 5 years an additional 80MW of generation proposing to connect into this area has withdrawn from the NYISO queue. While some of these projects may have withdrawn due to siting or financing issues, it is believed that some projects have withdrawn due to insufficient transmission capability.

Table 2: Generation in the NYISO Interconnection Queue

Queue	MW	Type	Interconnection Point
0449	73	W	Cortland – Oneida 115kV
0276	90	S	Cortland – Oneida 115kV
0545	20	S	Tilden - Cortland 115kV
0718	50	S	Cortland 115kV
0805	140	S	Cortland – Oneida 115kV
1000	20	S	Oneida - Rome 115kV
1052	20	S	Teall – Oneida 115kV

Table 3: 2019 CARIS Generation Additions Necessary to Meet the 70x30 Mandate

Bus	Type	MW	Interconnection Point
Fenner	W	63	Cortland – Oneida 115kV
Labrador	W	147	Cortland – Oneida 115kV
Whitman	W	118	Cortland – Oneida 115kV
Cortland	S	156	Cortland 115kV
Fenner	S	312	Cortland – Oneida 115kV
Tilden	S	45	Tilden 115kV
Tully Center	S	20	Tilden - Cortland 115kV
Yahnundasis	S	21	Oneida – Porter 115kV

As previously stated, generator representation (e.g. type, size and location for new renewables) used in this assessment was based on the 2019 CARIS 70x30 sensitivity case. These cases modeled 328MW of new and existing wind and 553MW of new and proposed solar in the region (see Table 3). Figure 2 shows geographically where new resources were added, with each yellow dot representing a new solar generator location and each blue dot representing a new wind generator location.

The base cases assume 328MW of wind and 312MW of solar connected between Cortland and Oneida, 156MW of solar at Cortland, 45MW of solar at Tilden and 20MW of solar between Cortland and Tilden.

<u>Test 1: 2030 Regional Congestion Assessment - Proposed Distributed Energy Resources</u>

In addition to the generation proposed in the NYISO queue, Distributed Energy Resources (DER) have also proposed to connect to National Grid's distribution system. The DER queue for the region contains over 160MW of proposed generation, the majority of which is solar with only 10MW of wind proposed at Delphi. The stations where the largest amount of solar DER is proposed is summarized in Table 4. While the DER was not explicitly modeled in the base cases, the proposed locations are similar to the proposed locations used to model the new resources (Table 3) needed to meet the 70x30 mandate. Because energy produced from DER may make its way from the distribution system to the transmission system through the existing transmission stations modeled in this study, DER is expected to have a similar impact as the generation directly connected to the transmission system and would benefit from the same projects identified as necessary to unbottle the region.

Table 4: Generation in the DER Interconnection Queue

Station	MW
Bridgeport	15
Chadwicks	24
Delphi	20
Oneida	29
Peterboro	27
Tully Center	16
Yahnundasis	30

There is also approximately 30MW of solar generation that is proposing to connect directly to 34.5kV circuits throughout the area. While this DER was not explicitly modeled in the base cases, the proposed locations are similar to the locations used to model the new resources (Table 3) needed to meet the 70x30 mandate.

Test 1: 2030 Regional Congestion Assessment - Study Results (System Bottlenecks)

Based on the study base cases, one area of congestion was identified (generation pocket). All sections of the Clarks Corners – Cortland, Cortland – Fenner and Fenner – Oneida circuits were found to be overloaded. The overloads occurred in peak, light and shoulder load levels and occurred in cases with only solar dispatched, only wind dispatched and cases with both solar and wind dispatched. The largest overloads are summarized in Table 5.

In the shoulder load cases with wind dispatched to 75% of nameplate 90MW of generation had to be curtailed to correct the overloads. In the heavy load cases with a wind/solar mix of either 30%/50% or 45%/35% of nameplate 90MW of generation had to be curtailed.

Table 5: Test 1 East of Syracuse Facility Overloads

Facility	Worst Case Overload (% LTE)
Cortland - Labrador	157
Whitman – Oneida	150
Delphi - Fenner	147
Labrador - Delphi	143
Tuller - Cortland	123
Clarks Corners – Tuller	123
Fenner – Fenner Wind	116
Fenner Wind - Whitman	101

Test 2: Capacity Headroom Test - Methodology and Results

To further determine the areas that could cause congestion, a Capacity Headroom test was performed. According to the DPS Headroom Test whitepaper (Case 20-E-0197), Capacity Headroom uses the lowest identified optimal transfer value observed in a heavy, light and shoulder load case. This test was done using the Optimal Transfer feature in TARA. Unlike Test 1 where the location of the generation was based on generation identified by the NYISO in the 70X30 CARIS case, Test 2 involves assigning possible locations for generation to interconnect, then having the program determine which one or more of the sites is an optimal location and how much generation could connect. The optimized dispatch keeps all transmission elements in the pocket within acceptable loading for any N-0 or N-1 condition. The analysis does not distinguish between the type of generation, only estimates the capability for simultaneous output from generation within the local network.

Under Test 2, base cases are initialized with no solar or wind generation in service. Including no solar or wind generation in upstream or downstream locations or on the bulk power system. All other load, hydro and nuclear generation and system topology assumptions made in the Test 1 base case were held constant. For Test 2, it was assumed that generation could only be added to the existing 115kV switching stations in the region. The impact of adding generation to the middle of a line, which is likely not an electrically optimal location, will not be captured. One of the limitations of this test is that the model can add a relatively large amount of generation into one site, ignoring or reducing the other options. To provide a more realistic indication of the headroom provided, a limit of 500MW was placed on all 115kV switch stations.

For this region, the selected 115kV buses were Cortland, Tilden, Fenner, Oneida and Yahnundasis.

The amount and location of generation for each study base case is summarized in Table 6. The program identified several bottlenecks. The test identified the same binding elements as found in the RNA/CARIS base cases; Clarks Corners – Cortland, Cortland – Fenner and Fenner – Oneida circuits. Also identified was the Tilden – Cortland circuit, the Geres Lock – Tilden circuit, the Oneida – Yahnundasis – Porter circuits, the Teall – Oneida circuits and the Oneida – Rome circuit. The most limiting case for this region was the heavy load with pumping case.

Table 6: Existing System Capacity Headroom (MW)

	Cortland	Fenner	Oneida	Yahnundasis	Tilden	Total
Heavy Load	120	120	190	200	90	720
Heavy Load w/Pumping	160	100	170	190	40	660
Light Load	10	140	290	170	210	820
Light Load w/Pumping	20	140	300	160	200	820
Shoulder Load	40	140	250	190	190	810
Shoulder Load w/Pumping	70	140	240	190	180	820

Regional Transmission Plan: Recommended System Upgrades

Based on both the 2030 Regional Congestion Assessment (Test 1) and the Capacity Headroom test (Test 2), increasing the rating of the Clarks Corners – Cortland, Cortland – Fenner and Fenner – Oneida circuits by addressing limiting terminal equipment would correct all overloads and eliminate all generation curtailments.

The headroom tests found an additional constraint that when corrected could provide regional benefits. The Tilden – Cortland circuit was one of the binding constraints on locating generation. This circuit is limited by station connections and clearance limits. Screening studies showed that the headroom can be increased by 20MW in the most limiting case and up to 70MW for other cases. The screening also suggested increased flexibility connecting resources at Cortland, Tilden or on the circuit between. Because of the small scope of the upgrades on the Tilden – Cortland circuit, this work is also recommended to be completed.

Table 7: Regional Project Plan Summary*

Project ID	Project Name	Phase	Project Description
S1	Clarks Corners – Oneida 115kV Terminal Upgrades	Phase 1	Address all limiting 115kV terminal equipment at various stations between Clarks Corners, Oneida and Tilden

*No Phase 2 projects are proposed for this area

Regional Transmission Plan: Project Benefits

In the 2030 Regional Congestion Assessment (Test1), correcting the terminal equipment and clearance limits of the Clarks Corners – Cortland, Cortland – Fenner, Fenner – Oneida, and Tilden – Cortland circuits eliminates the 90MW of generation constraint.

Table 8: Project Congestion Benefits

System Configuration	Constraint (MW)
Existing System	90
All Phase 1 Projects Complete	0
All Phase 2 Projects Complete	NA

In the Capacity Headroom test, the recommended projects resulted in a 110MW increase in the headroom available in the heavy load with pumping case. The headroom testing also showed much greater flexibility for generator location, especially showing a large increase in the capability at Cortland.

Table 9: System Capacity Headroom Post Project

	Cortland	Fenner	Oneida	Yahnundasis	Tilden	Total
Heavy Load	340	140	130	200	30	840
Heavy Load w/Pumping	320	170	90	190	0	770
Light Load	330	80	260	160	130	960
Light Load w/Pumping	330	90	280	170	120	990
Shoulder Load	330	110	220	190	80	930
Shoulder Load w/Pumping	330	120	200	190	60	900

Regional Transmission Plan: Project Alternatives

Given the small scope of the identified projects, no alternatives were identified.

Regional Transmission Plan: Project Details

The East of Syracuse pocket includes one Phase 1 project and no Phase 2 projects.

The Clarks Corners – Oneida 115kV terminal upgrade project is comprised of five individual project deliverables. The tables below provide specific Phase 1 project details. It is important to note the information provided is based on current estimates and will continue to improve in accuracy as the project engineering design and execution matures.

Table 10: Phase 1 Project Description

Project ID	Project Title	Scope	Additional ROW Required
S1	Fenner Wind Sta - LN3,8 Thermal Upgrades	This project, which is part of the Clarks Corners – Oneida 115kV terminal upgrade project will replace the existing 795 ACSR conductors with 1192 ACSR in the R30 and R80 breaker bays. The existing R30 and R80 CTs will be set to the 800:5A tap and the corresponding LN 3 and LN8 relaying will need to be reset and recommissioned.	No
S1	Tilden Sta - LN18 Thermal Upgrades	This project, which is part of the Clarks Corners – Oneida 115kV terminal upgrade project will replace the existing 500 Cu conductors with new 1192 ACSR in the R180 breaker bay. New insulators may be required to support the new conductors. The LN 18 system B electromechanical relays will be replaced with a new digital step distance relay and the R180 CT will be wired to the 1200:5A tap.	No
S1	Cortland Sta - LN1,3,18 Thermal Upgrades	This project, which is part of the Clarks Corners – Oneida 115kV terminal upgrade project will replace the existing 336.4 and 795 ACSR conductors in the R10, R30 and R180 breaker bays with new 1192 ACSR conductors. New 1192 ACSR conductors will also be installed between line disconnects SW13, SW33, and SW183 and their respective take-off structures. The existing 115kV structures will be re-used for support of the new conductors. New insulators may be required to support the new conductors. The existing LN 3, LN1, LN18 metering will be replaced with new Bitronics meters. All 115kV breakers and transformer bushing CT's wired to the North and South bus high-impedance bus-differentials will need their ratios moved to the full tap of 1200:5. The LN 3, LN1, and LN18 relays will also need to be reset and recommissioned.	No
S1	Delphi - LN3 115kV Thermal Upgrades	This project, which is part of the Clarks Corners – Oneida 115kV terminal upgrade project will replace the existing 336.4 ACSR conductors between SW33 and SW34 and their respective takeoff structures with new 1192 ACSR conductors.	No

S1	Tilden-Cortland LN18 Clearance Upgrades	This project, which is part of the Clarks Corners – Oneida 115kV terminal upgrade project will replace fourteen (14) wood H-Frame suspension structures with single circuit steel H-Frame structures and one (1) wood three pole suspension structure with a steel three pole suspension structure. The existing 795 ACSR conductor and 3/8" EHS 7 Shield Wire will be transferred.	No

Table 11: Phase 1 Estimated Construction Milestones

	Fenner Sta	Tilden Sta	Cortland Sta	Delphi Sta	Tilden-Cortland Clearance
Final Engineering Complete	9-May-24	9-Aug-23	24-Jul-24	23-Feb-23	11-May-23
Construction Start	8-Jul-24	6-Oct-23	20-Sep-24	24-Apr-23	5-Oct-23
Ready for Load	6-Aug-24	6-Nov-23	19-Nov-24	23-May-23	3-Nov-23

Table 12: Phase 1 Estimated Project Spend Profile

Fenner

S1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	-	-	10	99	-	-	-	-	-	-	109
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	-	-	12	-	-	-	-	-	-	12
Total	-	-	10	111	-	-	-	-	-	-	121

Tilden

S1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	-	1	62	1	-	-	-	-	-	-	63
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	-	-	-	-	-	-	-	-	-	-
Total	-	1	62	1	-	-	-	-	-	-	63

Cortland

S1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	-	-	81	1,242	-	-	-	-	-	-	1,323
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	-	-	40	-	-	-	-	-	-	40
Total	-	-	81	1,282	-	-	-	-	-	-	1,363

Delphi

S1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	-	11	52	-	-	-	-	-	-	-	63
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	-	9	-	-	-	-	-	-	-	9
Total	-	11	61	-	-	-	-	-	-	-	72

Tilden - Cortland

S1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	131	225	3,762	-	-	-	-	-	-	-	4,118
Opex	-	-	1,771	-	-	-	-	-	-	-	1,771
Removal	-	-	261	-	-	-	-	-	-	-	261
Total	131	225	5,794	-	-	-	-	-	-	-	6,150

Watertown/Oswego/Porter Region
Transmission and Renewable Generation Assessment

August 1, 2021

This review was undertaken to determine if portions of the local 115kV system in the region covering the system in the Watertown, Oswego and Porter area would prevent the delivery of existing and proposed renewable generation. The Company examined multiple different generation dispatches for three different base case load scenarios; light load, shoulder load and heavy load. Upon identifying that the existing local transmission system would create constraints on renewable generation, several solutions were considered.

The conclusion of this analysis is that a significant amount of 115kV circuit rebuilds are required to support the deliverability of renewable energy. The combination of these projects was found to address the constraints on renewable generation, reducing curtailment in a shoulder load case from 870MW to 0MW. Separately a headroom test was performed where the optimal location and size of generation was identified before and after the proposed reinforcements. This headroom test found that the projects increased headroom by about 1110MW, with much of that capacity added to areas with the highest developer interest.

This region contains Phase 1 and Phase 2 projects. Terminal equipment upgrades and correction of some clearance limits are considered Phase 1. All line rebuilds and some additional terminal upgrades are considered Phase 2.

Existing System Overview

The Watertown/Oswego/Porter Region is a large geographic network with three separate transmission paths connecting to Taylorville (see Figure 1 for a single line and Figure 2 for a geographic map). Today the system is primarily serving load and connecting several hundred MW's of hydro generation, delivering the energy to the southern pocket exits at Oswego, Clay and Porter.

The northern transmission path of the system starts with a single circuit from Willis to Malone, a single circuit from Malone to Colton, two circuits from Colton to Browns Falls and two circuits from Browns Falls to Taylorville. At Colton a loop connects Colton, Dennison, Alcoa, McIntyre, Corning, Battle Hill and back to Colton. Power can flow in and out of the system at Willis and Alcoa, with both providing connections back to the existing 230kV system. The Browns Falls to Taylorville circuits are also one of the paths out of the area.

The western transmission path of the system starts at Taylorville, with two circuits connected to Black River, one circuit connecting Black River and Lighthouse Hill, one circuit connecting Black River and Coffeen and one three terminal line connecting Black River, Coffeen and Lighthouse Hill. At Lighthouse Hill one circuit connects to Clay and two circuits connect to South Oswego.

The southern transmission path of the system starts at Taylorville, with two circuits connecting to Boonville. At Boonville two circuits connect to Porter and two circuits connect to Rome, with one circuit connecting Rome and Oneida. Two circuits connect Oneida and Porter.

An existing bulk power system runs loosely in parallel with this local system. The local system is only connected to the bulk system at Willis and Moses in the north and at Clay, Oswego and Porter in the south. Because of the high impedance associated with the long length of the local circuits, upgrades to the bulk system can have a minimal impact on the north to south flows on the local system. [redacted]

[redacted] NYPA and National Grid are planning to convert several major portions of the 230kV system to 345kV. Sensitivity testing was performed with this planned work, which found that the changes to the bulk system had almost no impact on the local system, especially after the planned addition of a Phase Angle Regulator (PAR) at Malone.

In all analysis, National Grid monitored facilities adjacent to this area that were owned by NYPA and Avangrid. All recommendations were developed considering if upgrades to the NYPA or Avangrid system could address issues on the National Grid system. The Company has collaborated with neighboring utilities and all recommended upgrades were shared with other Transmission Owners and their comments were considered before finalizing plans.

[redacted]

Figure2: Watertown/Oswego/Porter Transmission Map

While age is not always an indicator of condition, in the absence of condition assessments, the relative age of a circuit can provide some insight into how close the circuit may be to end of life refurbishment or replacement. Table 1 is a list of area circuits with the age of the oldest components.

Table 1: Transmission Circuit Age

Circuit	Year	Age	Mileage
Colton - Browns Falls #1	1912	109	30.5
Colton - Browns Falls #2	1912	109	30.6
Lighthouse Hill - Clay #7	1913	108	26.1
Taylorville - Boonville #5	1920	101	33.4
Taylorville - Boonville #6	1920	101	33.9
Ogdensburg - McIntyre #2	1921	100	2.5
Browns Falls - Taylorville #3	1922	99	26.8
Browns Falls - Taylorville #4	1922	99	26.8
Boonville - Porter #1	1923	98	26.8
Boonville - Porter #2	1923	98	26.8
Colton - Battle Hill #7	1923	98	32.0
McIntyre - Colton #8	1923	98	31.4
McIntyre - Corning #6	1923	98	11.2
North Ogdensburg - McIntyre #9	1923	98	0.9
Black River - Middle Road #8	1924	97	4.9
Middle Rd - Lighthouse Hill #6	1924	97	30.7
Coffeen - Black River - Lighthouse Hill #5	1924	97	45.2
Dennison - Colton #4	1924	97	28.5
Dennison - Colton #5	1924	97	28.5
Black River - Taylorville #2	1925	96	26.1
Black River - North Carthage #1	1925	96	11.9
North Carthage - Taylorville #8	1925	96	14.1
Boonville - Rome #3	1925	96	24.1
Boonville - Rome #4	1925	96	26.2
Indeck Oswego - Lighthouse Hill #2	1926	95	28.5
FitzPatrick - Lighthouse Hill #3	1928	93	25.6
Nine Mile Pt. #1 - FitzPatrick #4	1928	93	0.6
South Oswego - Indeck Oswego #6	1928	93	4.3
South Oswego - Nine Mile Pt.#1 #1	1928	93	10.3
Levitt - Rome #8	1930	91	20.4
Rome - Oneida #1	1930	91	12.5
Colton - Malone #3	1932	89	38.4
Corning - Battle Hill #4	1932	89	26.4
Battle Hill - Balmat #5	1940	81	6.0
Coffeen - Black River #3	1959	62	7.7
Alcoa - Dennison #12	1961	60	3.0
Alcoa - North Ogdensburg #13	1961	60	35.0
Thousand Islands - Coffeen #4	1962	59	19.6
North Gouverneur - Battle Hill #8	1971	50	4.9
Coffeen - West Adams #2	1982	39	14.1

Planned Reliability and Condition Driven Transmission Projects

All transmission projects identified as firm in the NYISO 2020 Gold Book were include in the study cases. Generally, projects are only listed in the Gold Book if they result in a modification to the system; such as a change in rating, change in impedance, or a change in system or station configuration. National Grid has other transmission projects in the medium to long term horizon. These projects are generally condition based projects. The following describes all major projects in the region, including some projects that are not expected to have an impact on the system. These projects were assessed as either having; a benefit to CLCPA as designed, a benefit to CLCPA if the project design was revised, or no benefit to CLCPA if revised. Those revised projects that have CLCPA benefits and lead to a significant increase in project cost are proposed as Phase 1 and Phase 2 project.

Northern NY Priority Transmission Project – NYPA and National Grid are planning to upgrade the bulk system to convert several major portions of the 230kV system in Northern NY to 345kV. Sensitivity testing was performed with this planned work, which found that the changes to the bulk system had almost no impact on the local system, especially when considered with the Malone PAR project discussed below. The higher dispatches of renewable generation on the bulk system between Plattsburgh and Willis, which this project will facilitate, can have a negative impact on the existing system as this additional flow through the area can result in higher power flow into the local 115kV system. The planned installation of a PAR at Malone prevents this injection.

Malone PAR – This project will add a Phase Angle Regulator to the Willis – Malone circuit. This project was not included in the initial NYISO study base cases as it was planned by the Company after the study base cases were developed. [redacted] This adjustment reduces the flows across the northern path of this region, allowing additional local generation to be delivered. However, this project does not need to be revised from the current plan and is not a Phase 1 or Phase 2 project.

Yahnundasis Station Refurbishment – At Yahnundasis, many of the existing station components are planned for replacement. These replacements are not expected to result in any changes to the station configuration and will not impact the thermal rating of any circuits. No changes to the study base cases were required. The study included a desktop assessment of a scenario where the configuration of the station was modified, but the expanded project scope did not result in any identified system capacity benefits.

Coffeen Station Refurbishment – At Coffeen, many of the existing station components are planned for replacement. These replacements are not expected to result in any major changes to the station configuration and will not impact the thermal rating of any circuits. The project will add a capacitor bank at the station and add a second bus tie breaker to prevent a breaker failure from causing an outage to the entire station. These changes were incorporated into the study cases. No other changes to the study base cases were required. The study included a desktop assessment of a scenario where the configuration of the station was modified, but the expanded project scope did not result in any identified system capacity benefits. The study found that some terminal equipment at Coffeen was limiting the delivery of renewal generation. If in the future correcting these limits will result in capturing readily identifiable benefits these upgrades may proceed in advance of the major station refurbishment. To achieve the full benefits of the proposed Phase 2 projects in this area, terminal equipment at this station must be replaced or it will be more limiting then the rebuilt circuits. Depending on timing, the terminal equipment may be replaced as a separate project or the scope incorporated into this refurbishment project.

Taylorville Station Refurbishment – At Taylorville, many of the existing station components are planned for replacement. These replacements are not expected to result in any changes to the station configuration and will not impact the thermal rating of any circuits. No changes to the study base cases were required. The study included a desktop assessment of a scenario where the configuration of the station was modified. The study found that some terminal equipment at Taylorville was limiting the delivery of renewal generation. If in the future correcting these limits will result in capturing readily identifiable benefits these upgrades may proceed in advance of the major station refurbishment. To achieve the full benefits of the proposed Phase 2 projects in this area, terminal equipment at this station must be replaced or it will be more limiting then the rebuilt circuits. Depending on timing, the terminal equipment may be replaced as a separate project or the scope incorporated into this refurbishment project.

Browns Falls Station Refurbishment – At Browns Falls, many of the existing station components are planned for replacement. These replacements are not expected to result in any changes to the station configuration and will not impact the thermal rating of any circuits. No changes to the study base cases were required. The study included a desktop assessment of a scenario where the configuration of the station was modified, but the expanded project scope did not result in any identified system capacity benefits.

South Oswego Station Refurbishment – At South Oswego, many of the existing station components are planned for replacement. These replacements are not expected to result in any changes to the station configuration and will not impact the thermal rating of any circuits. No changes to the study base cases were required. The study included a desktop assessment of a scenario where the configuration of the station was modified. Reconfiguring the station to a breaker and a half to eliminate bus faults and stuck breaker contingencies would address some of the outages that were found to be binding in the headroom testing. However, the additional headroom created by this change was not significant enough to justify expanding the project scope at this time. To achieve the full benefits of the proposed Phase 2 projects in this area, terminal equipment at this station must be replaced or it will be more limiting then the rebuilt circuits. Depending on timing, the terminal equipment may be replaced as a separate project or the scope incorporated into this refurbishment project.

Colton Station Refurbishment – At Colton, many of the existing station components are planned for replacement. These replacements are not expected to result in any changes to the station configuration and will not impact the thermal rating of any circuits. No changes to the study base cases were required. The study included a desktop assessment of a scenario where the configuration of the station was modified, but the expanded project scope did not result in any identified system capacity benefits.

Boonville Station Refurbishment – At Boonville, many of the existing station components are planned for replacement. These replacements are not expected to result in any changes to the station configuration and will not impact the thermal rating of any circuits. No changes to the study base cases were required. The study included a desktop assessment of a scenario where the configuration of the station was modified, but the expanded project scope did not result in any identified system capacity benefits. To achieve the full benefits of the proposed Phase 2 projects in this area, terminal equipment at this station must be replaced or it will be more limiting then the rebuilt circuits. Depending on timing, the terminal equipment may be replaced as a separate project or the scope incorporated into this refurbishment project.

Oneida Station Refurbishment – The National Grid 10-year plan includes funding for refurbishment work at Oneida. The project scope includes changing the station to a breaker and a half arrangement. The new arrangement and replacement of several thermally limiting components were reflected in the study. The rating increase associated with the replacement of thermally limiting components does provide CLCPA benefits. However, this project does not need to be revised from the current plan and is not a Phase 1 or Phase 2 project

Lighthouse Hill Station Refurbishment – At Lighthouse Hill, many of the existing station components are planned for replacement with the station planned to be reconfigured to a breaker and a half scheme. This new arrangement was incorporated into the study base cases after determining that eliminating some of the bus faults and breaker failure contingencies would relieve constraints on the delivery of renewable generation. However, this project does not need to be revised from the current plan and is not a Phase 1 or Phase 2 project.

Boonville – Porter Refurbishment – The National Grid 10-year plan includes funding for refurbishment work on the two Boonville – Porter 115kV circuits. At this time the expectation is that this project will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. The study considered a scenario of increasing the ratings of this circuit. As described later in this document, replacing this condition driven project with a full rebuild would result in capacity increases in the area when combined with other recommended projects. This project is recommended to be replaced with a Phase 2 project.

South Oswego – Lighthouse Hill Refurbishment – The National Grid 10-year plan includes funding for refurbishment work on the South Oswego – Lighthouse Hill 115kV circuits. At this time the expectation is that this project will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. The study considered a scenario of increasing the ratings of this circuit. As described later in this document, replacing this condition driven project with a full rebuild would result in capacity increases in the area when combined with other recommended projects. This project is recommended to be replaced with a Phase 2 project.

Colton – Browns Falls Refurbishment – The National Grid 10-year plan includes funding for refurbishment work on the Colton – Browns Falls 115kV circuits. At this time the expectation is that this project will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. These circuits have been known to be binding in real time system operation. The Malone PAR is expected to relive the loading on these circuits. The study considered a scenario of increasing the ratings of this circuit. Potential increases in headroom were identified once all other recommended upgrades in the area are complete. However, the additional headroom created by a full rebuild of these lines does not justify the added project scope at this time. A rebuild of these circuits would not change the recommendations made in this study. During the development of the project, an option to rebuild with lines will be considered further.

Indian River – Lyme Junction New Line – Indian River and Lyme stations are in the Western end of the Northern area of NY. They are both at the end of radial taps (Lyme tapped from Thousand Islands – Coffeen 4; Indian River tapped from the radial line Fort Drum – Black River 9). [redacted] This project uses a new line and new three breaker ring station to tie a significant portion of the radial feeds into a network configuration and add resiliency to the area. [redacted] This project was added after the creation of the NYISO study base cases. In the near term this project should provide regional capacity benefits and present new opportunities for generation interconnection locations. However, the proposed reinforcements recommended in this paper will still be needed to fully support the 2030 generator assumptions. This project does not need to be revised from the current plan and is not a Phase 1 or Phase 2 project.

Lighthouse Hill – Clay Refurbishment – The National Grid 10-year plan includes funding for refurbishment work on the Lighthouse Hill – Clay 115kV circuit, which is two circuits bussed together and operated as a single line. This circuit is one of the National Grid worst performing circuits. To address customer impacts the load serving stations supplied from this line will be moved to alternative circuits. While this will address customer impacts, it does not address the performance of the circuit. Refurbishment of the circuit to address the condition is expected to be required. At this time the expectation is that this refurbishment project will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. The study considered a scenario of increasing the ratings of this circuit. As described later in this document, replacing this condition driven project with a full rebuild would result in capacity increases in the area when combined with other recommended projects. This project is recommended to be replaced with a Phase 2 project.

Local Design Criteria

For purposes of this study, National Grid performed steady state testing in accordance with its Transmission Group Procedure 28 (TGP28), *National Grid Transmission Planning Criteria*. Simulations were performed to assess the system response with all elements in service (N-0) as well as for N-1 outage conditions. These N-1 tests included loss of a circuit, transformer, generator or shunt device as well as breakers opening without a fault, bus outages, faults with a breaker failure and double circuit tower outages. All testing was limited to steady state for N-0 and N-1 conditions.

The system response to these N-1 outages is generally considered acceptable when all local facilities are loaded below 100 percent of their Long-Term Emergency (LTE) rating. For pre-contingency conditions, loading is considered acceptable when all local facilities are loaded below 100 percent of their Normal (continuous) rating. The summer ratings are used in all cases. Acceptable post-contingency system voltages on the 115kV and 69kV system are between 90 percent of nominal and 105 percent of nominal and acceptable pre-contingency voltages are between 95 percent of nominal and 105 percent of nominal.

All solutions are required to meet the full set of local and regional Planning Criteria to ensure that the reliability of the planned system is not compromised. These criteria include dynamic, short circuit and expanded steady state requirements. Additional testing will be required for some proposed Phase 2 solutions to ensure that they are designed to conform with and adhere to all applicable North American Electric Reliability Corporation (“NERC”), Northeast Power Coordinating Council (“NPCC”), New York State Reliability Council (“NYSRC”) Reliability Rules, as well as applicable National Grid specifications, procedures, and guidelines.

Test 1: 2030 Regional Congestion Assessment - Methodology and Assumptions

The Regional Congestion Assessment (Test 1) is meant to; 1) identify existing local system congestion in a planning region based on the 2030 load and generation input assumptions and 2) eliminate all identified congestion within the region through system upgrade.

This study is based upon the database established and used by the NYISO for the 2020 Reliability Needs Assessment (RNA) 70x30 CLCPA Scenario using generation buildout assumptions from the Congestion Assessment and Resource Integration Study (CARIS) 70x30 scenario. The three cases selected as the starting point for the 70x30 scenario studies were: (i) Day Peak Load of 30,000 MW; (ii) Shoulder Load of 21,500 MW; and (iii) Light Load of 12,500 MW. The load is modeled based on the 2020 Gold Book forecast for 2030, with the load distributed within the regions based on the same 2020 RNA cases.

Starting from the 70x30 scenario peak load, shoulder load, and light load cases created by the NYISO, National Grid built sensitivity cases examining different renewable dispatch conditions. These dispatch scenarios were communicated with neighboring utilities for their consideration and use in their study work. While developing the case dispatches, monitoring and correcting overloads and voltage limitations on the 345kV and 230kV systems was considered out of scope for this assessment of the local system performance.

All study cases used by National Grid assumed no fossil generation was operating in NYISO Zones A (West) through F (Capital) and assumed that nuclear generators at Nine Mile 1, Nine Mile 2, and Fitzpatrick were all in service at maximum output and Ginna was assumed to be out of service. For the ties from New York to the external areas, no import or export was allowed from New York to PJM (across the free-flowing ties), New England or Ontario.

Hydro generation at Gilboa was set to maximum generation in the peak and shoulder cases and set to pumping in light load cases. In all cases, the Moses generation was set to maximum output. At the Niagara/Lewiston facility, Niagara was set to 2160MW, evenly distributed across the thirteen machines and Lewiston was set to either 240MW of generation or 360MW of pumping load depending on the case. Run of river hydro generation was set to typical seasonal values. The import of Hydro generation from Hydro Quebec was set to either 1110MW or 535MW. No hydro generation was imported to Dennison from the Cedars generation.

The above assumptions were modeled in each case, and Land Based Wind (LBW) and Utility Scale Photovoltaic (UPV) generation was then dispatched to various levels. In the National Grid testing, LBW, primarily located in Western, Central and Northern NY, was varied between 0 percent of nameplate up to 75 percent of nameplate and UPV, located primarily in Central, Northern and Eastern NY was dispatched between 0 percent of nameplate up to 70 percent of nameplate. Neither wind nor solar resources were modeled at 100 percent of nameplate.

The NYISO zonal data of hourly load, LBW output, and the UPV output from its CARIS 70x30 scenario was also reviewed for consistency with National Grid modeling assumptions. All dispatches modeled by National Grid were consistent with the NYISO CARIS 70x30 scenarios wherein an assumed generation output level was achieved for 100 hours or more. For example, a dispatch scenario model by National Grid was LBW greater than or equal to 30 percent of nameplate concurrent with UPV output greater than or equal to 27 percent. The dispatch occurred in the CARIS 70x30 scenario for 802 hours. Another example of the many scenarios studied by National Grid was LBW at 15 percent of nameplate and UPV at 52 percent of nameplate. The dispatch at or above this level occurring in the CARIS 70x30 scenario for 457 hours.

For the National Grid assessment, no assumptions were made for the generation mix in New York City or Long Island, including no specific assumptions for offshore wind, as the generation mix downstate does not have any impact on the result of testing within National Grid's service territory. However, for simplicity of developing the scenario cases, it was assumed that the flow across the UPNY – CONED interface would not exceed 7000MW.

Test 1: 2030 Regional Congestion Assessment - Modeled Existing and Proposed Generation

Approximately sixty hydro generators connected to the local network are located throughout this area. The aggregate of this local hydro total about 200MW. These generators were generally in service in all testing. The exception is several small units modeled as load modifiers by the NYISO, most less than 2MW and aggregating to about 30MW, which were modeled as net with the area load.

An 80MW wind generator is connected on the Black River to Lighthouse Hill circuit at Middle Rd Station.

As of 1/31/2021, the NYISO interconnection queue includes 508MW of wind, 1,339MW of solar projects and one 20MW storage project proposing to connect to the area's local system. The projects are summarized in Table 2. Referring to Figure 1, Projects upstream of the northern transmission path total to 461MW, projects in the area adjoining the western transmission path total to 1,106MW and projects downstream of the southern transmission path total to 300MW.

In the last 5 years an additional 974MW of generation, roughly split between solar and wind projects, proposing to connect into this area has withdrawn from the NYISO queue. While some of these projects may have withdrawn due to siting or financing issues, it is also possible that some projects have withdrawn due to insufficient transmission capability. This activity from developers also indicate their desire to site projects in this region.

Table 2: Generation in the NYISO Interconnection Queue

Queue	MW	Type	Interconnection Point
0468	110	W	Hammermill – Wine Creek 115kV
0526	100	W	Malone – Colton 115kV
0531	106	W	Taylorville – Boonville 115kV
0560	100	W	Black River– Lighthouse Hill 115kV
0589	15	S	Boonville 46kV Substation
0624	150	S	Malone 115kV Substation
0670	20	S	Clinton 46kV Substation
0774	119	S	Thousand Island – Lyme 115kV
0843	20	S	Coffeen – West Adams 115kV
0848	20	S	McIntyre – Colton 115kV
0864	120	S	Coffeen – East Watertown 115kV
0881	100	S	Bremen – Lowville 115kV
0882	100	S	Lyme 115kV Substation
0901	20	S	Lighthouse Hill – Black River 115kV
0953	165	S	Coffeen St – Taylorville 115kV
1000	20	S	Oneida – Rome 115kV
1028	20	ES	Raquette Lake 46 kV Substation
1039	20	S	Battle Hill – Balmat 115kV
1061	20	S	Ogdensburg – Bradly Rd 115 kV
1062	20	S	West Adams – Coffeen115 kV
1063	20	S	Thousand Island– Coffeen 115 kV
1069	24	S	Ogdensburg – McIntyre 115 kV
1077	110	S	Middle Rd 115kV Substation
1090	20	S	Clinton 46kV Substation
1103	110	S	Thousand Island– Coffeen 115 kV
1108	107	S	Malone – Colton 115kV
1109	92	W	E. Watertown – Lighthouse Hill 115kV
1118	19	S	Taylorville – Boonville 115kV

Table 3: 2019 CARIS Generation Additions Necessary to Meet the 70x30 Mandate

Bus	Type	MW	Interconnection Point
Black River	W	751	Black River 115kV Substation
Indeck Oswego	W	180	Hammermill – Wine Creek 115kV
Lowville	W	144	Taylorville – Boonville 115kV
Nicholville	W	103	Malone – Colton 115kV
Boonville	S	16	Boonville 115kV Substation
Bremen	S	126	Taylorville – Boonville 115kV
Coffeen	S	126	Coffeen 115kV Substation
Lyme	S	229	Lyme 115kV Substation
West Adams	S	21	Coffeen – West Adams 115kV

As previously stated, generator representation (e.g. type, size and location for new renewables) used in this assessment was based on the 2019 CARIS 70x30 sensitivity case. In addition to the existing hydro generation, the study cases modeled 80MW of existing wind and 1,696MW of new and proposed solar and wind in the region (see Table 3). All generation was added to the 115kV system. Figure 2 shows geographically where new resources were added, with each yellow dot representing a new solar generator location and each blue dot representing a new wind generator location.

The base cases assume 144MW wind and 142MW of solar in the area downstream of the southern transmission path of the system, 103MW of wind in the area upstream of the north transmission path and 931MW of wind and 375MW of solar in the area adjoining the west transmission path.

Several of the projects added to the cases were added to existing tap buses. When outages or contingencies occur, these tap buses are usually disconnected. No changes were made to the contingency definitions to reflect the addition of this generation. It was assumed that the contingencies would result in the generation tripping, same as the load. New three breaker ring generation interconnections could change this contingency but were not modeled. The change in contingency could increase the amount of congestion identified by this testing. This is especially true for the generators at Lowville (144MW), Nicholville (103MW) and Bremen (126MW).

Test 1: 2030 Regional Congestion Assessment - Proposed Distributed Energy Resources

In addition to the generation proposed in the NYISO queue, Distributed Energy Resources (DER) have also proposed to connect to National Grid's distribution system. The DER queue for the region contains over 683MW of proposed generation, 632MW of which is solar, 25MW is wind and 26MW is hydro. The stations where the largest amount of DER is proposed is summarized in Table 4. While the DER was not explicitly modeled in the base cases, the proposed locations are similar to the proposed locations used to model the new resources (Table 3) needed to meet the 70x30 mandate. Because energy produced from DER may make its way from the distribution system to the transmission system through the existing transmission stations modeled in this study, DER is expected to have a similar impact as the generation directly connected to the transmission system and would benefit from the same projects identified as necessary to unbottle the region.

Table 4: Generation in the DER Interconnection Queue

Station	MW
AKWESASNE 825	13
BOONVILLE	9
BRADY 957	28
BRASHER 851	7
BREMEN 815	8
COFFEEN 760	35
COLLINSVILLE 716	5
COLOSSE 321	5
DEKALB 984	8
E. PULASKI 324	17
E. WATERTOWN 817	44
INDIAN RIVER 323	67
LAWRENCE AVE 976	27
LEHIGH 669	12
LITTLE RIVER 955	46
LOWVILLE 773	25
LYME 733	29
MALONE 895	24
MCADOO 914	10
MCINTYRE	20
N. CARTHAGE 816	44
N. GOVERNEUR 983	21
NEW HAVEN 256	8
OGDENSBURG 938	19
PALOMA 254	7
PORT LEYDEN 755	5
ROME 762	23
SANDY CREEK 66	6
STITTVILLE 670	10
THOUSAND ISLANDS 814	30
TURIN RD 653	14
W. ADAMS 875	26
WETZEL ROAD	10
WHITAKER 296	10
WINE CREEK 283	11

Test 1: 2030 Regional Congestion Assessment - Study Results (System Bottlenecks)

Based on the study base cases, several conditions were identified that would constrain the output of generation (generation pocket).

Before any outages occur, several areas of the system were found to be loaded beyond the circuits' summer normal rating. These loadings occur for shoulder load periods with wind dispatched to 75% of nameplate, except the Lyme Junction – Coffeen overload which occurred for heavy load with solar dispatched to 70% of nameplate.

Table 5: Summer Normal Ratings Overloads with All Circuits in Service

Circuits	% Normal
Lighthouse Hill – Clay	218
Taylorville – Boonville	175
Black River – Lighthouse Hill	166
South Oswego – Lighthouse Hill	125
Lyme Junction– Coffeen	116
Boonville – Porter	100
Black River – Taylorville	100

[redacted] Once the power reaches Boonville, most of the flow heads towards Porter, but some heads to Rome, Oneida and then to Porter. The highest loading on the southern transmission path of the system was Taylorville – Boonville at 256% of LTE and Boonville – Porter at 165% of LTE, both in a shoulder load case with wind generation dispatched to 75%. The Boonville – Rome circuit was also at 100% of LTE in that same case.

[redacted]

[redacted] Once the power reaches Lighthouse Hill, flow heads towards Clay and South Oswego. The highest loadings on the western transmission path of the system was the Lighthouse Hill – Clay circuit at 369% of LTE, the Black River – Lighthouse Hill circuits as high as 260% of LTE and the Lighthouse Hill – South Oswego circuits at 184% of LTE. These overloads occurred in the shoulder load case with wind dispatched to 75% of nameplate.

[redacted]

In both scenarios shown in Figures 3 and 4, heavy loading occurs on the circuits between [redacted] just in different directions for each outage. The highest loading on these circuits was 250% of LTE.

The study also identified that overloads could occur on the circuits connected to Coffeen, which study case assumed would connect a large amount of solar generation. Two radial lines collect generation and deliver it to Coffeen. At Coffeen, only two circuits are available to deliver the generation to Black River and then on to the rest of the system. The highest loading on these circuits was 167% of LTE, occurring in a heavy load case with solar dispatched to 70% of nameplate.

While all the previous issues described thermal overloads, a voltage issue was also found in this area. As shown in Figure 5, an outage of the Lighthouse Hill – Clay circuit, designated by the red X, leaves the existing area voltage primarily supported by South Oswego and Porter, as Oneida does not provide any significant support. The long circuit lengths and resulting high impedances combined with high generation output causing circuit flows well above the circuit ratings results in large voltage drops between theses main switching stations. Even after assuming that renewable generators would be providing reactive support, the system was found to reach voltage collapse at renewable dispatches of 500 - 900MW (depending on the generation interconnection locations)

[redacted]

Table 6: Test 1 Watertown/Oswego/Porter Facility Overloads

Facility	Worst Case Overload (% LTE)
Lighthouse Hill - Clay	369
Black River - East Watertown	260
Taylorville - Boonville 6	256
Middle Rd - Lighthouse Hill	253
North Carthage - Taylorville	250
Black River - Taylorville	250
Black River - North Carthage	248
East Watertown - Lighthouse Hill	229
Taylorville - Boonville 5	221
Black River - Middle Rd	203
South Oswego - Indeck	184
Coffeen - East Watertown	167
Boonville - Porter 1	165
Black River - Coffeen	162
Fitzpatrick - Lighthouse Hill	140
Boonville - Porter 2	135
Indeck - Lighthouse Hill	131
Nine Mile - Fitzpatrick	123
Colton - Malone	121
South Oswego - Nine Mile	119
Coffeen - Lyme	116
Boonville - Rome 3	100
Boonville - Rome 4	98

To determine how much generation would have to be curtailed a test was performed with a shoulder load case with wind generation dispatched to 75% of nameplate and solar generation not in service. To correct all area overloads, 870MW of generation had to be curtailed. The 870MW reduction is based on optimal dispatch adjustments, first curtailing the most impactful generation, then moving on to additional facilities.

To understand how various portions of the system contribute to the constraints, several sensitivity tests were performed using the same shoulder load case starting with wind dispatched to 75% of nameplate. The sensitivities evaluate the impact of relaxing the area constraints. Each row in Table 7 relaxes an additional set of circuits and incorporates the upgrades in the previous row. The next upgrade was selected based on the highest loaded elements in the previous test.

This testing showed that the Malone PAR provides 180MW of additional capability by blocking flow from entering the 115kV network [redacted]. Additional capability is very difficult to achieve due to several circuits and contingencies simultaneously binding. Rebuilding Lighthouse Hill – Clay, Black River – Taylorville, Black River – Lighthouse Hill and Taylorville – Boonville reduces the constraint from 690MW to 370MW. Once those projects are completed, 90MW of additional capability can be achieved by rebuilding South Oswego – Lighthouse Hill and Boonville – Porter. Doing these upgrades in any other order would not address the constraint any differently. Once the constraint reaches 0MW, capability for additional generation, not modeled in the generation assumptions may be available.

Table 7: Test 1 Curtailment Analysis

System Configuration	Constraint (MW)
Existing System	870
[redacted]	[redacted]
Rebuild Lighthouse Hill – Clay, Black River – Taylorville, Black River – Lighthouse Hill and Taylorville – Boonville	370
Rebuild South Oswego – Lighthouse Hill	310
Rebuild Boonville – Porter	280
Rebuild Black River – Coffeen	150
Rebuild Coffeen – East Watertown	0

Test 1: 2030 Regional Congestion Assessment - DER Sensitivity

This area has more DER proposed than any other National Grid pocket. To see if the DER alone would cause any issues, a sensitivity test was performed where the DER assumed in Table 4 is placed in service at 100% of nameplate with no transmission connected solar or wind generation in service.

This test found that the Lighthouse Hill – Clay circuit is at 163% of LTE, Black River – Lighthouse Hill – Coffeen is at 119% of LTE, Black River – Lighthouse Hill is 106% of LTE, Taylorville – Boonville is at 105% of LTE and North Carthage – Taylorville is at 100% of LTE. The worst-case overloads occurred in the light load case. The Lighthouse Hill – Clay, Black River – Lighthouse Hill and Black River – Lighthouse Hill – Coffeen overloads also occurred in the heavy and shoulder load cases.

Because it is not expected to be possible to adjust DER during real time operation, these overloads may constitute a reliability violation that would have to be corrected to keep the system in compliance with mandatory reliability standards. While the system upgrades discussed in the later sections will fully address all overloads created by the DER, smaller targeted projects may also provide enough correction to address the system needs when only DER is assumed to be in service.

Test 2: Capacity Headroom Test – Methodology and Results

To further determine the areas that could cause congestion, a Capacity Headroom test was performed. According to the DPS Headroom Test whitepaper (Case 20-E-0197), Capacity Headroom uses the lowest identified optimal transfer value observed in a heavy, light and shoulder load case. This test was done using the Optimal Transfer feature in TARA. Unlike Test 1 where the location of the generation was based on generation identified by the NYISO in the 70X30 CARIS case, Test 2 involves assigning possible locations for generation to interconnect, then having the program determine which one or more of the sites is an optimal location and how much generation could connect. The optimized dispatch keeps all transmission elements in the pocket within acceptable loading for any N-0 or N-1 condition. The analysis does not distinguish between the type of generation, only estimates the capability for simultaneous output from generation within the local network.

Under Test 2, base cases are initialized with no solar or wind generation in service. Including no solar or wind generation in upstream or downstream locations or on the bulk power system. All other load, hydro and nuclear generation and system topology assumptions made in the Test 1 base case were held constant. For Test 2, it was assumed that generation could only be added to the existing 115kV switching stations in the region. The impact of adding generation to the middle of a line, which is likely not an optimal location, will not be captured. One of the limitations of this test is that the model can add a relatively large amount of generation into one site, ignoring or reducing the other options. To provide a more realistic indication of the headroom provided, a limit of 500MW was placed on all 115kV switch stations.

For this region, the selected 115kV buses were Malone, Colton, Dennison, McIntyre, Browns Falls, Taylorville, Boonville, Rome, Black River, Coffeen, Lighthouse Hill and Indeck Oswego.

The amount and location of generation for each study base case is summarized in Table 8. The program identified several bottlenecks. The test identified that Malone – Willis, Alcoa Bus Tie, McIntyre – Colton, Dennison – Colton, Black River – Taylorville, Lighthouse Hill – Clay, Boonville – Porter and Boonville – Rome circuits were all binding. These binding elements are consistent with the results of Test 1. The most limiting case for this region was the light load case, however both light load cases and both shoulder load cases had similar results.

The headroom test showed that Black River and Coffeen, the areas of highest developer interest, had almost 0MW of capability. To highlight this a sensitivity test was performed where generation could only be added to existing system at Coffeen and Black River. It was found that in the light load cases that the total optimized headroom capability at these two stations, when all other area solar and wind generation was out of service, was only 190MW.

Table 8: Existing System Capacity Headroom (MW)

	Malone	Colton	Dennison	McIntyre	Taylorville	Boonville	Rome	Coffeen	Black River	LHH	Indeck Oswego	Total
Heavy Load	80	0	200	60	120	80	180	0	30	0	40	790
Heavy Load w/Pumping	70	0	200	70	120	110	170	0	30	0	50	820
Light Load	80	0	190	60	120	0	170	0	0	0	100	720
Light Load w/Pumping	70	0	190	60	90	0	200	0	0	0	110	720
Shoulder Load	60	0	190	80	160	0	190	0	0	0	50	730
Shoulder Load w/Pumping	50	0	190	80	140	0	220	0	0	0	60	740

Regional Transmission Plan: Recommended System Upgrades

Prior to the initiation of this study, previous assessments of this region identified that installing a PAR at Malone on the Malone – Willis line would provide operators more flexibility managing the power flows [redacted] This conclusion is supported by this study. During periods of high generation output on the bulk system, [redacted] and uses local transmission capability that could otherwise be used by local generation. Test 1 showed benefits associated with the PAR will reduce curtailments by 180MW. This project should proceed as planned to provide additional local system capability and flexibility needed today.

During the Test 1 base case and sensitivity testing, it was observed that several circuits are limited by either terminal equipment or clearance spans. Addressing these limitations on local circuits can maximize the rating and provide additional capacity for renewables. The Company continues to assess the near term need for these upgrades and may wait to perform them in order to improve efficiency. Eventually, some of these upgrades may be completed as part of other planned station refurbishment projects or as part of line upgrades recommended in this Regional Plan.

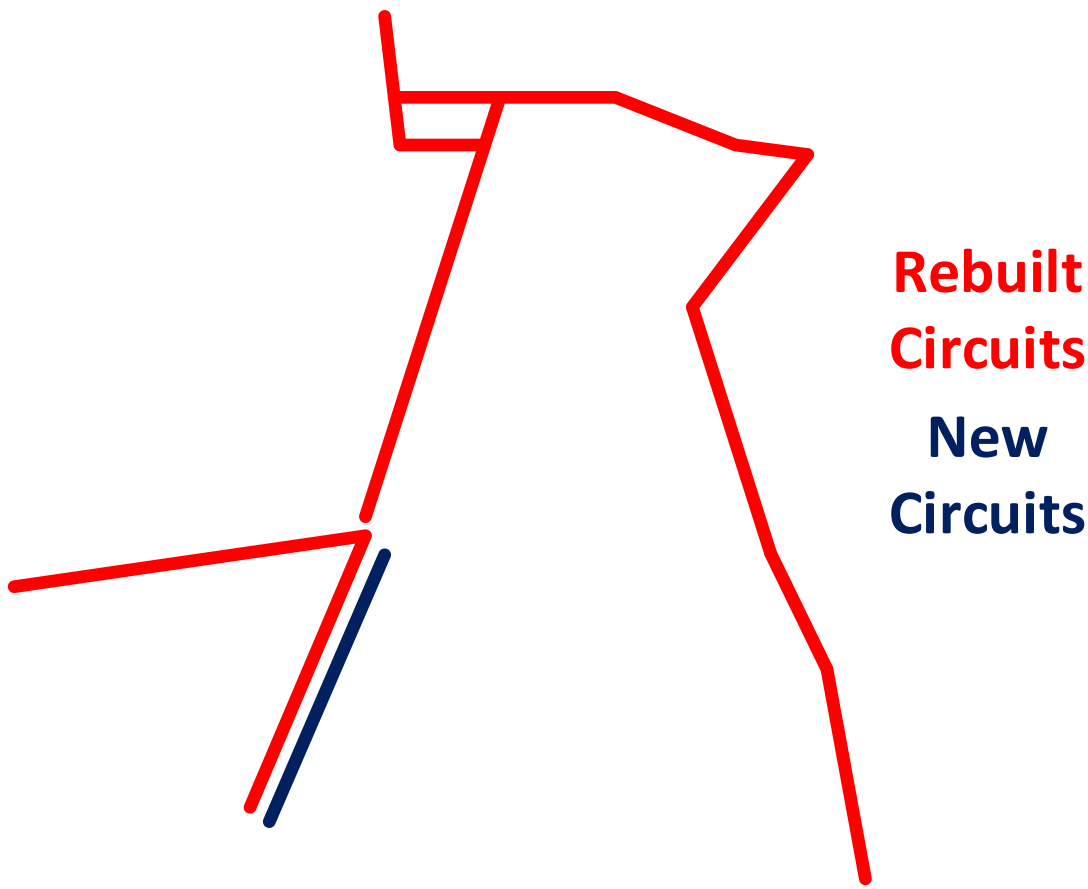
With the Phase 1 upgrades complete, significant curtailments and low levels of capacity headroom remain. To provide the needed capability the Phase 2 projects are recommended. These projects (Phase 2) are also highlighted in Figure 6.

To provide the needed local capability and to address a critical voltage issue, several of the circuits are recommended to be constructed on single circuit structures, eliminating the existing double circuit structures.

Table 9: Regional Project Plan Summary

Project ID	Project Name	Phase	Project Description
WO1	Lighthouse Hill – Clay 115kV Clearance Limits	Phase 1	Address all clearance limits on the Lighthouse-Clay 115kV line
WO2	Coffeen – Black River 115kV Terminal Upgrades	Phase 1	Address all limiting 115kV terminal equipment on lines connected to Coffeen
WO3	Black River – Lighthouse Hill 115kV Line Upgrade	Phase 2	115kV upgrade: Black River to Lighthouse Hill
WO4	Taylorville – Boonville 115kV Line Upgrade	Phase 2	115kV upgrade: Taylorville to Boonville
WO5	Coffeen – Black River 115kV Line Upgrade	Phase 2	115kV upgrade: Coffeen to Black River
WO6	Lighthouse Hill – Clay 115kV Line Upgrade	Phase 2	115kV upgrade: Lighthouse Hill to Clay
WO7	Coffeen – Lyme 115kV Line Upgrade	Phase 2	115kV Upgrade: Coffeen to Lyme
WO8	Black River – Taylorville 115kV Line Upgrade	Phase 2	115kV upgrade: Black River to Taylorville
WO9	South Oswego – Lighthouse Hill 115kV Line Upgrade	Phase 2	115kV upgrade: South Oswego to Lighthouse Hill
WO10	Boonville – Porter 115kV Line Upgrade	Phase 2	115kV upgrade: Boonville to Porter

Figure 6: Scope of Work



Regional Transmission Plan: Project Benefits

In the 2030 Regional Congestion Assessment (Test1) and Capacity Headroom (Test2) the benefits of the solution set were estimated.

In all testing the Malone PAR was held fixed at 0MW. If the PAR was operated to push power from Malone to Willis, additional headroom and reduced curtailment is expected.

The Capacity Headroom test shows that additional generation can be optimally added once associated system upgrades are completed.

Table 10: Malone PAR and Phase 1 and Phase 2 Rebuild Benefits

Shoulder Load Wind Dispatched to 75%	Area Constraint MWs
Existing System	870
Malone PAR	690
Phase 1 Projects Complete	540
Phase 2 Projects Complete	0

Table 11: Test 2 – System Capacity Headroom Summary

	Existing System	PAR and Phase 1 Projects	Phase 2 Projects
Heavy Load	790	900	1890
Heavy Load w/Pumping	820	900	1850
Light Load	720	800	1980
Light Load w/Pumping	730	820	1970
Shoulder Load	740	830	1880
Shoulder Load w/Pumping	740	830	1910

.

Table 12: Phase 1 System Capacity Headroom Terminal Equipment and PAR Completed

	Colton	Dennison	McIntyre	Browns Falls	Taylorville	Boonville	Rome	Black River	Coffeen	Lighthouse Hill	Indeck Oswego	Total
Heavy Load	0	200	80	0	30	50	190	170	70	90	20	900
Heavy Load w/Pumping	0	200	80	0	30	80	180	150	40	120	20	900
Light Load	0	190	90	0	0	0	180	0	100	220	20	800
Light Load w/Pumping	0	190	90	0	0	0	210	0	60	250	20	820
Shoulder Load	0	190	90	0	0	0	200	50	150	130	20	830
Shoulder Load w/Pumping	0	190	90	0	0	0	220	10	150	150	20	830

Table 13: Phase 1 and Phase 2 System Capacity Headroom

	Colton	Dennison	McIntyre	Browns Falls	Taylorville	Boonville	Rome	Black River	Coffeen	Lighthouse Hill	Indeck Oswego	Total
Heavy Load	0	0	80	0	0	160	100	500	500	500	60	1900
Heavy Load w/Pumping	0	0	80	0	0	160	110	500	500	500	10	1860
Light Load	0	30	0	0	50	280	40	400	480	500	210	1990
Light Load w/Pumping	0	40	0	0	50	280	40	380	480	500	210	1980
Shoulder Load	0	40	0	0	50	200	60	480	480	500	190	2000
Shoulder Load w/Pumping	0	40	0	0	50	200	60	460	480	500	170	1960

Regional Transmission Plan: Project Alternatives

National Grid developed an alternative that would build a 345kV backbone across this region. While the set of projects would have a similar cost and provide similar benefits compared to the recommended set of projects, National Grid determined that the 345kV project has higher execution risk and provides fewer supporting benefits. Some of the identified concerns were:

- The number and location of the existing 115kV lines are critical to providing a reliable supply to the load in the area. None of the existing 115kV circuits could be removed to make way for a 345kV circuit. National Grid also has no vacant right of way, with the 115kV lines occupying all available corridor width. Thus, to add a new 345kV circuit or circuits it will be necessary to procure new right of way. Assuming the 345kV backbone would run in parallel with the 115kV system would require approximately 75 miles of new right of way. The availability and cost of the required right of way is highly uncertain which would add complexity, cost and time to this option.
- In the testing completed in this study, overloads when all lines are in service were found. If a 345kV backbone is added, an outage of this backbone would result in the same existing system N-0 overloads, only now occurring for an N-1 outage of the 345kV circuit. To address these overloads without rebuilding the 115kV circuits it would be necessary to build two 345kV circuits.
- Nearly all the circuits that are proposed to be rebuilt were put into service between 1913 and 1928, making them 93 to 108 years old. The National Grid 10-year plan already includes refurbishment work on several of these circuits. By rebuilding these circuits, all future age and condition driven needs will be addressed. An option that builds a 345kV backbone without rebuilding the 115kV system will not provide this condition improvement.
- Providing a 345kV line into this area, without connecting the 345kV circuit to the existing 115kV system would force generation to connect at 345kV, or force generators to build long lines from their facility to a 345/115kV collector station. Either case would result in high interconnection cost and complexity, especially for small to medium sized generators. The capability on this single 345kV line could either be limited to 1300MW by the NYCA loss of source limit, or result in a new largest loss of source, which would increase statewide reserve requirements.
- A 345kV backbone connecting to the existing 115kV system would create interconnection points or hubs at the 345/115kV stations with high amounts of headroom. However, the existing 115kV circuits that travel between these hubs would still have the existing wire with the existing small circuit ratings. Any generators that connect in locations remote from these hubs, including DER, would encounter constraints and curtailments due to the low rating of the existing circuits, preventing full utilization of the 345kV backbone.
- Expansion of the existing 115kV switching stations to add 345/115kV connections and a 345kV switching station will require additional property, which would have to be in the vicinity of the existing station. The availability of property near the existing station is an unknown that could add complexity, cost and time to this option.
- National Grid believes that once the 115kV upgrades are complete, if additional capability was required for this area, the addition of a 345kV backbone would likely be a viable solution that could add another 1000MW of headroom.

Dynamic Line Ratings, which can increase the rating of existing circuits without any conductor replacements would not provide a sufficient increase to address the identified overloads.

Alternatives that used power flow controllers were rejected as for these types of devices (Series Reactors or Capacitors, Phase Angle Regulators, Static Synchronous Series Compensators) to be effective, an alternative underutilized parallel path must be available to shift power onto. No underutilized parallel paths exist in this area, especially for the limiting contingency conditions that were identified.

The use of advanced conductors, which have higher allowed operation temperature due to the material used in the conductor core, were not recommended in this area due to the expectation that the maximum high temperature conductor size that could be supported on the existing structures would not sufficiently address the identified overloads. The need to address the age of the structures also makes the use of the more expensive high temperature conductor uneconomic. For when all structures are planned for replacement due to age or condition, the incremental cost of selecting a sufficiently large ACSR conductor is small compared to the cost of using the advanced conductor.

As described in this document, a full rebuild of the Lighthouse Hill – Clay circuit, including separating it into two single circuits, would result in capacity increases in the area when combined with other recommended projects. An alternative 345kV transmission solution was considered that included a new station built in Parish, NY that would connect to the Volney – Marcy 345kV circuit and possibly the Fitzpatrick – Edic 345kV circuit and include two 345/115kV transformers that would connect to a 9-mile-long portion of a rebuilt Lighthouse Hill – Clay circuits. The remainder of the Lighthouse Hill – Clay circuit could then be removed. National Grid continues to evaluate the rebuild of the entire Lighthouse Hill – Clay circuit compared to this 345kV alternative that only requires 9 miles of the circuit to be rebuilt.

Regional Transmission Plan: Project Details

The Watertown/Oswego/Porter pocket includes two Phase 1 projects and eight Phase 2 projects. The in-service date and detailed capital and operating cost estimates for all of the National Grid Phase 2 projects will be provided in future filings.

The tables below provide specific Phase 1 project details. It is important to note the information provided is based on current estimates and will continue to improve in accuracy as the project engineering design and execution matures.

Table 14: Phase 1 Project Description

Project ID	Project Title	Scope	Additional ROW Required
WO2	Coffeen Sta-LN1,3,18 THERM UPG	This project will replace the existing conductors in the R10, R30 and R180 breaker bays with 2 bundled 1192 ACSR conductors. The bushing CT ratios in the R30 and R50 bays will also need to be adjusted. R30 CTs will be adjusted to 400:4, and R50 CTs will be adjusted to 800:5.	No
WO1	LHH - Clay LN7 Clearance	This project will Install fifteen (15) midspan double circuit wood pole davit arm suspension structures with direct embed foundations. The existing 4/0 cu conductor and 3/8" SMGS shield wire will be reused. A significant amount of matting will likely be required due to many wetlands along the Line.	No

Table 15: Phase 1 Estimated Construction Milestones

	Coffeen Sta	LHH - Clay LN7 Clearance
Final Engineering Complete	21-Sep-23	19-Dec-22
Construction Start	20-Oct-23	15-Feb-23
Ready for Load	20-Nov-23	14-Apr-23

Table 16: Phase 1 Estimated Project Spend Profile

Coffeen Sta

WO2	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	-	2	230	1	-	-	-	-	-	-	233
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	-	-	-	-	-	-	-	-	-	-
Total	-	2	230	1	-	-	-	-	-	-	233

LHH - Clay LN7 Clearance

WO1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	150	1,808	1,591	-	-	-	-	-	-	-	3,549
Opex	-	1,366	952	-	-	-	-	-	-	-	2,318
Removal	-	-	-	-	-	-	-	-	-	-	-
Total	150	3,174	2,544	-	-	-	-	-	-	-	**5,868**

Porter – Rotterdam Region
Transmission and Renewable Generation Assessment

August 1, 2021

This review was undertaken to determine if portions of the local 69kV and 115kV system in the region between Porter and Rotterdam would prevent the delivery of existing and proposed renewable generation. The Company examined multiple different generation dispatches for three different base case load scenarios; light load, shoulder load and heavy load. Upon identifying that the existing local transmission system would create constraints on renewable generation, several solutions were considered.

The conclusion of this analysis is that a new 345/115kV station should be built at Marshville and that area projects would also need to include rebuilding the 115kV lines between Inghams and Rotterdam, 115/69kV transformer replacements at Rotterdam, Marshville and Meco and the addition of a second 115/69kV transformer at Rotterdam and Meco. The combination of these projects was found to address many of the constraints on renewable generation, reducing curtailment from 600MW to 0MW. Separately a headroom test was performed where the optimal location and size of generation was identified before and after the proposed reinforcements. This headroom test found that the projects increased headroom by about 790MW.

This region contains both Phase 1 and Phase 2 projects. All station upgrades and line rebuild projects are considered Phase 1. The only project proposed herein that is considered Phase 2 is the new 345/115kV Marshville substation.

<u>Existing System Overview</u>

The Porter – Rotterdam Region is a two-circuit path from Porter to Rotterdam, see Figure 1. The system is split at Inghams, where a Phase Angle Regulator (PAR) is installed to control the system throughflow. At Inghams a circuit also connects to the Avangrid system extending down to Richfield Springs and eventually Fraser. One of the two circuits traveling from Inghams to Rotterdam is a three-terminal line with one branch of the circuit serving the Marshville area.

As can be seen in Figure 2 and Figure 3, a 69kV subtransmission network extends to the four corners of the system between Inghams and Rotterdam. It is connected to the 115kV system through 115kV/69kV transformers in four substations: Vail Mills (northeast corner), Meco (northwest corner), Rotterdam (southeast corner), and Marshville (southwest corner). The Vail Mills and Meco substations are directly connected by 69kV lines that constitute the northern loop of the network. The Rotterdam and Marshville substations are directly connected by 69kV lines that constitute the southern loop of the network. The northern loop is connected to the southern loop on the western side of the area by a series of 69kV lines. The northwestern corner of the northern loop is also connected to the southeastern corner of the southern loop by a series of 69kV lines.

[redacted]

In all analysis National Grid monitored facilities adjacent to this area that were owned by Avangrid. All recommendations were developed considering if upgrades to the Avangrid system could address issues on the National Grid system. The Company has collaborated with neighboring utilities and all recommended upgrades were shared with other transmission owners and their comments were considered before finalizing plans.

[redacted]

[redacted]

Figure 3: Porter – Rotterdam Transmission Map, including 69kV (orange), 115kv (blue), 230 kV (green), and 345 kV (red)

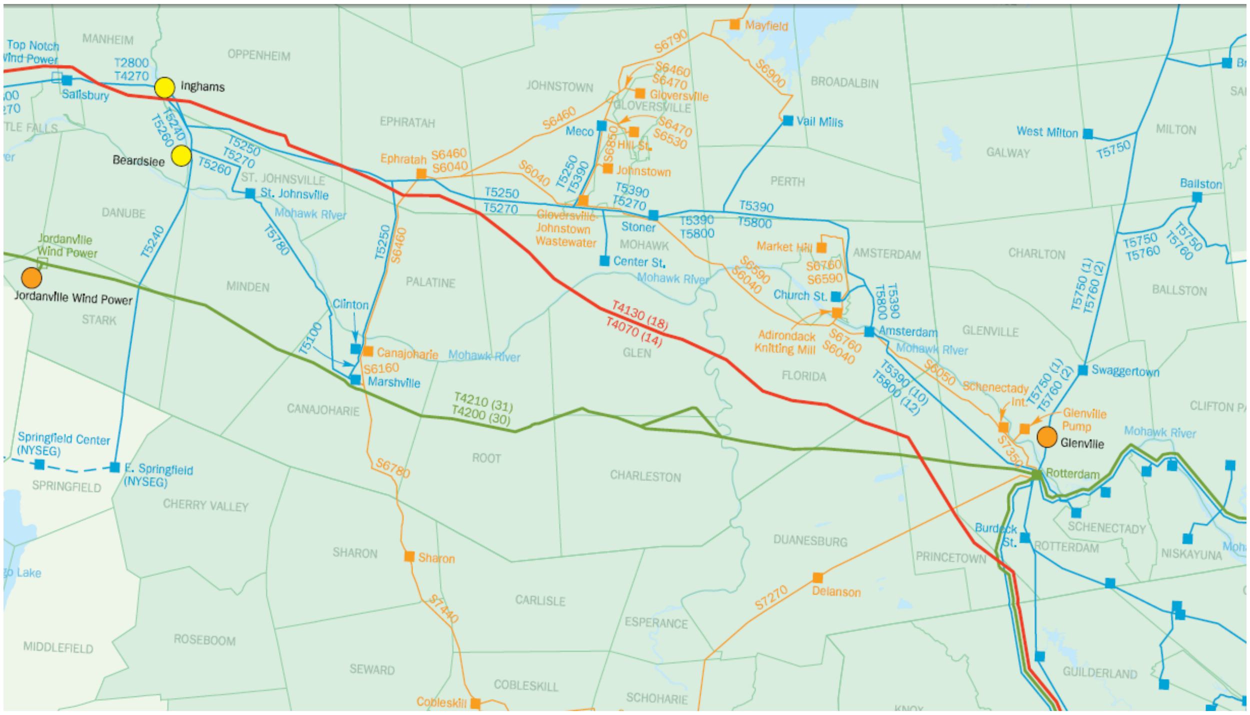
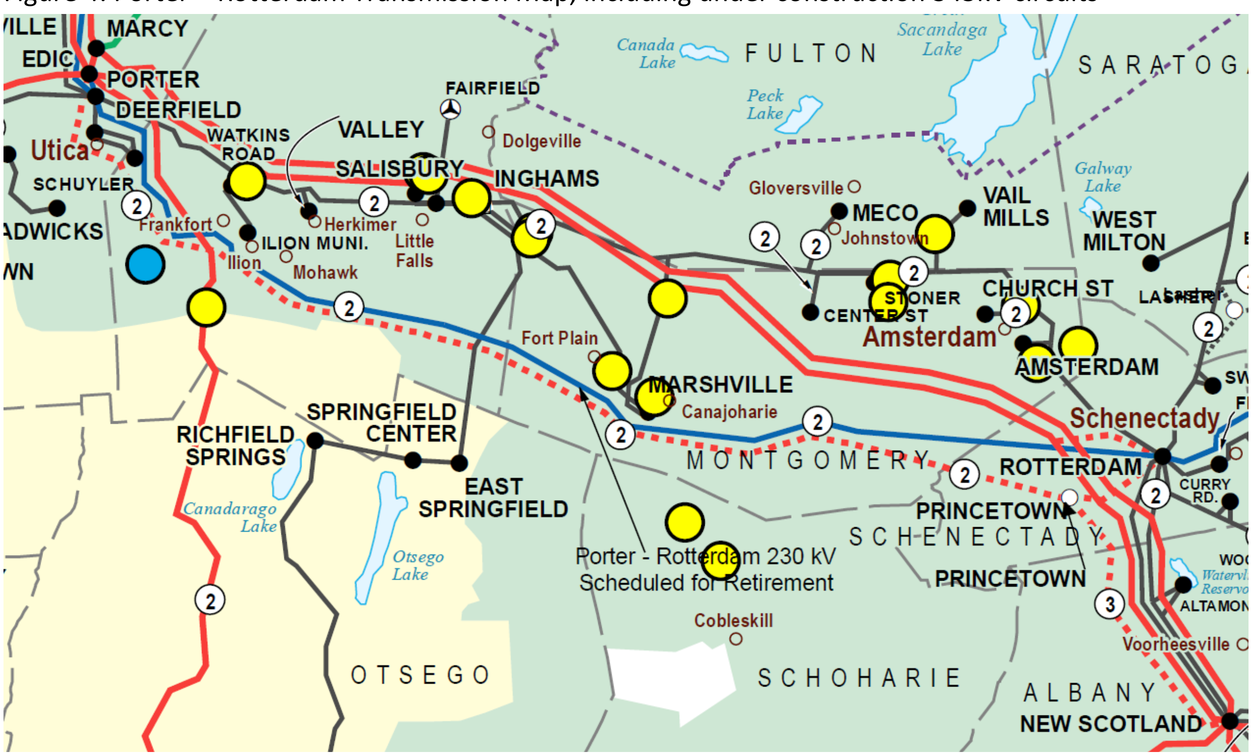


Figure 4: Porter – Rotterdam Transmission Map, including under construction 345kV circuits



While age is not always an indicator of condition, in the absence of condition assessments, the relative age of a circuit can provide some insight into how close the circuit may be to end of life refurbishment or replacement. Table 1 is a list of area circuits with the age of the oldest components.

Table 1: Transmission Circuit Age

Circuit	Year	Age	Mileage
Inghams - Meco #15	1923	98	30.8
Maple Ave - Rotterdam #10	1923	98	15.1
Meco - Maple Ave #22	1923	98	15.7
Inghams - Richfield Springs #7-942	1924	97	26.0
Inghams - St. Johnsville #6	1924	97	7.1
Inghams - Stoner #9	1925	96	23.8
Stoner - Rotterdam #12	1925	96	23.1
Porter - Valley #4	1927	94	17.5
Porter - Watkins Road #5	1927	94	11.6
Valley - Fairfield #12	1927	94	5.4
Watkins Road - Inghams #2	1927	94	15.5
Clinton - Marshville #12	1960	61	1.6
Fairfield - Inghams #3	1960	61	7.2
St. Johnsville - Marshville #11	1965	56	9.9
Cobleskill - Schoharie #6	1938	83	10.1
Ephratah - Florida #7	1906	115	0.0
Florida - Schenectady International #3	1906	115	5.7
Johnston - Market Hill #8	1906	115	22.0
Market Hill - Amsterdam #11	1906	115	7.9
Meco - Johnston #12	1906	115	2.4
Gloversville - Marshville #6	1911	110	21.1
Schenectady International - Amsterdam #3	1921	100	7.7
Schenectady International - Rotterdam #4	1921	100	3.3
Rotterdam - Schoharie #18	1940	81	21.1
Gloversville - Hill St #3	1957	64	4.0
Hill St - Meco #4	1957	64	1.8
Mayfield - Meco #7	1959	62	17.0
Northville - Mayfield #8	1959	62	11.0
Mayfield - Vail Mills #9	1961	60	7.9
Marshville - Sharon #16	1962	59	9.2
Sharon - Cobleskill #17	1962	59	6.8
Cobleskill - Summit #5	1965	56	7.6

Planned Reliability and Condition Driven Transmission Projects

All transmission projects identified as firm in the NYISO 2020 Gold Book were include in the study cases. Generally, projects are only listed in the Gold Book if they result in a modification to the system; such as a change in rating, change in impedance, or a change in system or station configuration. National Grid has other transmission projects in the medium to long term horizon. These projects are generally condition based projects. The following describes all the major projects in the region, including some projects that are not expected to have an impact on the system. These projects were assessed as either having; a benefit to CLCPA as designed, a benefit to CLCPA if the project design was revised, or no benefit to CLCPA if revised. Those revised projects that have CLCPA benefits and lead to a significant increase in project cost are proposed as Phase 1 and Phase 2 project.

Energy Highway Project (Segment A) – The project is an effort to increase the Central East/Total East bulk transfer limits. The effort primarily includes converting the 230 kV Porter – Rotterdam circuits to 345kV. All local and bulk components of the selected project were included in the study base cases.

Inghams Station Rebuild – This project is a rebuild of the Inghams station. The project includes a new 115kV PAR with a larger angle range then the existing unit. This project was included in the study base cases, with the proposed size and range of the new PAR assumed. After conducting the 2030 Regional Congestion Assessment, the size of the PAR was increased. However, this change in scope does not materially increase cost and is not a Phase 1 or Phase 2 project.

Rotterdam 115kV Station Rebuild – The National Grid 10-year plan includes funding for refurbishment work on the Rotterdam 115kV switchyard. At this time the plan is that this work will not result in a change to the station configuration or any rating increases and thus no changes to the study base cases were required. The study included a desktop assessment of a scenario where the configuration of the station was modified. Initial testing showed that several Rotterdam bus faults and stuck breaker contingencies were limiting renewable generation. However, it was confirmed that reconfiguring Rotterdam would not address these constraints as other contingencies quickly become binding. Thus, no scope changes are recommended for this project.

St Johnsville – Marshville Refurbishment – The National Grid 10-year plan includes funding for refurbishment work on the St Johnsville – Marshville 115kV circuit. At this time the expectation is that this project will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. The study considered a scenario of increasing the ratings of this circuit. As described later in this document, replacing this condition driven project with a full rebuild would result in capacity increases in the area when combined with other recommended projects. This project will be replaced with a Phase 1 project.

Inghams lines 6 and 7 rebuild – The scope of this project is a complete replacement of all structures and conductor on 3 miles (of the total 7-mile length) of the Inghams – St Johnsville circuit and the Inghams – Richfield Springs circuit for the portions where the two lines are on the same transmission structures. The project will result in an increase in the thermal limit of the overall Inghams – St Johnsville circuit and a small change to the circuit impedance. This project was not included in the initial NYISO study base cases as it was planned by the Company after the study base cases were developed. As described later in this document, this project was found to be critical to increasing the capacity in the region. This project will be replaced with a Phase 1 project.

Rotterdam 69kV Rebuild & New Transformer – This project will rebuild the Rotterdam 69kV station including the replacement of the existing 115/69kV transformer and addition of a second 115/69kV transformer. This project was not included in the initial NYISO study base cases as it was planned by the Company after the study base cases were developed. As described later in this document, this project was found to be critical to increasing the capacity in the region. However, this project does not need to be revised from the current plan and is not a Phase 1 or Phase 2 project.

Scho/Sch Int-Rott 18/4 Rebuild – Rebuild 1 mile of double-circuit Schenectady International – Rotterdam 69kV line #4 and Rotterdam – Schoharie 69kV line #18 from Rotterdam to structure 101. This project was not included in the initial NYISO study base cases as it was planned by the Company after the study base cases were developed. This project was found to be critical to increasing the capacity in the region. However, this project does not need to be revised from the current plan and is not a Phase 1 or Phase 2 project.

Local Design Criteria

For purposes of this study, National Grid performed steady state testing in accordance with its Transmission Group Procedure 28 (TGP28), *National Grid Transmission Planning Criteria*. Simulations were performed to assess the system response with all elements in service (N-0) as well as for N-1 outage conditions. These N-1 tests included loss of a circuit, transformer, generator or shunt device as well as breakers opening without a fault, bus outages, faults with a breaker failure and double circuit tower outages. All testing was limited to steady state for N-0 and N-1 conditions.

The system response to these N-1 outages is generally considered acceptable when all local facilities are loaded below 100 percent of their Long-Term Emergency (LTE) rating. For pre-contingency conditions, loading is considered acceptable when all local facilities are loaded below 100 percent of their Normal (continuous) rating. The summer ratings are used in all cases. Acceptable post-contingency system voltages on the 115kV and 69kV system are between 90 percent of nominal and 105 percent of nominal and acceptable pre-contingency voltages are between 95 percent of nominal and 105 percent of nominal.

All solutions are required to meet the full set of local and regional Planning Criteria to ensure that the reliability of the planned system is not compromised. These criteria include dynamic, short circuit and expanded steady state requirements. Additional testing will be required for some proposed Phase 2 solutions to ensure that they are designed to conform with and adhere to all applicable North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), New York State Reliability Council ("NYSRC") Reliability Rules, as well as applicable National Grid specifications, procedures, and guidelines.

Test 1: 2030 Regional Congestion Assessment - Methodology and Assumptions

The Regional Congestion Assessment (Test 1) is meant to; 1) identify existing local system congestion in a planning region based on the 2030 load and generation input assumptions and 2) eliminate all identified congestion within the region through system upgrades.

This study is based upon the database established and used by the NYISO for the 2020 Reliability Needs Assessment (RNA) 70x30 CLCPA Scenario using generation buildout assumptions from the Congestion Assessment and Resource Integration Study (CARIS) 70x30 scenario. The three cases selected as the starting point for the 70x30 scenario studies were: (i) Day Peak Load of 30,000 MW; (ii) Shoulder Load of 21,500 MW; and (iii) Light Load of 12,500 MW. The load is modeled based on the 2020 Gold Book forecast for 2030, with the load distributed within the regions based on the same 2020 RNA cases.

Starting from the 70x30 scenario peak load, shoulder load, and light load cases created by the NYISO, National Grid built sensitivity cases examining different renewable dispatch conditions. These dispatch scenarios were communicated with neighboring utilities for their consideration and use in their study work. While developing the case dispatches, monitoring and correcting overloads and voltage limitations on the 345kV and 230kV systems was considered out of scope for this assessment of the local system performance.

All study cases used by National Grid assumed no fossil generation was operating in NYISO Zone A (West) through F (Capital) and assumed that nuclear generators at Nine Mile 1, Nine Mile 2, and Fitzpatrick were all in service at maximum output and Ginna was assumed to be out of service. For the ties from New York to the external areas, no import or export was allowed from New York to PJM (across the free-flowing ties), New England or Ontario.

Hydro generation at Gilboa was set to maximum generation in the peak and shoulder cases and set to pumping in light load cases. In all cases, the Moses generation was set to maximum output. At the Niagara/Lewiston facility, Niagara was set to 2160MW, evenly distributed across the thirteen machines and Lewiston was set to either 240MW of generation or 360MW of pumping load depending on the case. Run of river hydro generation was set to typical seasonal values. The import of Hydro generation from Hydro Quebec was set to either 1110MW or 535MW. No hydro generation was imported to Dennison from the Cedars generation.

The above assumptions were modeled in each case, and Land Based Wind (LBW) and Utility Scale Photovoltaic (UPV) generation was then dispatched to various levels. In the National Grid testing, LBW, primarily located in Western, Central and Northern NY, was varied between 0 percent of nameplate up to 75 percent of nameplate and UPV, located primarily in Central, Northern and Eastern NY was dispatched between 0 percent of nameplate up to 70 percent of nameplate. Neither wind nor solar resources were modeled at 100 percent of nameplate.

The NYISO zonal data of hourly load, LBW output, and the UPV output from its CARIS 70x30 scenario was also reviewed for consistency with National Grid modeling assumptions. All dispatches modeled by National Grid were consistent with the NYISO CARIS 70x30 generation output levels assumed to be achieved for 100 hours or more. For example, a dispatch scenario model by National Grid was LBW greater than or equal to 30 percent of nameplate concurrent with UPV output greater than or equal to 27 percent. This dispatch occurred in the CARIS 70x30 scenario for 802 hours. Another example of the many scenarios studied by National Grid was LBW at 15 percent of nameplate and UPV at 52 percent of nameplate. The dispatch at or above this level occurred in the CARIS 70x30 scenario for 457 hours.

For the National Grid assessment, no assumptions were made for the generation mix in New York City or Long Island, including no specific assumptions for offshore wind, as the generation mix downstate does not have any impact on the result of testing within National Grid's service territory. However, for simplicity of developing the scenario cases, it was assumed that the flow across the UPNY – CONED interface would not exceed 7000MW.

Test 1: 2030 Regional Congestion Assessment - Modeled Existing and Proposed Generation

A single 20MW hydro generator is connected in the Inghams area and was assumed to be in service in all study work. A 74MW wind generator is connected on the one of the circuits between Porter and Inghams.

As of 1/31/2021, the NYISO interconnection queue includes 730MW of solar projects proposing to connect to the area's local system. The projects are summarized in Table 2. Only 120MW is proposed to connect between Porter and Inghams with the other 610MW connecting to the 115kV or 69kV systems between Inghams and Rotterdam.

In the last 5 years 360MW of generation proposing to connect into this area has withdrawn from the NYISO queue. While some of these projects may have withdrawn due to siting or financing issues, it is believed that some projects have withdrawn due to insufficient transmission capability.

Table 2: Generation in the NYISO Interconnection Queue

Queue	MW	Type	Interconnection Point
0495	91	S	St. Johnsville - Marshville 115kV
0564	20	S	Sharon - Cobleskill 69kV
0565	20	S	St. Johnsville - Inghams 115kV
0581	20	S	Fairfield - Inghams 115kV
0586	20	S	Watkins Rd - Ilion 115kV
0618	90	S	Inghams - Rotterdam 115kV
0619	50	S	Cobleskill - Marshville 69kV
0638	20	S	Meco - Rotterdam 115 kV
0682	20	S	Ephratah - Florida 115kV
0719	40	S	Meco - Rotterdam 115 kV
0748	20	S	Market Hill - Johnstown 69kV
0780	20	S	Stoner - Rotterdam 115kV
0806	20	S	Stoner - Rotterdam 115kV
0841	20	S	Sharon - Cobleskill 69kV
0865	20	S	Inghams 115kV Substation
0869	80	S	Clinton Substation 115kV
0885	20	S	Watkins Rd - Inghams 115kV
0960	20	S	Cobleskill - Schoharie 69kV
0962	20	S	St. Johnsville - Inghams 115kV
0972	20	S	Middleburg Tap - Middleburg 69kV
1019	20	S	Marshville 69kV Substation
1030	20	S	Stoner - Rotterdam 115kV
1038	20	S	Rotterdam - Meco 115kV
1047	20	S	Porter - Watkins 115kV

Table 3: 2019 CARIS Generation Additions Necessary to Meet the 70x30 Mandate

Bus	Type	MW	Interconnection Point
Fairfield	W	74	Fairfield 115kV Station
Amsterdam	S	335	Meco - Rotterdam
Church	S	122	Meco - Rotterdam
Clinton	S	244	Marshville – Inghams – Meco
Watkins	S	21	Porter – Watkins - Inghams
Inghams	S	42	Inghams Central 115kV Station
Marshville	S	512	Marshville 115kV Station
Meco	S	122	Inghams – Meco - Rotterdam
Q565	S	23	Inghams – St Johnsville - Marshville
Q581	S	20	Fairfield - Inghams
Salisbury	S	21	Fairfield - Inghams
Stoner	S	61	Inghams – Stoner - Rotterdam
St Johnsville	S	61	Inghams – St Johnsville - Marshville
Vail Mills	S	61	Stoner - Rotterdam

As previously stated, generator representation (e.g. type, size and location for new renewables) used in this assessment was based on the 2019 CARIS 70x30 sensitivity case. These cases modeled 74MW of existing wind and 1645MW of new and proposed solar in the region (see Table 3). All generation was added to the 115kV system. No generation was added to the 69kV system between Inghams and Rotterdam, though 170MW of the generation in the NYISO queue is proposing to connect at 69kV. Figure 4 shows geographically where new resources were added, with each yellow dot representing a new solar generator location and each blue dot representing a new wind generator location.

The base cases assume 104MW of solar connected between Porter and Inghams, 701MW connected to the circuits between Inghams and Rotterdam and 840MW in the Marshville area.

Before completing area studies, two changes were made to the generation assumptions shown in Table 3. Between St Johnsville, Marshville and Clinton, it was originally assumed that 840MW of generation was added to the case. For contingency conditions, this area would only have one 115kV exit and two 115/69kV transformers that connect to two 69kV circuits that could be used as exits. The load in the area absorbs less than 10MW of the generation. Using the emergency ratings for the largest 115kV wire size and the largest 115/69kV transformer sizes used by National Grid and assuming perfect control over where the power flows, the maximum capability to export generation from the St Johnsville – Marshville – Clinton area would be 630MW. Exporting the full 840MW from this sub-area would require a new 115kV line, multiple new 69kV lines and transformers or an onramp the 345kV system. Because this pocket is past the maximum theoretical capability, it was decided to move 90MW from Clinton to the Inghams East bus and move 150MW from Marshville to the Inghams East bus. This still leaves over 600MW in this pocket, which creates significant overloads for many dispatches.

The generation added to the Inghams – Rotterdam circuits was mostly added to the Meco – Rotterdam line. Originally the Meco – Rotterdam line had 335MW at Amsterdam, 122MW at Church and 122MW at Meco for a total of 579MW. The parallel Stoner – Rotterdam line had 61MW at Stoner and 61MW at Vail Mills for a total of 122MW. [redacted] A more reasonable assumption would be that as projects connect to these circuits, National Grid will attempt to keep the circuit loading balanced. National Grid, working alone or with developers, may expand some interconnections to tie the projects to both circuits. To reflect the expectation that National Grid will balance the generation on these lines, 180MW was moved off the Meco – Rotterdam line and connected to the Stoner – Rotterdam line. This was accomplished by moving 61MW from the Amsterdam bus to the Church West bus and moving 122MW from Church East to the Church West bus.

Several of the projects added to the cases were added to existing tap buses. When outages or contingencies occur, these tap buses are usually disconnected. No changes were made to the contingency definitions to reflect the addition of this generation. It was assumed that the contingencies would result in the generation tripping, same as the load. New three breaker ring generation interconnections could change this contingency but were not modeled. The change in contingency could increase the amount of congestion identified by this testing. This is especially true for the generators at Amsterdam (335MW), Church (122MW), Clinton (244MW) and Vail Mills (61MW).

Test 1: 2030 Regional Congestion Assessment - Proposed Distributed Energy Resources

In addition to the generation proposed in the NYISO queue, Distributed Energy Resources (DER) have also proposed to connect to National Grid's distribution system. The DER queue for the region contains over 200MW of proposed generation, all of which is solar. The stations where the largest amount of solar DER is proposed is summarized in Table 4. While the DER was not explicitly modeled in the base cases, the proposed locations are similar to the proposed locations used to model the new resources (Table 3) needed to meet the 70x30 mandate. Because energy produced from DER may make its way from the distribution system to the transmission system through the existing transmission stations modeled in this study, DER is expected to have a similar impact as the generation directly connected to the transmission system and would benefit from the same projects identified as necessary to unbottle the region.

Table 4: Generation in the DER Interconnection Queue

Station	MW
Center	24
Church	16
Delanson	14
Florida	23
Gloversville	14
Maple	20
Middleburg	15
St Johnsville	13
Stoner	33
Vail Mills	29

Test 1: 2030 Regional Congestion Assessment - Study Results (System Bottlenecks)

Based on the study base cases, several areas of congestion were identified that would constrain the output of generation (generation pocket).

Across the region, the highest loading occurred in cases with the highest solar dispatch. At the shoulder load level, the highest dispatch was 50% of nameplate. In these cases, all 115kV line sections between Inghams and Rotterdam, including the 115kV line sections around Marshville were overloaded. The maximum loading was over 268%. For the heavy load level, the highest dispatch was 70% of nameplate capacity. In these cases, the same line sections were overloaded, with the highest overload at 337%. If the shoulder load cases were dispatched higher than 50% of nameplate, overloads would exceed those in the heavy load case. This is also expected to be true if the light load cases were dispatched to 70%.

The Inghams PAR can be used to help relieve some overload conditions. However, in the heavy load case with solar dispatched to 70%, the flow on the Porter – Inghams circuits are already at 100% of their rating, leaving no opportunity to adjust the PAR to relieve the Inghams – Rotterdam circuits. In this testing the PAR was optimized to prevent all overloads between Porter and Inghams.

In the same cases with high solar dispatch, all the 115/69kV transformers in the region were overloaded. Meco was at 200%, Rotterdam 199%, Marshville 156% and 133% and Vail Mills at 96%.

Finally, many portions of the 69kV system were also overloaded, some sections up to 128%. This includes the Meco – Vail Mills, Meco – Rotterdam and Marshville – Rotterdam circuits.

Table 5: Test 1 Porter-Rotterdam Facility Overloads

Facility	Worst Case Overload (% LTE)
Maple - Rotterdam	337
Stoner - Rotterdam	319
Inghams - St Johnsville	189
Inghams - Richfield Springs	180
Meco - Maple	178
Clinton Tap	173
Inghams - Meco	157
Inghams - Stoner	151
Fairfield - Inghams	104
Valley - Fairfield	103
Porter - Watkins	99
Watkins - Inghams	99
Meco 115/69kV TR	200
Rotterdam 115/69kV TR	199
Marshville 115/69kV TR2	156
Marshville 115/69kV TR1	133
Vail Mills 115/69kV TR	96
Ephratah - Florida	128
Gloversville - Marshville	126
Florida - Schenectady Intl	116
Schenectady Intl - Rotterdam	114
Marshville - Sharon	106
Sharon - Cobleskill	102
Cobleskill - Schoharie	102
Mayfield - Meco	99
Mayfield - Vail Mills	91

Test 2: Capacity Headroom Test - Methodology and Results

To further determine the areas that could cause congestion, a Capacity Headroom test was performed. According to the DPS Headroom Test whitepaper (Case 20-E-0197), Capacity Headroom uses the lowest identified optimal transfer value observed in a heavy, light and shoulder load case. This test was done using the Optimal Transfer feature in TARA. Unlike Test 1 where the location of the generation was based on generation identified by the NYISO in the 70X30 CARIS case, Test 2 involves assigning possible locations for generation to interconnect, then having the program determine which one or more of the sites is an optimal location and how much generation could connect. The optimized dispatch keeps all transmission elements in the pocket within acceptable loading for any N-0 or N-1 condition. The analysis does not distinguish between the type of generation, only estimates the capability for simultaneous output from generation within the local network.

Under Test 2, base cases are initialized with no solar or wind generation in service. Including no solar or wind generation in upstream or downstream locations or on the bulk power system. All other load, hydro and nuclear generation and system topology assumptions made in the Test 1 base case were held constant. For Test 2, it was assumed that generation could only be added to the existing 115kV switching stations in the region. The impact of adding generation to the middle of a line, which is likely not an electrically optimal location, will not be captured. One of the limitations of this test is that the model can add a relatively large amount of generation into one site, ignoring or reducing the other options. To provide a more realistic indication of the headroom provided, a limit of 500MW was placed on all 115kV switch stations.

For this region, the selected 115kV buses were Watkins, Valley, Inghams Central, Inghams East, St Johnsville, Marshville, Meco and Stoner.

The amount and location of generation for each study base case is summarized in Table 6. The program identified several bottlenecks. The test identified that the Porter – Inghams circuits determine the maximum setting of the PAR as well as the amount of generation that can be connected between Porter and Inghams. The test also found that the generation between Inghams and Rotterdam was limited by the rating of the 115kV circuits that connect to Rotterdam, as several contingencies result in all flow moving towards Rotterdam. The most limiting case for this region was the light load case, however both light load cases and both shoulder load cases had similar results.

Table 6: Existing System Capacity Headroom (MW)

	Watkins	Valley	Inghams C	Inghams E	St Johnsville	Marshville	Meco	Stoner	Total
Heavy Load	20	60	20	170	0	130	150	0	550
Heavy Load w/Pumping	20	60	20	180	0	160	100	0	540
Light Load	10	40	150	0	0	110	130	0	440
Light Load w/Pumping	10	40	160	0	0	110	130	0	450
Shoulder Load	10	50	20	140	0	120	130	0	470
Shoulder Load w/Pumping	10	50	20	150	0	120	130	0	480

Regional Transmission Plan: Recommended System Upgrades

All the previous testing showed that increasing the capability or headroom of this system is very difficult without adding a new path for generation to exit the area. While several solutions were identified by National Grid, the most economical solution would be the incorporation of a new 345/115kV substation along with several local transmission upgrades.

After screening options with the 345/115kV onramp located at Inghams or near Marshville, the recommendation is to build a two bank 345/115/69kV station at or near Marshville, see Figure 5. The station will include two 345/115kV transformers, two 115/69kV transformers, connect to all 115kV and 69kV lines at Marshville today and connect to both Edic – Princetown 345kV lines via a new breaker and a half station. However, the recommended Marshville 345/115kV solution still requires all 115kV lines between Inghams and Rotterdam to be rebuilt to address the overloads of those lines. At Rotterdam the existing 115/69kV transformer will be replaced and a second transformer will be added. At Meco the existing 115/69kV transformer will be replaced and a second transformer will be added.

For the 115kV circuit rebuilds, the initial assumption is that the lines would remain on double circuit structures, though significant benefits may be realized if the lines could be split onto two single circuit structures. For example, sensitivity testing on several options showed that headroom capacity could be increased by 250-350MW if lines were not on double circuit towers

Because the recommended solutions include significant local upgrades, the benefits of only the local upgrades was calculated. The local upgrades include a complete rebuild of the Inghams – Rotterdam and Inghams – Marshville circuits, Rotterdam 115/69kV transformer replaced and a second transformer added, Meco 115/69kV transformer replaced and a second transformer added and at Marshville both existing 115/69kV transformers replaced.

Figure 5: Marshville Station Location

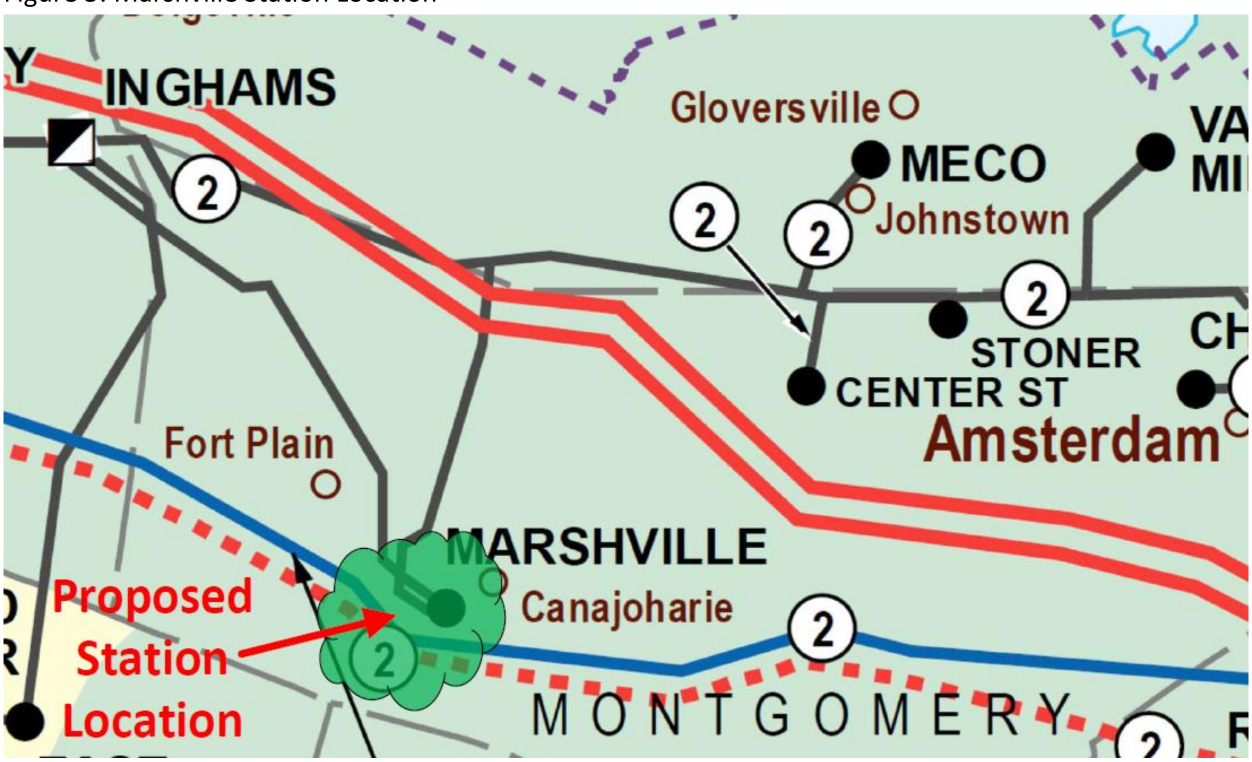


Table 7: Regional Project Plan Summary

Project ID	Project Name	Phase	Project Description
R1	Meco Station Upgrade	Phase 1	Meco 115/69kV Transformer Replacement and Second Transformer
R2	Marshville Station Upgrade	Phase 1	Marshville 115/69kV Transformer Replacements
R3	Inghams – Rotterdam 115kV Line Upgrades	Phase 1	115kV Upgrade: Inghams-Rotterdam circuits
R4	Marshville 345/115kV Station	Phase 2	New Marshville area 345/115kV Station

Regional Transmission Plan: Project Benefits

In the 2030 Regional Congestion Assessment (Test 1) cases and the Capacity Headroom test (Test 2), the benefits of the solution set were estimated. Note that an assessment of the impact the new Marshville 345/115kV station would have on the 345kV system needs to be verified by the NYISO. If the new station has a material impact on the bulk system, especially if it has a negative impact on the Central East transfer capability, the project may need to be reevaluated against the alternative of rebuilding the Porter to Inghams circuits.

Table 8: Project Congestion Benefits

System Configuration	Constraint (MW)
Existing System	600
All Phase 1 Projects Complete	310
All Phase 2 Projects Complete	0

Table 9: Phase 1 System Capacity Headroom 115kV Circuits Rebuilt and 115/69kV TR Replaced

	Watkins	Valley	Inghams C	Inghams E	St Johnsville	Marshville	Meco	Stoner	Total
Heavy Load	20	60	0	0	0	150	330	50	610
Heavy Load w/Pumping	20	60	0	0	0	140	340	50	610
Light Load	10	40	0	0	0	280	180	30	540
Light Load w/Pumping	10	40	0	0	0	200	260	30	540
Shoulder Load	10	50	0	0	0	190	270	40	560
Shoulder Load w/Pumping	10	50	0	0	0	180	280	40	560

Table 10: Phase 1 & 2 System Capacity Headroom

	Watkins	Valley	Inghams C	Inghams E	St Johnsville	Marshville	Meco	Stoner	Total
Heavy Load	20	60	0	0	380	500	290	100	1350
Heavy Load w/Pumping	20	60	0	0	330	500	300	120	1330
Light Load	10	40	100	0	440	500	190	110	1390
Light Load w/Pumping	10	40	70	0	440	500	200	130	1390
Shoulder Load	10	50	0	50	440	500	210	150	1410
Shoulder Load w/Pumping	10	50	0	10	440	500	220	170	1400

Regional Transmission Plan: Project Alternatives

Based on extensive testing, the rebuild of the Porter – Inghams circuits, reconfiguration of Inghams station and repurposing the PAR was identified as an alternative to the Marshville 345/115kV station. While the Porter – Inghams rebuild would provide a similar amount of congestion relief and headroom compared to the Marshville 345/115kV option, the Porter – Inghams rebuild is expected to be significantly more expensive then the recommended Marshville 345/115kv solution. It's important to note, that both the Porter-Inghams rebuild and Marshville 345/115kV station require all 115kV lines between Inghams and Rotterdam to be rebuilt to address the overloads of those lines.

Rebuilding double circuit structures as single circuit structures was considered as most of the contingencies that are most limiting even after the solutions set is completed are double circuit tower outages. This variation was rejected due to added cost and the assumption that the right of way needed to rebuild the lines as two single circuit lines would not be available. This variation may warrant further consideration to confirm the cost and feasibility. For example, sensitivity testing on several options showed that headroom capacity could be increased by 250-350MW.

An Inghams 345/115kV onramp was rejected due to higher 115kV loading for 345kV outages.

A rebuild of the Inghams – Richfield Springs – Fraser circuits was rejected due to the line's significant length making the 345/115kV station a more economical option.

Rebuilding 69kV circuits was rejected due to the circuit lengths. The 2030 Regional Congestion Assessment found 88 circuit miles of 69kV lines were overloaded, making the 345/115kV station a more economical option.

Dynamic Line Ratings, which can increase the rating of existing circuits without any conductor replacements would not provide a sufficient increase to address the identified overloads.

Alternatives that used power flow controllers were rejected as for these types of devices (Series Reactors or Capacitors, PAR, Static Synchronous Series Compensators) to be effective, an alternative underutilized parallel path must be available to shift power onto. No underutilized parallel paths exist in this area.

The use of advanced conductors, which have higher allowed operation temperature due to the material used in the conductor core, were not recommended in this area due to the expectation that the maximum high temperature conductor size that could be supported on the existing structures would not sufficiently address the identified overloads. The need to address the age of the structures also makes the use of the more expensive high temperature conductor uneconomic. For when all structures are planned for replacement due to age or condition, the incremental cost of selecting a sufficiently large ACSR conductor is small compared to the cost of using the advanced conductor.

Regional Transmission Plan: Project Details

The Porter – Rotterdam pocket includes three Phase 1 projects and one Phase 2 projects. The Inghams – Rotterdam 115kV Line upgrade project is comprised of four individual project deliverables. The remaining two Phase 1 projects also include components necessary to complete the Inghams – Rotterdam 115kV line upgrade project. The in-service date and detailed capital and operating cost estimates for all of the National Grid Phase 2 projects will be provided in future filings.

The tables below provide specific Phase 1 project details. It is important to note the information provided is based on current estimates and will continue to improve in accuracy as the project engineering design and execution matures.

Table 11: Phase 1 Project Description

Project ID	Project Title	Scope	Additional ROW Required
R3	Inghams – Rotterdam Circuits	This project will completely rebuild the 7.12-mile 115kV Inghams – St. Johnsville LN6 (T5260), 23.9-mile 115kV Inghams – Stoner LN9 (T5270), 15.9-mile 115kV Maple Ave – Rotterdam LN10 (T7040), 9.86-mile 115kV St. Johnsville – Marshville LN11 (T5780), 1.16-mile 115kV Clinton – Marshville LN12 (T5100), 23.1-mile 115kV Stoner – Rotterdam LN12 (T5800), 23.3-mile 115kV Inghams – Meco LN15 (T5250), 7.51-mile tap to Clinton Substation, and 15-mile 115kV Meco – Maple Ave LN22 (T7030), The rebuild of the Inghams – St Johnsville LN6 main line sections will require the removal of fifty-five (55) wood structures, and twenty-four (24) Lattice structures. The rebuilt line will require the Installation of 43 SCT steel vertical davit arm suspension structures, one (1) SCT steel 3-pole dead-end structure, six (6) SCT steel vertical dead-end structures, twenty-two (22) DCT steel vertical davit arm suspension structures, and six (6) DCT steel 2-pole vertical dead-end structures. The existing structure foundations will be removed and eighty-six (86) drilled pier foundations will be installed. The existing conductor will be replaced with two (2) bundled 795 ACSR 26/7 “Drake” conductor, and the existing shield wire with one (1) 3/8” steel and one (1) OPGW. The rebuild of Inghams – Stoner LN9 and Maple Ave – Meco LN22 main line double circuit will require the removal of two (2) wood structures, and thirty (30) Lattice structures. The rebuilt line will require the Installation of twenty-six (26) DCT steel davit arm suspension structures, three (3) DCT steel 2-pole vertical dead-end structures, one (1) SCT steel vertical dead-end structure, and two (2) SCT steel vertical dead-end tap structures. The existing structure foundations will be removed and thirty-five (35) drilled pier foundations will be installed. The existing conductor will be replaced with two (2) bundled 795 ACSR 26/7 “Drake” conductor, and the existing shield wire with one (1) 3/8” steel and one (1) OPGW.	Possible

		The rebuild of Inghams – Stoner LN9 and Meco – Inghams LN15 double circuit main line require the removal of one-hundred and thirty-four (134) lattice structures. The rebuilt line sections will require the Installation of one hundred and twenty (120) DCT steel davit arm suspension structures, twelve (12) DCT steel 2-pole vertical dead-end structures, two (2) SCT steel vertical dead-end structure, and two (2) SCT steel vertical dead-end tap structures. The existing structure foundations will be removed and one-hundred and forty-nine (149) drilled pier foundations will be installed. The existing conductor will be replaced with two (2) bundled 795 ACSR 26/7 "Drake" conductor, and the existing shield wire with one (1) 3/8" steel and one (1) OPGW. The rebuild of Inghams – Stoner LN9 single circuit main line will require the removal of three (3) wood structures. This rebuilt line section will require the Installation of one (1) SCT steel vertical dead-end structure, and two (2) SCT steel vertical switch structures. The existing structure foundations will be removed and three (3) drilled pier foundations will be installed. The two (2) existing switches will be replaced with 2000amp vertical switches (Str 135-1/2, Str 139-1/2). The existing conductor will be replaced with two (2) bundled 795 ACSR 26/7 "Drake" conductor, and the existing shield wire with one (1) 3/8" steel and one (1) OPGW. The rebuild of Maple Ave – Rotterdam LN10 and Stoner - Rotterdam LN12 double circuit main line will require the removal of fourteen (14) wood structures, three (3) steel structure, and one-hundred and eight (108) Lattice structures. This rebuilt line section will require the Installation of ninety-five (95) DCT steel davit arm suspension structures, one (1) DCT steel davit arm dead-end structure, three (3) DC steel 2-pole suspension pull off structures, two (2) DCT steel vertical dead-end switch structures, nineteen (19) DCT steel 2-pole vertical dead-end structures, one (1) SCT steel vertical dead-end structure, one (1) SCT steel vertical dead-end tap structure, and one (1) TCT steel 3-pole vertical dead-end structure. The four (4) existing switches will be replaced with 2000amp vertical switches (Str 242, 245, 257-1/2, 258-1/2). The existing structure foundations will be removed and one-hundred and forty-eight (148) drilled pier foundations will be installed. The existing conductor will be replaced with two (2) bundled 795 ACSR 26/7 "Drake" conductor, and the existing shield wire with one (1) 3/8" steel and one (1) OPGW. The rebuild of Maple Ave – Rotterdam LN10 main line will require the removal of two (2) Steel structures and one (1) lattice structures. This rebuilt line section will require the Installation of two (2) SCT steel vertical dead-end structure, and one (1) DCT steel 2-pole vertical dead-end structure. The existing structure foundations will be removed and five (5) drilled pier foundations will be installed. The existing conductor will be	

		replaced with two (2) bundled 795 ACSR 26/7 "Drake" conductor, and the existing shield wire with one (1) 3/8" steel and one (1) OPGW. The rebuild of St. Johnsville – Marshville LN11 main line will require the removal of one-hundred and twelve (112) wood structures, and two (2) lattice structures. This rebuilt line section will require the Installation of 89 SCT steel vertical davit arm suspension structures; and 25 SCT steel vertical dead-end structures. The existing structure foundations will be removed and one-hundred and fourteen (114) drilled pier foundations will be installed. The existing conductor will be replaced with two (2) bundled 795 ACSR 26/7 "Drake" conductor, and the existing shield wire with one (1) 3/8" steel and one (1) OPGW. The rebuild of Marshville – Clinton LN12 main line will require the removal of twenty-one (21) wood structures. This rebuilt line section will require the Installation of twelve (12) DCT steel davit arm suspension structures, eight (8) DCT steel 2-pole vertical dead-end structure, and one (1) SCT steel vertical dead-end structure. The existing structure foundations will be removed and twenty-nine (29) drilled pier foundations will be installed. The existing conductor will be replaced with two (2) bundled 795 ACSR 26/7 "Drake" conductor, and the existing shield wire with one (1) 3/8" steel and one (1) OPGW. The rebuild of Stoner – Rotterdam LN12 and Meco – Maple Ave LN22 double circuit main line will require the removal of eleven (11) wood structures, and forty-two (42) Lattice structures. This rebuilt line section will require the Installation of fifty (50) DCT steel davit arm suspension structures, three (3) DCT steel 2-pole vertical dead-end structures. The existing structure foundations will be removed and fifty-six (56) drilled pier foundations will be installed. The existing conductor will be replaced with two (2) bundled 795 ACSR 26/7 "Drake" conductor, and the existing shield wire with one (1) 3/8" steel and one (1) OPGW. The rebuild of Rotterdam – Stoner LN12 main line will require the removal of twelve (12) wood structures, one (1) Laminated structure, one (1) steel structure, and one (1) Lattice structures. This rebuilt line section will require the Installation of one (1) SCT steel davit arm suspension structure, ten (10) SCT steel vertical dead-end structures, one (1) SCT steel vertical dead-end tap structure Install one (1) SCT steel 3-pole dead-end tap structure; Install two (2) SCT steel vertical switch dead-end structures. The existing structure foundations will be removed and seventeen (17) drilled pier foundations will be installed. The two (2) existing switches will be replaced with 2000amp vertical switches (Str 180-2, 180-4). The existing conductor will be replaced with two (2) bundled 795 ACSR 26/7 "Drake" conductor, and the existing shield wire with one (1) 3/8" steel and one (1) OPGW.	

		The rebuild of Meco – Inghams LN15 main line will require the removal of thirty-six (36) wood structures. This rebuilt line section will require the Installation of thirty (30) SCT steel delta davit arm suspension structures, five (5) SCT steel vertical dead-end structures, and one (1) SCT steel H-frame dead-end structure. The existing structure foundations will be removed and thirty-seven (37) drilled pier foundations will be installed The Clinton Tap LN15 will require the removal of sixty-eight (68) wood structures, and five (5) Lattice structures. This rebuilt line section will require the Installation of Install eight (8) SCT steel vertical davit arm suspension structures, nine (9) DCT steel 2-pole vertical dead-end structures, fifty-one (51) DCT steel davit arm suspension structures, two (2) SCT steel h-frame suspension structures, two (2) SCT steel H-frame dead-end structures, and one (1) SCT steel 3-pole dead-end structure. The existing structure foundations will be removed and eighty-eight (88) drilled pier foundations will be installed. Two (2) new 2000amp disconnect switches will be installed on either side of the Clinton tap. The existing conductor will be replaced with two (2) bundled 795 ACSR 26/7 "Drake" conductor, and the existing shield wire with one (1) 3/8" steel and one (1) OPGW. The rebuild of Meco – Maple Ave LN22 main line will require the removal of thirty-seven (37) wood structures, two (2) steel structure, and one (1) Lattice structures. This rebuilt line section will require the Installation of (1) SCT steel davit arm suspension structure, twenty-nine (29) SCT Steel delta davit arm suspension structures, five (5) SCT steel vertical dead-end structures, three (3) SCT steel davit arm dead-end structures, and two (2) SCT steel H-frame dead-end structures. The existing structure foundations will be removed and forty-two (42) drilled pier foundations will be installed. The existing conductor will be replaced with two (2) bundled 795 ACSR 26/7 "Drake" conductor, and the existing shield wire with one (1) 3/8" steel and one (1) OPGW	
R3	Rotterdam LN10 &LN 12 THERM UPG	This project, which is part of the Inghams – Rotterdam line upgrade project, will replace the 1,200 A rated, group operated, horizontally mounted disconnect switches SW1288 and SW1299 with 2,000A disconnect switches and replace the 1,200 A rated, underhung mounted, hook-stick operated disconnect switches SW1088 and SW1099 with group operated disconnect switches rated 2,000A. The existing conductors between the 115kV bus 99G and 77G to their respective take-off structures will be replaced with bundled 1192 ACSR conductors (two (2) per phase).	No
R3	Stoner Sta - LN 9,12 THERM UPG	This project, which is part of the Inghams – Rotterdam line upgrade project, will replace the existing 115kV motor operated disconnects SW988 and SW1288 with new 2000A motor operated disconnects and the existing 115kV manually operated disconnects SW912 will be replaced with new 2000A gang-operated disconnects. The existing conductors between line	No

		disconnects SW988 and SW1288 and their respective take-off structures will be replaced with bundled 1192 ACSR conductors (two (2) per phase).	
R3	Clinton Sta - LN 12,15 THERM UPG	This Project, which is part of the Inghams – Rotterdam line upgrade project, will replace the existing 115kV motor operated disconnects SW1288 and SW1588 with new 2000A motor operated disconnects and replace the existing 115kV manually operated disconnects SW8199 and SW8177 with r new 2000A gang-operated disconnects. Each motor operated Disconnect will require new RE-01 control switches. The existing 795 ACSR conductors between disconnects SW1288 and SW1588 and their respective takeoff structures will be replaced with new bundled 1192 ACSR conductors (two (2) per phase).	No
R1	Meco 115kV Rebuild	This project will replace the existing 115kV-69kV 40/53.3MVA TR1 with a new 115kV-69kV 56 MVA with LTC a transformer and install a new 115kV-69kV 56 MVA with LTC TR2. The existing R22 and R21 circuit breakers will be replaced with new 115kV 2000amp circuit breakers. The existing four (4) 115kV gang operated disconnect switches SW2288, SW2277, SW1588 and SW1577 will be replaced with 115kV 2000amp gang operated disconnect switches. The existing 115kV MOD switch SW6177 will be replaced with a new 115kV 2000amp circuit switcher. In order to accommodate the new transformer land will need to be acquired and the Substation yard will be expanded approximately 120ft to the West along with a new access road. The new transformer bay will require the extension of the 115kV and 69kV buses. The new transformer bay will also have a new 115kV 2000amp circuit switcher, 1200amp 69kV circuit breaker and three (3) 69kV gang operated disconnect switches. All new equipment will require new foundations and structures. The high side protective relaying for TR1 and TR2 will require four (4) digital protection relays, four (4) lockout relays and eight (8) annunciator target relays. The low side 69kV transformer protection will require four (4) digital relays for phase and ground directional overcurrent. The two new circuit switchers will each require new RE-01 control switch and the new R52 breaker will require a RE-01 switch, 43A/M switch and a Bitronics meter installed. For Line 15 and Line 22, the existing SEL 321 and SEL 221 digital step distance relaying will be replaced with modern digital relaying and have new Bitronics meters installed.	No
R2	Marshville 115kV Rebuild	This project will replacement of the existing 115:69kV 40MVA TR1 and 115:69kV 50MVA TR2 with a new 115:69kV33/44/56MVA Y:Y transformer. This will require the replacement of the existing motor operated disconnect switches 6199 and 6299 with new 115kV 1200A circuit switchers CS1 and CS2 on new support structures. The two existing 115kV line breakers will be replaced with new 115kV 2000A SF6 type breakers. The four (4)115kV Disconnect Switches SW1188, SW1199, SW1288, and SW1299 will be replaced with new 115kV 2000amp gang	No

		operated disconnect switches. Replace the three existing 115kV surge arresters on the 115kV bus with newer style 96 Duty Cycle/ 76MCOV arresters on a new support structure. The transformer relay protection will be replaced with four (4) digital protection relays, four (4) lockout relays and eight (8) annunciator target relays. The two 69kV low side bank breakers will require a total of four (4) digital protection relays.	

Table 12: Phase 1 Estimated Construction Milestones

	Inghams – Rotterdam Circuits	Rotterdam LN10 &LN 12	Stoner Sta - LN 9,12	Clinton Sta - LN 12,15	Meco 115kV Rebuild	Marshville 115kV Rebuild
Final Engineering Complete	1-Aug-26	21-Oct-22	25-May-22	22-Jun-22	6-Dec-23	16-Aug-23
Construction Start	1-Sep-25	21-Nov-22	23-Jun-22	21-Jul-22	2-Feb-24	13-Oct-23
Ready for Load	1-Sep-29	20-Dec-22	22-Jul-22	19-Aug-22	2-Apr-24	12-Dec-23

Table 13: Phase 1 Estimated Project Spend Profile

Inghams –
Rotterdam Circuits

R3	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	67	201	201	32,070	52,277	77,768	100,237	100,237	42,861	-	405,920
Opex	-	-	-	886	1,519	2,916	3,915	3,915	1,631	-	14,782
Removal	-	-	-	1,950	3,342	6,419	8,616	8,616	3,590	-	32,532
Total	67	201	201	34,906	57,138	87,103	112,768	112,768	48,082	-	**453,234**

Rotterdam LN10
&LN 12

R3	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	7	547	14	-	-	-	-	-	-	-	569
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	63	-	-	-	-	-	-	-	-	63
Total	7	610	14	-	-	-	-	-	-	-	631

Stoner Sta - LN 9,12

R3	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	18	613	-	-	-	-	-	-	-	-	631
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	65	-	-	-	-	-	-	-	-	65
Total	18	678	-	-	-	-	-	-	-	-	**695**

Clinton Sta - LN 12,15

R3	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	25	591	-	-	-	-	-	-	-	-	616
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	91	-	-	-	-	-	-	-	-	91
Total	25	681	-	-	-	-	-	-	-	-	707

Meco 115kV Rebuild

R1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	84	1,473	4,014	4,445	1,549	-	-	-	-	-	11,565
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	-	-	211	70	-	-	-	-	-	282
Total	84	1,473	4,014	4,657	1,620	-	-	-	-	-	**11,847**

Marshville 115kV Rebuild

R2	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	95	1,055	4,124	610	-	-	-	-	-	-	5,885
Opex	-	-	-	-	-	-	-	-	-	-	-
Removal	-	-	342	85	-	-	-	-	-	-	427
Total	95	1,055	4,466	695	-	-	-	-	-	-	**6,312**

Capital/Northeast Region
Transmission and Renewable Generation Assessment

August 1, 2021

This review was undertaken to determine if portions of the local 115kV system in the Capital/Northeast region would prevent the delivery of existing and proposed renewable generation. The Company examined multiple different generation dispatches for three different base case load scenarios; light load, shoulder load and heavy load. Upon identifying that the existing local transmission system would create constraints on renewable generation, several solutions were considered.

The conclusion of this analysis is that the Rotterdam – Curry – Wolf and Rotterdam – Woodlawn – State Campus circuits would see increased flow due to upstream generation and that the circuits will need to be reconductored. Portions of this path have already been reconductored and this additional work would complete circuit upgrades between Rotterdam and Menands. This project does not unbottle specific generation in the region but does address overloads that are created by upstream generation, including generation connecting between Inghams and Rotterdam. Addressing the overloads eliminated the need to curtail at least 650MW of remote upstream generation.

All projects in the region are Phase 2.

Existing System Overview

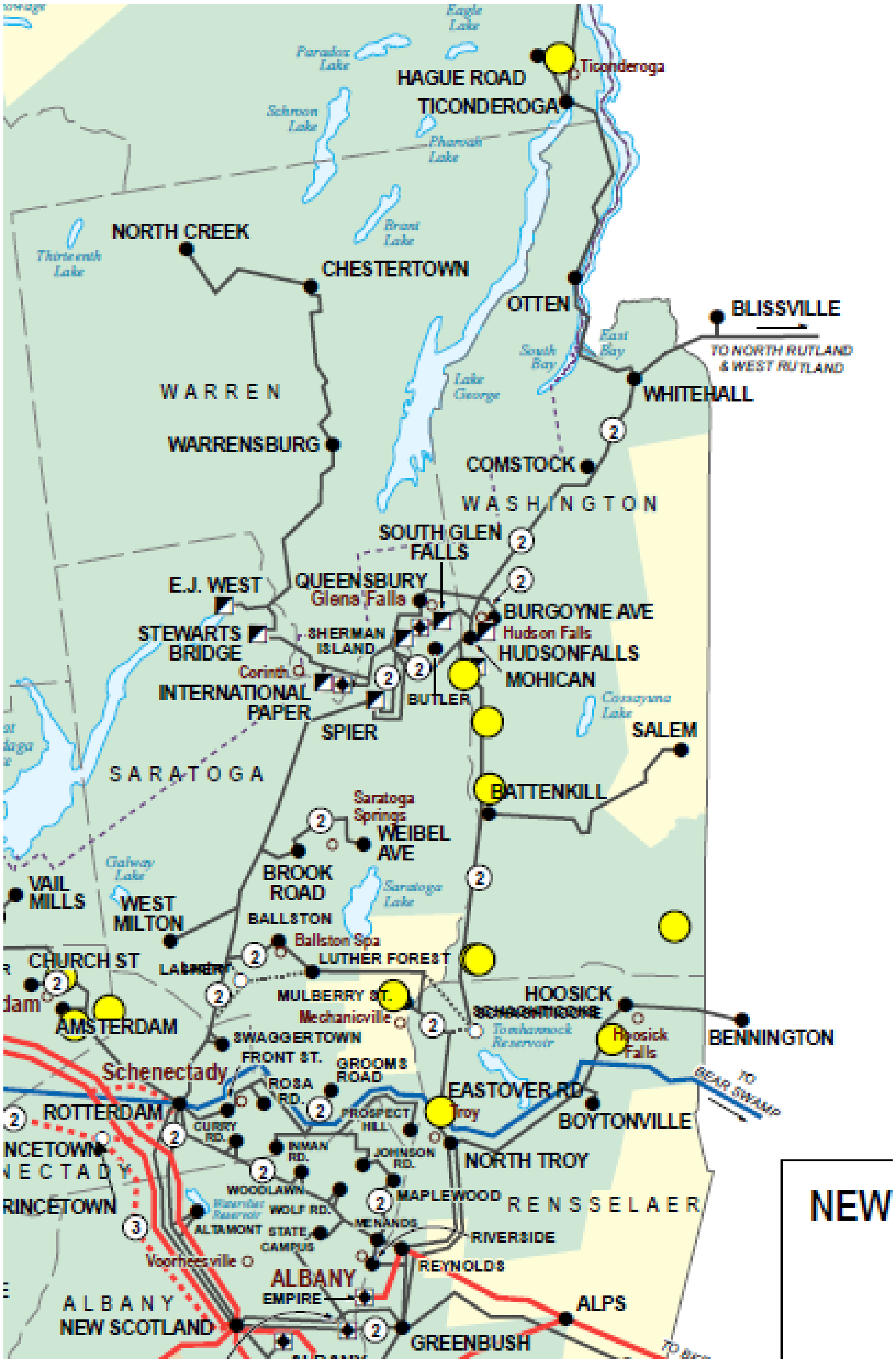
The Capital/Northeast Region (Figure 1 and Figure 2) is bordered by Rotterdam Station at the west end, New Scotland Station on the south end, the New England border on the east and stretches into the Adirondack Park in the north. This extensive meshed network includes a large number of 115kV circuits as well as an underlying 34.5kV system.

The system in this region is changing due to the construction of the Energy Highway Segment A and Segment B projects. All study efforts describe the post Segment A/B system as the existing system.

The study assumed that the interchange with New England would be neither importing or exporting by keeping it fixed at 0MW. Increased exports to New England would increase stress on some of the circuits in this region. It is unknown if periods of high export would coincide with periods of high renewable generation. If the high renewable periods do coincide with high exports to New England, further study would be necessary.

[redacted]

Figure 2: Capital/Northeast Transmission Map



While age is not always an indicator of condition, in the absence of condition assessments, the relative age of a circuit can provide some insight into how close the circuit may be to end of life refurbishment or replacement. Table 1 is a list of area circuits with the age of the oldest components.

Table 1: Transmission Circuit Age

Circuit	Year	Age	Mileage
Battenkill - Schaghticoke #310	1923	98	14.1
Lasher Rd - Luther Forest #43	1923	98	12.5
Luther Forest - Eastover Rd #308	1923	98	18.9
Mohican - Battenkill #15	1923	98	14.2
Mohican - Butler #18	1923	98	3.7
Mohican - Schaghticoke #309	1923	98	28.7
Rotterdam - Lasher Rd #1	1923	98	11.0
Rotterdam - Luther Forest #44	1923	98	23.4
Schaghticoke - Eastover #10	1923	98	8.6
Schaghticoke - Luther Forest #3	1923	98	10.7
Spier - Butler #4	1923	98	5.7
Spier - Mohican #7	1923	98	9.4
Spier - Queensbury #17	1923	98	9.5
Spier - Queensbury #5	1923	98	9.2
Spier Falls - Lasher Rd #2	1923	98	21.7
Spier Falls - Lasher Rd #302	1923	98	21.7
Whitehall - Cedar #6	1927	94	21.1
Whitehall - Mohican #13	1927	94	22.9
Queensbury - Cedar #10	1958	63	3.6

Currently Planned Reliability and Condition Driven Transmission Projects Proposed in the Region

All transmission projects identified as firm in the NYISO 2020 Gold Book were include in the study cases. Generally, projects are only listed in the Gold Book if they result in a modification to the system; such as a change in rating, change in impedance, or a change in system or station configuration. National Grid has other transmission projects in the medium to long term horizon. These projects are generally condition based projects. The following describes all major projects in the region, including some projects that are not expected to have an impact on the system. These projects were assessed as either having; a benefit to CLCPA as designed, a benefit to CLCPA if the project design was revised, or no benefit to CLCPA if revised. Those revised projects that have CLCPA benefits and lead to a significant increase in project cost are proposed as Phase 1 and Phase 2 project.

Reynolds Rd Station Refurbishment – At Reynolds Rd, many of the existing station components are planned for replacement. These replacements are not expected to result in any changes to the station configuration and will not impact the thermal rating of any circuits. No changes to the study base cases were required. The study included a desktop assessment of a scenario where the configuration of the station was modified, but the expanded project scope did not result in any system capacity benefits.

Mohican Station Refurbishment – At Mohican, many of the existing station components are planned for replacement. These replacements are not expected to result in any changes to the station configuration and will not impact the thermal rating of any circuits. No changes to the study base cases were required. The study included a desktop assessment of a scenario where the configuration of the station was modified, but the expanded project scope did not result in any identified system capacity benefits.

Spier Station Refurbishment – At Spier, many of the existing station components are planned for replacement. These replacements are not expected to result in any changes to the station configuration and will not impact the thermal rating of any circuits. No changes to the study base cases were required. The study included a desktop assessment of a scenario where the configuration of the station was modified, but the expanded project scope did not result in any identified system capacity benefits.

Ticonderoga 2 refurbishment – This project is addressing the condition of the radial Ticonderoga 2 115kV circuit. At this time the expectation is that this project will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. The study considered if expanding the project scope could have system capacity benefits. An increase in the rating of this circuit may result in additional flexibility for the placement of new generation in the headroom test but because this project is well underway, an upgrade to the line rating is not being pursued at this time.

Spier – Mohican 7 and 4/18 refurbishment – This project is addressing the condition of the Spier – Mohican, Spier – Butler and Butler – Mohican 115kV circuits. At this time the expectation is that this project will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. An increase in the rating of these circuits may result in additional flexibility for the placement of new generation in the headroom test but because this project is well underway, an upgrade to the line rating is not being pursued at this time.

Local Design Criteria

For purposes of this study, National Grid performed steady state testing in accordance with its Transmission Group Procedure 28 (TGP28), *National Grid Transmission Planning Criteria*. Simulations were performed to assess the system response with all elements in service (N-0) as well as for N-1 outage conditions. These N-1 tests included loss of a circuit, transformer, generator or shunt device as well as breakers opening without a fault, bus outages, faults with a breaker failure and double circuit tower outages. All testing was limited to steady state for N-0 and N-1 conditions.

The system response to these N-1 outages is generally considered acceptable when all local facilities are loaded below 100 percent of their Long-Term Emergency (LTE) rating. For pre-contingency conditions, loading is considered acceptable when all local facilities are loaded below 100 percent of their Normal (continuous) rating. The summer ratings are used in all cases. Acceptable post-contingency system voltages on the 115kV and 69kV system are between 90 percent of nominal and 105 percent of nominal and acceptable pre-contingency voltages are between 95 percent of nominal and 105 percent of nominal.

All solutions are required to meet the full set of local and regional Planning Criteria to ensure that the reliability of the planned system is not compromised. These criteria include dynamic, short circuit and expanded steady state requirements. Additional testing will be required for some proposed Phase 2 solutions to ensure that they are designed to conform with and adhere to all applicable North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), New York State Reliability Council ("NYSRC") Reliability Rules, as well as applicable National Grid specifications, procedures, and guidelines.

Test 1: 2030 Regional Congestion Assessment - Methodology and Assumptions

The Regional Congestion Assessment (Test 1) is meant to; 1) identify existing local system congestion in a planning region based on the 2030 load and generation input assumptions and 2) eliminate all identified congestion within the region through system upgrades.

This study is based upon the database established and used by the NYISO for the 2020 Reliability Needs Assessment (RNA) 70x30 CLCPA Scenario using generation buildout assumptions from the Congestion Assessment and Resource Integration Study (CARIS) 70x30 scenario. The three cases selected as the starting point for the 70x30 scenario studies were: (i) Day Peak Load of 30,000 MW; (ii) Shoulder Load of 21,500 MW; and (iii) Light Load of 12,500 MW. The load is modeled based on the 2020 Gold Book forecast for 2030, with the load distributed within the regions based on the same 2020 RNA cases.

Starting from the 70x30 scenario peak load, shoulder load, and light load cases created by the NYISO, National Grid built sensitivity cases examining different renewable dispatch conditions. These dispatch scenarios were communicated with neighboring utilities for their consideration and use in their study work. While developing the case dispatches, monitoring and correcting overloads and voltage limitations on the 345kV and 230kV systems was considered out of scope for this assessment of the local system performance.

All study cases used by National Grid assumed no fossil generation was operating in areas A (West) through F (Capital) and assumed that nuclear generators at Nine Mile 1, Nine Mile 2, and Fitzpatrick were all in service at maximum output and Ginna was assumed to be out of service. For the ties from New York to the external areas, no import or export was allowed from New York to PJM (across the free-flowing ties), New England or Ontario.

Hydro generation at Gilboa was set to maximum generation in the peak and shoulder cases and set to pumping in light load cases. In all cases, the Moses generation was set to maximum output. At the Niagara/Lewiston facility, Niagara was set to 2160MW, evenly distributed across the thirteen machines and Lewiston was set to either 240MW of generation or 360MW of pumping load depending on the case. Run of river hydro generation was set to typical seasonal values. The import of Hydro generation from Hydro Quebec was set to either 1110MW or 535MW. No hydro generation was imported to Dennison from the Cedars generation.

The above assumptions were modeled in each case, and Land Based Wind (LBW) and Utility Scale Photovoltaic (UPV) generation was then dispatched to various levels. In the National Grid testing, LBW, primarily located in Western, Central and Northern NY, was varied between 0 percent of nameplate up to 75 percent of nameplate and UPV, located primarily in Central, Northern and Eastern NY was dispatched between 0 percent of nameplate up to 70 percent of nameplate. Neither wind nor solar resources were modeled at 100 percent of nameplate.

The NYISO zonal data of hourly load, LBW output, and the UPV output from its CARIS 70x30 scenario was also reviewed for consistency with National Grid modeling assumptions. All dispatches modeled by National Grid were consistent with the NYISO CARIS 70x30 generation output levels assumed to be achieved for 100 hours or more. For example, a dispatch scenario model by National Grid was LBW greater than or equal to 30 percent of nameplate concurrent with UPV output greater than or equal to 27 percent. This dispatch occurred in the CARIS 70x30 scenario for 802 hours. Another example of the many scenarios studied by National Grid was LBW at 15 percent of nameplate and UPV at 52 percent of nameplate. The dispatch at or above this level occurred in the CARIS 70x30 scenario for 457 hours.

For the National Grid assessment, no assumptions were made for the generation mix in New York City or Long Island, including no specific assumptions for offshore wind, as the generation mix downstate does not have any impact on the result of testing within National Grid's service territory. However, for simplicity of developing the scenario cases, it was assumed that the flow across the UPNY – CONED interface would not exceed 7000MW.

Test 1: 2030 Regional Congestion Assessment - Modeled Existing and Proposed Generation

Several hydro generators are located in the area concentrated around Spier, which in aggregate total over 170MW. These generators were generally in service in all testing. The exception is several small units modeled as load modifiers by the NYISO were modeled as net with the area load.

As of 1/31/2021, the NYISO interconnection queue includes 320MW of solar and 20WM of storage proposing to connect to the area's local system. The projects are summarized in Table 2.

In the last 5 years an additional 140MW of generation proposing to connect into this area has withdrawn from the NYISO queue.

Table 2: Generation in the NYISO Interconnection Queue

Queue	MW	Type	Interconnection Point
0730	20	S	Mohican - Schaghticoke 115kV
0731	20	S	Battenkill - Eastover 115kV
0734	20	S	Ticonderoga 115kV - Republic Line 2
0735	20	S	Luther Forest - Mohican 115kV
0807	20	S	Eastover - Schaghticoke 115kV
0832	20	S	North Troy - Hoosick 115kV
0833	20	S	Battenkill - Mohican 115kV
0853	20	S	Mohican - Schaghticoke 115kV
0855	20	S	Mohican - Schaghticoke 115kV
1015	20	S	Mohican - Battenkill 115kV
1035	20	S	Battenkill Substation 34.5kV
1042	100	S	Mohican - Battenkill 115kV
1101	20	ES	Chestertown-Warrensburg #6

Table 3: 2019 CARIS Generation Additions Necessary to Meet the 70x30 Mandate

Bus	MW	Type	Interconnection Point
BATKILL	243	S	Battenkill Substation
IP_TICON	61	S	Ticonderoga 115kV - Republic Line 2
EASTOVER	61	S	Eastover Substation
N.TROY	61	S	North Troy Substation
MOHICAN	61	S	Mohican Substation

As previously stated, generator representation (e.g. type, size and location for new renewables) used in this assessment was based on the 2019 CARIS 70x30 sensitivity case. In addition to the hydro generation in the area, the study cases modeled 487MW of new renewable generation in the region (see Table 3). Figure 2 shows geographically where new resources were added, with each yellow dot representing a new solar generator location.

Test 1: 2030 Regional Congestion Assessment - Distributed Energy Resource Assumption

In addition to the generation proposed in the NYISO queue, Distributed Energy Resources (DER) have also proposed to connect to National Grid's distribution system. The DER queue for the region contains over 350MW of proposed generation and is almost entirely solar. The stations where the largest amount of solar DER is proposed is summarized in Table 4. While the DER was not explicitly modeled in the base cases, the proposed locations are similar to the proposed locations used to model the new resources (Table 3) needed to meet the 70x30 mandate. Because energy produced from DER may make its way from the distribution system to the transmission system through the existing transmission stations modeled in this study, DER is expected to have a similar impact as the generation directly connected to the transmission system and would benefit from the same projects identified as necessary to unbottle the region.

Table 4: Generation in the DER Interconnection Queue

Station	MW
ALTAMONT 283	18
BATTENKILL 342	12
BOYNTONVILLE 333	11
BROOK RD 369	12
FRONT ST 360	19
GLOVERSVILLE 72	20
GROOMS RD 345	24
HAGUE RD 418	18
HEMSTREET 328	18
HOOSICK 314	11
HUDSON 87	25
LASHER RD	15
N. TROY 123	25
ROTTERDAM 138	16
RUTH RD 381	11
SCHODACK 451	25
SODEMAN ROAD	20
SWAGGERTOWN 364	11
SYCAWAY 372	16
VOORHEESVILLE 178	16
WEIBEL AVE 415	18
ALTAMONT 283	18

Test 1: 2030 Regional Congestion Assessment - Study Results (System Bottlenecks)

Based on the study base cases, one area of congestion was identified that would constrain the output of renewable generation outside of this region. Overloads were found on the Rotterdam – Curry – Wolf and the Rotterdam – Woodlawn – State Campus circuits. The loading on these circuits was as high as 159% of LTE. [redacted]

[redacted] To understand what is causing the overloads, several tests were performed.

In the first test base cases for the heavy, shoulder and light load conditions were reviewed with no solar or wind generation in remote NYISO Zones assumed in service. For these cases, the loading on these circuits was less than 75% of LTE. The overloads only developed in cases with remote renewable generation in service. For the light load cases, overloads developed at wind dispatches above approximately 25%. For shoulder load overloads developed for solar dispatches above approximately 25%. In the heavy load cases overloads developed for solar dispatches of approximately 30%.

Next a test was performed to see if transfers on the bulk system, across the Central East interface, were causing or contributing to the overloads. The worst-case overloads of the Rotterdam 115kV circuits were as high as 125% of LTE. Testing was performed first with just the bulk system secured, then with just the 115kV lines secured and finally with both the bulk and 115kV circuits secured. For a heavy load case with wind dispatched to 30% and solar dispatched to 45%, securing only the local system would require 2570MW of generation reduction, securing only the bulk system would require 1840MW reduction and securing both the bulk and local systems would require 2490MW reduction. The local system is the most constraining portion of the system. Even with the bulk system secured, securing the local system in this testing would require an addition 650MW of generation reduction. Because of the amount of generation that needed to be curtailed, reductions occurred well away from the overloaded elements, with some curtailed generation as far away as northern NY.

It is also possible that the overloads on these local 115kV circuits at Rotterdam would become a binding constraint on the bulk interfaces, specifically becoming binding on Central East/Total East. If these local circuit overloads became the binding element on these interfaces, bulk transfers would have to be curtailed to prevent the overloads from occurring. The curtailment would require renewable generation reductions in Western, Central or Northern NY.

Table 5: Test 1 Capital/Northeast Facility Overloads

Facility	Worst Case Overload (% LTE)
Curry - Wolf	159
Rotterdam - Woodlawn	142
Rotterdam - Curry	122
Woodlawn - State Campus	121
Rotterdam 345/115kV TR6	92
Rotterdam 345/115kV TR7	90

Test 2: Capacity Headroom Test - Study Methodology

To further determine the areas that could cause congestion, a Capacity Headroom test was performed. According to the DPS Headroom Test whitepaper (Case 20-E-0197), Capacity Headroom uses the lowest identified optimal transfer value observed in a heavy, light and shoulder load case. This test was done using the Optimal Transfer feature in TARA. Unlike Test 1 where the location of the generation was based on generation identified by the NYISO in the 70X30 CARIS case, Test 2 involves assigning possible locations for generation to interconnect, then having the program determine which one or more of the sites is an optimal location and how much generation could connect. The optimized dispatch keeps all transmission elements in the pocket within acceptable loading for any N-0 or N-1 condition. The analysis does not distinguish between the type of generation, only estimates the capability for simultaneous output from generation within the local network.

Under Test 2, base cases are initialized with no solar or wind generation in service. Including no solar or wind generation in upstream or downstream locations or on the bulk power system. All other load, hydro and nuclear generation and system topology assumptions made in the Test 1 base case were held constant. For Test 2, it was assumed that generation could only be added to the existing 115kV switching stations in the region. The impact of adding generation to the middle of a line, which is likely not an optimal location, will not be captured. One of the limitations of this test is that the model can add a relatively large amount of generation into one site, ignoring or reducing the other options. To provide a more realistic indication of the headroom provided, a limit of 500MW was placed on all 115kV switch stations.

For this region, the selected 115kV buses were Whitehall, Mohican, Battenkill, Luther Forest, Spier, Queensbury, Lasher and Schaghticoke.

The amount and location of generation for each study base case is summarized in Table 6. The program identified several bottlenecks. [redacted] These circuits were likely not found to be binding in the other cases due to the lack of system throughflow due to the cases being initialized with no upstream generation in service. This can be seen from the differences between the cases with and without pumping. When hydro generation was pumping, the system throughflow was less than the throughflow when hydro was generating. The lower throughflow resulted in more headroom. The binding case for this region was the heavy load case, but the shoulder and light load cases showed similar results.

Table 6: Existing System Headroom

	Whitehall	Mohican	Battenkill	Luther Forest	Spier	Queensbury	Schaghticoke	Lasher	Total
Heavy Load	0	0	150	0	210	180	0	170	710
Heavy Load w/Pumping	0	0	0	190	180	0	0	480	850
Light Load	0	0	10	480	0	0	0	240	730
Light Load w/Pumping	0	0	0	470	0	0	0	340	810
Shoulder Load	0	0	0	230	0	0	0	530	760
Shoulder Load w/Pumping	0	0	0	270	0	0	0	530	800

Regional Transmission Plan: Recommended System Upgrades

Based on both the 2030 Regional Congestion Assessment (Test 1) and the Capacity Headroom test (Test 2), it is recommended that the Curry – Wolf, portions of the Rotterdam – Woodlawn and portions of the Woodlawn – State Campus circuits be reconductored. Upgrades of station components on these circuits and the Rotterdam – Curry circuit would also be required. Based on recent projects on other portions of these circuits, the project scope will include only replacement of the overhead 4/0 copper and 336 MCM ACSR conductor on these line sections. The project would cover about 16.5 circuit miles in 9 miles of right of way. Figure 3 is a simplified diagram of the area showing the approximate scope of work on these circuits.

Figure 3: Simplified Rotterdam – Menands configuration

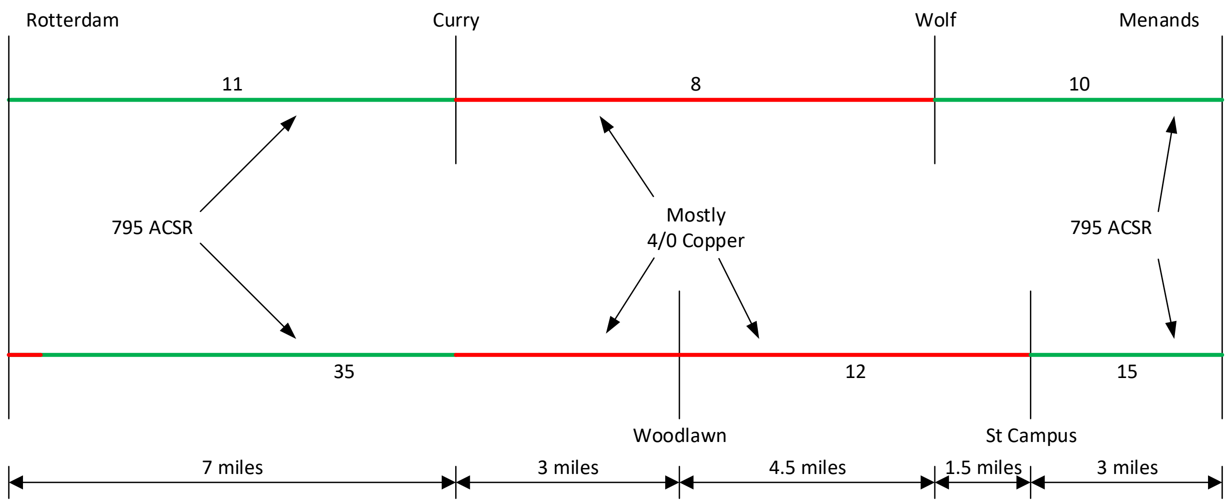


Table 7: Regional Project Plan Summary*

Project ID	Project Name	Phase	Project Description
NE1	Rotterdam – Wolf/State Campus 115kV Line Upgrades	Phase 2	115kV Upgrade: Rotterdam-Wolf, Rotterdam-State Campus

*No Phase 1 projects are proposed for this area

Regional Transmission Plan: Project Benefits

In the 2030 Regional Congestion Assessment, the proposed project eliminates the need for redispatching upstream generation to address transmission constraints within this pocket. Because the generation is remote to the overload, pre-project a large amount of generation adjustment would be required to reduce the loading. The project results in 650MW of upstream generation that will no longer be constrained, even in cases where other parts of the local and bulk system are already being secured.

Table 8: Project Congestion Benefits

System Configuration	Constraint (MW)
Existing System	650
All Phase 1 Projects Complete	650
All Phase 2 Projects Complete	0

The headroom test showed that the proposed project results in some increases in the area headroom. However, the headroom benefits are not as significant as the generation curtailment reduction found in the base case testing. This is due to the nature of the headroom test. The headroom test is done using base cases initialized with no generation in service. So, the impact of upstream generation and thus the improvement a project has on the ability to move upstream generation through the area can be understated.

Table 9: System Capacity Headroom Post Project

	Whitehall	Mohican	Battenkill	Luther Forest	Spier	Queensbury	Schaghticoke	Lasher	Total
Heavy Load	0	0	0	180	140	0	0	500	820
Heavy Load w/Pumping	0	0	0	210	150	0	0	500	860
Light Load	0	0	0	430	0	0	0	350	780
Light Load w/Pumping	0	0	0	470	0	0	0	340	810
Shoulder Load	0	0	0	230	40	0	0	500	770
Shoulder Load w/Pumping	0	0	0	260	50	0	0	500	810

Regional Transmission Plan: Project Alternatives

Alternatives that used power flow controllers were rejected as for these types of devices (Series Reactors or Capacitors, Phase Angle Regulators, Static Synchronous Series Compensators) to be effective, an alternative underutilized parallel path must be available to shift power onto. Screening of this option showed the potential for other facilities to become overloaded.

The use of advanced conductors, which have higher allowed operation temperature due to the material used in the conductor core, were not recommended in this area due to the expectation that the overload could be addressed by installing a standard ACSR conductor on the existing structures.

Regional Transmission Plan: Project Details

The Capital/Northeast pocket includes no Phase 1 projects and one Phase 2 project. The in-service date and detailed capital and operating cost estimates for all of the National Grid Phase 2 projects will be provided in future filings.

Albany South Region
Transmission and Renewable Generation Assessment
August 1, 2021

This review was undertaken to determine if portions of the local 115kV system in the region South of Albany would prevent the delivery of existing and proposed renewable generation. The Company examined multiple different generation dispatches for three different base case load scenarios; light load, shoulder load and heavy load. Upon identifying that the existing local transmission system would create constraints on renewable generation, several solutions were considered.

The conclusion of this analysis is that a new 345/115kV station should be built at Leeds, a Phase Angle Regulator needs to be added between Churchtown and Milan and that a 2-mile section of the Churchtown – Milan circuit needs to be rebuilt. The combination of these projects was found to reduce the area curtailment from 670MW to 90MW. Separately a headroom test was performed where the optimal location and size of generation was identified before and after the proposed reinforcements. This headroom test found that the projects increased headroom by about 730MW.

This region contains Phase 1 and Phase 2 projects. The Leeds 345/115kV station and the PAR are considered Phase 2, the line rebuild is included in Phase 1.

Existing System Overview

The system South of Albany is changing due to the construction of the Energy Highway Segment B projects. All study efforts describe the post Segment B system as the existing system.

As can be seen in Figure 1, the system in this region consists of several 115kV lines leaving Albany and heading south to Churchtown with a single line from Churchtown to Milan. Two 115kV lines connect between New Scotland and Feura Bush, with one 115kV line continuing from Feura Bush to North Catskill to Churchtown. A single 115kV line connects New Scotland, Long Lane, Lafarge and Churchtown. A single 115kV line connects Greenbush and Churchtown, looping into Schodack, Valkin, Falls Park and Hudson. The 115kV line from Churchtown to Milan connects to Blue Stores. One line also connects between Feura Bush and Greenbush. A radial Avangrid circuit connects from Churchtown to Craryville and Klinekill.

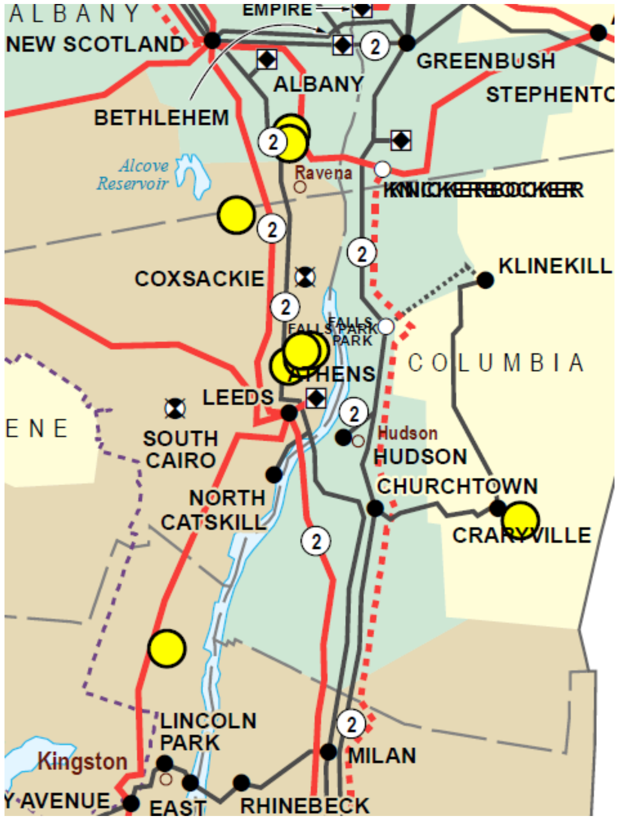
A Central Hudson owned 69kV system connects to North Catskill, Hurley and Sturgeon.

While other connections exist between New Scotland and Greenbush, such as those connecting through Albany Station, these circuits were not found to be material to this analysis.

In all analysis National Grid monitored facilities adjacent to this area that were owned by Avangrid and Central Hudson. All recommendations were developed considering if upgrades to the Avangrid or Central Hudson system could address issues on the National Grid system. The Company has collaborated with neighboring utilities and all recommended upgrades were shared with other Transmission Owners and their comments were considered before finalizing plans.

[redacted]

Figure 2. Albany South Transmission Map



While age is not always an indicator of condition, in the absence of condition assessments, the relative age of a circuit can provide some insight into how close the circuit may be to end of life refurbishment or replacement. Table 1 is a list of area circuits with the age of the oldest components.

Table 1: Transmission Circuit Age

Circuit	Year	Age	Mileage
Lafarge - Pleasant Valley #8	1923	98	60.4
Long Lane - Lafarge #6	1923	98	7.7
New Scotland - Feura Bush #9	1923	98	4.1
New Scotland - Long Lane #7	1923	98	4.2
Churchtown - Pleasant Valley #13-987	1932	89	42.8
Falls Park - Churchtown # 11-731	1932	89	
Feura Bush - North Catskill #2	1932	89	24.8
Greenbush - Hudson #15	1932	89	26.4
Greenbush - Schodack #13	1932	89	4.4
Hudson - Pleasant Valley #12	1932	89	39.2
Milan - Pleasant Valley #10	1932	89	16.8
North Catskill - Milan #T7	1932	89	26.8
Schodack - Falls Park #14-730	1932	89	21.5
Greenbush - Feura Bush #17	1964	57	10.9
New Scotland - Feura Bush #3	1965	56	5.3

Planned Reliability and Condition Driven Transmission Projects

All transmission projects identified as firm in the NYISO 2020 Gold Book were include in the study cases. Generally, projects are only listed in the Gold Book if they result in a modification to the system; such as a change in rating, change in impedance, or a change in system or station configuration. National Grid has other transmission projects in the medium to long term horizon. These projects are generally condition based projects. The following describes all major projects in the region, including some projects that are not expected to have an impact on the system. These projects were assessed as either having; a benefit to CLCPA as designed, a benefit to CLCPA if the project design was revised, or no benefit to CLCPA if revised. Those revised projects that have CLCPA benefits and lead to a significant increase in project cost are proposed as Phase 1 and Phase 2 project.

Greenbush - 115kV & 34.5kV Station Refurbishment – At Greenbush, many of the existing station components are planned for replacement. At this time the expectation is that this project will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. The study considered if expanding the project scope could have system capacity benefits. The study included a desktop assessment of a scenario where the configuration of the station was modified, but the expanded project scope did not result in any identified system capacity benefits.

Feura Bush - N. Catskill refurbishment – The National Grid 10-year plan includes funding for refurbishment work on the Feura Bush - N. Catskill 115kV circuit. At this time the expectation is that this project will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. The study included a desktop assessment of a scenario where the rating of this circuit was increased, but the expanded project scope did not result in any identified system capacity benefits. An increase in the rating of these circuits, which would be achieved by a complete rebuild, would result in additional flexibility for the placement of new generation in the headroom test, especially when combined with the following project. However, a rebuild of these circuits would not change the recommendations made in this study. During the development of the project, an option to rebuild with lines will be considered further.

New Scotland-Feura Bush/Long Lane refurbishment – The National Grid 10-year plan includes funding for refurbishment work on the New Scotland-Feura Bush/Long Lane 115kV circuits. At this time the expectation is that this project will not result in a rating increase or an impedance change and thus no changes to the study base cases were required. The study included a desktop assessment of a scenario where the rating of this circuit was increased, but the expanded project scope did not result in any identified system capacity benefits. An increase in the rating of these circuits, which would be achieved by a complete rebuild, would result in additional flexibility for the placement of new generation in the headroom test, especially when combined with the previous project. However, a rebuild of these circuits would not change the recommendations made in this study. During the development of the project, an option to rebuild with lines will be considered further.

Local Design Criteria

For purposes of this study, National Grid performed steady state testing in accordance with its Transmission Group Procedure 28 (TGP28), *National Grid Transmission Planning Criteria*. Simulations were performed to assess the system response with all elements in service (N-0) as well as for N-1 outage conditions. These N-1 tests included loss of a circuit, transformer, generator or shunt device as well as breakers opening without a fault, bus outages, faults with a breaker failure and double circuit tower outages. All testing was limited to steady state for N-0 and N-1 conditions.

The system response to these N-1 outages is generally considered acceptable when all local facilities are loaded below 100 percent of their Long-Term Emergency (LTE) rating. For pre-contingency conditions, loading is considered acceptable when all local facilities are loaded below 100 percent of their Normal (continuous) rating. The summer ratings are used in all cases. Acceptable post-contingency system voltages on the 115kV and 69kV system are between 90 percent of nominal and 105 percent of nominal and acceptable pre-contingency voltages are between 95 percent of nominal and 105 percent of nominal.

All solutions are required to meet the full set of local and regional Planning Criteria to ensure that the reliability of the planned system is not compromised. These criteria include dynamic, short circuit and expanded steady state requirements. Additional testing will be required for some proposed Phase 2 solutions to ensure that they are designed to conform with and adhere to all applicable North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), New York State Reliability Council ("NYSRC") Reliability Rules, as well as applicable National Grid specifications, procedures, and guidelines.

Test 1: 2030 Regional Congestion Assessment - Methodology and Assumptions

The Regional Congestion Assessment (Test 1) is meant to; 1) identify existing local system congestion in a planning region based on the 2030 load and generation input assumptions and 2) eliminate all identified congestion within the region through system upgrades.

This study is based upon the database established and used by the NYISO for the 2020 Reliability Needs Assessment (RNA) 70x30 CLCPA Scenario using generation buildout assumptions from the Congestion Assessment and Resource Integration Study (CARIS) 70x30 scenario. The three cases selected as the starting point for the 70x30 scenario studies were: (i) Day Peak Load of 30,000 MW; (ii) Shoulder Load of 21,500 MW; and (iii) Light Load of 12,500 MW. The load is modeled based on the 2020 Gold Book forecast for 2030, with the load distributed within the regions based on the same 2020 RNA cases.

Starting from the 70x30 scenario peak load, shoulder load, and light load cases created by the NYISO, National Grid built sensitivity cases examining different renewable dispatch conditions. These dispatch scenarios were communicated with neighboring utilities for their consideration and use in their study work. While developing the case dispatches, monitoring and correcting overloads and voltage limitations on the 345kV and 230kV systems was considered out of scope for this assessment of the local system performance.

All study cases used by National Grid assumed no fossil generation was operating in NYISO Zone A (West) through F (Capital) and assumed that nuclear generators at Nine Mile 1, Nine Mile 2, and Fitzpatrick were all in service at maximum output and Ginna was assumed to be out of service. For the ties from New York to the external areas, no import or export was allowed from New York to PJM (across the free-flowing ties), New England or Ontario.

Hydro generation at Gilboa was set to maximum generation in the peak and shoulder cases and set to pumping in light load cases. In all cases, the Moses generation was set to maximum output. At the Niagara/Lewiston facility, Niagara was set to 2160MW, evenly distributed across the thirteen machines and Lewiston was set to either 240MW of generation or 360MW of pumping load depending on the case. Run of river hydro generation was set to typical seasonal values. The import of Hydro generation from Hydro Quebec was set to either 1110MW or 535MW. No hydro generation was imported to Dennison from the Cedars generation.

The above assumptions were modeled in each case, and Land Based Wind (LBW) and Utility Scale Photovoltaic (UPV) generation was then dispatched to various levels. In the National Grid testing, LBW, primarily located in Western, Central and Northern NY, was varied between 0 percent of nameplate up to 75 percent of nameplate and UPV, located primarily in Central, Northern and Eastern NY was dispatched between 0 percent of nameplate up to 70 percent of nameplate. Neither wind nor solar resources were modeled at 100 percent of nameplate.

The NYISO zonal data of hourly load, LBW output, and the UPV output from its CARIS 70x30 scenario was also reviewed for consistency with National Grid modeling assumptions. All dispatches modeled by National Grid were consistent with the NYISO CARIS 70x30 generation output levels assumed to be achieved for 100 hours or more. For example, a dispatch scenario model by National Grid was LBW greater than or equal to 30 percent of nameplate concurrent with UPV output greater than or equal to 27 percent. This dispatch occurred in the CARIS 70x30 scenario for 802 hours. Another example of the many scenarios studied by National Grid was LBW at 15 percent of nameplate and UPV at 52 percent of nameplate. The dispatch at or above this level occurred in the CARIS 70x30 scenario for 457 hours.

For the National Grid assessment, no assumptions were made for the generation mix in New York City or Long Island, including no specific assumptions for offshore wind, as the generation mix downstate does not have any impact on the result of testing within National Grid's service territory. However, for simplicity of developing the scenario cases, it was assumed that the flow across the UPNY – CONED interface would not exceed 7000MW.

Test 1: 2030 Regional Congestion Study Assessment - Modeled Existing and Proposed Generation

As of 1/31/2021, the NYISO interconnection queue includes 390MW of solar and 120MW of storage proposing to connect to the area's local system. The projects are summarized in Table 2.

In the last 5 years an additional 400MW of generation proposing to connect into this area has withdrawn from the NYISO queue. While some of these projects may have withdrawn due to siting or financing issues, it is believed that some projects have withdrawn due to insufficient transmission capability.

Table 2: Generation in the NYISO Interconnection Queue

Queue	MW	Type	Interconnection Point
0570	20	S	Long Lane - Lafarge 115kV
0572	20	S	Coxsackie - North Catskill 69kV
0573	10	S	Coxsackie Substation 13.8kV
0577	20	S	New Baltimore - Coxsackie 69 kV
0597	20	S	North Catskill - Coxsackie 69kV
0598	20	S	Long Lane - Lafarge 115kV
0637	100	S	LaFarge - Churchtown, Feura Bush - North Catskill 115kV
0644	60	S	Craryville Substation 115kV
0694	20	S	New Baltimore - Westerlo 69 kV
0770	20	ES	South Cairo Substation 13.2kV
0779	20	S	New Baltimore - Westerlo 69kV
0952	100	ES	North Catskill - Milan 115kV
1018	20	S	Churchtown 115kV Substation
1027	20	S	Valkin - Greenbush 115kV
1029	20	S	Valkin - Greenbush 115kV
1100	20	S	Greenbush-Valkin 115kV

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Table 3: 2019 CARIS Generation Additions Necessary to Meet the 70x30 Mandate

Bus	MW	Type	Interconnection Point
JMC1_7TP	61	S	Long Lane 115kV
BLUECIRC	61	S	Long Lane - Churchtown
INDC_BKL	305	S	Long Lane - Churchtown
CRARY115	183	S	Craryville 115kV
N.CAT.1	962	S	North Catskill 115kV

As previously stated, generator representation (e.g. type, size and location for new renewables) used in this assessment was based on the 2019 CARIS 70x30 sensitivity case. These cases modeled 1572MW of solar in the region (see Table 3). Figure 2 shows geographically where new resources were added, with each yellow dot representing a new solar generator location

The base cases assume 427MW of solar generation connected between Long Lane and Churchtown, 962MW of solar connected between Feura Bush and Churchtown and 183MW of solar generation connected to a radial line connected to Churchtown.

<u>Test 1: 2030 Regional Congestion Assessment - Proposed Distributed Energy Resources</u>

In addition to the generation proposed in the NYISO queue, Distributed Energy Resources (DER) have also proposed to connect to National Grid's distribution system. The DER queue for the region contains over 70MW of proposed solar generation. This area has less DER than other portions of the system because there are few distribution stations. The stations where the largest amount of solar DER is proposed is summarized in Table 4. While the DER was not explicitly modeled in the base cases, the proposed locations are similar to the proposed locations used to model the new resources (Table 3) needed to meet the 70x30 mandate. Because energy produced from DER may make its way from the distribution system to the transmission system through the existing transmission stations modeled in this study, DER is expected to have a similar impact as the generation directly connected to the transmission system and would benefit from the same projects identified as necessary to unbottle the region.

Table 4: Generation in the DER Interconnection Queue

Station	MW
Hudson	37
Schodack	25
Valkin	10

Test 1: 2030 Regional Congestion Assessment - Study Results (System Bottlenecks)

Based on the study base cases, the entire area was found to be heavily loaded during periods of solar generation creating a wide area of congestion (generation pocket). The largest overloads are summarized in Table 5. Four main contingency overloads were identified. However, pre-contingency overloads were also found with Feura Bush – Churchtown at 212% of normal, Greenbush – Churchtown at 123% of normal and Churchtown – Milan at 204% of normal.

[redacted]

Table 5: Test 1 Albany South Facility Overloads

Facility	Worst Case Overload (% LTE)
Feura Bush - North Catskill	252
Blue Stores - Milan	236
Milan - Pleasant Valley	223
North Catskill - Churchtown	214
Churchtown - Blue Stores	208
Long Lane - Lafarge	193
Hudson - Churchtown	186
New Scotland - Long Lane	177
Lafarge - Churchtown	174
Falls Park - Hudson	173
Greenbush - Schodack	130
Valkin - Falls Park	127
Schodack - Valkin	124

To address all these constraints 670MW of generation had to be curtailed in the heavy load case with solar dispatched to 70% of nameplate. With 670MW curtailed, only 410MW could be delivered. The shoulder and light load case were not tested with solar dispatched to 70% of nameplate. If these load levels were reviewed with solar dispatched to this level, it is likely that higher level of curtailments would need to occur to address these constraints, meaning less generation could be delivered.

Test 2: Capacity Headroom Test - Methodology and Results

To further determine the areas that could cause congestion, a Capacity Headroom test was performed. According to the DPS Headroom Test whitepaper (Case 20-E-0197), Capacity Headroom uses the lowest identified optimal transfer value observed in a heavy, light and shoulder load case. This test was done using the Optimal Transfer feature in TARA. Unlike Test 1 where the location of the generation was based on generation identified by the NYISO in the 70X30 CARIS case, Test 2 involves assigning possible locations for generation to interconnect, then having the program determine which one or more of the sites is an optimal location and how much generation could connect. The optimized dispatch keeps all transmission elements in the pocket within acceptable loading for any N-0 or N-1 condition. The analysis does not distinguish between the type of generation, only estimates the capability for simultaneous output from generation within the local network.

Under Test 2, base cases are initialized with no solar or wind generation in service. Including no solar or wind generation in upstream or downstream locations or on the bulk power system. All other load, hydro and nuclear generation and system topology assumptions made in the Test 1 base case were held constant. For Test 2, it was assumed that generation could only be added to the existing 115kV switching stations in the region. The impact of adding generation to the middle of a line, which is likely not an optimal electric location, will not be captured. One of the limitations of this test is that the model can add a relatively large amount of generation into one site, ignoring or reducing the other options. To provide a more realistic indication of the headroom provided, a limit of 500MW was placed on all 115kV switch stations.

For this region, the selected 115kV buses were Churchtown, Hudson, Schodack, Lafarge, North Catskill, Long Lane and Feura Bush. Originally Falls Park was also a location, but testing showed that generation at Falls Park was nearly interchangeable with Hudson and Schodack.

The amount and location of generation for each study base case is summarized in Table 6. The program identified the same bottlenecks as were identified in the RNA/CARIS base cases with one addition. The Green Bush – Feura Bush line was also found to limit the location and size of the ideal generation. The binding case for this region was the light load case, but other cases found similar headroom.

The headroom test showed higher amounts of generation could be located within the pocket compared to the 2030 Regional congestion Assessment (Test 1). This is partially due to the headroom test identifying the ideal locations. However, the lack of system throughflow due to minimal upstream generation is also believed to result in the ability to add additional generation in the headroom test. The lack of throughflow is the cause of the difference between the cases with and without pumping.

Table 6: Existing System Capacity Headroom (MW)

	Churchtown	Hudson	Schodack	Lafarge	N Catskill	Long Ln	Feura Bush	Total
Heavy Load	80	70	60	30	280	140	150	810
Heavy Load w/Pumping	140	20	60	50	270	130	140	810
Light Load	0	0	130	0	260	140	180	710
Light Load w/Pumping	0	40	100	10	280	140	170	740
Shoulder Load	0	0	140	0	250	150	190	730
Shoulder Load w/Pumping	0	10	120	20	260	160	180	750

Regional Transmission Plan: Recommended System Upgrades

The overloads identified in the 2030 Regional Congestion Assessment were originally found on approximately 150 miles of 115kV conductor. Testing showed that an option based on rebuilding existing 115kV line would require replacement of approximately 90 circuit miles. Even with all this conductor replaced to maximize the rating, the system would continue to be configured as three lines from the Albany area to Churchtown and one line from Churchtown to Milan, creating a bottleneck at Churchtown.

To provide a new exit for the area, the recommended solution is to start with building a 345/115kV onramp. After a review of potential options, the recommendation is to expand the Leeds 345kV station to add two 345/115kV transformers. A new 115kV switchyard will need to be constructed at Leeds. The proposed configuration is for the new 115kV station to loop the Feura Bush – Churchtown and Long Lane – Churchtown circuits into the new station. From the new Leeds 115kV station two new 115kV circuits will provide a radial supply to the existing North Catskill station. The existing and proposed system at Leeds and North Catskill is shown in Figure 3.

Even with the new 345/115kV onramp, it will be necessary to install a Phase Angle Regulator on the Churchtown – Milan circuit to control the area throughflow and thus the loading on that circuit. To maximize the utilization of the 115kV and the PAR, it is recommended to replace a 2-mile section of the Churchtown – Milan circuit that loops into the Blue Stores station to maximize the circuit rating. This line has several condition related issues and a project was already being considered but had not yet been included in National Grid's plans. The PAR and 2-mile line upgrade do not eliminate the need for the 345/115kV station but are necessary to capture the full benefits of the new 345kV exit.

Figure 3. Existing and Proposed System Near Leeds and North Catskill

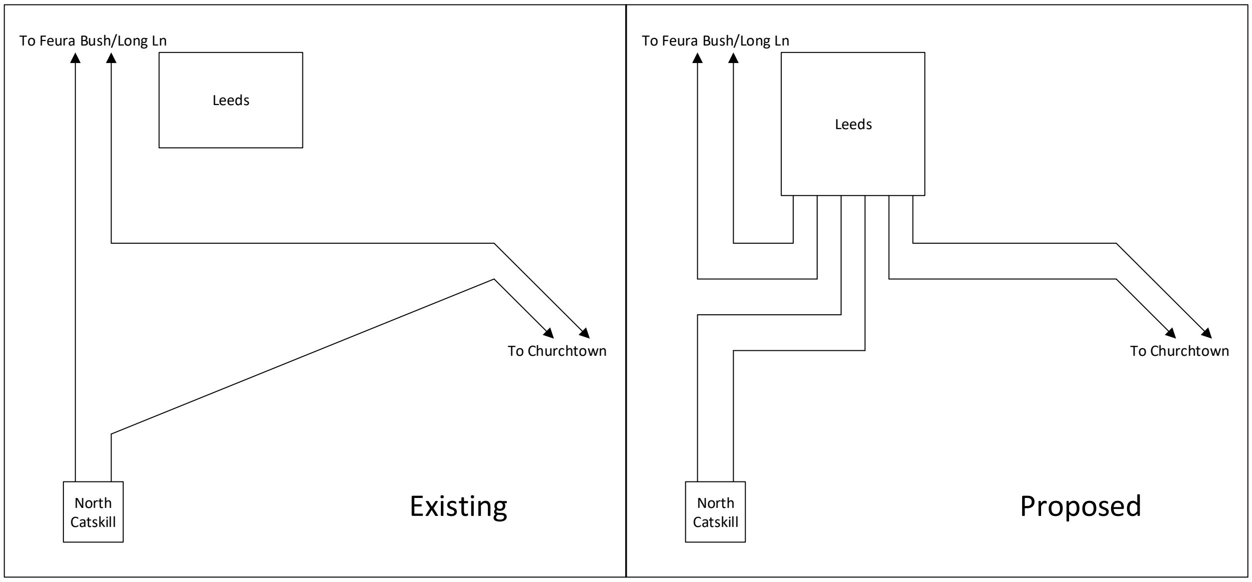

Table 7: Regional Project Plan Summary

Project ID	Project Name	Phase	Project Description
AS1	Churchtown– Pleasant Valley 115kV Upgrades	Phase 1	115kV Upgrade: sections of Churchtown- Pleasant Valley
AS2	Albany 115kV PAR	Phase 2	Add a 115kV Phase Angle Regulator or SSSC South of Albany
AS3	Leeds Station Upgrade	Phase 2	Expand Leeds to a 345/115kV Station

Regional Transmission Plan: Project Benefits

In the 2030 Regional Congestion Assessment some benefits were identified with just the 2-mile section of the Churchtown – Milan circuit replaced. After the Phase 2 projects are completed, congestion is reduced from 670MW to 90MW.

Table 8: Project Congestion Benefits

System Configuration	Constraint (MW)
Existing System	670
All Phase 1 Projects Complete	450
All Phase 2 Projects Complete	90

The headroom test assumes that in addition to the regional upgrades proposed above, existing terminal equipment limitations on the Greenbush – Feura Bush circuit, the North Catskill – Churchtown circuit and limitations at Greenbush and Hudson on the Greenbush – Churchtown circuit are addressed by the planned station refurbishment projects and the Segment B project. If these terminal equipment limitations are not addressed by other projects, or are not addressed soon enough, additional projects may be necessary to increase these circuit ratings.

Table 9: Phase 1 System Capacity Headroom, 115kV Circuit Rebuild Only

	Churchtown	Hudson	Schodack	Lafarge	N Catskill	Long Ln	Feura Bush	Total
Heavy Load	240	20	20	70	290	110	250	1000
Heavy Load w/Pumping	240	20	20	70	280	100	250	980
Light Load	250	10	10	70	300	80	250	970
Light Load w/Pumping	240	10	10	70	290	80	240	940
Shoulder Load	250	10	10	80	300	100	260	1010
Shoulder Load w/Pumping	250	10	10	80	290	100	260	1000

Table 10: Phase 1& 2 System Capacity Headroom

	Churchtown	Hudson	Schodack	Lafarge	N Catskill	Long Ln	Feura Bush	Total
Heavy Load	270	160	90	0	500	150	300	1470
Heavy Load w/Pumping	270	170	70	0	500	150	300	1460
Light Load	260	80	140	0	500	140	330	1450
Light Load w/Pumping	260	90	130	0	500	140	320	1440
Shoulder Load	250	80	140	0	500	140	340	1450
Shoulder Load w/Pumping	260	100	120	0	500	140	330	1450

Regional Transmission Plan: Project Alternatives

Alternatives considered to the recommended solution were:

Alternatives to the PAR – Instead of using a PAR on the Churchtown – Milan circuit, it may be feasible to use a series reactor or a Static Synchronous Series Compensator (SSSC) such as the Smart Wires system to achieve the same overload correction. A series reactor would not provide any control over the flow but may be less expensive than either of the other options. The SSSC would provide similar control to the PAR. As the project is developed, an additional review of the cost and feasibility of these options will be performed.

Circuit Rebuilds – an option was developed that avoided adding a 345/115kV onramp by rebuilding many of the existing 115kV circuit with larger conductor. The rebuilt circuits would include the New Scotland – Long Lane – Lafarge – Churchtown circuits, the New Scotland – Feura Bush – North Catskill – Churchtown circuits and portions of the Greenbush – Churchtown path. In total 41 miles of double circuit towers (82 circuit miles) and 6 miles of single circuit towers would need to be rebuilt. The option would also still require a series reactor, PAR or SSSC or the Churchtown – Milan circuit. This option would allow the series reactors on the New Scotland – Long Lane and New Scotland – Feura Bush circuits to be removed, which would increase flows towards New Scotland and increase area capability. Because of the amount of circuit rebuilds that would be required for this option, it is expected to be significantly more expensive then the recommended option. Moreover, only about 10% of the total project cost is already in the 10-year plan as Asset Condition work.

Dynamic Line Ratings, which can increase the rating of existing circuits without any conductor replacements would not provide a sufficient increase to address the identified overloads.

Alternatives that used power flow controllers were rejected as options on the overloaded circuits north of Churchtown as for these types of devices (Series Reactors or Capacitors, Phase Angle Regulators, Static Synchronous Series Compensators) to be effective, an alternative underutilized parallel path must be available to shift power onto. No underutilized parallel paths exist in this area.

Regional Transmission Plan: Project Details

The Albany South pocket includes one Phase 1 projects and two Phase 2 projects. The in-service date and detailed capital and operating cost estimates for all of the National Grid Phase 2 projects will be provided in future filings.

The tables below provide specific Phase 1 project details. It is important to note the information provided is based on current estimates and will continue to improve in accuracy as the project engineering design and execution matures.

Table 14: Phase 1 Project Description

Project ID	Project Title	Scope	Additional ROW Required
AS1	LN13 Churchtown - Pleasant Valley - Blue Stores Tap 115kV	This project will rebuild 2.12 miles of the Churchtown - Pleasant Valley T5090 #14 from Str 265 to Blue Stores Substation. This requires the removal of twenty-four (24) wood structures and the installation of twenty (20) steel davit arm suspension structures, one (1) steel h-frame dead-end structure, one (1) steel davit arm dead-end structure, one (1) steel vertical dead-end pull off structure, and one (1) steel 3-pole dead-end pull off structure. The existing 795 kcmil ACSR 36/1 "COOT" will be replaced with two (2) bundled 795 ACSR 26/7 “Drake” conductor, and existing shield wire with one (1) 3/8” steel and one (1) OPGW.	No

Table 15: Phase 1 Estimated Construction Milestones

	Blue Stores Tap
Final Engineering Complete	19-Jun-23
Construction Start	16-Aug-23
Ready for Load	13-Oct-23

Table 16: Phase 1 Estimated Project Spend Profile

Blue Stores Tap

AS1	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capex	50	450	4,217	832	-	-	-	-	-	-	5,549
Opex	-	-	820	164	-	-	-	-	-	-	984
Removal	-	-	146	29	-	-	-	-	-	-	175
Total	50	450	5,183	1,025	-	-	-	-	-	-	**6,708**

Appendix C

Niagara Mohawk Phase 1 Facility Charge

TABLE OF CONTENTS

GENERAL INFORMATION

SERVICE FORMS

70. Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge ("Phase 1 Facility Charge")

70.1 The Phase I Facility Charge will recover the deferred carrying charges, depreciation expense and operating expenses for local transmission upgrades associated with the Initial Phase I Projects that support New York State's energy goals under the Climate Leadership and Community Protection Act, in accordance with the Commission's Phase I Order in Case 20-E-0197, that are not otherwise recovered in base delivery rates.

70.1.1 Carrying charges will be recovered at the Company's pre-tax weighted average cost of capital ('WACC").

70.1.2 Any unrecovered costs will be included for recovery in the Company's next rate case filing.

70.1.3 The Phase I Facility Charge will include costs associated with projects placed in service during the previous fiscal year and will include any over/under reconciliation as specified in Rule 70.5. Costs will be recovered on a two-month lag following the end of the fiscal year.

70.2 The amount to be recovered shall be allocated to applicable service classifications based on the percent allocation of transmission revenue in the Company's most current embedded cost of service study, as specified in Rule 43.6. Customers taking service under SC-4 and SC-7 shall be subject to the Phase I Facility Charge rates of their parent service classification.

70.3 The amounts to be recovered from each parent service classification as determined in Rule 70.2 above shall be divided by the respective parent service classification's forecast sales associated with the corresponding annual period which the surcharge will be collected from customers.

70.4 The Phase I Facility Charge rates will be applied to a customer's actual billed consumption and applicable to customers serviced under PSC No. 220 service classifications No. 1, 1-C, 2 Non-demand, 2 demand, 3, 3-A, 4 and 7 and all PSC No. 14 service classifications. The Phase I Facility Charge will also be applied to a customer's deliveries associated with NYPA load, including ReCharge New York load, and may be applicable to PSC No. 220 service classification No. 12 in accordance with the terms of their individual contracts.

70.4.1 The Phase I Facility Charge is not applicable to Empire Zone and Excelsior Jobs Program qualifying load.

70.4.2 The Phase I Facility Charge shall be recovered from customers on a per kWh basis for non-demand service classes, a per kW basis for demand service classes, and a Contract Demand basis for SC7 customers, if applicable.

70.5 The Phase I Facility Charge will be subject to an annual true-up, with any over/under collection at the end of the annual collection period, inclusive of carrying charges at the Company's pre-tax WACC, to be included in the balance for refund or recovery in the next annual period, or in future base delivery rates as applicable.

70.6 The Phase I Facility Charge shall be shown on statements filed with the Public Service Commission apart from this rate schedule not less than fifteen (15) days before its effective date.

GENERAL INFORMATION

34. ECONOMIC DEVELOPMENT PROGRAMS: (Continued)

34.3 Program 2 - Empire Zone Rider (EZR) (Continued)

34.3.2.3 An electric customer who submeters electricity to customers certified under this program is eligible for the rates for that portion of the purchases deemed eligible by the zone administrator but subject to all rules and provisions of P.S.C. No. 220 Electricity governing submetering.

34.3.3 Alternate Billing Methodology: Non Separated EZR Load

34.3.3.1 For customers taking service under Program 2 (EZR) and who have elected not to separately meter incremental load, the Company will administer EZR discounts according to Rule 34.2.3, Rule 34.3.3.3, and Rule 34.3.4.

34.3.3.2 Customers served under the EZR program who do not separately meter their load shall only be exempt from Rule 41- System Benefits Charge (“SBC”), Rule 43-Transmission Revenue Adjustment, Rule 49 – Earnings Adjustment Mechanism,Rule 64 - Dynamic Load Management Surcharge on Qualifying EZR Load, and Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge. Rule 41.2.3 sets forth the grandfathering provision for customers who have previously elected to pay the SBC on their exempt load.

34.3.3.3 For eligible Service Classification No. 7 customers, the alternate billing methodology used to separate incremental EZR load from Service Classification No. 7 load (i.e., base load), as provided in Rule 34.2.3 shall be modified as provided herein.

34.3.3.3.1 The customer’s total facility load shall replace the billing metered units in the determination of the base period billing units specified in Rule 34.2.3.1. The total facility load represents the customer’s load excluding power and energy supplied by the customer’s on-site generation, and shall be calculated on a interval-by-interval basis as the sum of the generation metered units and the billing metered units minus any excess generation metered units that are delivered back to the Company’s electric system. In the event power and energy was supplied by on-site generation during the 12-month period used to calculate the base year billing determinants and generation interval-by-interval metering data was not available for all or part of the 12-month period, the Company shall estimate the total facility load.

34.3.3.3.2 In each billing period, the total facility load shall be determined by adding, on a metered interval-by-interval basis, the generation demand and energy values to the billing demand and energy values, minus any excess generation demand and energy values that are delivered back to the Company’s electric system. The total facility load demand and energy shall replace the current month’s demand and energy specified in Rule 34.2.3.2 in the determination of the customer’s eligibility for EZR benefits in the applicable Billing Period, the customer’s EZR demand and energy available for the EZR discount, and the Company billing demands and energy for non-EZR service.

GENERAL INFORMATION

34. ECONOMIC DEVELOPMENT PROGRAMS: (Continued)

34.7 Program 6 - Excelsior Jobs Program ("EJP") (Continued)

34.7.4 Electric Pricing For Qualifying EJP Load

34.7.4.1 Unless otherwise taking service under Rule 31, NYPA Supply Service or Rule 39, Retail Access Program, customers served under Program 6, EJP shall be subject to Electricity Supply Cost in accordance with Rule 46.1 (Electricity Supply Cost).

34.7.4.2 EJP Load shall be subject to all surcharges and adjustments of the customer's otherwise applicable parent service classification. EJP customers will not be subject to Rule 57- Revenue Decoupling Mechanism, Rule 46.2-Legacy Transition Charge, Rule 41-Transmission Revenue Adjustment, Rule 49 – Earnings Adjustment Mechanism, Rule 64 – Dynamic Load Management Surcharge, and Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge.
on the EJP portion of their load.

34.7.4.3 Customers who have met the qualifications in accordance with Rule 34.7.1 above and from whom the Company has received the Certificate of Tax Credit from the NYS Department of Economic Development will have their EJP load priced at the following rates.

Delivery Rates Applicable to Qualifying EJP Load:

	Per kWh	Per kW
SC2	$0.03741	
SC2D		$5.36
SC3 - Secondary		$3.64
SC-3 Primary		$2.57
SC-3 Sub Transmission		$1.69
SC-3 Transmission		$1.69
SC-3A Secondary		$2.79
SC-3A Primary		$2.79
SC-3A Sub Transmission		$2.79
SC-3A Transmission		$1.30

*SC7 customers will be subject to the rates of their Parent Service Classification above.

**All EJP Customers pay full standard tariff Customer Charges.

34.7.4.4 Certification and Verification

Customers qualifying for the EJP discount will be eligible to qualify to receive a certificate of tax credit from the State of New York each year which will entitle the customer to receive service at the discounted rates in Rule 34.7.4.3 for the following 12 month period commencing with the next full billing period after the utility receives the certificate of tax credit. Service at discounted rates will end no later than fifteen months after receipt of such notification The Company shall receive a copy of this certificate of tax credit prior to billing the discounted rate.

SERVICE CLASSIFICATION NO. 1 (Continued)

ADJUSTMENTS TO STANDARD TARIFF RATES AND CHARGES:
Customers served under this service classification may be subject to adjustments and applied in the manner described in each respective Rule.

Rule 32.2 - Municipal Undergrounding Surcharge
Rule 40.1.8 - Value of Distributed Energy Resources' Customer Benefit Contribution Charge
Rule 41 - System Benefits Charge
Rule 42 - Merchant Function Charge
Rule 43 - Transmission Revenue Adjustment
Rule 45 - Non-Wires Alternative Surcharge
Rule 46 - Supply Service Charges
Rule 49 - Earnings Adjustment Mechanism
Rule 50 - Reliability Support Services Surcharge
Rule 52 - Electric Vehicle Make-Ready Surcharge
Rule 57 - Revenue Decoupling Mechanism
Rule 58 - Service Class Deferral Credit/Surcharge
Rule 64 - Dynamic Load Management (DLM) Surcharge
Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge

INCREASE IN RATE AND CHARGES:
The charges under this Service Classification, including minimum charge, will be increased by a tax factor pursuant to Rule 32.

TERMS OF PAYMENT:
Bills are due and payable when rendered. Full payment must be received on or before the date shown on the bill to avoid a late payment charge pursuant to Rule 26.4.

TERM:
One month and continuously from month to month thereafter until permanently terminated on three days' notice to Company, or one year, and thereafter until terminated as provided in the written application for service.

SPECIAL PROVISIONS:
A. Service under this Service Classification is primarily intended for residential customers residing in individual dwelling units.

1. When minor professional or commercial operations are conducted within the individual dwelling unit, service under this Service Classification will be permitted providing all of the following three qualifications are met:

a. The minor professional or commercial operations must be exclusively by the residential customer residing at the individual dwelling unit served. Use of the professional or commercial area by another professional person or persons in addition to the resident disqualifies the customer to receive Electric Service or Electricity Supply Service under this Service Classification.
b. The area used by the minor professional or commercial operations does not exceed 50 percent of the total cubical content of the individual dwelling unit.
c. Not more than two (2) rooms of any size are contained within the 50 percent cubical content of the area used for professional or commercial operations.

Residential customers having professional or commercial operations within an individual dwelling unit that do not meet all of the three qualifications must take service under the General Service Classification. Such customers, however, can elect to separate the electrical use between the residential area and the area used for professional or commercial operations and to have the Company set an additional meter. The meter used to measure the electrical use in the professional or commercial operations area will be billed under the General Service Classification.

SERVICE CLASSIFICATION NO. 1-C (Continued)

STANDARD TARIFF CHARGES:
Distribution Delivery Charges for all Load Zones:

Basic Service Charge, for all Load Zones:	$30.00
Per kWh:	$0.03494

(the per kWh charge above is inclusive of the SERVICE CLASS DEFERRAL CREDIT contained in Rule 58)

Company Supplied Electricity Supply Service Charges, per kWh:

Company supplied Electricity Supply Service ("ESS") charges shall be set according to the market price of electricity determined in accordance with Rule 46.1, Electricity Supply Service. Effective September 1, 2006, ESS charges shall be calculated as the daily class load shaped thirty-day weighted average market price for each Rate Period defined above, except that the Summer Off-Peak, Winter Off-Peak and/or Off-Season Rate Periods shall be considered one Rate Period for this purpose.

MONTHLY MINIMUM CHARGE: $30.00

In accordance with Special Provision M of this service classification, customers participating in the Company's Energy Affordability Program will be eligible for a credit as stated in the Statement of Energy Affordability Credit ("EAC").

ADJUSTMENTS TO STANDARD CHARGES:
Customers served under this service classification may be subject to adjustments and applied in the manners described in each respective Rule.

Rule 32.2 - Municipal Undergrounding Surcharge
Rule 40.1.8 - Value of Distributed Energy Resources' Customer Benefit Contribution Charge
Rule 41 - System Benefits Charge
Rule 42 - Merchant Function Charge
Rule 43 - Transmission Revenue Adjustment
Rule 45 - Non-Wire Alternative Surcharge
Rule 46 - Supply Service Charges
Rule 49 - Earnings Adjustment Mechanism
Rule 50 - Reliability Support Services Surcharge
Rule 52 - Electric Vehicle Make-Ready Surcharge
Rule 57 - Revenue Decoupling Mechanism
Rule 58 - Service Class Deferral Credit/Surcharge
Rule 64 - Dynamic Load Management (DLM) Surcharge
Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge

INCREASE IN CHARGES:
The charges under this Service Classification, including the minimum charge, will be increased by a tax factor pursuant to Rule 32.

TERM:
One year from commencement of service under Service Classification No. 1-C and continuously from month to month thereafter until canceled upon written notice to the Company.

TERMS OF PAYMENT:
Bills are due and payable when rendered. Full payment must be received on or before the date shown on the bill to avoid a late payment charge pursuant to Rule 26.4.

SERVICE CLASSIFICATION NO. 2 (Continued)

STANDARD TARIFF CHARGES FOR METERED DEMAND SERVICE**:**

Distribution Delivery Rates and Charges for all Load Zones:

Basic Service Charge	$52.52
Basic Service Charge Special Provision P	$95.98
Distribution Delivery Charges, per kW:	$12.44

(the per kW charge above is inclusive of the SERVICE CLASS DEFERRAL CREDIT contained in Rule 58)

Company supplied Electricity Supply Service Charges, per kWh:

Company supplied Electricity Supply Service charges shall be set according to the market price of electricity determined in accordance with Rule 46.1, Electricity Supply Cost. Electricity Supply Cost Customers subject to Special Provision P will be billed for Electricity Supply Service in accordance with Rule 46.1.3.

MONTHLY MINIMUM CHARGE: $64.96

MONTHLY MINIMUM CHARGE:
Special Provision P $108.42

ADJUSTMENTS TO STANDARD TARIFF CHARGES:

Customers served under this service classification may be subject to adjustments and applied in the manner described in each respective Rule.

Rule 32.2 - Municipal Undergrounding Surcharge
Rule 40.1.8 - Value of Distributed Energy Resources' Customer Benefit Contribution Charge
Rule 41 - System Benefits Charge
Rule 42 - Merchant Function Charge
Rule 43 -Transmission Revenue Adjustment
Rule 45 - Non-Wires Alternative Surcharge
Rule 46 - Supply Service Charges
Rule 49 - Earnings Adjustment Mechanism
Rule 50 - Reliability Support Services Surcharge
Rule 52 - Electric Vehicle Make-Ready Surcharge
Rule 57 - Revenue Decoupling Mechanism
Rule 58 - Service Class Deferral Credit/Surcharge
Rule 64 - Dynamic Load Management (DLM) Surcharge
Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge

INCREASE IN RATES AND CHARGES:
The rates and charges under this Service Classification, including minimum charge, will be increased by a tax factor pursuant to Rule 32.

DETERMINATION OF DEMAND:
A. A demand meter shall be installed whenever the monthly energy consumption for any four consecutive months of a customer exceeds 2000 kWh per month or whenever the connected load of customer indicates that the energy consumption will exceed 2000 kWh per month. A demand meter, once installed, shall not be removed until after the energy consumption has been less than 2000 kWh per month for twelve consecutive months, which requirement may not be avoided by temporarily terminating service.

SERVICE CLASSIFICATION NO. 3 (Continued)

MONTHLY MINIMUM CHARGE:

The monthly minimum charge is the charge computed under MONTHLY RATE, the demand being determined in accordance with the provisions included under Determination of Demand.

ADJUSTMENTS TO STANDARD RATES AND CHARGES:

Customers served under this service classification may be subject to adjustments and applied in the manner described in each respective Rule.

Rule 32.2 - Municipal Undergrounding Surcharge
Rule 41 - System Benefits Charges
Rule 43 -Transmission Revenue Adjustment
Rule 42 - Merchant Function Charge
Rule 45 - Non-Wires Alternative Surcharge
Rule 46 - Supply Service Charges
Rule 49 - Earnings Adjustment Mechanism
Rule 50 - Reliability Support Services Surcharge
Rule 52 - Electric Vehicle Make-Ready Surcharge
Rule 57 - Revenue Decoupling Mechanism
Rule 58 - Service Class Deferral Credit/Surcharge
Rule 64 - Dynamic Load Management (DLM) Surcharge
Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge

INCREASE IN RATES AND CHARGES:

The rates and charges under this service classification, including System Benefits Charge and minimum charge, will be increased by a tax factor pursuant to Rule 32.

DETERMINATION OF DEMAND:

A. The Distribution Delivery demand for delivery voltage up to 2.2 kV and 2.2-15 kV shall be based on the highest kW measured over any fifteen minute interval during the month, but not less than one-half of the highest such demand occurring during any of the preceding eleven months, nor less than the demand contracted for.

B. The Distribution Delivery demand for delivery voltage 22-50 kV and Over 60 kV, shall be the highest kW measured over any fifteen minute interval during the month, but not less than the demand specified for.

C. The Reactive Demand shall be based on the highest RkVA of lagging reactive demand measured over a fifteen minute interval during the month less one-third of the highest kW demand measured during the month. The Reactive Demand shall be determined:

1. when a customer's demand has exceeded 500 kW for three consecutive months for service rendered before May 1, 2010; or
2. when a customer's demand has exceeded 500 kW in any two of the previous twelve months for service rendered on and after May 1, 2010; or
3. when the connected load of the customer indicates that the kW demand may normally exceed 500 kW.

Reactive Demand determination shall continue until the demand has been less than 500 kW for twelve consecutive months.

SERVICE CLASSIFICATION NO. 3A (Continued)

Company Supplied Electricity Supply Service Charges: Company supplied Electricity Supply Service Charges shall be set on an hourly basis according to the market price of electricity determined in accordance with Rule 46.1, Electricity Supply Cost.

ADJUSTMENTS TO STANDARD RATES AND CHARGES:

Customers served under this service classification may be subject to adjustments and applied in the manner described in each respective Rule.

Rule 32.2 - Municipal Undergrounding Surcharge
Rule 41 - System Benefits Charges
Rule 42 - Merchant Function Charge
Rule 43 - Transmission Revenue Adjustment
Rule 45 - Non-Wires Alternative Surcharge
Rule 46 - Supply Service Charges
Rule 49 - Earnings Adjustment Mechanism
Rule 50 - Reliability Support Services Surcharge
Rule 52 - Electric Vehicle Make-Ready Surcharge
Rule 58 - Service Class Deferral Credit/Surcharge
Rule 57 - Revenue Decoupling Mechanism
Rule 64 - Dynamic Load Management (DLM) Surcharge
Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge

SERVICE CLASSIFICATION NO. 7 (Continued)

All SERVICE CLASSIFICATION NUMBERS:

Electricity Supply Service:
Company Supplied Electricity Supply Service Charges, per kWh:
All SC-7 parent class SC-3A and SC-7 parent class SC-3 (otherwise subject to SC-3, Special Provision L) demand metered customers who are required to install an interval-meter will be billed for commodity service based on their actual hourly usage and the hourly day-ahead market prices as described in Rule 46.1.3 herein. All SC-7 parent class SC-2D and SC-3 (otherwise not subject to SC-3, Special Provision L) customers may elect to be billed for commodity service based on their actual hourly usage and the hourly day-ahead market prices as described in Rule 46.1.3 herein. Such election shall be made by the customer in the Form G Application for Electric Standby Service. All other SC-7 customers will be billed for commodity services based on Rule 46.1.1 or Rule 46.1.2.

Company supplied Electricity Supply Service charges shall be set according to the market price of electricity determined in accordance with Rule 46.1, Electricity Supply Cost.

Customers served under this Service Classification No. 7 are also eligible to participate in Rule 39 - Retail Access Program.

Wholesale Generators receiving Station Power service from the NYISO in accordance with Special Provision J shall receive Electricity Supply Service from the NYISO and shall be exempt from Electricity Supply Service charges under Rule 46.1.
SURCHARGES AND ADJUSTMENTS

Customers served under this Service Classification No. 7 may be subject to the following surcharges and adjustments:

Rule 32.2 - Municipal Undergrounding Surcharge
Rule 40 - Value of Distributed Energy Resources' Customer Benefit Contribution Charge
Rule 41 - System Benefits Charges
Rule 42 - Merchant Function Charge
Rule 43 - Transmission Revenue Adjustment
Rule 45 - Non-Wires Alternative Surcharge
Rule 46 - Supply Service Charges
Rule 49 - Earnings Adjustment Mechanism
Rule 50 - Reliability Support Services Surcharge
Rule 52 - Electric Vehicle Make-Ready Surcharge
Rule 57 - Revenue Decoupling Mechanism
Rule 58 - Service Class Deferral Credit/Surcharge
Rule 64 - Dynamic Load Management (DLM) Surcharge
Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge

MINIMUM CHARGE:
Customers served under this Service Classification No. 7 shall be subject to a minimum Charge which shall be the Customer Charge, the Incremental Customer Charge (where applicable), and the Standby Contract Demand Charge.

GENERAL INFORMATION

IV. TERMS AND CONDITIONS APPLICABLE TO ALL SERVICE CLASSIFICATIONS

B. Adjustment to Volumetric Charges SC-1, 2, 3, 4, 6

The Volumetric Charges, measured in kWh, shall be subject to specific adjustments applied in compliance with the Rules identified below, as more fully described in the Electric Tariff and as amended from time to time.

Rule 32.2 - Municipal Undergrounding Surcharge
Rule 41 - System Benefits Charge
Rule 42 - Merchant Function Charge
Rule 43 - Transmission Revenue Adjustment
Rule 45 - Non-Wires Alternative (“NWA”) Surcharge
Rule 46 - Supply Service Charges
Rule 56 - Incremental State Assessment Surcharge
Rule 57 - Revenue Decoupling Mechanism (RDM)
Rule 64 - Dynamic Load Management (DLM) Surcharge
Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge

C. Increase in Rates and Charges SC-4
E. Increase in Rates and Charges SC-3
F. Increase in Rates and Charges SC-1, 6
G. Increase in Rates and Charges SC-2

The rates and charges including any adjustment to charges and the minimum charge will be increased by a tax factor pursuant to Rule 32 of the Electric Tariff.

Determination of Billing SC-1, 2, 3, 4, 6
The billing of rendered services shall comply with, but not be limited to, the terms and conditions as provided hereunder and as may be further defined within the service classification.

A. Minimum Charge SC-1, 2, 3, 4, 6
Customer is obligated to pay the charges for service provided hereunder as is further defined within the service classification.

B. Determination of Billing Quantities SC-1, 2, 3, 4, 6
The charge for lighting service hereunder during each billing cycle shall be based upon facilities/equipment in service and any related energy and adjustments as of the first day of that billing cycle.

C. Terms of Payment SC-1, 2, 3, 4, 6
Bills are due and payable. Full payment must be received on or before the date shown on the bill to avoid a late payment charge of one and one-half percent (l-l/2%) per month pursuant to Rule 26.4 of the Electric Tariff.

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70. Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge ("Phase 1 Facility Charge")

70.1 The Phase I Facility Charge will recover the deferred carrying charges, depreciation expense and operating expenses for local transmission upgrades associated with the Initial Phase I Projects that support New York State's energy goals under the Climate Leadership and Community Protection Act, in accordance with the Commission's Phase I Order in Case 20-E-0197, that are not otherwise recovered in base delivery rates.

70.1.1 Carrying charges will be recovered at the Company's pre-tax weighted average cost of capital ('WACC").

70.1.2 Any unrecovered costs will be included for recovery in the Company's next rate case filing.

70.1.3 The Phase I Facility Charge will include costs associated with projects placed in service during the previous fiscal year and will include any over/under reconciliation as specified in Rule 70.5. Costs will be recovered on a two-month lag following the end of the fiscal year.

70.2 The amount to be recovered shall be allocated to applicable service classifications based on the percent allocation of transmission revenue in the Company's most current embedded cost of service study, as specified in Rule 43.6. Customers taking service under SC-4 and SC-7 shall be subject to the Phase I Facility Charge rates of their parent service classification.

70.3 The amounts to be recovered from each parent service classification as determined in Rule 70.2 above shall be divided by the respective parent service classification's forecast sales associated with the corresponding annual period which the surcharge will be collected from customers.

70.4 The Phase I Facility Charge rates will be applied to a customer's actual billed consumption and applicable to customers serviced under PSC No. 220 service classifications No. 1, 1-C, 2 Non-demand, 2 demand, 3, 3-A, 4 and 7 and all PSC No. 14 service classifications. The Phase I Facility Charge will also be applied to a customer's deliveries associated with NYPA load, including ReCharge New York load, and may be applicable to PSC No. 220 service classification No. 12 in accordance with the terms of their individual contracts.

70.4.1 The Phase I Facility Charge is not applicable to Empire Zone and Excelsior Jobs Program qualifying load.

70.4.2 The Phase I Facility Charge shall be recovered from customers on a per kWh basis for non-demand service classes, a per kW basis for demand service classes, and a Contract Demand basis for SC7 customers, if applicable.

70.5 The Phase I Facility Charge will be subject to an annual true-up, with any over/under collection at the end of the annual collection period, inclusive of carrying charges at the Company's pre-tax WACC, to be included in the balance for refund or recovery in the next annual period, or in future base delivery rates as applicable.

70.6 The Phase I Facility Charge shall be shown on statements filed with the Public Service Commission apart from this rate schedule not less than fifteen (15) days before its effective date.

GENERAL INFORMATION

34. ECONOMIC DEVELOPMENT PROGRAMS: (Continued)

34.3 Program 2 - Empire Zone Rider (EZR) (Continued)

34.3.2.3 An electric customer who submeters electricity to customers certified under this program is eligible for the rates for that portion of the purchases deemed eligible by the zone administrator but subject to all rules and provisions of P.S.C. No. 220 Electricity governing submetering.

34.3.3 Alternate Billing Methodology: Non Separated EZR Load

34.3.3.1 For customers taking service under Program 2 (EZR) and who have elected not to separately meter incremental load, the Company will administer EZR discounts according to Rule 34.2.3, Rule 34.3.3.3, and Rule 34.3.4.

34.3.3.2 Customers served under the EZR program who do not separately meter their load shall only be exempt from Rule 41- System Benefits Charge ("SBC"), Rule 43-Transmission Revenue Adjustment, Rule 49 – Earnings Adjustment Mechanism~~, and~~ Rule 64 - Dynamic Load Management Surcharge on Qualifying EZR Load, and Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge. Rule 41.2.3 sets forth the grandfathering provision for customers who have previously elected to pay the SBC on their exempt load.

34.3.3.3 For eligible Service Classification No. 7 customers, the alternate billing methodology used to separate incremental EZR load from Service Classification No. 7 load (i.e., base load), as provided in Rule 34.2.3 shall be modified as provided herein.

34.3.3.3.1 The customer's total facility load shall replace the billing metered units in the determination of the base period billing units specified in Rule 34.2.3.1. The total facility load represents the customer's load excluding power and energy supplied by the customer's on-site generation, and shall be calculated on a interval-by-interval basis as the sum of the generation metered units and the billing metered units minus any excess generation metered units that are delivered back to the Company's electric system. In the event power and energy was supplied by on-site generation during the 12-month period used to calculate the base year billing determinants and generation interval-by-interval metering data was not available for all or part of the 12-month period, the Company shall estimate the total facility load.

34.3.3.3.2 In each billing period, the total facility load shall be determined by adding, on a metered interval-by-interval basis, the generation demand and energy values to the billing demand and energy values, minus any excess generation demand and energy values that are delivered back to the Company's electric system. The total facility load demand and energy shall replace the current month's demand and energy specified in Rule 34.2.3.2 in the determination of the customer's eligibility for EZR benefits in the applicable Billing Period, the customer's EZR demand and energy available for the EZR discount, and the Company billing demands and energy for non-EZR service.

GENERAL INFORMATION

34. ECONOMIC DEVELOPMENT PROGRAMS: (Continued)

34.7 Program 6 - Excelsior Jobs Program ("EJP") (Continued)

34.7.4 Electric Pricing For Qualifying EJP Load

34.7.4.1 Unless otherwise taking service under Rule 31, NYPA Supply Service or Rule 39, Retail Access Program, customers served under Program 6, EJP shall be subject to Electricity Supply Cost in accordance with Rule 46.1 (Electricity Supply Cost).

34.7.4.2 EJP Load shall be subject to all surcharges and adjustments of the customer's otherwise applicable parent service classification. EJP customers will not be subject to Rule 57- Revenue Decoupling Mechanism, Rule 46.2-Legacy Transition Charge, Rule 41-Transmission Revenue Adjustment, Rule 49 – Earnings Adjustment Mechanism, Rule 64 – Dynamic Load Management Surcharge, and Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge on the EJP portion of their load.

34.7.4.3 Customers who have met the qualifications in accordance with Rule 34.7.1 above and from whom the Company has received the Certificate of Tax Credit from the NYS Department of Economic Development will have their EJP load priced at the following rates.

Delivery Rates Applicable to Qualifying EJP Load:

	Per kWh	Per kW
SC2	$0.03741	
SC2D		$5.36
SC3 - Secondary		$3.64
SC-3 Primary		$2.57
SC-3 Sub Transmission		$1.69
SC-3 Transmission		$1.69
SC-3A Secondary		$2.79
SC-3A Primary		$2.79
SC-3A Sub Transmission		$2.79
SC-3A Transmission		$1.30

*SC7 customers will be subject to the rates of their Parent Service Classification above.

**All EJP Customers pay full standard tariff Customer Charges.

34.7.4.4 Certification and Verification

Customers qualifying for the EJP discount will be eligible to qualify to receive a certificate of tax credit from the State of New York each year which will entitle the customer to receive service at the discounted rates in Rule 34.7.4.3 for the following 12 month period commencing with the next full billing period after the utility receives the certificate of tax credit. Service at discounted rates will end no later than fifteen months after receipt of such notification The Company shall receive a copy of this certificate of tax credit prior to billing the discounted rate.

SERVICE CLASSIFICATION NO. 1 (Continued)

ADJUSTMENTS TO STANDARD TARIFF RATES AND CHARGES:
Customers served under this service classification may be subject to adjustments and applied in the manner described in each respective Rule.

Rule 32.2 - Municipal Undergrounding Surcharge
Rule 40.1.8 - Value of Distributed Energy Resources' Customer Benefit Contribution Charge
Rule 41 - System Benefits Charge
Rule 42 - Merchant Function Charge
Rule 43 - Transmission Revenue Adjustment
Rule 45 - Non-Wires Alternative Surcharge
Rule 46 - Supply Service Charges
Rule 49 - Earnings Adjustment Mechanism
Rule 50 - Reliability Support Services Surcharge
Rule 52 - Electric Vehicle Make-Ready Surcharge
Rule 57 - Revenue Decoupling Mechanism
Rule 58 - Service Class Deferral Credit/Surcharge
Rule 64 - Dynamic Load Management (DLM) Surcharge
Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge

INCREASE IN RATE AND CHARGES:
The charges under this Service Classification, including minimum charge, will be increased by a tax factor pursuant to Rule 32.

TERMS OF PAYMENT:
Bills are due and payable when rendered. Full payment must be received on or before the date shown on the bill to avoid a late payment charge pursuant to Rule 26.4.

TERM:
One month and continuously from month to month thereafter until permanently terminated on three days' notice to Company, or one year, and thereafter until terminated as provided in the written application for service.

SPECIAL PROVISIONS:
A. Service under this Service Classification is primarily intended for residential customers residing in individual dwelling units.

1. When minor professional or commercial operations are conducted within the individual dwelling unit, service under this Service Classification will be permitted providing all of the following three qualifications are met:

a. The minor professional or commercial operations must be exclusively by the residential customer residing at the individual dwelling unit served. Use of the professional or commercial area by another professional person or persons in addition to the resident disqualifies the customer to receive Electric Service or Electricity Supply Service under this Service Classification.
b. The area used by the minor professional or commercial operations does not exceed 50 percent of the total cubical content of the individual dwelling unit.
c. Not more than two (2) rooms of any size are contained within the 50 percent cubical content of the area used for professional or commercial operations.

Residential customers having professional or commercial operations within an individual dwelling unit that do not meet all of the three qualifications must take service under the General Service Classification. Such customers, however, can elect to separate the electrical use between the residential area and the area used for professional or commercial operations and to have the Company set an additional meter. The meter used to measure the electrical use in the professional or commercial operations area will be billed under the General Service Classification.

SERVICE CLASSIFICATION NO. 1-C (Continued)

STANDARD TARIFF CHARGES:
Distribution Delivery Charges for all Load Zones:

Basic Service Charge, for all Load Zones:	$30.00
Per kWh:	$0.03494

(the per kWh charge above is inclusive of the SERVICE CLASS DEFERRAL CREDIT contained in Rule 58)

Company Supplied Electricity Supply Service Charges, per kWh:

Company supplied Electricity Supply Service ("ESS") charges shall be set according to the market price of electricity determined in accordance with Rule 46.1, Electricity Supply Service. Effective September 1, 2006, ESS charges shall be calculated as the daily class load shaped thirty-day weighted average market price for each Rate Period defined above, except that the Summer Off-Peak, Winter Off-Peak and/or Off-Season Rate Periods shall be considered one Rate Period for this purpose.

MONTHLY MINIMUM CHARGE: $30.00

In accordance with Special Provision M of this service classification, customers participating in the Company's Energy Affordability Program will be eligible for a credit as stated in the Statement of Energy Affordability Credit ("EAC").

ADJUSTMENTS TO STANDARD CHARGES:
Customers served under this service classification may be subject to adjustments and applied in the manners described in each respective Rule.

Rule 32.2 - Municipal Undergrounding Surcharge
Rule 40.1.8 - Value of Distributed Energy Resources' Customer Benefit Contribution Charge
Rule 41 - System Benefits Charge
Rule 42 - Merchant Function Charge
Rule 43 - Transmission Revenue Adjustment
Rule 45 - Non-Wire Alternative Surcharge
Rule 46 - Supply Service Charges
Rule 49 - Earnings Adjustment Mechanism
Rule 50 - Reliability Support Services Surcharge
Rule 52 - Electric Vehicle Make-Ready Surcharge
Rule 57 - Revenue Decoupling Mechanism
Rule 58 - Service Class Deferral Credit/Surcharge
Rule 64 - Dynamic Load Management (DLM) Surcharge
Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge

INCREASE IN CHARGES:
The charges under this Service Classification, including the minimum charge, will be increased by a tax factor pursuant to Rule 32.

TERM:
One year from commencement of service under Service Classification No. 1-C and continuously from month to month thereafter until canceled upon written notice to the Company.

TERMS OF PAYMENT:
Bills are due and payable when rendered. Full payment must be received on or before the date shown on the bill to avoid a late payment charge pursuant to Rule 26.4.

SERVICE CLASSIFICATION NO. 2 (Continued)

STANDARD TARIFF CHARGES FOR METERED DEMAND SERVICE**:**

Distribution Delivery Rates and Charges for all Load Zones:

Basic Service Charge	$52.52
Basic Service Charge Special Provision P	$95.98
Distribution Delivery Charges, per kW:	$12.44

(the per kW charge above is inclusive of the SERVICE CLASS DEFERRAL CREDIT contained in Rule 58)

Company supplied Electricity Supply Service Charges, per kWh:

Company supplied Electricity Supply Service charges shall be set according to the market price of electricity determined in accordance with Rule 46.1, Electricity Supply Cost. Electricity Supply Cost Customers subject to Special Provision P will be billed for Electricity Supply Service in accordance with Rule 46.1.3.

MONTHLY MINIMUM CHARGE: $64.96

MONTHLY MINIMUM CHARGE:
Special Provision P $108.42

ADJUSTMENTS TO STANDARD TARIFF CHARGES:

Customers served under this service classification may be subject to adjustments and applied in the manner described in each respective Rule.

Rule 32.2 - Municipal Undergrounding Surcharge
Rule 40.1.8 - Value of Distributed Energy Resources' Customer Benefit Contribution Charge
Rule 41 - System Benefits Charge
Rule 42 - Merchant Function Charge
Rule 43 -Transmission Revenue Adjustment
Rule 45 - Non-Wires Alternative Surcharge
Rule 46 - Supply Service Charges
Rule 49 - Earnings Adjustment Mechanism
Rule 50 - Reliability Support Services Surcharge
Rule 52 - Electric Vehicle Make-Ready Surcharge
Rule 57 - Revenue Decoupling Mechanism
Rule 58 - Service Class Deferral Credit/Surcharge
Rule 64 - Dynamic Load Management (DLM) Surcharge
Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge

INCREASE IN RATES AND CHARGES:
The rates and charges under this Service Classification, including minimum charge, will be increased by a tax factor pursuant to Rule 32.

DETERMINATION OF DEMAND:
A. A demand meter shall be installed whenever the monthly energy consumption for any four consecutive months of a customer exceeds 2000 kWh per month or whenever the connected load of customer indicates that the energy consumption will exceed 2000 kWh per month. A demand meter, once installed, shall not be removed until after the energy consumption has been less than 2000

kWh per month for twelve consecutive months, which requirement may not be avoided by temporarily terminating service.

SERVICE CLASSIFICATION NO. 3 (Continued)

MONTHLY MINIMUM CHARGE:

The monthly minimum charge is the charge computed under MONTHLY RATE, the demand being determined in accordance with the provisions included under Determination of Demand.

ADJUSTMENTS TO STANDARD RATES AND CHARGES:

Customers served under this service classification may be subject to adjustments and applied in the manner described in each respective Rule.

Rule 32.2 - Municipal Undergrounding Surcharge
Rule 41 - System Benefits Charges
Rule 43 -Transmission Revenue Adjustment
Rule 42 - Merchant Function Charge
Rule 45 - Non-Wires Alternative Surcharge
Rule 46 - Supply Service Charges
Rule 49 - Earnings Adjustment Mechanism
Rule 50 - Reliability Support Services Surcharge
Rule 52 - Electric Vehicle Make-Ready Surcharge
Rule 57 - Revenue Decoupling Mechanism
Rule 58 - Service Class Deferral Credit/Surcharge
Rule 64 - Dynamic Load Management (DLM) Surcharge
Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge

INCREASE IN RATES AND CHARGES:

The rates and charges under this service classification, including System Benefits Charge and minimum charge, will be increased by a tax factor pursuant to Rule 32.

DETERMINATION OF DEMAND:

A. The Distribution Delivery demand for delivery voltage up to 2.2 kV and 2.2-15 kV shall be based on the highest kW measured over any fifteen minute interval during the month, but not less than one-half of the highest such demand occurring during any of the preceding eleven months, nor less than the demand contracted for.

B. The Distribution Delivery demand for delivery voltage 22-50 kV and Over 60 kV, shall be the highest kW measured over any fifteen minute interval during the month, but not less than the demand specified for.

C. The Reactive Demand shall be based on the highest RkVA of lagging reactive demand measured over a fifteen minute interval during the month less one-third of the highest kW demand measured during the month. The Reactive Demand shall be determined:

1. when a customer's demand has exceeded 500 kW for three consecutive months for service rendered before May 1, 2010; or
2. when a customer's demand has exceeded 500 kW in any two of the previous twelve months for service rendered on and after May 1, 2010; or
3. when the connected load of the customer indicates that the kW demand may normally exceed 500 kW.

Reactive Demand determination shall continue until the demand has been less than 500 kW for twelve consecutive months.

SERVICE CLASSIFICATION NO. 3A (Continued)

Company Supplied Electricity Supply Service Charges: Company supplied Electricity Supply Service Charges shall be set on an hourly basis according to the market price of electricity determined in accordance with Rule 46.1, Electricity Supply Cost.

ADJUSTMENTS TO STANDARD RATES AND CHARGES:

Customers served under this service classification may be subject to adjustments and applied in the manner described in each respective Rule.

Rule 32.2 - Municipal Undergrounding Surcharge
Rule 41 - System Benefits Charges
Rule 42 - Merchant Function Charge
Rule 43 - Transmission Revenue Adjustment
Rule 45 - Non-Wires Alternative Surcharge
Rule 46 - Supply Service Charges
Rule 49 - Earnings Adjustment Mechanism
Rule 50 - Reliability Support Services Surcharge
Rule 52 - Electric Vehicle Make-Ready Surcharge
Rule 58 - Service Class Deferral Credit/Surcharge
Rule 57 - Revenue Decoupling Mechanism
Rule 64 - Dynamic Load Management (DLM) Surcharge
Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge

SERVICE CLASSIFICATION NO. 7 (Continued)

All SERVICE CLASSIFICATION NUMBERS:

Electricity Supply Service:
Company Supplied Electricity Supply Service Charges, per kWh:
All SC-7 parent class SC-3A and SC-7 parent class SC-3 (otherwise subject to SC-3, Special Provision L) demand metered customers who are required to install an interval-meter will be billed for commodity service based on their actual hourly usage and the hourly day-ahead market prices as described in Rule 46.1.3 herein. All SC-7 parent class SC-2D and SC-3 (otherwise not subject to SC-3, Special Provision L) customers may elect to be billed for commodity service based on their actual hourly usage and the hourly day-ahead market prices as described in Rule 46.1.3 herein. Such election shall be made by the customer in the Form G Application for Electric Standby Service. All other SC-7 customers will be billed for commodity services based on Rule 46.1.1 or Rule 46.1.2.

Company supplied Electricity Supply Service charges shall be set according to the market price of electricity determined in accordance with Rule 46.1, Electricity Supply Cost.

Customers served under this Service Classification No. 7 are also eligible to participate in Rule 39 - Retail Access Program.

Wholesale Generators receiving Station Power service from the NYISO in accordance with Special Provision J shall receive Electricity Supply Service from the NYISO and shall be exempt from Electricity Supply Service charges under Rule 46.1.
SURCHARGES AND ADJUSTMENTS

Customers served under this Service Classification No. 7 may be subject to the following surcharges and adjustments:

Rule 32.2 - Municipal Undergrounding Surcharge
Rule 40 - Value of Distributed Energy Resources’ Customer Benefit Contribution Charge
Rule 41 - System Benefits Charges
Rule 42 - Merchant Function Charge
Rule 43 - Transmission Revenue Adjustment
Rule 45 - Non-Wires Alternative Surcharge
Rule 46 - Supply Service Charges
Rule 49 - Earnings Adjustment Mechanism
Rule 50 - Reliability Support Services Surcharge
Rule 52 - Electric Vehicle Make-Ready Surcharge
Rule 57 - Revenue Decoupling Mechanism
Rule 58 - Service Class Deferral Credit/Surcharge
Rule 64 - Dynamic Load Management (DLM) Surcharge
Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge

MINIMUM CHARGE:
Customers served under this Service Classification No. 7 shall be subject to a minimum Charge which shall be the Customer Charge, the Incremental Customer Charge (where applicable), and the Standby Contract Demand Charge.

GENERAL INFORMATION

IV. TERMS AND CONDITIONS APPLICABLE TO ALL SERVICE CLASSIFICATIONS

B. Adjustment to Volumetric Charges SC-1, 2, 3, 4, 6

The Volumetric Charges, measured in kWh, shall be subject to specific adjustments applied in compliance with the Rules identified below, as more fully described in the Electric Tariff and as amended from time to time.

Rule 32.2 - Municipal Undergrounding Surcharge
Rule 41 - System Benefits Charge
Rule 42 - Merchant Function Charge
Rule 43 - Transmission Revenue Adjustment
Rule 45 - Non-Wires Alternative ("NWA") Surcharge
Rule 46 - Supply Service Charges
Rule 56 - Incremental State Assessment Surcharge
Rule 57 - Revenue Decoupling Mechanism (RDM)
Rule 64 - Dynamic Load Management (DLM) Surcharge
Rule 70- Climate Leadership and Community Protection Act Phase 1 Transmission Solutions Surcharge

C. Increase in Rates and Charges SC-4
E. Increase in Rates and Charges SC-3
F. Increase in Rates and Charges SC-1, 6
G. Increase in Rates and Charges SC-2

The rates and charges including any adjustment to charges and the minimum charge will be increased by a tax factor pursuant to Rule 32 of the Electric Tariff.

Determination of Billing SC-1, 2, 3, 4, 6
The billing of rendered services shall comply with, but not be limited to, the terms and conditions as provided hereunder and as may be further defined within the service classification.

A. Minimum Charge SC-1, 2, 3, 4, 6
Customer is obligated to pay the charges for service provided hereunder as is further defined within the service classification.

B. Determination of Billing Quantities SC-1, 2, 3, 4, 6
The charge for lighting service hereunder during each billing cycle shall be based upon facilities/equipment in service and any related energy and adjustments as of the first day of that billing cycle.

C. Terms of Payment SC-1, 2, 3, 4, 6
Bills are due and payable. Full payment must be received on or before the date shown on the bill to avoid a late payment charge of one and one-half percent (l-l/2%) per month pursuant to Rule 26.4 of the Electric Tariff.