Initial Report on the New York Power Grid Study

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NEW YORK STATE OF OPPORTUNITY.
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NYSERDA

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NOTICE

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LIST OF ACRONYMS

AAR	Ambient Adjusted Rating
ACSS	Aluminum-Conductor Steel-Supported
the Act	Accelerated Renewable Energy Growth and Community Benefit Act
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
ATRR	Annual Transmission Revenue Requirement
ATWG	Advanced Technology Working Group
BCA	Benefit Cost Analysis
BOEM	Bureau of Ocean Energy Management
CARIS	Congestion Assessment and Resource Integration Study
CECONY	Consolidated Edison Company of New York
CLCPA	Climate Leadership and Community Protection Act
ConEd	Consolidated Edison Company of New York
DER	Distributed Energy Resource
DLR	Dynamic Line Rating
DPS	Department of Public Service
DSCADA	Distribution Supervisory Control and Data Acquisition Systems
FICS	Flexible Interconnection Capacity Solution
HTLS	High-Temperature, Low-Sag
IESO	(Ontario) Independent Electric System Operator
LIPA	Long Island Power Authority
LOLE	Loss of Load Event
LT&D	Local Transmission and Distribution
MPFC	Modular Power Flow Control
NGET	National Grid Electricity Transmission
NYISO	New York Independent System Operator

NYPA	New York Power Authority
NYSERDA	New York State Energy Research and Development Authority
O&R	Orange & Rockland Utilities
OSW	Offshore Wind
PARs	Phase-Angle Regulators
PGS	Power Grid Study
POIs	Points of Interconnection
PPTPP	Public Policy Transmission Planning Process
PV	Photovoltaic
REZ	Renewable Energy Zones
SCADA	Supervisory Control and Data Acquisition
SSSC	Static Synchronous Series Compensators
T&D	Transmission and Distribution
TCPAR	Thyristor-Controlled Phase Angle Regulators
TLA	Transmission Lead Areas
TOs	Transmission Owners
VRE	Variable Renewable Energy
WEAs	Wind Energy Lease Areas

Executive Summary

New York's Climate Leadership and Community Protection Act (CLCPA) requires an unprecedented transformation of the State's electricity grid to achieve 70% renewable generation by 2030, zero-emission electricity by 2040, and an 85% economy-wide reduction in greenhouse gas emissions from 1990 levels by 2050. The CLCPA specifies minimum amounts of certain types of resources, including 6,000 MW of distributed solar resources by 2025, 3,000 MW of storage by 2030, and 9,000 MW of offshore wind (OSW) generation by 2035. Even greater quantities of various types of renewable generation are necessary to achieve the clean energy mandates for 2040 and 2050. Meeting these milestones will require investment in renewable generation, as well as storage, energy efficiency measures, electrification of the transportation and heating sectors, and electric transmission and distribution (T&D) infrastructure.

T&D infrastructure will play a critical role in meeting the State's goals by connecting new renewable resources to the grid and transmitting and delivering energy to consumers. Accordingly, the recently enacted Accelerated Renewable Energy Growth and Community Benefit Act directs the Public Service Commission (PSC) to advance the work of identifying T&D upgrades needed to reliably and cost-effectively integrate the required renewable resources, and to establish planning processes to support cost-effective and timely infrastructure development.

To meet these directives, the PSC, through the Department of Public Service, initiated a set of system studies, collectively referred to as the Power Grid Study (PGS), which is the subject of this Initial Report. The PGS consists of three components, each of which is included in this Report:

- A study conducted by the Joint Utilities[1] on local transmission and distribution (LT&D) needs (Utility Study);

[1] The Joint Utilities include the New York utilities of Central Hudson Gas & Electric Corp. ("Central Hudson"), Consolidated Edison Company of New York, Inc., (ConEd), Long Island Power Authority (LIPA or LIPA/PSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation (NYSEG and RG&E or AVANGRID), and Orange & Rockland Utilities, Inc. (Orange and Rockland or O&R).

- A study of offshore and onshore bulk-power transmission infrastructure scenarios, and related environmental permitting considerations, to illustrate possible solutions to integrate the mandated 9,000 MW of offshore wind (OSW generation by 2035, sponsored by the New York State Energy Research and Development Authority (NYSERDA) and conducted by DNV-GL, PowerGem, and WSP (OSW Study)
- A state-wide scenario-based study to analyze transmission, generation, and storage options for achieving 70% renewable generation by 2030 and a zero emissions grid by 2040, sponsored by NYSERDA and conducted by Siemens (Zero Emissions Study).

The overall results of the Power Grid Study indicate that:

- Transmission expansion programs already underway have positioned the State well to achieve its **2030** milestones.[2] Additional efforts are likely needed to: (a) accelerate certain LT&D upgrades over the next decade; (b) expand Long Island bulk transmission to facilitate the interconnection of OSW generation and its delivery to the rest of the State (the OSW Study proposes that interconnecting 6,000 MW of wind in New York City and the remaining 3,000 MW on Long Island should be feasible, but capacity beyond this quantity on Long Island will require upgrades); (c) identify feasible and cost-effective OSW interconnection-related substations and local transmission upgrades in the New York City area; and (d) implement carefully-planned storage deployment that is closely coordinated with OSW and land-based renewable generation interconnection needs.
- Integrating 9,000 MW of offshore wind generation by **2035** is projected to be achievable without major onshore bulk transmission upgrades beyond expanding Long Island bulk transmission links and likely local upgrades in New York City, as previously noted. Interconnecting a maximum amount of OSW in the New York City area would be advantageous given the large load and strong bulk transmission system. However, overcoming cable routing limitations in New York Harbor, space constraints in substations on Manhattan, and permitting complexities in both the Harbor and along the Long Island coastline (including approaches to New York City through the Long Island Sound) will require careful planning of OSW transmission cable routes and points of interconnection. Creating the option for a meshed offshore network by linking the offshore substations of several individual OSW plants near each other is valuable

[2] The already-planned projects assumed to be developed include the Western NY Empire State line 345 kV project in Zone A, the AC Transmission Segment A & Segment B 345 kV projects in Zone E and F, and the Northern New York 345 kV projects in Zone D and E (including upgrades from Porter to Edic). Additionally, the Zero Emissions Study assumes a new 1,250 MW high-voltage direct current transmission line delivering dispatchable renewable energy into New York City.

because a meshed configuration can achieve a more reliable and resilient delivery of OSW generation. However, a decision to implement a meshed system can be delayed (and perhaps should be delayed pending federal approval of new wind energy areas), as long as the State ensures that any projects with radial connections are constructed in ways that include the option to integrate the radial lines into a meshed system later.

- Projections for future bulk transmission needs through **2040**—beyond the already-planned projects and an expected new high-voltage direct current line delivering dispatchable renewable energy into New York City—depend to some extent on how the State progresses toward its renewable generation goals, among other factors. For example, changes in the mix and locations of generation development as the State approaches the zero-emission grid milestone may affect congestion costs and the need for new bulk transmission. These may include the downstate congestion relief projects identified in the Zero Emission Study as potentially needed by 2040. However, the study's conclusions about bulk transmission needs rely on particular simulations and assumptions that are more idealized and optimized than is likely achievable. Some of the recent NYISO studies,[3] utilizing different assumptions, suggest that congestion costs may be incurred in an earlier time frame. The State should coordinate with NYISO to revisit these and other relevant study assumptions at regular intervals to ensure that bulk transmission needs are pro-actively identified. The NYISO's economic and public policy planning processes provide an effective mechanism for identifying such needs and developing timely solutions.

Assessment of the Power Grid Needs

The three PGS studies suggest the following potential distribution, local transmission, and bulk transmission needs:

- Through 2030, the need for upgrades to the Utilities' **local transmission and distribution** systems may be limited to the acceleration of LT&D projects that are already in the Utilities' plans to address expected reliability needs and refurbishment of aging assets. On a total state-wide basis, these Phase 1 projects appear to expand the local grid's headroom sufficiently to integrate the land-based renewable resources needed to meet the CLCPA's 2030 requirements, and possibly beyond. Thus, accelerating the utilities' planned reliability upgrades and asset maintenance programs

[3] Examples are the 2019 CARIS Report, 2020 RNA Report, the New York Grid Evolution Study, and the Climate Impact Study prepared by or on behalf of NYISO in 2020.

will capture significant CLCPA benefits—although some Phase 2 projects should be prioritized to support renewable generation development in attractive locations.

- Proposed Phase 1 Utility projects include the following:
  - Utility distribution investments that would add 1,970 MW of headroom interconnection of distributed renewable resources
  - Planned local transmission projects that would add up to 5,710 MW of headroom for renewable resources located in export-constrained upstate generation pockets to on-ramp them onto the bulk transmission
  - Planned Phase 1 local transmission projects that would add 910 MW of headroom to off-ramp generation from the bulk transmission system to downstate load pockets, needed in the short term to allow for the retirement of peaking generation while supporting delivery of renewable generation as the State approaches its zero-emission milestone in 2040

- The Utility Study does not identify specific CLCPA-driven transmission needs for land-based resources beyond those that may be addressed through the acceleration of local Phase 1 projects. However, in case additional renewable generation headroom is needed beyond that provided through Phase 1 projects, the Utilities proposed a number of Phase 2 candidate projects that would be able to further expand headroom for CLCPA benefits.[4]

- Utility Phase 1 projects may not provide enough headroom in some locations with attractive renewable development opportunities. For these specific locations, some Phase 2 CLCPA-driven projects will be necessary and should be prioritized.

- To address already-anticipated challenges associated with integrating 9,000 MW of OSW generation, the Utility Study suggests the following Phase 2 candidate solutions:
  - LIPA proposes to increase export capability from Long Island—a need LIPA submitted in the NYISO public policy transmission planning process—and related upgrades to convert a portion of its local transmission system to bulk-power voltage levels.

[4] The Utilities also proposed a policy framework for the selection, prioritization, benefit-cost analysis, and cost allocation of such CLCPA-driven LT&D projects. The proposed policy framework will be addressed by the PSC in a future order in Case No. 20-E-0197. This Initial Report focuses on the power grid implications of the Utility Study and does not address the Phase 2 policy proposals.

  - ConEd is proposing candidate Phase 2 projects to address reliability needs and space constraints at its New York City substations, with two OSW integration hubs capable of integrating 5,200 MW of additional OSW generation into the City's system.
- The OSW Study indicates additional **transmission from Long Island** (NYISO Zone K) to the mainland (Zones I and J) will be needed by 2035. The study shows this need arises as interconnecting more than 3,000 MW of OSW generation to Long Island would cause increased curtailments. Interconnecting more than 3,000 MW to the Long Island grid may be inevitable as more than 9,000 MW of OSW generation is likely required for achieving the State's zero emission mandate by 2040, or even earlier if constraints in New York City force more of the 9,000 MW to Long Island.
- The OSW Study indicates connecting the off-shore substations of nearby OSW plants to create a **meshed offshore network** can achieve a more reliable and resilient delivery of OSW generation—even given necessary delays to such an approach pending federal approval of new wind energy areas by the Bureau of Ocean Energy Management (BOEM).
- The Zero Emissions Study also projects that additional **bulk transmission from upstate into New York City and Long Island** (from Zone H to Zones I, J, and K) will likely become cost-effective after 2035 as the grid approaches zero emissions, as a means to address high congestion costs associated with the unavailability of fossil-fueled generation options. These congestion-reducing transmission investments would reduce upstate congestion and renewable generation curtailments and allow the downstate (New York City and Long Island) area to reduce its projected reliance on backstop renewable-fueled thermal generation.
- The Zero Emissions and OSW Studies both find that location-optimized **battery storage** will be necessary to cost-effectively address the renewable generation integration and avoid more substantial transmission upgrades. The OSW Study finds that avoiding major transmission upgrades requires the carefully planned colocation of 1,700 MW of battery storage at the substations in the New York City area and Long Island utilized for integrating OSW generation. The Zero Emissions Study optimizes the location-specific deployment of 3,000 MW of battery storage by 2030, of which 1,600 MW would be deployed in New York City and Long Island. The study finds storage needs accelerate rapidly after 2035 as an emission-free grid needs to be achieved by 2040, with approximately 15,000 MW of battery storage projected state-wide by 2040, of which 7,300 MW would be located in New York City and Long Island.

Recommendations for the Future Grid

The Power Grid Study is a first step toward planning the investments in New York's electric system that are needed to meet CLCPA goals. It provides valuable information to the State, utilities, and transmission and renewable generation developers. However, cost-effective transmission development and utilization of the existing grid requires foresight and coordination that will necessitate the continuation of active planning, coordination, and process management. Without them, challenges and costs will likely exceed those identified in the studies. For the State to cost-effectively achieve its CLCPA milestones, this report offers the following recommendations for further consideration by the PSC and State policy makers.

Local Transmission and Distribution

- The PSC should consider implementing an expedited approval process for the proposed **Phase 1 local transmission and distribution projects**. Many of the Phase 1 projects facilitate timely interconnection of renewable generation in constrained upstate generation pockets.
- The Utilities' proposed Phase 2 projects should be assessed further. These projects can be evaluated—along with advanced technology options—based on the utilities' proposed Phase 2 project selection and cost-benefit framework.
  - Some proposed Phase 2 projects should be prioritized as they provide unique opportunities to expand Phase 1 projects and/or address high-interest, high-potential renewable generation pockets.
  - As a next step, the PSC should work with the Utilities and NYSERDA to advance high-priority Phase 2 projects to address headroom constraints in high-interest, high-potential renewable generation development areas, such as the Hornell generation pocket, for which the proposed Phase 1 projects do not create sufficient headroom.
- Significant renewable generation potential also appears to exist in areas of the State that currently do not have access to the existing transmission infrastructure. These areas have not been addressed in the Utility Study or the NYISO CARIS analyses which formed the starting point of the Utility Study. The PSC may want to consider whether several such areas in the NYISO footprint should be developed as local renewable energy zones through the construction of new local transmission infrastructure.
- In future assessments of the CLCPA benefits of LT&D projects, we recommend the Utilities adopt a *common* set of methodologies that more comprehensively identify

renewable integration benefits. The benefits created by projects should be quantified both in terms of renewable capacity and energy, rather than just capacity. Assessments of local transmission projects should include models of neighboring utilities' systems. Assessment of distribution projects should: (1) incorporate detailed modeling of the electrical system upstream and downstream of the distribution substation, (2) account for variability in load and renewable output, (3) address demonstrated DER developer interest through the use of queue data, and (4) include technical issues beyond thermal capacity ratings.

Offshore Wind Transmission

- The planning process to address OSW-related **transmission needs from Long Island** should be initiated. All studies indicate that additional tie-line capacity would be needed by 2035–2040 as renewable requirements expand and emissions limits tighten. Advancing such a project would provide additional value earlier if constraints into New York City force more than 3,000 MW of OSW into Long Island and mitigate curtailments associated with real-world operating conditions not captured in the studies' simulations. Given the decade it may take to plan, permit, and construct such a project, the planning process should start soon. The State should consider utilizing the NYISO Public Policy Transmission Planning Process as it is uniquely suited for developing cost-effective solutions to this need.
- A multi-disciplinary coordination effort should be undertaken to support solutions to route up to 6,000 MW of OSW generation into **New York City** (through the Narrows and inner harbor or the Long Island Sound) to connect to the City's transmission substations.
- The State should consider creating the option to develop a **meshed offshore power grid** that, at some point, could connect OSW plants serving the State with each other and possibly with plants serving needs in New England and New Jersey. This may require that NYSERDA's OSW procurements incorporate offshore substation designs that include—as an option—the capability to be meshed to two neighboring stations. This would create the option, likely at only modest incremental costs, to integrate the State's OSW plants into a more reliable, more valuable offshore transmission grid that could also provide new interconnections with neighboring power markets. Close coordination with BOEM to make more wind energy areas available will foster more competitive OSW procurements and facilitate the potential development of meshed offshore transmission systems. Therefore, the State should advocate for the expeditious development of new wind energy areas that take into consideration state policy needs.

Advanced Technologies

- The Utility Study discusses the potential for advanced transmission technologies, but its recommendations do not go far enough to deploy in a timely fashion, well-tested technologies that could provide CLCPA benefits and reduce costs.
- The State should encourage the Utilities and other transmission owners to expeditiously evaluate and deploy **advanced transmission technologies**—such as dynamic line ratings for which commercial-scale applications, for example, have demonstrated a 20-30% increase of average annual transmission capacity above static ratings (e.g., with a 10% increase during 90% of the year, 25% during 75% of the year, and 50% during 15% of the year), while maintaining or enhancing system reliability.
- Several of the available technologies have advanced well beyond their research and development and pilot program phases and are ready for commercial deployment in the State. Collectively, the Utilities have experience with most of the advanced technologies evaluated in the Utility Study, many of which can be deployed to both the local and bulk-power grid more quickly and cost-effectively than traditional transmission upgrades. They also can be deployed quickly in targeted locations to expand the renewable resource integration capability of both the existing transmission system and proposed new projects.
- Both utility and NYISO transmission planning processes should be improved to recognize the unique advantages that advanced technologies can provide to address CLCPA-driven needs. Cost recovery mechanisms will need to be clarified for storage facilities that can both cost-effectively address a CLCPA transmission need and participate in NYISO wholesale power markets.

Improved and Coordinated Planning Processes

- The State will need to continue to refine its **planning processes** to achieve the necessary coordination of distribution, local transmission, and bulk-power transmission infrastructure and renewable resource investments. The Zero Emissions Study's projected development of more than 9,000 MW of OSW generation, at least 30,000 MW of land-based renewables, and approximately 15,000 MW of storage by 2040 will need to be coordinated closely (both in terms of location and in-service dates) with grid infrastructure investments to achieve the most cost-effective outcomes.

- The State should facilitate additional coordination across the different existing planning processes. Specifically, since some of the local transmission needs may be resolved by upgrading the systems to bulk transmission voltage levels, closer coordination between NYISO and local utility planning will be necessary. For example, LIPA's and ConEd's Phase 2 local transmission proposals to facilitate OSW interconnections will require coordination with bulk transmission planning to achieve cost-effective outcomes. The more integrated and coordinated planning processes should also be designed to recognize the unique advantages that storage and advanced technologies can provide to address CLCPA-driven needs.
- As previously noted, multi-disciplinary planning and coordination efforts should be initiated to support the development of cost-effective options for routing up to 6,000 MW of OSW generation into New York City and its interconnection with the City's substations. Additionally, the State should explore available policy options to support appropriate coordination to ensure the State's offshore wind energy goals are reached. In addition to minimizing disruptions for stakeholders, such coordination may also significantly reduce developer risks, likely yielding a lower-cost outcome for the State.
- To date, **forecasting of renewable generation development** in specific locations has been based on applications for interconnection at the bulk power level through NYISO and at the local T&D level through individual utilities under the PSC's standard interconnection requirements. To improve planning and support procurement efforts, these forecasts of renewable development locations on the bulk and local transmission systems should be improved by including mapping of solar and wind resource potential, regional econometric indicators for new development, environmental constraints, inter-regional energy exchanges, local regulations that impact greenfield development, and interconnection headroom estimates.

Further Studies

- More detailed and consistent studies will be necessary to **quantify existing headroom** in various transmission-constrained areas on the local and bulk transmission systems and to identify high-priority, high-value locations that should be targeted with transmission upgrades. These studies should be based on both a power-flow model that better measures headroom capacity and a production simulation model—ideally aligned with the NYISO's economic planning process assumptions and modeling tools—that can estimate annual curtailments and the extent to which proposed upgrades can reduce these curtailments.

- The State should also coordinate with NYISO further studies of the **operational challenges** not fully analyzed in the OSW and Zero Emissions Studies, aimed at better understanding transmission needs given the likely real-world flexibility challenges, congestion costs, and renewable curtailments. Building on recent NYISO analyses, such studies would focus on the operational implications of factors such as day-ahead renewable generation forecasting errors, real-time renewable generation uncertainties and associated intra-hour system flexibility needs, the impacts of planned and unplanned transmission outages, and system performance under more challenging weather conditions (such as storms, heat waves, and cold snaps).
- Further studies will be required to more completely understand the generation and storage technology options that will be needed after 2035 to cost-effectively reduce emissions to zero by 2040, and the extent of how these technologies will impact grid investment needs. The Zero Emissions Study projects that emissions could be eliminated fully with approximately 20,000 MW of **backstop thermal generation** that is fueled with landfill gas, bio gas, or other renewable natural gas. This option yields high congestion costs, which makes bulk-power transmission upgrades from upstate to downstate cost effective. At this point, however, the projected solution should be seen mostly as a placeholder until more clarity exists about available future technologies, such as green hydrogen and long-duration storage.

I. Introduction

As mandated in the Accelerated Renewable Energy Growth and Community Benefit Act (the Act), the Department of Public Service (Department or DPS), in consultation with the New York State Energy Research and Development Authority (NYSERDA), the New York Power Authority (NYPA), the New York Independent System Operator (NYISO), and New York's investor-owned utilities (Utilities), undertook a study "for the purpose of identifying distribution upgrades, local transmission upgrades, and bulk transmission investments that are necessary or appropriate" to the timely achievement of the climate targets established in the Climate Leadership and Community Protection Act (CLCPA).[5] The results of that study, referred to here and in the Act as the Power Grid Study, are summarized and discussed in this Initial Report, prepared by Staff of the Department and NYSERDA with support from consultants of The Brattle Group and Pterra Consulting.

The Power Grid Study consists of three component studies:

1. The "**Utility Transmission & Distribution Investment Working Group Study**" (Utility Study) describing the potential distribution and local transmission upgrades identified by each of the New York Utilities. It is attached to this Initial Report as Appendix C.[6]
2. The "**Offshore Wind Integration Study**" (OSW Study) identifying possible grid interconnection points and offshore transmission configurations and assessing onshore bulk transmission needs relating to the integration of 9,000 MW of offshore-wind generation; attached as Appendix D.[7]

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5 The Act, Chapter 58 of the laws of 2020, Section 2; CLCPA Chapter 106 of the laws of 2019.

6 Utility Transmission & Distribution Investment Working Group Report, November 2, 2020. The Utility Study was prepared by the Utilities and filed with the Commission in Case 20-E-0197. Appendix C to this Initial Report is a copy of the Utility Study.

7 Mike Tabrizi, Manos Obessis, and Steven MacLeod, "Offshore Wind Integration Study: Final Report," prepared by DNV GL., PowerGEM, and WSP Global for NYSERDA and NY DPS, January 2021.

3. The "**Zero-Emissions Electric Grid in New York by 2040**" study (Zero Emissions Study), identifying bulk transmission upgrades potentially necessary to support the State's path to a 100% decarbonization of the electricity sector by 2040; attached as Appendix E.[8]

This Initial Report describes the overall conclusions of the three studies and provides a preliminary synthesis of the work considered as whole. Where relevant, this Initial Report also references and considers the findings and information provided by stakeholders and in other system studies, such as those performed by the NYISO[9] and other stakeholders.

The primary purpose of this Initial Report is to provide recommendations to the Public Service Commission (PSC) for planning the investments in the New York electric system that are needed to meet CLCPA goals. As required by the Act, the PSC will use the results and findings of the three Power Grid Study components and this Initial Report to develop distribution and local transmission capital plans for each utility and to establish a bulk system investment program.[10] The studies described here accomplish that objective by providing well-founded indications of the likely impacts of the State's renewable energy targets for future grid needs. However, given the scale and complexity of the challenge presented, this Initial Report appropriately notes the limitations of the work accomplished so far and provides guidance on how the risks and uncertainties not addressed in these studies may be mitigated.

Because of these limitations, it is important to recognize that the potential grid solutions and projects identified in the underlying studies are just that: *potential* approaches to building a system that will support the State's goals. They indicate that there are feasible pathways to meeting the CLCPA targets but should not be taken in any case as a specific blueprint. As noted in this Initial Report, further study work may be necessary to clarify or develop the conclusions of the Power Grid Study, and actual project designs will need to be evaluated and tested to

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8 Jay Boggs and Ben Stravinsky, "Zero-Emissions Electric Grid in New York by 2040," prepared by Siemens Power Technologies for NYSERDA, January 2021.

9 For example, several related studies were prepared by or on behalf of NYISO in 2020: the *2019 CARIS Report* (July 24, 2020), the *2020 RNA Report* (October 28, 2020), *New York's Evolution to a Zero Emission Power System*, prepared by the Brattle Group for NYISO (June 22, 2020), and *Climate Change Impact Phase II*, prepared by Analysis Group for NYISO (September 2020).

10 The Act, Sections 3 and 4. The PSC initiated work on utility local T&D planning earlier this year, when it directed the Utilities to undertake the Utility Study and to propose a planning and investment framework for local transmission and distribution investments driven by CLCPA needs. Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, Case 20-E-0197 (May 14, 2020) (May Order). The Utilities filed the study and their proposals for CLCPA investment criteria on November 2, 2020 in that proceeding.

ensure that the State's grid investments achieve those goals in the most cost-effective manner possible.

The remainder of this Initial Report summarizes and discusses the Utility Study's LT&D analysis and proposals (Section III), the Utility Study's advanced technologies proposal (Section IV), the OSW Study results (Section V), and the Zero Emissions Study results (Section VI). Section VII then presents our overall Power Grid Study findings and recommendations. Appendices A and B summarize preliminary recommendations about individual utility-proposed Phase 1 local transmission and distribution projects. Complete copies of the Utility, OSW, and Zero Emissions studies are attached as Appendices C, D, and E.

II. Utility Local T&D Infrastructure

The Utility Study was prepared by the Joint Utilities[11] (Utilities) through a Technical Analysis Working Group convened by Department Staff. The study was completed and filed on November 2, 2020 as Part 2 of a larger Utility Filing.[12] In the Utility Study, the Utilities identify a number of upgrades to the local transmission and distribution systems that they expect will accelerate progress towards the CLCPA's 2030 renewable energy mandates, which include the goal of meeting 70% of the State's electric energy demand with renewable sources. For these purposes, consistent with the PSC's directions, the study defines *local* transmission and distribution as transmission and distribution lines and equipment that operate at less than 200 kV.[13]

This section of the Initial Report summarizes the methods the Utilities used to assess their systems' needs and describes the types of distribution and local transmission needs they identified. We then provide recommendations relating to the state-wide implications of the study results and recommendations for future studies of the Utilities' LT&D systems. An overview of the individual LT&D projects proposed in the Utility Study is included in Appendices A and B, which also provides a preliminary assessment of the projects.

[11] As noted earlier, the Joint Utilities include the New York utilities of Central Hudson Gas & Electric Corp. (Central Hudson), Consolidated Edison Company of New York, Inc., (ConEd), Long Island Power Authority (LIPA or LIPA/PSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation (NYSEG and RG&E or AVANGRID), and Orange & Rockland Utilities, Inc. (Orange and Rockland or O&R).

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

[13] May Order, p. 3, footnote 4: "…For purposes of this discussion, we understand 'local transmission' to refer to transmission line(s) and substation(s) that generally serve local load and transmission lines which transfer power to other service territories and operate at less than 200kV."

A. Study Approach and Assumptions

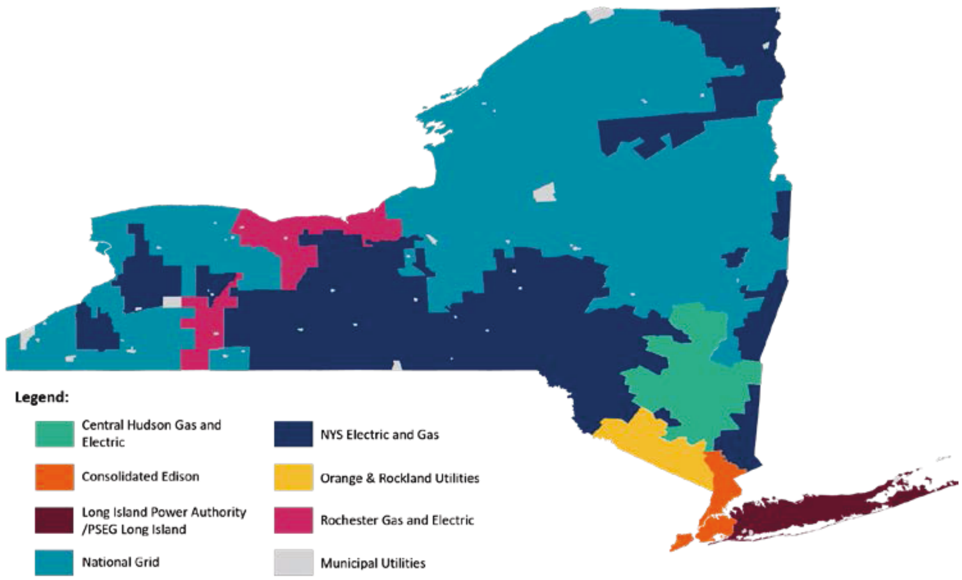
The Utility Study responds to the following guidelines established by the PSC in its May 2020 Order:

- Evaluate the local transmission and distribution system of the individual utility service territories, to understand where capacity "headroom" exists today;
- Identify existing constraints or bottlenecks that limit energy deliverability;
- Consider synergies with traditional capital expenditure projects (i.e., aging infrastructure, reliability, resilience, market efficiency, operational flexibility, etc.);
- Identify least-cost upgrade projects to increase the capacity of the existing system;
- Identify potential new or emerging solutions that can accompany or complement traditional upgrades;
- Identify potential new projects that would increase capacity on the local transmission and distribution system to allow for interconnection of new renewable generation resources; and
- Identify the possibility of fossil generation retirements and the impacts and potential availability of those interconnection points.

1. Renewable Generation Assumptions

The Working Group coordinated the approaches of the six New York utilities, whose service territories are shown in Figure 1. The Utilities' general approach was to assess the operation of their LT&D systems at the levels of renewable generation projected for 2030. The Utilities based their 2030 renewable generation assumptions on NYISO's 2019 CARIS 70x30 scenario, which models approximately 30,000 MW of utility-scale renewable generation resources across the eleven NYISO zones by 2030, as shown in Figure 2. Utilities employed these CARIS renewable assumptions with the exception of those related to offshore wind resources and as modified by some utilities to reflect 2020 changes to the NYISO queue and their own local system queues for distributed energy resource (DER) interconnections. With respect to offshore wind, the Utilities assessed the impact of the full 9,000 MW of offshore wind that is mandated by 2035, rather than the 6,100 MW modeled in CARIS in 2030. The Utilities then proposed LT&D projects that can relieve transmission limit violations for the projected 2030 system conditions.

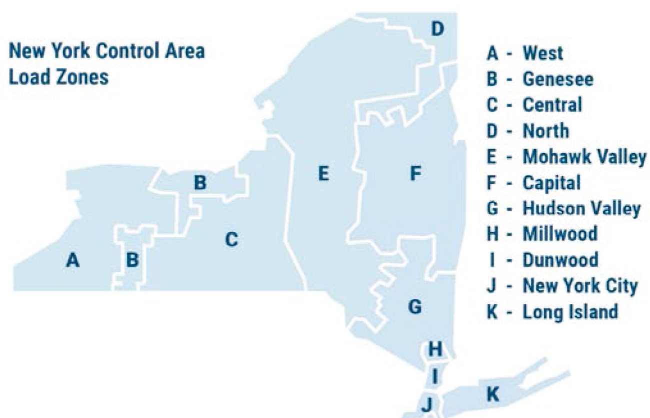
FIGURE 1: NEW YORK STATE ELECTRIC UTILITY TERRITORIES 2020



Notes: Data is from State of New York, *NYS Electric Utility Service Territories*, accessed December 10, 2020: https://data.ny.gov/Energy-Environment/NYS-Electric-Utility-Service-Territories/q5m9-rahr
Avangrid subsidiaries include NYSEG and RG&E.

FIGURE 2: TOTAL 2030 RENEWABLE GENERATION CAPACITY IN CARIS 70X30 "BASE LOAD" CASE

Base Load				
2030 MW	OSW	LBW	UPV	BTM-PV
A		2,286	4,432	995
B		314	505	298
C		2,411	2,765	836
D		1,762		76
E		2,000	1,747	901
F			3,592	1,131
G			2,032	961
H				89
I				130
J	4,320			950
K	1,778		77	1,176
NYCA	6,098	8,772	15,150	7,542



Sources:
New York ISO, *2019 Congestion Assessment and Resource Integration Study*, July 24, 2020.
New York ISO, *Manual 26: Reliability Planning Process Manual*, p. 12, December 12, 2019.
Notes: Of the utility-scale wind and solar generation capacity assumed in 2030 in the CARIS analysis (shown in the table above), approximately 2 GW consist of existing resources, with the remaining 28 GW assumed to be added over the next decade. The Utility Study modified CARIS OSW assumptions to study the full 9 GW of OSW development.

The renewable capacities modeled by Utilities in their individual studies were generally consistent with the CARIS 70x30 assumptions shown in Figure 2 above. However, the Utilities' assumed points of interconnection for renewables on the local transmission system sometimes deviated from the CARIS assumptions. CARIS modeled about 24 GW of land-based wind and utility-scale solar, which included approximately 2 GW of existing and 22 GW of *new* capacity. Of the 22 GW of new land-based renewable capacity, approximately 12 GW was modeled in CARIS as interconnecting at the local (69, 115, or 138 kV) transmission level. The Utilities also updated some of CARIS assumed points of interconnections for *offshore* wind resources, moving up to 1.8 GW of the 6.1 GW of CARIS' offshore wind capacity to selected points of interconnections on the local transmission system.

The Utilities refined the interconnection points for new renewables (both land-based and offshore wind) on the *local transmission system* as follows. Central Hudson and National Grid modeled the same points of interconnection as CARIS. ConEd and LIPA modified the points of interconnection according to specific knowledge of their systems. O&R's 2030 analysis is primarily based on an "enhanced" summer case that has higher renewable capacity and different points of interconnection assumptions than CARIS; for the enhanced summer case, O&R based its points of interconnection on more recent developer interests in its service territory, as documented in the *current* NYISO Interconnection Queue. Lastly, AVANGRID relocated new renewables from the CARIS 115 kV points of interconnection to their electrically closest sub-transmission stations (e.g., 34.5 kV). Notably, AVANGRID also deviated from CARIS by excluding *planned transmission* that CARIS expected to be in-service between 2025 and 2030 on the basis that the development of these projects is still uncertain.

2. Project Identification

The Utilities identified and developed local transmission and distribution projects that would improve headroom for renewable generation in constrained areas. The projects are categorized as "Phase 1" or "Phase 2" projects depending on base drivers, project timelines, and the volume of planning and regulation that remain to be resolved. As stated in the Utility Study, Phase 1 and Phase 2 projects are defined as follows:

- Phase 1 projects are immediately actionable projects needed to satisfy Reliability, Safety, and Compliance purposes but that also expand constraints that limit renewable energy delivery within a utility's system. These projects may be in addition to projects that have been approved as part of the utility's most recent rate plan or are in the utility's current capital plans. Because they are driven by local planning criteria, the costs of Phase 1 projects will be recovered from the customers of the utility proposing the project.[14]

- Phase 2 projects may increase capacity on the local transmission and distribution system to allow for interconnection and delivery of new renewable generation resources within the utility's system. These projects are not currently in the utility's capital plans. Phase 2 projects tend to have needs cases that are driven primarily by achieving CLCPA targets. Broad regional public policy benefits suggest the likelihood that cost sharing across the Utilities may be appropriate. These projects require additional time to plan and prioritize using the investment criteria and benefit cost analysis (BCA) methodology proposed in Part 1 of the Utility Study.[15]

3. Headroom Analysis for the Local Transmission Grid

The Utilities estimated both (1) the **existing headroom** of their local transmission systems, reflecting the available hosting capacity for renewables based on either the present existing or the projected 2030 New York electric system and (2) the **incremental headroom** that would be created by each proposed project, in addition to the existing headroom. As clarified by the Utilities in follow-up discussions, the methodologies to estimate *existing* headroom differ substantially across the Utilities and differ from the methodologies used to estimate the *incremental* headroom created by the proposed projects. The scope of existing headroom calculations is generally limited to partial renewable generation output level and only the closest constraint for each location. Consequently, it is not a reliable estimate of the system's capability to integrate renewable generation. As calculated, the existing headroom is not additive across locations, and cannot be compared across the Utilities nor with the estimates of incremental headroom. However, the analyses of *incremental* headroom are based on reliability needs and provide a more meaningful estimate of the CLCPA benefit of the analyzed LT&D projects.

Headroom needs identified by the Utilities can be characterized as "on-ramp" to the bulk power grid (e.g., from export constrained generation pockets) or "off-ramp" from the bulk power grid to import-constrained load pockets. On-ramp needs reflect increased transmission capacity need to export renewable energy from the local generation pocket to the bulk system. The direction of export is from a lower voltage system to a higher voltage system. In contrast, off-ramp needs reflect increased capacity to import renewable energy from the bulk system to

[14] Utility Study, p. 24.

[15] *Ibid*.

the local transmission system. A third form of local transmission need, in addition to on-ramp and off-ramp needs, addresses internal constraints within a load pocket. Such constraints limit the ability of local generation to serve loads within the load pocket.

As a measure of how effective a local transmission project is with respect to providing CLCPA benefits, the Utilities calculated incremental headroom capability for each project. The Utilities employed different methods for calculating incremental headroom capability. These methods include:

- **Net Capability calculations**, wherein load and generation is netted against the export or import capacity (e.g., Export Headroom = local load – existing generation + outlet capability);
- **Optimal Power Flow (OPF) techniques** to determine the maximum incremental injection within generation or load pockets feasible under thermal steady state and contingency criteria, primarily using the OPF feature for determining security constrained dispatch in software such as TARA;[16]
- **Transfer Limit Analysis** to determine the available export or import capacity on the transmission interface out of generation pockets or into load pockets; and
- **Upgrade Capability** which equates headroom with the thermal rating of the LT&D project.

National Grid employed an OPF technique to analyze on-ramp local transmission needs in seven generation pockets across its service territory. AVANGRID also employed an OPF technique to determine the range of headroom values at its generation pockets. Orange & Rockland and Central Hudson employed Net Capability calculations, while LIPA employed Transfer Limit Analysis to analyze both on-ramp and off-ramp issues in its service territory. ConEd applied Upgrade Capability to determine the headroom for its proposed local transmission projects.

4. Headroom Analysis for the Distribution Grid

For distribution projects, the Utilities, with the exception of ConEd, employed a common method for calculating incremental headroom capability for proposed Phase 1 projects. The headroom calculations consider the capacity-based addition of renewable generation as limited by distribution substation capacity. Many Phase 1 distribution projects are substation transformer upgrade projects. For such projects, the incremental headroom is calculated as the

[16] Transmission Assessment and Reliability Analysis (TARA) software, a product of PowerGEM Inc.

increase in substation transformer rating, derated by a factor.[17] Other projects include increasing the voltage rating of a feeder, or reconductoring lines to higher capacities. In these cases, the headroom is determined based on the incremental capacity introduced by the new rating over the existing rating.

A crucial assumption in the Utilities' distribution headroom analysis is that the DERs can "backfeed" power from the distribution substation onto the local transmission grid. However, there is no apparent coordination with the upstream local transmission headroom analyses, so there may be bottlenecks at the local transmission level that would prevent DERs from backfeeding. The Utilities also did not account for constraints downstream of the distribution substation (i.e., on the distribution feeders). These feeder-level constraints are ignored because DER developers typically pay for the needed upgrades identified through their interconnection process. However, this would not account for expensive upgrades that a DER project may not be able to support on its own.

ConEd's headroom calculations for proposed distribution projects is distinct from the earlier discussion. Due mainly to the nature of its compact meshed distribution networks, ConEd determined DERs are unlikely to cause constraint violations up through 2030. ConEd's proposed Phase 1 projects are upgrades that provide operational flexibility, take advantage of the meshed networks, and primarily address constraints that would prevent renewable generation in one distribution area from supplying another area. Utility energy storage projects are also included among ConEd's projects.

Headroom analysis for Phase 2 projects varied among the Utilities. In some cases, the same Phase 1 methodology was applied. However, the majority of analyses were more detailed and included elements such as detailed feeder models, chronological variations in renewable output and consumer loads, and analytical distribution system software (e.g., EPRI Drive). Although the Phase 2 headroom analyses provide more insight into needs downstream of the distribution substation, there is still a lack of coordination with the upstream needs (i.e., the local transmission headroom assessments).

[17] The derate factor varies by utility. For example, AVANGRID and LIPA use 75% and 85% of the forced-cooled rating, respectively, while O&R applies 100% of the self-cooled rating for a single bank substation upgrade and 100% of the forced-cooled rating of a single transformer for a-two bank substation upgrade.

B. Summary of Utility Study Results

The Utilities' proposed Phase 1 and Phase 2 projects are summarized in Figure 3 and Figure 4 below. Altogether, the Utilities' estimate that proposed Phase 1 *local transmission* projects would unbottle the delivery of an estimated 6.6 GW of renewable generation. Similarly, the Utilities' proposed Phase 1 *distribution* projects would unbottle an estimated 2.0 GW of renewable generation.[18] Note that these estimates are based on the headroom calculations that the Utilities have presented.

The generally less detailed and more preliminary Phase 2 project proposals for local transmission investments are estimated to provide 12.7 GW of renewable integration benefits based on the Utilities' headroom calculations. Phase 2 proposals for the distribution system could support an estimated 2.8-4.3 GW of renewable integration benefits.

The majority of proposed Phase 1 transmission projects address on-ramp issues, including projects proposed by National Grid, AVANGRID, and Central Hudson. Most of the local transmission projects proposed by downstate Utilities (ConEd, LIPA, and Orange and Rockland) address off-ramp needs.

For the proposed distribution projects, most of the incremental headroom capacity addresses projected on-ramp needs. On-ramp distribution projects assume that renewable energy developed at the distribution level can backfeed renewable generation to the local transmission system when generation is in excess of the distribution feeder's load. A smaller portion of the proposed projects address internal load pocket constraints. Load pocket incremental headroom reflects the increased local distribution capacity to support new renewable energy within the load pocket.

[18] The actual total amount of renewable generation that the Phase 1 projects will support is very likely less than 8.6 GW due to: (1) the headroom for off-ramp projects likely double counts the headroom of on-ramp projects, and, 2) local transmission headroom is not coordinated with distribution headroom.

FIGURE 3: SUMMARY OF UTILITIES' PHASE 1 PROJECTS AND ESTIMATED CLCPA BENEFITS
(All Phase 1 projects and costs are driven by traditional reliability, asset condition, or compliance needs)

Utility	Projects (No.)	Estimated Project Cost (to Address Traditional Need)	Estimated CLCPA Benefit (MW)
Central Hudson			
Transmission	6	$152.1M	433
Distribution	12	$137.0M	132
CECONY			
Transmission	3	$860M	900
Distribution	8	$1,130M	418
LIPA			
Transmission	8	$402M	615
Distribution	19	$351M	520
National Grid			
Transmission	13	$773M	1,130
Distribution	5	$649M	428
NYSEG/RG&E			
Transmission	16	$1,560M	3,041
Distribution	8	$229M	165.8
O&R			
Transmission	6	$417M	500
Distribution	9	$156M	308
Total	**113**	**$6,816M**	**8,591**
Transmission Total	52	$4,164M	6,619
Distribution Total	61	$2,652M	1,972

Note: Proposed Phase 1 projects and the associated costs are required to address reliability, asset condition or compliance needs.

FIGURE 4: SUMMARY OF UTILITIES' POTENTIAL PHASE 2 PROJECTS AND ESTIMATED CLCPA BENEFITS
(Phase 2 projects are driven by CLCPA needs)

Utility	Projects (No.)	Estimated Project CLCPA Benefit (MW)
Central Hudson		
Transmission	6	766
Distribution	7	222
CECONY		
Transmission	6	7,686
Distribution	2	360
LIPA		
Transmission	6	1,830
Distribution	8	937
National Grid		
Transmission	13	1,500
Distribution	7	1,152 - 2,700
NYSEG/RG&E		
Transmission	11	943
Distribution	5	88.3
Total	**71**	**15,484 - 17,032**
Transmission Total	42	12,725
Distribution Total	29	2759 - 4,307

Sources for Figure 3 and Figure 4:
Utility Study, pp. 6, 77.
Utility Transmission and Distribution Investment Working Group Report Errata (filed by National Grid), Case 20-E-0197, December 1, 2020.

C. State-wide Recommendations and Takeaways

1. Utility Methodologies for LT&D Headroom Evaluation and Need for a more Coordinated System-wide Assessment

The discussion below first address takeaways regarding the Utilities' assessment of headroom for the local transmission and distribution systems and then recommend areas for further studies.

i. Assessment of Utility Methodologies for Local Transmission Headroom Evaluation

The State mandates for CLCPA targets are expressed in terms of energy consumption, measured in Megawatt-hours (MWh). Utilities' estimated headroom capacities are measured in Megawatts (MW) and do not indicate how much energy will be deliverable as a result of the proposed projects. To determine deliverability of renewable generation, the variability of load and supply must be considered, including potential renewable curtailments. A consequence of measuring CLCPA benefits in capacity MW is the focus on wires solutions to accommodate the extremes in electric system usage while not fully capturing the benefits of energy solutions such as storage, advanced grid management systems, and load programs. Estimating the MWh-energy-based headroom would require a modeling tool that can capture the chronological variations in renewable generation and electric system use. We recommend that future assessment of CLCPA benefits be measured with a combination of capacity and energy headroom. The utilities have in fact already proposed an MWh-based benefit-cost analysis framework for the future evaluation of Phase 2 projects.

As explained in Section II.A.3, the Utilities employed different methods for calculating incremental headroom capability created by proposed local transmission projects. Some of the methods are better suited than others for evaluating renewable hosting capability in generation and load pockets. For evaluating *on-ramp hosting capability in generation pockets*, we recommend that Utilities employ Optimal Power Flow techniques, using a common set of scenarios and dispatch assumptions. Because generation pockets affect each other (e.g., the power from one generation pocket may flow through another generation pocket before reaching the bulk transmission system) we also recommend that such analysis identify generation pockets based on interface definition (i.e., using current NYISO interfaces as a starting point but identifying new interfaces as introduced by local transmission projects), and develop a common set of power flow models that can capture how power flow from resources in generation pockets interact. This method would be most applicable to National Grid, AVANGRID and Central Hudson. Additionally, utilities should look to employ expanded power flow models with details of sub-transmission and medium voltage systems for future studies. These models would benefit from incorporating updated distributed energy resource (DER) forecasts from local DER queues.

For *off-ramp headroom capability in load pockets*, we recommend that the Utilities employ techniques similar to those we recommend for on-ramps *if* the local transmission system serving load pockets is operated in a parallel configuration with the higher-rated bulk power system. For off-ramp load pockets that are more radial in nature—where the radial local transmission system primarily serves to import generation from the bulk system to load pockets—or for off-ramp load pockets that allow only energy imports from the bulk system through the use of flow control devices, the simpler *Net Capability calculation* method is acceptable. However, to the extent possible, we recommend minimizing the use of Upgrade

Capability as this method may miss other opportunities to provide for incremental headroom within the load pocket.

For generation pockets, the Utilities' headroom analysis tends to be limited to the individual service territories to the exclusion of impacts from the flows of electrically nearby generation pockets. For example, unbottling renewable delivery from western and southwestern New York generation pockets in National Grid and AVANGRID's service territories would inject power onto the 115 kV and 230 kV transmission system that links to other generation pockets downstream and further east, such as to the Binghamton and Hornell generation pockets of AVANGRID. In analyses of headroom created by proposed projects, the Utilities have not fully considered the impact of how various downstream generation pockets would be affected by flows from the upstream generation pockets.

Without a more coordinated, system-wide, power flow assessment that can evaluate such generation pocket interactions and flow-through issues—which would likely identify additional renewable delivery limitations—it is not possible to determine the existing headroom nor is it possible to fully evaluate the combined headroom created by the proposed Phase 1 and Phase 2 projects or how they should be prioritized. It is also not possible to clearly determine whether the proposed Phase 1 projects would be sufficient to fully enable the unbottling of renewables in those analyzed generation pockets or whether additional needs could manifest themselves. Our review indicates that for at least some Phase 1 projects, it may not be possible to fully utilize the estimated headroom due to the impacts of power flows from other upstream generation pockets that flow-through the 115 kV and 230 kV facilities of the downstream generation pockets. We recommend that the Commission direct the Utilities that future studies of proposed LT&D projects employ a more consistent, system-wide power flow assessment. The results of such analyses should be included in petitions for CLCPA-related project approval within or outside the State's rate case processes.

When assessing headroom capacity, Utilities considered a variety of cases and varied the analyzed load and level of renewable generation (as a percentage of installed capacity) across the cases. This means that the headroom capacity reported by most utilities was evaluated only for certain generation output levels that are well below the full installed renewable generation capacity. In the absence of simulations covering all hours of the year, evaluating headroom based on renewable output closer to the installed capacity would be a better proxy for assessing the feasibility of how much renewable capacity could be interconnected to the local transmission system without significant curtailment risks.

More specifically, the renewable generation headroom *capacity* analyzed in the Utility Study only measures how much incremental power can be injected under the modeled generation output levels—such as during summer peak, light load, and shoulder load conditions—without exceeding the system's component ratings. In most of the studies conducted by the Utilities, renewable generation resources have been assumed to inject well below 100% of their installed capacity into the grid during the modeled system load conditions.[19] This means that the headroom analysis for 100 MW of additional renewable generation may only have been examined using a 40 MW injection from that resource to reflect a specific system condition, such as summer peak load. It also means that when the renewable resources are generating above the evaluated output levels, such as at 70 MW, they may be subject to curtailment.

A summary of the average generation level assumptions employed by the Utilities in its study cases is shown in Figure 5. As shown, offshore wind generation evaluated ranges from 20% to 100% of installed capacity, land-based wind generation ranges from 0-75%, and utility solar generation ranges from 0-70%. To assess the true renewable hosting capability of the local transmission system, utilities would need to evaluate the extent to which the installed capacity can be accommodated at different output levels, which could be accomplished by employing more robust study methods, such as optimal power flow with generation re-dispatch. As evaluated, however, the headroom estimates would likely be associated with significant curtailments and thus will tend to overestimate the system's renewable generation hosting capability.

FIGURE 5: UTILITIES' ASSUMED GENERATION LEVELS FOR RENEWABLES (% OF ICAP)

Utility	Offshore Wind	Land-Based Wind	Utility Solar
AVANGRID and Central Hudson	Day-Peak Load: 20% Light Load: 45% Shoulder Load: 45%	Day-Peak Load: 10% Light Load: 15% Shoulder Load: 15%	Day-Peak Load: 45% Light Load: 0% Shoulder Load: 40%
Consolidated Edison	100%	n/a	n/a
Long Island Power Authority	20-100%	n/a	0-45%
National Grid	n/a	0-75%	0-70%
Orange and Rockland	n/a	n/a	100%

Sources:
Utility Study, pp. 80, 103, 128, 156-157, 179, and 229.
2020 Reliability Needs Assessment Report, November 2020, p. 93.
Notes: Central Hudson and AVANGRID assumptions based on dispatch cases 1, 3, and 6.

[19] Exceptions include: ConEd, which included injection of offshore wind generation at 100% of the offshore wind installed capacity interconnecting to the ConEd transmission system, and Orange and Rockland, which modeled new renewables at 100% of nameplate in its power flow studies.

While local transmission headroom is based on new renewables being hosted on the local transmission, the impact of power injections from DERs located on the distribution system appears to have been neglected. In most cases, DER generation was assumed to only serve loads on the distribution feeder and is not assumed to backfeed to the local transmission system. Utilities that have accounted for backfeed include AVANGRID, which has confirmed that the backfeed will have no material impact on its local transmission projects' headroom, and ConEd, whose meshed secondary network can absorb a high level of renewable production without backfeed up to 2030. In general, we recommend better integration of local transmission and distribution headroom assessments so that backfeeding from DERs is accounted for.

ii. Assessment of Utility Methodologies for Distribution Headroom Evaluation

Distribution headroom calculations are focused on substation capacity which has the disadvantage of ignoring downstream needs. The Utilities generally assume that feeder upgrades needed as a result of a new DER interconnection would be the responsibility of the DER developer. However, this could have an adverse effect on DER developments that face high-cost upgrades. For example, ground fault overvoltage is a common issue that needs to be addressed during the DER interconnection process. The typical utility solution is the implementation of a "3V0" protection scheme on the substation's high voltage side. This scheme can be expensive for developers of relatively small DER projects (less than 2 MVA) and can take time to implement. Utilities should identify downstream needs that may require a costly and/or time-consuming solution in order to continue supporting the CLCPA targets. To do this, the Utilities will need to use a detailed model of the feeder, as well as information on the chronological variations in load and DER output and likely locations for DER interconnections.

Like the local transmission headroom calculations, the Utility Study's distribution headroom results are capacity-based. It is recommended that an added perspective of energy production be applied here as well. Another necessary consideration for distribution headroom is whether DERs can backfeed from the distribution system to the local and bulk transmission levels without causing any transmission-level constraints to bind.

iii. Recommendation for Additional Future Analyses to Facilitate Informed and Timely Project Approval Decisions

We recommend that—as the Utilities seek PSC approval of specific Phase 1 projects, particularly through petitions outside the normal rate case processes (when rate case cycles do not allow for sufficiently timely approval decisions)—the PSC consider requiring the submission of a more detailed evaluation of how the proposed projects address the renewable unbottling needs. To this end, we recommend that the PSC consider requiring the Utilities to submit:

1. Updated data on renewable generation development activities within the analyzed generation pockets (e.g., based on most recent interconnection queue and procurement information). This information would provide additional justification for the need to act on the advancement of the proposed projects outside normal rate case processes.
2. Headroom assessment in terms of both MW capacity and MWh energy benefits. This would broaden the types of solutions that may be viable and cost-effective to address electric system needs towards meeting the CLCPA targets, and place on comparable footing advanced transmission technologies (such as dynamic line ratings) and non-wires alternatives (such as storage, advanced grid management systems, and load control).
3. An assessment of both existing headroom and the headroom created by the proposed projects consistent with the recommendations on improved power flow analyses as discussed in in Section III.C.1 above. This would more accurately capture how renewable generation and local transmission projects affect nearby or upstream areas (including those in neighboring utility service territories).
4. Coordinated assessments of distribution project headroom and local transmission project headroom so that there are no unforeseen constraints for DER development when DERs backfeed to the local transmission level.
5. More detailed technical information for proposed projects should include:
   - Project description, electrical description, associated single line drawings and geographical map, including information on generation pocket, in-service date, incremental ROW requirements and expected change in import/export (headroom) capability from/to bulk system;
   - Existing and forecast local loads, non-renewable generation, renewable generation and import/export (headroom) capability from/to bulk system;
   - Currently planned and approved transmission projects included in the proponent utility's analyses, associated drivers (e.g., reliability violations, asset condition, customer requests, mandates, upgrades needed, etc.) and associated changes in import/export (headroom) capability;
   - Project alternatives and alternative project designs, including advanced technologies, considered to address the CLCPA-related need and the renewable generation unbottling benefits they would provide; and

- Detailed cost information for the proposed project and considered alternatives.

2. Phase 1 Local T&D Project Proposals

As noted above, the Utilities identified numerous Phase 1 LT&D projects, with a total estimated cost of about $6.8 billion. These projects are or will be proposed to address asset condition, reliability, security or compliance needs that are expected to manifest beginning in 2021 and through the next decade. Collectively, they represent an opportunity to leverage ongoing asset maintenance and reliability programs to capture important CLCPA benefits. The Utilities estimate that these projects would create incremental headroom of approximately 8,600 MW,[20] much of which (such as the on-ramp headroom) can support the CLCPA mandate by facilitating renewable generation delivery to the bulk system out of constrained generation pockets.

The proposed Phase 1 *off-ramp* projects ultimately would also support the State's transition to the 100 percent zero carbon emissions goal by 2040 and beyond, but may have only limited CLCPA benefits in the near term. Off-ramp projects primarily facilitate additional import capability in to load pockets. However, additional import capacity to load pockets will reduce renewable curtailments only when the bulk system cannot absorb all renewable generation output from generation pockets statewide. Such conditions are unlikely to occur before 2030 when 30% or more of the State's generation will still be sourced from fossil fuels. Off-ramps will, however, reduce such renewable curtailments more frequently as the State transitions towards 100% renewables by 2040 and beyond.

Several proposed Phase 1 projects have near-term in-service dates, ranging from 2021 through 2024 that would also provide significant CLCPA benefits. Because pre-established rate case schedules may not allow for timely project approval decisions for such near-term projects, alternative cost recovery processes may be necessary to ensure advancement of beneficial near-term Phase 1 projects proposed by the Utilities. A similar alternative approval and cost recovery process may be needed for projects with 2025-2030 in-service dates if project development activities need to start soon to make the in-service date achievable.

[20] Of the 8,600 MW of total incremental headroom created by Phase 1 projects, 6,600 MW is from Phase 1 local transmission projects and about 2,000 MW is from Phase 1 distribution projects.

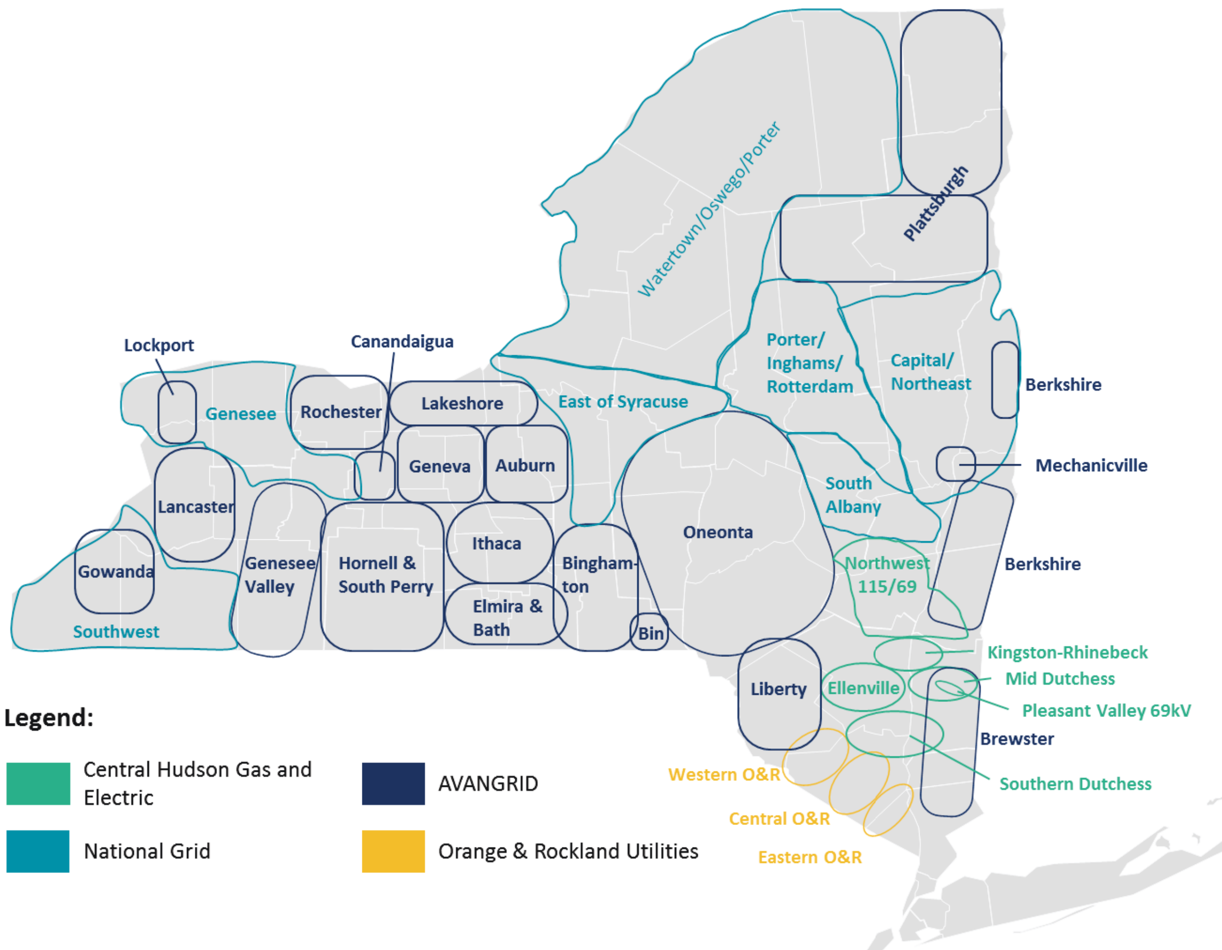
i. Local Transmission Project Discussion – State-wide Needs

Employing the CARIS model assumptions, the Utilities analyzed whether the existing and currently planned local transmission system could reliably integrate the projected renewable generation in their respective local generation and load areas. The Utility Study findings suggest that the incremental 6,600 MW headroom created by the Phase 1 transmission projects, plus the available hosting capability of the existing transmission system, may allow for the integration of the renewable resource additions assumed in the CARIS study—assuming these resources are generating only at the assumed average output levels.

For upstate Utilities, the high-level analyses presented in the Utility Study, on a state-wide basis, might suggest that the proposed Phase 1 projects may be sufficient to integrate the assumed 2030 level of renewable generation interconnected at voltages below 200 kV if generating at the studied output levels. However, as discussed above, these MW-capacity-based study results do not indicate the level of curtailments that these resources may face when generating above the studied output levels.[21] In addition, the renewable integration headroom required in some specific locations with attractive renewable development opportunities, particularly those different from the CARIS assumptions, may not be sufficiently addressed by Phase 1 projects. This also assumes that only limited additional constraints would be encountered due to interactions across upstate local transmission areas illustrated in Figure 6 below.

[21] As explained above, if the Utility Study determined there is 100 MW of headroom for the studied system condition (e.g., summer peak load), this means the system (or upgrade) can accommodate 100 MW of installed renewable capacity if it generates at the assumed lower average output level for the studied system conditions (e.g., 40 MW). A 100 MW resource may encounter curtailments, however, if generating at output levels (e.g., 70 MW) that are above those studied (i.e., 40 MW). An evaluation of all hours of the year, such as is performed by production cost models, would be necessary to predict MWh headroom and curtailments levels.

FIGURE 6: LOCAL TRANSMISSION AREAS IN UPSTATE UTILITIES' SERVICE TERRITORIES



Sources: AVANGRID area map is from Utility Study, p. 177, Fig. 75. Locations of Central Hudson, National Grid and Orange & Rockland Utilities local transmission areas were estimated by Pterra,

Of the total 6,600 MW in incremental headroom, the Utility Study projects *upstate* Phase 1 projects to provide about 5,100 MW of incremental headroom as shown in Figure 7. Combined with the existing headroom, this would appear to be able to integrate the 8,396 MW of new renewables interconnected at 200 kV or below that CARIS assumes to be located upstate, given the Utilities' assumed generation output levels. The figure also shows Utilities' wide range of existing headroom estimates and the estimated incremental headroom capacity created by the proposed Phase 1 and Phase 2 local transmission projects in each upstate and central NY local transmission areas.

FIGURE 7: UPSTATE UTILITIES' LOCAL TRANSMISSION "HEADROOM" VS. RENEWABLE GENERATION INTERCONNECTED TO LOCAL TRANSMISSION GRID (MW)

Local Transmission Area	Zone	Existing Renewables	CARIS New Renewables by 2030	Existing Headroom Estimates		Proposed LT Project Headroom Benefits	
				Low	High	Phase 1	Phases 1+2
National Grid							
Watertown/Oswego/Porter	C-E	2,748	1,329	1,010	1,080	300	870
Porter/Inghams/Rotterdam	E-F	137	878	430	550	150	660
East of Syracuse	C	157	777	1,620	1,850	90	-
Albany South	F	82	122	710	810	280	570
Southwest	A	2	892	540	810	310	440
Capital/Northeast	F	9	671	660	730	-	-
Genesee	B	30	752	630	900	-	-
AVANGRID							
Binghamton	C	-	-	159	715	755	790
Lancaster	A	228	137	149	827	675	685
Lockport	A	-	-	46	76	530	-
Geneva	C	0	267	146	514	28	183
Hornell and South Perry	B-C	101	614	16	978	330	840
Oneonta	C	76	282	62	523	460	500
Ithaca	C	18	111	163	428	263	273
Genesee Valley	B	62	67	8	77	-	75
Gowanda	A	-	-	17	28	-	-
Auburn	B-C	123	129	63	163	-	-
Rochester and Canandaigua	C	605	10	287	2,078	-	-
Elmira and Bath	C	2	45	-	557	-	8
Lakeshore	C	-	-	5	29	-	-
NYPA - Zone D	D	1,182	-	-	-	-	-
Plattsburgh	D	56	-	41	307	-	90
Berkshire and Mechanicville	F	12	244	129	431	-	-
Brewster	G	-	-	65	408	-	-
Liberty	E	-	-	101	255	-	10
Central Hudson							
Northwest	G	72	642	(204)	-	75	425
Southern Dutchess	G	-	-	251	-	143	143
Pleasant Valley 69 kV	G	-	-	98	-	60	120
New Smithfield	G	-	-	-	-	-	95
Mid-Dutchess	G	-	-	216	-	-	261
Ellenville	G	1	-	184	-	155	155
Kingston-Rhinebeck	G	-	-	176	-	-	-
69kV WM Line	G	-	-	13	-	-	-
115kV RD-RJ	G	-	-	138	-	-	-
Myers Corners Supply	G	-	-	51	-	-	-
Orange & Rockland							
Western O&R	E-G	12	214	-	-	500	500
Central O&R	G	-	214	-	-	-	-
Total		**5,716**	**8,396**	*Not Additive*		**5,104**	**7,693**

Notes:
Existing renewables includes hydroelectric resources.
Capacities reported for "Existing Renewables" and "CARIS New Renewables" correspond to renewables that interconnect to the system at <200 kV.
Not Additive: Methodologies and assumptions for existing headroom estimates vary substantially by utility, and therefore are not directly comparable or additive.
Orange & Rockland do not report existing headroom by local transmission area.

While the Utilities' analyses indicate that the proposed Phase 1 and Phase 2 projects will provide significant additional hosting capability, the exact level of that hosting capability, especially for aggregating across Utilities on a statewide basis, is uncertain given that each utility employed different methods and assumptions to assess existing headroom on its local transmission systems. The differences in assumptions and methodologies across Utilities makes the existing headroom estimates in Figure 7 not comparable or additive. However, we note that the Utilities' analysis of *incremental headroom* is based on reliability-needs analyses that are more consistent across the Utilities. This gives us the indication that, together, on a total state-wide basis, the proposed Phase 1 projects (or a similar portfolio) may add sufficient incremental headroom to accommodate the integration of the land-based renewable resources projected to be necessary to meet the CLCPA's 2030 requirements, and possibly beyond.

However, as explained above, the headroom estimates associated with Phase 1 projects may be associated with significant curtailments, given that the Utilities' analyses evaluated headroom capacity needs mostly at "average" renewable output levels rather than at installed capacity. This means that additional local transmission upgrades may become necessary (beyond the proposed Phase 1 projects) as actual projects attempt to interconnect. Nevertheless, the risk that the combination of the existing grid's and the Phase 1 projects' headroom may be insufficient should be modest until 2030 and possibly beyond. This is because the Utilities relied on CARIS 70x30 Case assumptions, which include approximately 11.5GW more renewable capacity by 2030 than what is projected to develop statewide based in the Zero Emissions Study. Section VI of this report describes the Zero Emissions bulk study results and its implications in more detail. Thus, given the higher level of installed 2030 renewable generation in the CARIS model assumptions, and given that the proposed Phase 1 projects combine with existing system capability to provide sufficient headroom for the average output levels of the CARIS-assumed renewable generation, the combination of the existing LT&D system and the implementation of most Phase 1 projects (or a similar portfolio of local upgrades) may allow the State to meet its CLCPA mandate through 2030.

Preparing more precise estimates of renewable generation curtailments and the un-bottling benefit of additional LT&D projects will, however, be important for the next phase of this effort. While helpful for the purpose of describing the impact of Phase 1 projects in this initial study, "headroom" is not a very meaningful measure of the CLCPA benefit of LT&D investments. Rather, and consistent with the Utilities' recommended benefit-cost analyses approach for evaluating Phase 2 projects, the CLCPA benefits of LT&D investments should be measured based on the MWh of avoided or "un-bottled" renewable generation curtailments.

ii. Local Transmission Project Discussion – Potential Location-specific Gaps

Although on an aggregate basis the proposed Phase 1 projects may be sufficient to reliably integrate the necessary level of renewable generation through 2030, the renewable integration headroom needs in some specific locations with attractive renewable development opportunities and current developer interests may not be sufficiently addressed by Phase 1 projects. In such cases, high priority "Phase 2" projects may be needed to expand renewable integration headroom.

As shown in Figure 7 above, headroom needs differ locationally across the local transmission areas evaluated in the Utility Study. Recent generation interconnection queue data[22] indicate that certain locations[23] show more renewable generation development activities and may thus offer more attractive renewable development opportunities than other locations. (Outside of the areas covered in the interconnection queue, there may also be areas where local transmission projects may spur renewable generation development in the form of dedicated zones as discussed in Section III.C.4)

This means that some of the Utilities' proposed local transmission projects may need to be prioritized to the most active renewable development locations. In particular, projects that expand headroom in renewable generation pockets that have significant developer interest but have limited available headroom to host such interconnections, may need to be prioritized and approved outside the normal rate-case process, if timely approval decisions require engaging an alternative approval and cost recovery process. Such a prioritization would enable the PSC to identify high priority Phase 1 and Phase 2 projects that would be greatly beneficial for CLCPA.

Based on the recent generation interconnection queue data,[24] below we discuss three examples of locations where the level of current developer interest, based on the most recent interconnection queue data, may exceed the capability of the local transmission area even with the potential incremental headroom created by the proposed Phase 1 projects. The examples also highlight the need for a more coordinated, system-wide, power flow assessment that can evaluate interactions between local transmission areas.

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22 NYISO Interconnection Process, "NYISO Interconnection Queue 11/30/20," New York ISO, https://www.nyiso.com/interconnections.

23 This includes sub-zones that have seen significant number of application withdrawals due to lack of transmission capacity.

24 NYISO Interconnection Process, "NYISO Interconnection Queue 11/30/20," New York ISO, https://www.nyiso.com/interconnections.

- **Genesee, Lockport and Lancaster**: The region from Buffalo to Rochester encompasses National Grid's Genesee and AVANGRID's Lockport and Lancaster local transmission areas. In this region, locally interconnecting renewables can access, via the local transmission system, (1) the bulk transmission 345 kV lines from Niagara to Rochester and the Empire State Line from Dysinger to Stolle Rd, and (2) the 230 kV transmission lines from Niagara. These bulk transmission lines facilitate close interactions between the three local transmission areas.

  National Grid estimates the existing headroom in its Genesee local transmission area to be 630 MW to 900 MW, which appears to be sufficient to integrate the 440 MW of new renewable generation modeled in CARIS in this area. Consequently, National Grid has not proposed any Phase 1 transmission projects in the Genesee area. However, the current interconnection queue indicates that nearly 1,400 MW of queued renewable projects are looking to interconnect in the Genesee area. If a large number of these queued projects get developed, the existing headroom in the area would be fully exhausted by 2023.

  In contrast, AVANGRID proposes Phase 1 local transmission projects in the nearby Lancaster and Lockport local transmission areas that create an additional 1,205 MW of headroom over the areas' existing headroom capacity of 195-903 MW. However, the current interconnection queue indicates that there are only about 120 MW of proposed renewable generation projects requesting transmission interconnections in these areas, indicating that there may not be a need for the additional headroom from a CLCPA perspective when these two areas are studied independently from National Grid's electrically nearby Genesee area. However, because these three local transmission areas are electrically proximate, and because significantly more renewable generation development is projected in some areas than in others, a closely coordinated, system-wide power flow assessment between the two utilities can identify transmission projects that consider interactions between the local transmission areas, and in particular flow-through issues.

- **Hornell and South Perry**: In this AVANGRID local transmission area, both the current queue[25] (for interconnections below 200 kV) and CARIS show a large interest in renewable development (564 MW and 614 MW, respectively). However, the proposed Phase 1 projects only yield 330 MW of incremental headroom. Furthermore, this local transmission area also provides flow-through capacity for upstream areas (including National Grid's Southwest and Genesee and AVANGRID's Genesee Valley) which could reduce the available

[25] NYISO Interconnection Process, "NYISO Interconnection Queue 11/30/20," New York ISO, https://www.nyiso.com/interconnections.

headroom within Hornell and South Perry. AVANGRID's existing headroom calculation shows significant uncertainty in this area with estimates ranging from only 16 MW to 978 MW, depending on the POI assumptions used in the analysis. A closer assessment, accounting for regional transmission conditions, likely would indicate a need for additional on-ramp capacity—such as provided by AVANGRID's proposed Phase 2 projects for this area, which are estimated to provide up to an additional 510 MW of headroom.

- **Watertown/Oswego/Porter**: These National Grid's local transmission areas are prime for additional renewable generation development. The CARIS' 70x30 analysis projected that the North Country region's local transmission areas would experience significant curtailment of locally interconnected renewable generation. CARIS projected a renewable buildout of 1,995 MW for this region, of which 1,399 MW will interconnect at the local transmission level. This closely matches the NYISO interconnection queue, which shows applications for 2,004 MW with 1,269 MW proposed on the local transmission level. National Grid's proposed Phase 1 projects will offer incremental gains to these renewable-rich local areas; however they are not likely to be sufficient to accommodate the interconnection of all projected renewables in the region. National Grid's proposed *Phase 2 projects* could further address the headroom need in this region. However, the projected need for more headroom capacity is more immediate than the timing for these proposed Phase 2 projects, which have in-service dates between 2025 and 2035. New renewable generation development in this area is expected earlier than proposed Phase 2 project in-service dates. This means that the development of Phase 2 projects in this region may need to be prioritized for expeditious development.

We recommend periodically assessing potential gaps in location-specific needs based on the most recent generation interconnection queue and State procurement data and, as discussed above, with a more robust analytical method of assessing the current system's existing headroom. Ideally this would also lead to local headroom estimates that will be available to renewable project developers prior to State procurement efforts.

3. Phase 2 Local T&D Project Proposals

The Utility Study also identified a number of potential Phase 2 projects that are estimated to provide additional headroom capacity of 15,500-17,000 MW, as shown in Figure 4. As an initial observation, the identified Phase 2 projects are, for the most part, not fully developed and should be seen as examples of the types of solutions that may be necessary, rather than actionable proposals. Unless prioritized (as discussed above), they generally would not be available to address near-term headroom needs.

While the headroom estimates for local transmission projects were evaluated in a manner similar to the approaches used for Phase 1 projects, the Utilities proposed that a benefit-cost framework be applied to Phase 2 local transmission projects that would be based on MWh of reduced renewable generation curtailment.[26] As defined by the Utilities, Phase 2 projects may be driven solely by CLCPA needs or may include projects that expand needed reliability, safety, and compliance driven projects to facilitate incremental renewable generation unbottling benefit. For Phase 2 projects that expand traditional projects, only the additional CLCPA-related benefits of the expansion would be compared to the incremental cost portion of the project expansion, using the proposed CLCPA benefit-cost analysis (BCA) to determine whether the expansion is beneficial. In our review of the proposed *Phase 1* projects, we identified certain projects that may be good candidates for expansion and treatment under the Utilities' Phase 2 framework. Additionally, the proposed BCA approach could also be applied to accelerated traditional projects (including certain Phase 1 projects) that are expanded or modified (at incremental costs) to provide additional CLCPA benefits.

We recommend that proposed Phase 2 projects, including any Phase 1 projects that are expanded to provide incremental CLCPA benefits and those that have been significantly accelerated for their CLCPA value, be evaluated under the proposed Phase 2 project selection and BCA framework. The proposed BCA framework evaluates the CLCPA value more robustly than the headroom metric. It compares the 40-year present value of renewable unbottling benefits (i.e., the value of avoided renewable curtailments) with the 40-year present value of the unbottling-related project costs, wherein costs are based on the annual transmission revenue requirement (ATRR) of the proposed transmission project, and the benefits are based on the cost of replacing the renewable generation that, in the absence of the proposed transmission project, would be curtailed.

We also recommend more coordination between the Utilities, the NYISO, and NYSERDA so that the planning of Phase 2 LT&D upgrades can be coordinated with planning of bulk-power system upgrades and renewable generation and storage interconnections. This will be particularly useful for local transmission line upgrades to the bulk level. In addition, LIPA and Consolidated Edison's Phase 2 projects to facilitate OSW interconnections would benefit from more coordinated planning to ensure overall cost-effective solutions at local and bulk levels.

[26] The Utilities included a proposal for a BCA to be used in the evaluation of Phase 2 investments in their November 2 Report at p. 30.

i. Priority Phase 2 Local Transmission Projects

There are three Utility-proposed Phase 2 local transmission projects that we recommend the PSC consider prioritizing for approval at the same time as the Phase 1 projects. These projects are (1) AVANGRID's Hornell, Elmira, & Bath Phase 2 Reinforcement – Phase 2 component; (2) Central Hudson's Q Line Phase 2; and (3) Central Hudson's 10 & T-7 Line State Connections. Reasons for the prioritization of these Phase 2 projects are given below.

- **Hornell, Elmira, & Bath Phase 2 Reinforcement – Phase 2 component**: This project provides 500 MW of incremental headroom benefit in an area with substantial renewable development interest. (See Section III.C.2.I. for further discussion of the locational needs of the Hornell area and why Phase 1 projects may not be sufficient to address these needs.) We note that AVANGRID has proposed two alternative design options of smaller project scope to this proposed Phase 2 project. However, the company provided no cost or headroom estimate for these alternative smaller options. We recommend that the PSC consider all options before approving this project.
- **Q Line**: We recommend that the Phase 2 version of the Q Line project be chosen over the Phase 1 version. The current Phase 1 version would rebuild the line in-kind at 69 kV to address asset condition, whereas the proposed Phase 2 version would rebuild the aging line at a higher 115 kV voltage level. Rebuilding this line at 115 kV voltage will support substantially more renewable development, especially given that voltage constraints already define the 69 kV system limitations in this area. Developers siting additional future solar projects in the region would require more headroom than a 69 kV system would provide. This project, therefore, is an ideal candidate for Phase 2 project approval in lieu of approving the Phase 1 alternative because the estimated incremental cost for the Phase 2 version is modest. The Company notes the rebuilding this line now at a higher-rated voltage than in-kind at 69 kV is more cost effective than upgrading the line to 115 kV voltage later to address future renewable generation delivery needs.
- **10 & T-7 Line State Connections**: This is a highly cost-effective project, providing 261 MW of headroom capacity at a very low cost. This project is designed to relieve certain equipment and station connection limitations in the Pleasant Valley/Milan area, facilitating full use of the upgraded conductor as part of the NY Transco Segment B project. Completing the path of Segment B facilitates reliable transfer of upstate renewable generation to downstate load centers.

Additionally, certain National Grid's proposed Phase 2 projects could further address the local transmission headroom need in the North Country region. These needs are expected to manifest earlier than the proposed in-service dates for National Grid's Phase 2 projects, which range between 2025 and 2035. Additional study of the projected needs for this region—based on the more recent interconnection requests—is necessary to assess the timing of transmission needs. Such a study should also highlight whether the proposed Phase 2 projects are sized appropriately for the expected level of renewable development in the region. Additional Phase 2 projects may also need to be developed by the Utilities to address the potential "gaps" in attractive renewable development areas as discussed above. The PSC may then prioritize and accelerate the additional Phase 2 projects as necessary.

ii. Priority Phase 2 Distribution Projects

We further recommend prioritizing several Phase 2 distribution projects that are characterized as addressing potential feeder-related constraints for individual DERs while enabling higher levels of DER penetration on the feeder. These include:

- Projects that provide protection against ground fault overvoltage that require expensive and time-consuming schemes such as 3V0 protection;
- Projects that address circuit high or low voltage conditions that may come about from high penetration of DER such as local DVAR, and utility-owned storage; and
- Projects that provide for circuit capacity to connect to the distribution substation, such as new feeders and addition of circuit breaker cubicles.

A list of the priority Phase 2 distribution projects is included in Appendix B.

4. Facilitating New Local Renewable Energy Zones

Significant renewable generation potential appears to exist in areas of the State that currently do not have access to existing transmission infrastructure. New transmission development in those areas of the State would thus facilitate renewable generation development. Lack of existing transmission infrastructure in renewable-rich currently areas prevent project developers from seeking points of interconnection for renewable generation projects in those areas. Several such areas, which could be developed as local renewable energy zones (REZ), likely exist in the NYISO footprint. Illustrative examples of potential new REZs areas are discussed below. We recommend that the State further assess the renewable potential (e.g., solar) in certain areas and the value of creating REZs and that the Utilities propose local transmission projects (or NYISO propose bulk transmission projects) to support renewable generation development in those locations. Local transmission projects to create such REZ areas could be submitted for review and assessment under the Phase 2 CLCPA benefit framework.

Examples of potential new local renewable energy zones include the following:

- **Central Hudson Service Territory**: Dutchess County, east of Milan. The utility has already proposed the new 69 kV Smithfield line in this area. Expanding this proposed project to a 115 kV meshed configuration, and potentially interconnecting with the NYSEG facilities in the southern Dutchess and Putnam counties would open opportunities for new renewable generation development and interconnection.
- **Orange and Rockland Service Territory**: Southern Sullivan County. O&R operates mainly as a load pocket with imports from the 345 kV system. There is potential for greenfield renewable development in open areas in the northern portion of the O&R footprint. Renewables may provide supply to the O&R load or use the existing connections to on-ramp to the 345 kV.
- **AVANGRID/National Grid Service Territories:** Eastern Columbia County. This area is served by a single 115 kV loop from Falls Park-Craryville-Churchtown, which can be expanded eastward to provide new points of interconnection for renewable projects. If high renewable generation development manifests, a connection to the 345 kV system at Leeds (requiring Hudson River crossing) or tapping the line from Leeds to Pleasant Valley (which avoids river crossing) could be considered.

III. Advanced Technologies

While the Power Grid Study did not model the implementation of advanced transmission technologies, this section offers recommendations on the need for integrating such technologies expeditiously into both local T&D and bulk transmission investment plans because of the substantial potential for cost-effective un-bottling of renewable generation that is offered by these technologies.

The comments here are based on our review of the Utilities' current proposals for and experience with these technologies as described in Part 3 of Utility Study as filed in Case 20-E-0197.[27] There, the Advanced Technologies Working Group (ATWG) made recommendations for research and development plans for new and/or underutilized technologies and innovations it considered necessary to meet and advance New York's clean energy goals under the CLCPA. The ATWG recommendations focus on roles and opportunities for investments in advanced technologies through 2030 that would apply to the Utilities, transmission owners, and operators of transmission facilities—especially those operating at 138/115 kV and below.

In that section of the Utility Study and Utility Filing, the ATWG explored the capability of advanced transmission technologies to: (a) alleviate transmission system bottlenecks to allow for better deliverability of renewable energy throughout the State, (b) unbottle constrained resources to allow more hydro and/or wind imports and the ability to reduce system congestion, (c) optimize the utilization of existing transmission capacity and right of ways, and (d) increase circuit load factor through dynamic ratings. The group then evaluated seven groups of advanced technologies:

- Dynamic line ratings and improved transmission utilization;
- Power flow control devices (both distributed and centralized);
- Energy storage for transmission and distribution services;
- Tools for improving operator situational awareness;
- Transformer monitoring;

[27] Case 20-E-0197.

- Advanced high-temperature, low-sag (HTLS) conductors; and
- Compact tower design.

The ATWG finally recommends on pages 263-268 of the Utility Study that:

- There is an opportunity to transfer knowledge among the State's utilities because several of them are already implementing some of the technology solutions identified and reviewed;
- The State's utilities share R&D knowledge on a more regular basis and collaborate in testing the new technologies with NYSERDA funding. Any such joint R&D effort should first focus on dynamic line ratings, power flow control devices, and deploying storage for T&D services;
- Transmission Operators be encouraged to utilize new technologies, such as low-sag conductors and innovative tower design, when these technologies are more cost effective than traditional ones;
- Benefit estimates for new technologies should be adjusted down to account for the additional risks (likelihood of success) associated with relying on new technologies; and
- An R&D consortium (consisting of the State's utilities) should be created in the next 6 months to evaluate "state-of-the-art and advanced technologies that are already being used elsewhere in the U.S. or the world" and should pursue two or three R&D projects over the next 1-2 years. Projects selected by the R&D consortium would be funded by NYSERDA and through Commission-approved rate-case allowances.

A. Preliminary Assessment of the Utilities' Advanced Technologies Proposal

Advanced transmission technologies can offer significant CLCPA benefits by increasing the transfer capabilities and associated renewable generation integration headroom of both the existing grid and new transmission investments. Because many of the advanced technologies can be implemented more quickly than traditional transmission upgrades, they can be applied rapidly to locations where the un-bottling of curtailed renewable generation is most urgent. This allows for advanced transmission technologies to be applied to un-bottle renewable generation through a combination of: (1) permanently expanding the transfer capabilities of *existing grid facilities* as a potentially lower-cost alternative to traditional transmission upgrades; (2) temporarily expand the transfer capability of existing transmission facilities until they can be upgraded (at which point it often is possible to move the advanced transmission equipment to other grid locations); and (3) increase the transfer capability of traditional transmission upgrades.

The Utilities' advanced technologies proposal is focused mostly on undertaking more R&D and pilot studies of advanced technologies. The proposed additional R&D efforts and pilot studies will be reasonable for some technologies that are early-stage and have not yet undergone and completed pilot studies. For example, two early-stage technologies that would need significant and joint R&D efforts and pilots are HVDC network technologies and superconductor technologies.

However, we note that none of the technologies listed by the ATWG fits this description. The ATWG proposal is overly conservative for advanced technologies that have already passed R&D and pilot program stages and demonstrated successful commercial-scale deployment. Most of the technologies identified in the Utility Study and Utility Filing are available and have already been deployed by some of the utilities within New York and even more extensively outside of New York.

We agree with the Utilities' assessment that there is an opportunity to transfer knowledge among the group's members because several of them are already implementing some of the technology solutions identified and reviewed. But their proposed pace is unnecessarily slow, and risks missing opportunities to integrate clean energy resources and relieve congestion at a lower cost than traditional investment. We therefore recommend that the PSC encourage the State's utilities to deploy the available advanced technologies more expeditiously.

B. Experience with Advanced Transmission Technologies

Advanced technologies with significant operational deployment experience in New York, in North America, and internationally include the following.

Dynamic Line Rating (DLR) technologies install sensors on transmission facilities or use high-definition weather information to precisely determine a transmission line's transfer capability in real-time (e.g., by measuring the temperature and/or sag of the transmission line's conductors) or under forecasted conditions in operations. DLR is able to (a) significantly increase transmission capability above static or seasonal line ratings during most of the year and (b) simultaneously increase the reliability by identifying occasional periods where a transmission line's actual capability drops below its static rating. Even if DLR may not substantially increase the transfer capability during peak load hours, the higher ratings during most of the year will offer significant renewable energy un-bottling benefits over the course of the year. The technology is thus most valuable to address generation constraints, such as constrained local renewable generation on-ramps. Because the technology can easily and quickly be retrofitted to existing lines, it can be used to un-bottle on-ramps more expeditiously than traditional transmission upgrades.

DLR should not be confused with Ambient Adjusted Rating (AAR) approaches that adjust the static line ratings solely based on average seasonal weather conditions. Some system operators (such as National Grid Electricity Transmission UK)[28] have used seasonally-adjusted ARR for decades. NYISO has noted that it already employs ARR in the form of seasonally-adjusted line ratings.[29] The FERC has recently proposed rules (in Order RM20-16) that would require ISOs and RTOs to deploy ARR for their most congested transmission facilities. The ARR approach is at a distinct disadvantage relative to dynamic line rating (DLR) technology, which utilizes sensors or high-resolution weather data to determine the actual transfer capability of a transmission lines.

The ATWG recommends further studies to determine future DLR benefits and the extent to which DLR could be utilized in NY. We believe no further studies are necessary as there already is extensive operational and commercial experience with DLR that could be utilized in the State today. This experience includes:

- As noted on page 264 of the Utility Study, National Grid has already demonstrated DLR in New England and is currently deploying DLR-related technology in upstate New York. Pilot studies are already being conducted by AVANGRID and NYPA as well.
- In particular, National Grid has operated DLR technologies since August 2019 on two 115 kV transmission lines in New England. The experience shows that DLR implementation challenges can be addressed and that DLR provides improved visibility with dynamic ratings

[28] National Grid UK also is currently exploring enhancements to its seasonal transmission ratings. *See* Smarter Networks, "Advanced Line Rating Analysis (ALiRA)," National Grid UK. https://www.smarternetworks.org/project/nia_ngto014

[29] Aaron Markham, Opening Remarks on Behalf of NYISO, FERC Technical Conference on Managing Transmission Line Ratings, Docket No. AD19-15-000, September 10-11, 2020, p. 1, https://ferc.gov/sites/default/files/2020-09/Markham-NYISO.pdf

that are generally above seasonal ratings and that are providing additional capacity for renewable integration.[30]

- NYISO has noted that it can already accommodate real-time DLR information from TOs for use in its real-time market and security operations.[31]
- Some transmission system operators have also long used highly dynamic versions of ARR. For example, the Ontario Independent Electric System Operator (IESO) works closely with Ontario transmission owners (such as Hydro One) to dynamically adjust line ratings every 30 seconds based on high-resolution measurement of ambient conditions that includes wind speed, temperature, and illumination conditions.[32]
- As a recent report by Greentech Media summarizes, significant U.S. and international experience has been gained over the last decade with deploying sensor-based DLR for the purpose of expanding transmission grid capacity for clean energy, with European and U.S. utilities and regulators actively taking steps to boost renewable integration by tracking power line capacity in real time.[33]
- A 2019 FERC staff report summarizes U.S. experience with DLR and offers recommendations for implementing DLR on constrained transmission facilities.[34]
- A 2019 report by the U.S. Department of Energy summarizes 11 case studies of DLR pilot studies and commercial implementation in the U.S. and abroad since 1998, recognizing the operational challenges (such as operator training and control room integration) that have to be addressed.[35] For example, a 2015 installation of DLR on a transmission line serving a

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[30] Planned Technical Conference Remarks of National Grid, FERC Technical Conference on Managing Transmission Line Ratings, Docket No. AD19-15-000, September 10-11, 2020, p. 1, https://ferc.gov/sites/default/files/2020-09/Enayati-NationalGrid.pdf

[31] Markham, Opening Remarks on Behalf of NYISO, p. 2.

[32] Conversation with IESO director of transmission planning.

[33] Jeff St. John, "Dynamic Line Rating: Expanding Transmission Grid Capacity for Clean Energy," *Greentech Media*, December 7, 2020, https://www.greentechmedia.com/articles/read/dynamic-line-rating-pushing-the-transmission-grid-envelope-on-clean-energy-capacity

[34] FERC Staff Paper, "Managing Transmission Line Ratings," DOCKET NO. AD19-15-000, August 2019, https://www.ferc.gov/sites/default/files/2020-05/tran-line-ratings.pdf

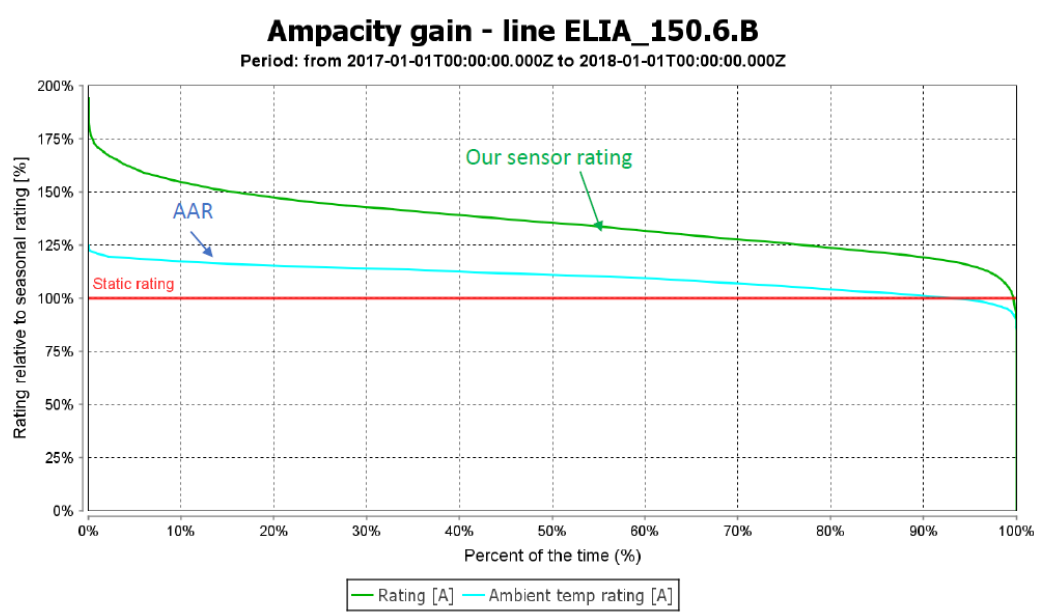
[35] United States Department of Energy, *Dynamic Line Rating*, June 2019, p. 25, https://www.energy.gov/sites/prod/files/2019/08/f66/Congressional_DLR_Report_June2019_final_508_0.pdf

NREL has long documented that dynamic line ratings can increase transfer capabilities while maintaining reliability. For example, *see*:

Balser et al., "Effective Grid Utilization: A Technical Assessment and Application Guide," National Renewable Energy Laboratory. April 2011-September 2012. https://www.nrel.gov/docs/fy13osti/53696.pdf wind plant in Alberta, Canada, found concurrent wind-related cooling avoided the need for transmission upgrades, increasing transfer capability by an average of 22% over static ratings 76% of the time. Similarly, a demonstration project by Oncor in Texas installed DLR and associated control systems on a transmission line before it could be upgraded, showing increases in transfer capability (a) between 6% and 14% over AARs that was available over 83% of the time and (b) between 30% and 70% relative to static line ratings.

- Elia, the grid operator in Belgium, has used DLR since 2008[36] and has now deployed DLR on a system-wide scale, involving 35 transmission lines.[37] Several years of recent operational experience has shown that DLR is more effective and more reliable than AAR and is capable of increasing transmission ratings above static ratings by 27-30% on average over a year. The increase varies depending on system conditions. It exceeds 10% during 90% of the year, exceeds 25% during 75% of the year, and exceeds than 50% during 15% of the year. DLR has also identified that during 2% of the year dynamic line ratings are below static ratings to maintain reliability. This experience is summarized in Figure 8 below.[38]

FIGURE 8: DLR EXAMPLE – ELIA



Source: Alexander, "Elia Large Scale DLR Deployment," slides 9 and 13.

[36] "Making the most of Europe's grids: Grid optimization technologies to build a greener Europe," Wind Europe, September 2020, p. 14, https://windeurope.org/wp-content/uploads/files/policy/position-papers/20200922-WindEurope-Grid-optimisation-technologies-to-build-a-greener-Europe.pdf

[37] Joey Alexander, "Elia Large-Scale DLR Deployment," FERC Technical Conference on Managing Transmission Line Ratings, Docket No. AD19-15-000, September 10-11, 2019, https://ferc.gov/sites/default/files/2020-09/Alexander-ELIA.pdf

[38] *Ibid*., slides 9 and 13.

Power-Flow Control Technologies increase the total transfer capability of the grid by shifting flows away from the most congested transmission facilities to parallel paths that remain underutilized.

The Utilities already have extensive operational experience with phase-angle regulators (PARs), which have been deployed and operated for decades. PARs can shift power flows from congested transmission lines to less utilized portions of the grid.

Several advanced new technologies are now available that can cost effectively achieve similar power-flow-control benefits. For example, in 2020, National Grid Electricity Transmission UK (NGET) has installed "Smart Wire" modular power flow control technology (MPFC) on five 275 kV and 400 kV circuits that limit three constrained transmission paths.[39] By installing the power flow controllers that allow the transmission system operator to quickly shift power flows away from the limiting circuits, the technology is anticipated to increase transfer capabilities across the three paths by 1500 MW in total. As noted, the modular technology enables sizing power flow controls to current needs (rather than uncertain future needs) and scaling up (or down) the installed modules to meet the system's needs as they evolve over time.

A number of power system operators also employ "topology control" software technology to identify grid switching options that can shift power flows by temporarily configuring the meshed transmission grid. The reconfigurations are implemented using existing circuit breakers and existing infrastructure for communications and control. For example, National Grid Electric Transmission UK routinely optimizes its network configuration in collaboration with Transmission Owners (TOs) through different switching solutions at substations that redirect power flows to parts of the network with spare capacity.[40] Similarly, network reconfigurations were able to relieve the top four transmission constraints in SPP in 2019.[41] SPP and ERCOT have similarly documented a number of case studies showing how advanced topology optimization

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39 "Making the most of Europe's grids," Wind Europe, p. 17.

40 "Transmission Thermal Constraints Management Information Note," National Grid ESO, July 2018, p. 4, https://www.nationalgrideso.com/sites/eso/files/documents/National%20Grid%20Transmission%20Thermal%20Constraint%20Management%20information%20note_July%202018.pdf.

See also, "Electricity Transmission, Network Innovation Allowance," National Grid, 2016-2017, p. 14, https://www.nationalgrid.com/sites/default/files/documents/National%20Grid%20Electricity%20Transmission%20NIA%20Annual%20Summary%202016-17.pdf

and "Transmission Network Topology Optimisation," National Grid, project NIA_NGET0169, July 28, 2017, http://www.smarternetworks.org/project/nia_nget0169/documents.

41 "State of the Market 2019," Southwest Power Pool (SPP), May 11, 2020, p. 199, fig. 5–10, https://www.spp.org/documents/62150/2019%20annual%20state%20of%20the%20market%20report.pdf

analyses tools for operational planning can quickly identify reliable grid reconfigurations that avoid renewable generation curtailments and relieve transmission constraints related to planned transmission outages.[42]

Storage technology is also increasingly deployed in transmission enhancement applications that allows utilities to similarly proceed with deployment of the technology without the need to wait for additional R&D and pilot efforts. For example:

- Several ISOs and RTOs have been implementing market and planning rules that allow the deployment of storage devices as transmission facilities, which documents that storage technology (while still "new") is starting to be deployed commercially for transmission applications.[43]
- New York's own experience with using a combination of storage and demand response to avoid more expensive substation upgrades is another example of that experience.[44] In fact, as noted on page 274 of the Utility Study, essentially all of the State's utilities already have limited experience with deploying storage.
- National Grid has successfully deployed an award-winning storage project as a transmission alternative in New England, to address transmission import constraints on the island of Nantucket.[45]

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[42] Pablo A. Ruiz, Jay Caspary and Luke Butler, "Transmission Topology Optimization Case Studies in SPP and ERCOT," FERC Technical Conference on Increasing Day-Ahead and Real-Time Market Efficiency and Enhancing Resilience through Improved Software, Docket No. AD10-1222-011, June 24, 2020, https://ferc.gov/sites/default/files/2020-06/W3-1_Ruiz_et_al.pdf

[43] *See*, "Storage as a Transmission Asset: Enabling transmission connected storage assets providing regulated cost-of-service-based transmission service to also access other market revenue streams," California ISO, March 30, 2018, p. 5, http://www.caiso.com/InitiativeDocuments/IssuePaper-StorageasaTransmissionAsset.pdf

[44] *See* Julian Spector, "Enel Builds New York City's Biggest Battery, With a Twist," *Greentech Media*, December 9, 2019, https://www.greentechmedia.com/articles/read/enel-is-back-in-new-york-city-with-a-bigger-battery (2019).

[45] "Two National Grid Projects Selected as Energy Storage North America 2019 Innovation Award Winner," National Grid press release, November 7, 2019, on the National Grid website, https://www.nationalgridus.com/News/2019/11/Two-National-Grid-Projects-Selected-as-Energy-Storage-North-America-2019-Innovation-Award-Winner-/

- At the national level, FERC has provided for cost recovery of storage facilities that address transmission needs but also participate in wholesale power markets[46] and some ISOs have started to explicitly consider storage solutions in their transmission planning processes.[47]

High-temperature Low-sag (HTLS) Conductors have been used in the industry for well over a decade in the U.S. and around the world.[48] Utilities in New York have deployed this technology, which makes further R&D and pilot efforts unnecessary for successful deployment. As noted on page 274 of the Utility Study:

- Orange and Rockland uses low-sag aluminum-conductor steel-supported (ACSS) technologies on a number of transmission projects with success;
- LIPA/PSEG already use of ACSS on overhead transmission lines; and
- National Grid already demonstrated HTLS technology in New England.

C. Misconceptions about Advanced Transmission Technologies

The ATWG's evaluation reflects several common misconceptions about some of the available advanced transmission technologies. These misconceptions threaten to limit deployment of advanced technologies that could help increase utilization of the transmission system to integrate clean energy and reduce congestion cost effectively:

- The ATWG report states that "power flow control devices do not increase system capability but redirect power." This is a misconception. The grid's capability is limited by its most constrained facility. By diverting power flows from the most constrained facilities to those that remain underutilized, power flow control devices increase the overall transfer capabilities of the system. For example, the New York Utilities have used PARs for decades, increasing the grid's transfer capability by shifting power flows away from constrained facilities to the underutilized portions of the grid.

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46 158 FERC ¶ 61,051, Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery, Docket No. PL17-2-000, issued January 19, 2017, https://www.ferc.gov/sites/default/files/2020-04/E-2_34.pdf

47 *See*, for example, California ISO, 2019-2020 Transmission Plan, March 25, 2020, http://www.caiso.com/Documents/ISOBoardApproved-2019-2020TransmissionPlan.pdf

48 Koustubh Banerjee, *Making the Case for High-Temperature Low Sag Overhead Transmission Line Conductors*, M.S. Thesis, Arizona State University, May 2014, https://repository.asu.edu/attachments/134758/content/Banerjee_asu_0010N_13601.pdf

- The report also states that with respect to DLR "it is difficult to ensure the higher ratings can always be achieved when they are needed in the future, particularly if the ratings depend on critical factors such as the wind speed that has high variability." This is based on the misconception that higher transfer capability with DLR is only beneficial if the higher transfer capabilities are "always achieved." Even if DLR-based transfer capabilities exceed static transfer capabilities during only 90% of all hours in the year, that added transfer capability would unbottle otherwise curtailed export-constrained renewable generation—particularly since higher transfer capabilities (e.g., due to higher wind speeds) can be highly correlated with renewable generation levels (e.g., from local onshore wind). DLR may, however, be less effective to increase the capability of off-ramps into load pockets if dynamic line ratings are close to static line rating during peak load periods.
- The report asserts with respect to utilizing storage to enhance transmission capabilities that "the true benefits or use cases for Storage are still unclear." This understates the substantial experience that has been gained with storage applications in recent years, including in New York.

D. Initial Thoughts on a Policy Framework for Advanced Transmission Technologies

As noted earlier, advanced transmission technologies can be a cost-effective transmission option to create additional un-bottling headroom and associated CLCPA benefits on both the local and bulk-power transmission grids. Often advanced technologies can create such headroom more quickly than traditional transmission investments.

We recommend that the Utilities routinely assess the benefits and costs of implementing advanced technologies as they develop and propose Phase 2 LT&D projects.[49] To accomplish this goal, the PSC should require consideration of the extent to which advanced technologies could:

- be a lower-cost transmission alternative to proposed traditional transmission projects;
- be added to the project to increase the benefit-cost ratio of the project (e.g., by increasing the quantity of unbottled MWh at only modest additional cost); or

[49] As noted above, the Utility Filing includes a proposed BCA framework for use in evaluating possible CLCPA-driven local transmission and distribution projects. As we suggest here, the same framework could be applied to advanced technologies.

- be implemented quickly, including as a temporary application and cost-effective stopgap measure until more comprehensive traditional transmission or distribution solutions can be implemented.

Advanced transmission technologies may also be cost effective in the context of proposed Phase 1 investments. In particular, Phase 1 projects raise the following three types of advanced technology considerations:

- The application of advanced technologies may be able to cost-effectively avoid or defer the need for a proposed Phase 1 project.
- Advanced technology may make a Phase 1 project more valuable at low incremental costs. In some cases, these advanced technology decisions will need to be made during the project design phase, before the project is built. An example is the use of a low-sag wire in the rebuild of an aging transmission line. If not deployed in time with Phase 1 project implementation that would be a lost opportunity.
- In other cases, the advanced technology that can cost-effectively enhance the capability of a Phase 1 project may be an "add-on" or "retrofit" option that remains available even after Phase 1 projects are placed in service based on their current (traditional) design. An example would be the addition of DLR equipment to a newly-refurbished line. Thus, these incremental advanced technology options can be assessed through the Phase 2 framework and BCA, irrespective of whether they are applied to the existing grid or to a Phase 1 project. Nevertheless, it may be valuable and cost effective to apply such advanced technologies more expeditiously than what would be the case through the Phase 2 process.

To capture the potential benefits, we recommend that the PSC direct the Utilities to consider these issues in designing and proposing Phase 1 projects.

As noted, advanced technologies applied to the existing grid may be able to create headroom more quickly and more cost effectively than traditional local transmission upgrades, including those proposed as Phase 1 or Phase 2 projects in the Utility Filing. This may be important and valuable in locations where bottled-up renewables are handicapped already today, particularly if such locations are not being addressed through a Phase 1 project. In these locations, the advanced technology may similarly be (a) a long-term solution for these locations as an alternative to a traditional transmission upgrade or (b) a stopgap measure until a cost-effective upgrade can be designed and built (at which point the equipment may no longer be necessary, so it could be redeployed to other locations that are constrained).

To identify high-priority locations where advanced transmission technologies could quickly and cost-effectively provide un-bottling benefits on the existing grid, the PSC could implement a process through which renewable generation owners and developers would be able to provide information on particularly constrained locations. This information could then be made public, such that either the utilities or advanced technologies vendors could propose cost-effective solutions to address the constraints.

With respect to bulk transmission applications, planning and cost recovery of advanced technologies through the NYISO tariff should be possible as long as the technology are considered "transmission" solutions (e.g., similar to how PARs and FACTS devices are treated already). Cost recovery for "non-transmission" technologies, however, may need to be addressed by the PSC outside the scope of the NYISO's FERC-jurisdictional tariff. The PSC may also need to further evaluate the extent to which the traditional rate-base/rate-of-return cost recovery mechanism may create incentives that inadvertently discourage the adaption and implementation of cost-effective advanced transmission technologies.

In some jurisdictions, such as the UK, incentive regulation schemes (such as shared savings approaches) are used to provide additional incentives to utilities who implement advanced technologies. These incentives in part compensate for the operational complexities, risks and extra efforts associated with employing technologies that are new to a particular utility. FERC's transmission incentive proceeding is similarly contemplating shared savings approaches. The PSC may need to explore whether such shared savings approaches would be appropriate for the application of advanced transmission technologies in New York.

E. Phase 1 Project Candidates for Advanced Technologies

This section discusses advanced technologies that can provide CLCPA benefits and suggestions for implementation, particularly in the context of the Utilities' proposed Phase 1 LT&D projects.

Dynamic Line Rating (DLR). As discussed earlier, DLR is a technology that has seen widespread testing and is being implemented commercially in several jurisdictions outside New York. This technology offers specific CLCPA benefits as it determines line loading capacity based on ambient temperature conditions, level of insolation, and wind speeds, which are also factors driving the output levels of variable renewable energy (VRE), such as wind and solar. Although the Utility Study focuses on new local transmission, DLR applications are also appropriate and effective for bulk power existing transmission lines that tend to operate at or near thermal constraints and thus impose congestion- and curtailment-related cost.

Implementation of DLR needs to be combined with Supervisory Control and Data Acquisition (SCADA) systems to take advantage of the forecast and real-time line rating information in operations of the electrical system on a local T&D basis, as well as from the NYISO grid viewpoint. Such SCADA systems are already deployed on the bulk power system but may need to be added to some local transmission operations. As noted earlier, the NYISO stated that it is already capable of accepting dynamic line ratings in real time.

The implementation of DLR technology for CLCPA benefits can take form in two ways:

- *Retrofits to existing lines*. DLR can be retrofitted fairly easily onto most existing lines. Utilities can target existing facilities where high renewable penetration may lead to potential constraints on the overhead facilities.

- *Built into the design of new lines*. As a built-in feature, new overhead line construction can integrate the environmental monitoring and communications functions and equipment of DLR in the design of the towers and conductor supports. Several proposed Phase 1 local transmission projects represent good opportunities to include built-in DLR features. These are listed in Figure 9 below. The addition of DLR to these projects would increase the headroom and capacity factors of existing and future VRE. Utilities developing these projects will need to confirm if they have existing or planned capability to utilize the real-time dynamic ratings in system control operations. Similarly, Phase 2 projects can be designed with DLR as built-in features to enhance the CLCPA benefits these projects may provide.

Advanced LT&D Monitoring and Control. The CLCPA targets would accelerate the development of Distribution Energy Resources (DER) as well as VRE interconnecting to the local transmission system. Utilities, in their report, have already noted higher number of applications for DER with interconnection queues in the hundreds. On the NYISO interconnection queue, three out of every four applications for solar and wind projects are targeted to connect at 115 kV or below. These higher penetrations of energy resources provide impetus for advanced monitoring and control at the local transmission and distribution level. Newer Distribution Management Systems (DMS) and sub-transmission SCADA are now available that allow for higher bandwidth data processing and real-time and forward-looking operations assessment to better utilize VREs.

The technology represents a major impact to how utilities manage their local grids and careful planning is necessary prior to implementation. At best, where no prior planning has been done to acquire this technology, it could take 3-5 years to put in place.

Utilities that have this LT&D automation experience implementation include:

- Central Hudson: Foundational Investments in Distribution Automation and Distribution Management System proposed for Phase 1 with estimated cost of $14.4 million.
- AVANGRID's Flexible Interconnection Capacity Solution (FICS) is an advanced technology solution for integrating higher levels of DERs in distribution feeders. By extending the data collection and processing capability of the DER Management System, FICS ensures safe operation within a feeder's transformer and line limits by curtailing DER generation during infrequent over-generation events. While the cost effectiveness of implementing FICS for specific locations has yet to be established, this technology has the potential to be an effective DER enabling technology.
- Orange & Rockland proposes a number of grid modernization projects that fall under Advanced Monitoring and Control, including smart grid automation, Distribution Supervisory Control and Data Acquisition Systems (DSCADA) and Advanced Distribution Management System (ADMS), a robust communication plan, and Advanced Metering Infrastructure (AMI). The estimated cost is about $80 million over the period 2020-2025.

This technology is a necessary companion to DLR for real-time operations when used on local transmission (the bulk transmission already has the necessary SCADA to use DLR).

Topology Optimization Software. At the local transmission and distribution level, alternate supply through switching is typically used to ensure reliable service. New York utilities presently use some form of switching operations to redirect flows for their electric systems based on staff experience. However, with the increase in DER penetration and the variability effects of VRE, the switching decision process also needs to account for real-time changes in supply. These optimization decisions can be made more quickly and reliably with decision-support software. Topology optimization used to support operations can help decrease curtailments of renewable energy in the State.

This technology is a logical first step for Utilities that have not yet implemented a broader form of Advanced Monitoring and Control through SCADA or DMS. As such, it can be implemented in a shorter timeframe of approximately 1 year.

Utilities that are facing major changes to load or generation pockets could increase CLCPA benefits through this technology as well. For example, load pockets with multiple entry points and which face generation deficiency due to, for one, retirement of peaker units, can use this technology to optimally switch entry points.

FACTS Devices. Fast, real-time control of flow on specific transmission paths can be achieved through Flexible AC Transmission devices such as thyristor-controlled phase angle regulators (TCPAR) and static synchronous series compensators (SSSC). These devices offer the operating flexibility to avoid congestion in meshed networks and provide an effective solution to congestion that may arise from VRE.

These technologies still have only limited industry experience and will need pilot implementation to demonstrate their use, reliability, performance and operating benefits. However, this is worthwhile effort given the potential benefits in terms of cost-savings and higher utilization of renewables. The traditional use of phase-angle regulators (PARs) for power flow control devices limits the ability to control flow on a real-time basis and can be cost-prohibitive.

Together with Advanced Monitoring and Control, FACTs devices are promising elements of a modernized smart grid. In fact, Avangrid proposes SSSC to complement two projects (located at Border City and Jennison) and may be the best candidates for piloting that technology. The heavily PAR-controlled load pockets of ConEd presents the potential for testing the TCPAR as an alternate solution for flow control. Smart valve technology, a single-phase, modular form of SSSC, is proposed by National Grid to control flow on the Lockport-Mortimer 115 kV line as a Phase 2 project.

Smart Inverters. One side of the smart grid paradigm are devices that have the capability to make grid-impacting decisions on a local basis. This is especially important as Advanced Monitoring and Control technology are still in process of development and implementation that puts DER devices and lower voltage systems beyond reach. Smart inverters address some of the concerns and challenges associated with high VRE integration into the electric grid via sophisticated monitoring and communication of the grid status, and the capability to make autonomous decisions to maintain grid stability and reliability. Many existing and proposed DER already have this capability but need the overall monitoring and control infrastructure to enable their use. In addition to system benefits, these types of inverters can also:

- Provide ride-through capability for frequency and voltage fluctuations that would typically trip the inverters;

- Adjust output to avoid overloads, over/under voltages, flicker, unwanted harmonics and other reliability, power quality and safety issues that may arise; and
- Regulate the use of ancillary services that may be provided by solar or storage devices.

While policies are still developing on how best to utilize smart inverters, developing a DER fleet with smart grid capability ensures that these resources will be able to work effectively in a future integrated grid.

FIGURE 9: PHASE 1 LOCAL TRANSMISSION CANDIDATES FOR DLR IMPLEMENTATION

Utility	Region	Project Name
National Grid	Southwest	Dunkirk – Falconer 115kV Line Upgrades
	Porter/Inghams/Rotterdam	Inghams – Rotterdam 115kV Line Upgrades
	Capital region	Rotterdam – Wolf/State Campus 115kV Line Upgrades
	Albany South	Churchtown– Pleasant Valley 115kV Upgrades
Central Hudson	Northwest 115/69 kV	H & SB Line
	Zone G	SK Line
	Northwest 115/69 kV	H & SB Line
	Westerlo Loop	NC Line
	69 kV E Line	New Smithfield Area Line
	Pleasant Valley	Q Line
LIPA	Zone K	138 kV Riverhead to Canal New Circuit
	Zone K	Wildwood to Riverhead 69 kV to 138 kV Conversion
NYSEG/RG&E	Lockport Area	Lockport Area Phase 1 Upgrades
	South Perry Area	South Perry Area Phase 1 Upgrades
	Binghamton Area	Binghamton Area Phase 1 Reinforcement
	Binghamton Area	Binghamton Area Phase 1 Reinforcement
	Ithaca Area	Ithaca Area Phase 1 Reinforcement

Source: Project names and information from Part 2 of Utility Study.

IV. Offshore Wind Study Findings and Recommendations

The Offshore Wind Integration Study conducted by DNV-GL, PowerGem, and WSP (attached as Appendix D of this Initial Report) addresses four questions:

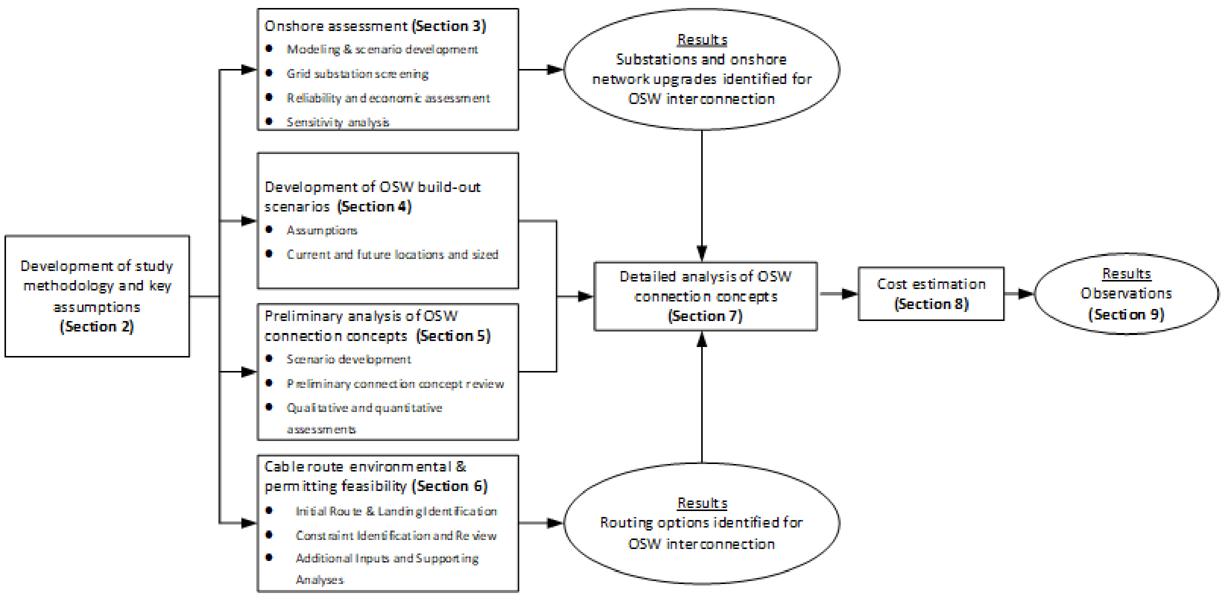
- At which onshore substations are there good opportunities to inject 9,000 MW of OSW into the bulk power grid of New York City and Long Island in a feasible, reliable, and least-cost manner?
- What are the environmental/permitting challenges associated with bringing OSW to existing onshore substations?
- Considering (a) the 1,825 MW of OSW that have recently been procured, (b) the onshore substations with identified capacity to interconnect future OSW, and (c) the environmental/permitting constraints, what are plausible planned transmission strategies for collecting and delivering the remaining 7,175 MW?
- How does a networked offshore transmission solution compare to a reference case "business as usual" scenario that utilizes only radial connections?

A. Summary of Offshore Wind Integration Study

1. Study approach

The OSW Study consists of several distinct analyses, as depicted in Figure 10 below: (1) an "onshore assessment" to identify points of interconnection (POIs) and on-shore bulk-power transmission upgrades needed to cost-effectively integrate 9,000 MW of OSW generation; (2) the development of viable offshore buildout scenarios regarding offshore wind energy areas and submarine transmission technologies to selected POIs; (3) an analysis of offshore grid networking options that would connect OSW plants through meshed or backbone offshore transmission; and (4) a preliminary environmental permitting and feasibility study of offshore cable routes and onshore landing points. The results from these analyses are then used to undertake a more detailed analysis of OSW connection concepts and costs.

FIGURE 10: OVERVIEW OF THE STUDY METHODOLOGY IN THE OSW REPORT



Source: OSW Study, Section 2 (Fig. 2-1).

2. OSW Points of Interconnection (POIs)

The OSW Study identified POIs through an iterative screening process. It started with every New York City area and Long Island substation above 69 kV and applied a thermal transfer screen analysis to identify 36 substations that could accept at least 300 MW of OSW. For those 36 substations, production cost simulations were conducted to identify 20 substations with the least curtailments.[50] The study then evaluated six POI combinations that could deliver 5,000 to 7,000 MW into the NYC area, with the remainder located in Long Island. The study's base case (Scenario 1 as shown in Figure 11 below) selected the following POIs and injection capacities:

- Zone J (NYC): Farragut (1,400 MW), Rainey (1,250 MW), Mott Haven (1,250 MW), and West 49th St. (1,200 MW)
- Zone K (Long Island): New Bridge (600 MW), Shore Rd. (500 MW), Northport (400 MW), and Syosset (300 MW), and Brookhaven (270 MW)

The study also explored "Scenario 2," which moved Zone K injections at Brookhaven, New Bridge, and Northport to Ruland Rd (970 MW) and East Garden City (300 MW) as shown in

50 OSW Study, Section 3.4.1.

Figure 12 below. “Scenario 3” is based on Scenario 2 but moves 915 MW of OSW POIs from Mott Haven in Zone J mostly to East Garden City (EGC).

FIGURE 11: POIs CONSIDERED IN SCENARIO 1 OF THE OSW REPORT

Source: OSW Study, Section 3.4.1 (fig. 3-5).

FIGURE 12: LIPA POIs CONSIDERED IN SCENARIO 2 OF THE OSW REPORT

Source: OSW Study, Section 3.5.1 (fig. 3-9).

Developing such POIs will depend on the availability of sites with enough space to accommodate inverters and other equipment, and on being able to site cables from the lease areas all the way to these points and to interconnect to the existing substations,[51] as discussed below.

3. Offshore Transmission to the Selected POIs

Delivering 6,000 MW into Zone J would require six cables (four beyond the two for already-contracted OSW) to reach the ConEd substations in Manhattan and Brooklyn. As the study notes, routing and permitting that many cables through the Narrows and into New York's inner harbor will be challenging. However, the OSW Study indicates that this should be feasible if researched and planned carefully in collaboration with maritime agencies and stakeholders. Alternative routes to reach New York City through the Long Island Sound are also possible (and have been proposed in NYSERDA's most recent solicitation)[52] but have not been explored in the OSW Study.

The OSW Study highlights the importance of matching cable technology and associated transfer capability to the available routing space into New York Harbor and the optimal capacity of the POIs. In Zone J, where the OSW Study finds that both cable routing and substation space are scarce, but the existing transmission system is strong enough to accept up to 1,310 MW per POI,[53] the ideal technology is currently 320 kV symmetric monopole HVDC cables—although the study also considered 525 kV for potential larger POI injections. For smaller injections of up to 450 MW and for distances of less than 70 miles, the Study indicates that 220 kV HVAC cables are likely the most cost-effective.

Regarding the configuration of offshore transmission, the OSW Study assessed conventional radial lines from each offshore project as the base case. This base case is then compared to meshed, backbone, and other configurations. The study concludes that a "meshed" design is the most flexible and can adapt to the availability and locations of future wind energy lease areas (WEAs) due to the fact that each WEA will also have a dedicated radial line. Other networked strategies in which several WEAs share transmission links to shore are less flexible if

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[51] The 1,260 MW Empire 2 Offshore Wind project, which was provisionally awarded to Equinor Wind US LLC in January 2020, is expected to interconnect at a different POI—at the Barrett Substation in Nassau County.

[52] NYSERDA, "2020 Offshore Wind Solicitation (Closed)," accessed January 15, 2021, https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/Focus-Areas/Offshore-Wind-Solicitations/2020-Solicitation

[53] OSW Study, Section 5.1.2.

WEAs remain uncertain. Other identified benefits of the meshed network configuration include operational flexibility, resiliency, and redundancy. The OSW Study observes that, "[f]or a networked design to be economically justifiable…, [it] should encompass at least three OSW projects with minimum aggregate rating of approximately 3 GW," and also that "[a] Radial connections can be later converted to Mesh or Backbone with upfront preparation and investment."[54] While the Study quantified benefits from reduced offshore wind curtailments associated with line outages to be only about $0.2/MWh compared to estimated incremental costs of about $2/MWh, as discussed below, the full set of benefits of networked configurations (including the monetary value of added flexibility and risk mitigation) has not yet been quantified.

4. Bulk Transmission Needs and Potential Projects for OSW

The OSW study concludes that 9,000 MW of offshore wind generation can be integrated without requiring major bulk transmission upgrades to mitigate adverse system impacts or curtailments. In the scenarios studied with 6,000 MW interconnected in Zone J and 3,000 MW in Zone K, simulated curtailments were less than 4 GWh in 2035, except in a sensitivity with "modified Zone K parameters" (reflecting input from LIPA on Long Island system operations), where curtailments increased to 24 GWh. The surprisingly low curtailment estimates, which are all well below 1% of offshore wind generation, are explained as follows:

> "[I]n nearly all hours, OSW local production did not greatly exceed local demand. It is expected that curtailment occurs due to targeted localized congestion and/or more generalized over-generation situations, where OSW production exceeds demand by such a significant amount that it cannot be exported to other regions. However, an hour-by-hour review of OSW output versus hourly demand indicates that for the majority of hours, OSW production did not exceed local demand. In hours where OSW exceeds demand plus export capability, over-generation may still be absorbed by energy storage facilities."[55]

With so little curtailment and no bulk system reliability violations, the only identified upgrades are reconductoring of some 69 kV and 138 kV lines. This conclusion depends on several optimistic assumptions, however. Scenario 3 explores the possibility that 4,000 MW is connected to Zone K, which could be needed if routing cables for 6,000 MW of offshore wind

[54] OSW Study, Section 5.3.

[55] OSW Study, Section 3.4.4.2.

into New York Harbor and interconnecting them to existing ConEd substations turns out to be too challenging or costly. In that scenario, and with "modified Zone K parameters," Zone K curtailments of offshore wind generation would increase to an estimated 1,229 GWh or (close to 10%) annually without bulk-power transmission upgrades. Increasing Long Island's bulk power export capability with a new 345 kV tie-line (such as from East Garden City to Dunwoodie) would mitigate these curtailments to 385 GWh. This 4,000 MW scenario could easily be realized.

B. Observations, Issues, Gaps, and Reconciliations with Other Studies and Report Requirements

1. Bulk Transmission

The OSW Study and the Zero Emissions Study are consistent in finding (as discussed in the next section) that interconnecting 9,000 MW should be achievable **without major bulk transmission upgrades** (other than reconductoring some existing local transmission lines). However, this conclusion depends on five conditions:

- **Well-coordinated system development**. The studies' integrated modeling approaches enable an OSW transmission design that optimizes POIs with the capabilities of the existing transmission system. In addition, to help balance offshore wind injections and transmission capabilities, both the OSW and Zero Emissions Studies assume that significant amounts of battery storage will be located (and developed on time) in specific locations.
- **Feasible siting and permitting.** The OSW Study preliminarily concludes that being able to connect 5-6 GW of OSW (of the 9 GW total) into Zone J, should be possible despite routing constraints for cables into the New York Harbor and limited space at the proposed POIs (ConEd substations).
- **Low congestion and curtailments.** The studies are based on industry-standard simulations of bulk transmission and market conditions, which tend to understate real-world congestion and curtailment.
- **Reliability needs defined by summer-peak-load conditions.** The OSW Study assessed reliability needs for high-load summer conditions but considered other time periods only in its production cost simulations (which are based on an N-1 generation commitment and dispatch criteria system without extended transmission outages and

assuming normal loads). It is possible that low-load/high-wind and transmission outages create additional reliability challenges associated with the integration of wind generation.

- **Local impacts will be addressed separately.** The OSW Study has not analyzed the impacts of OSW generation on the local transmission system. It implicitly assumes that injecting the proposed amounts at the selected LIPA and ConEd substations is feasible in terms of how the injections impact the Utilities' local transmission without additional curtailment, costly upgrades, or other insurmountable challenges.

i. Assumed Coordinated POIs, Transmission, and Storage Development

The studies' integrated modeling framework yielded an OSW transmission design (plus enabling storage) that is **optimized at the system-wide level** in a way that will require extensive coordination of individual rounds of OSW procurements and generation interconnection processes.[56] Uncoordinated individual procurements could result in different POIs that might be more economic for the individual OSW plants, but that may collectively be sub-optimal and require more on-shore transmission upgrades in order to integrate all 9,000 MW of OSW.

A similar challenge may be encountered with optimizing the storage investments assumed in the OSW and Zero Emissions studies. In particular, the Zero Emissions Study shows the critical role that battery storage is projected to play. The study's simulations project 3,000 MW of battery storage by 2030 and 15,500 MW by 2040 that is "strategically" positioned at specific locations (and developed in time) to avoid adverse system impacts.[57] For example, by 2040 over 4,000 MW of storage is projected to be needed in New York City and over 3,000 MW on Long Island. If OSW injections into the Long Island grid materialize at different locations or grow faster than projected in the studies, storage deployment will need to be revised accordingly and the amount of storage may need to be procured more quickly.

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[56] *See* OSW Study, Section 3.4.4.2: "There are several factors that explain the minimal OSW curtailment. First, during the initial substation screening task, many production cost scenarios and sensitivities were completed (in addition to the accompanying reliability analysis) that provided significant guidance on the potentially stronger locations for OSW connection. Therefore, since the analysis phase of the Study aimed at developing and analyzing an OSW interconnection scenario resulting in minimal adverse system impacts and OSW curtailment, screening results were utilized to place and size OSW such that severe local congestion was avoided. Second, in nearly all hours, OSW local production did not greatly exceed local demand."

[57] OSW Study, Section 3.4.3.1 (Table 3-10).

ii. Feasible Siting and Permitting

The OSW Study concludes that interconnecting 5-6 GW of OSW into Zone J should be feasible with sufficient planning and coordination to efficiently use scarce cable routing corridors through the New York Harbor and limited space at the POI substations. In addition to the planned cables, it would require **siting four 1,300 MW cables and securing landing points** in Zone J. Routing four additional cables through the New York inner harbor may be challenging, however. For example, Intertek (in a study for Anbaric) previously concluded that limited space through the Narrows and into the inner harbor may be able to accommodate only four cables, including the two for the already-contracted OSW facilities.[58] This could limit OSW interconnections into New York City to only 3-4 GW, even assuming larger transfer capability of the individual cables. OSW interconnections into New York City would be further limited if the cables were sized below the 1.3 GW that the OSW Study assumed for all cables beyond those currently planned. Should these challenges limit interconnections in New York City below the 5-6 GW amounts studied—either routed through the harbor or brought into New York City through the Long Island Sound—more than 3-4 GW of OSW generation may need to be interconnected to the onshore grid on Long Island, leading to substantially higher curtailment and the need for additional onshore transmission from Long Island to the rest of the State to mitigate the risk of these curtailments.

Integrating offshore wind will also depend on **accessing POIs** that are jointly feasible on the transmission system and have sufficient space for the necessary interconnection equipment. The various studies do not all reach the same conclusions on which POIs are feasible, nor are the studied POIs consistent with utilities' study assumptions and the NYISO interconnection queue, as shown in Figure 13 below. In fact, the Beacon and Empire 2 Offshore Wind projects, which were provisionally awarded to Equinor Wind US LLC in January 2020, are expected to interconnect at different POIs—Astoria 138 kV in Queens, and Barrett Substation in Nassau County of Long Island; these projects provide a total 2,490 MW of offshore wind capacity.[59] In

[58] Intertek, "Anbaric Export Cables Into New York Harbour: Cable routing through The Narrows and Export Cable Installation," July 24, 2020, pp. 8, 19, http://ny.anbaric.com/wp-content/uploads/2020/08/Intertek_Anbaric_AEJUN23_P2334_NY_Rev21.pdf;

"Offshore Wind Transmission: An Analysis of Options for New York," Prepared by The Brattle Group, Pterra Consulting, and InterTek for Anbaric, August 13 2020, p. 18, http://ny.anbaric.com/wp-content/uploads/2020/08/2020-08-05-New-York-Offshore-Transmission-Final-2.pdf.

[59] NYSERDA, "2020 Offshore Wind Solicitation (Closed)," accessed January 15, 2021, https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/Focus-Areas/Offshore-Wind-Solicitations/2020-Solicitation

addition, not all of the POI capacities identified in the OSW Study correspond to the most cost-effective scale of different cable types: Syosset is assumed to interconnect only 300 MW and Brookhaven only 270 MW,[60] which is less than the 400 MW efficient scale for 220 kV AC cables. If POIs cannot accommodate at least 400 MW, they might not be desirable POI candidates for cost-effective OSW development. However, feasible additional candidates for POIs not fully analyzed in the OSW Study will be the substations of retiring existing generating plants, which would be able to transfer their capacity rights to the interconnecting OSW generators without the need for transmission upgrade.[61] This ability to utilize the interconnection capacity of retiring fossil plants may mitigate the overall challenge of finding POIs that are jointly feasible without major transmission upgrades.

FIGURE 13: POINTS OF INTERCONNECTION

Source		Points of Interconnection for Potential Projects	
		Zone J	**Zone K**
OSW Study	[1]	Farragut (1400 MW) Rainey (1250 MW) Mott Haven (1250 MW) West 49th St. (1200 MW)	New Bridge (600 MW) Shore Rd. (500 MW) Northport (400 MW) Syosset (300 MW) Brookhaven (270 MW)
Zero Emissions Study	[2]	Farragut Rainey West 49th Street Fresh Kills	Ruland Rd. East Garden City River Head
Anbaric Study	[3]	Gowanus (2000 MW) Fresh Kills (1700 MW) Rainey (1200 MW)	Ruland Rd. (1200 MW) East Garden City (1084 MW)
CARIS 70x30	[4]	Farragut (1440 MW) Fresh Kills (1424 MW) Gowanus (816 MW)	Brookhaven (384 MW) Ruland Rd. (384 MW)
Utility Study: ConEd and LIPA	[5]	Two new OSW interconnection hubs with 3000 MW and 2180 MW.	Ruland Rd. (1400 MW) East Garden City (700 MW)
NYISO Interconnection Requests	[6]	Gowanus (2080 MW) Fresh Kills (880 MW)	Ruland Rd. (1816 MW) Brookhaven (880 MW) Barrett (2500 MW)

Sources and notes:
[1] From OSW Study, Section 3.4.1 (Table 3-6).
[2] Correspondence with NYSERDA. Note that, unlike the OSW Study, the Zero Emission Study did not seek to optimize POI locations.
[3] "Offshore Wind Transmission: An Analysis of Options for New York," Prepared by The Brattle Group, Pterra Consulting, and InterTek for Anbaric, August 13 2020, p. 10.
[4] NYISO, "2019 CARIS Report," July 24, 2020, FN 38 at p. 79.
[5] Utility Study, Figure 45 at p. 113 for Zone J; Figure 51 at p. 127 for Zone K.

[60] OSW Study, Section 3.4.1 (Table 3-6).

[61] For example, the provisionally-awarded Beacon Wind project will support the responsible retirement of aging fossil fuel plants in Queens as part of the transition to clean energy; and the Empire Wind project may evolve to potentially support the retirement/repowering of the E.F. Barrett Generation Station in Nassau County.

[6] Includes all projects from the NYISO Interconnection Queue as of December 4, 2020 with SRIS/SIS or FS in Progress, except 136 MW at East Hampton, 880 MW at Holbrook, and 816 MW at Gowanus.

The OSW Study concludes that the interconnection points it identifies are feasible, accounting for both routing and substation limitations. The Utility Study, however, notes that reliability needs and space limitations for adding necessary interconnection equipment to existing ConEd substations might prevent such approaches and should be addressed by developing "New York City Clean Energy Hubs #1 and #2." According to ConEd, the two hubs would avoid these limits and create new OSW interconnection points in Zone J for 3,000 MW and 2,180 MW. The OSW Study does not appear to include these types of costs associated with interconnecting to the highly space-constrained ConEd substations in Manhattan. Until developers can compete to propose creative solutions to address the challenging space constraints in Zone J, these costs will be uncertain. Nevertheless, ConEd's proposed solution indicates that these additional costs (not currently included in the OSW Study) potentially could be significant.

If delivering 5-6 GW of OSW in Zone J turned out to be infeasible or excessively costly, Zone K interconnections would have to increase beyond the 3-4 GW studied in order to achieve the combined 9 GW OSW mandate. For larger injections into Zone K, the OSW Study indicates increasing amounts of curtailment, although no reliability violations under projected summer peak conditions. As previously noted, in the Study's "Scenario 3" with 4 GW of OSW connected to Zone K and the "modified Zone K assumptions" provided by LIPA, curtailment increased to 1,200 GWh.[62] As a reference point, the Anbaric study found that OSW curtailments increase with more than 2.5 GW of OSW interconnected on Long Island without the benefits from the co-location of battery storage.[63]

iii. Low Congestion and Curtailments

As noted above and discussed further in the next Chapter of this Initial Report, both the OSW and Zero Emissions Studies use industry-standard production cost simulations that, necessarily, are based on a simplified representation of real-world market conditions. While state of the art, the simulations will tend to understate real-world congestion and curtailments associated with transmission constraints. The models have the benefit of perfect foresight (without forecasting errors and real-time uncertainties), do not simulate transmission outages, are based on normalized weather and system conditions, and do not simulate intra-hour system operations. Further analyses will be necessary to address the extent to real-world market conditions will

[62] OSW Study, Section 3.6.3.2, Table 3-27.

[63] "Offshore Wind Transmission: An Analysis of Options for New York," The Brattle Group, p. 23.

yield congestion and curtailment levels above the results from the OSW Study's screening analyses.

For example, studies of the NYISO system (e.g., the 2015 analysis of public policy projects) have shown that actual congestion may be at least 40% above the levels projected by these models.[64] In similar studies of other markets, Brattle simulations of Day Ahead and Real Time market conditions, including Day Ahead forecast errors and intra-hour granularity, also show that real-time curtailments tend to substantially exceed curtailments based on perfect foresight (such as in ISO day-ahead markets). While OSW may be curtailed after all other renewable resources, real-world conditions affecting the OSW interconnection points (such as planned or unplanned transmission outages on Long Island or New York City) will likely yield OSW curtailments above those simulated in the OSW and Zero Emission Studies.

In addition, the OSW Study and the Zero Emissions Study were not designed to focus on lower-voltage transmission facilities—which means constraints on transmission facilities below 100 kV were not evaluated in the OSW Study, and constraints below 138 kV were not evaluated in the Zero Emissions study (with a few exceptions). While the OSW Study does not specify exactly which constraints are monitored in its production cost modeling, the 100 kV limit means that study results will not include the impacts of bulk-power constraints caused by constraints on the parallel 69 kV transmission system in parts of Long Island. We understand that the Zero Emissions Study's production cost simulations only monitored and enforced about 200 potential transmission constraints, which (based on our experience) compares to NYISO's simulations that monitor and enforce approximately 650 constraints within the NYISO footprint and an additional 100-150 constraints to and within neighboring market areas. The Zero Emissions Study's screening analysis also excludes constraints on intra-zonal transmission at 115 kV or below, so local curtailments and congestion on local transmission facilities will not be captured. Some of this may be accounted for in the Utility Study, which focuses on these lower-voltage local transmission facilities. For example, LIPA suggests in the Utility Study that

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64 *See* "Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," prepared by The Brattle Group for NYISO and DPS, September 15, 2015, p. 84, showing actual congestion 56% higher than simulated. Available at https://brattlefiles.blob.core.windows.net/files/5721_benefit-cost_analysis_of_proposed_new_york_ac_transmission_upgrades.pdf;

See Potomac Economics, Market Monitoring Unit for the New York ISO, NYISO MMU Evaluation of the Proposed AC Public Policy Transmission Projects (Dated February 2019), p. 16, showing actual congestion 40% higher than simulated. Available at https://www.nyiso.com/documents/20142/5172540/04d%20AC%20Transmission%20ApnxE%20MMU%20Report.pdf/113062e4-4ae4-9b7d-46a5-3eec40ad739d (last accessed Sep. 29, 2020).

upgrades to the local transmission grid (to create 345 kV local backbone in addition to export cables to Zone I or J) may be needed to accommodate OSW injections on Long Island. ConEd similarly claims that its system cannot absorb the 1,310 MW of (single-largest-contingency based) injections assumed in the OSW and Zero Emissions studies.[65]

iv. Reliability Analysis

The OSW Study assessed the impacts of OSW injection on transmission reliability only for summer high-load conditions. Other reliability studies may also focus on winter peak and low-load, high renewable conditions. The latter can be more challenging from a renewable generation integration perspective. Such low-load, high renewable generation conditions can create more reliability challenges associated with the integration of wind generation, particularly during certain years within the range of actual load and wind patterns, than those analyzed in the OSW Study's screening analyses.

For example, a recent analysis of OSW integration prepared for Anbaric found that accounting for three seasonal conditions in the analysis—summer peak, winter peak and shoulder low-load conditions—identified additional reliability needs.[66] However, the OSW Study concludes, based on a "net load duration curve" analysis of projected hourly loads net of projected hourly OSW generation, that reliability needs during winter and shoulder periods should not be any more challenging than during summer peak-load conditions. Further reliability analyses, ideally in collaboration with NYISO and a wider range of actual hourly wind and load profiles, may be warranted to confirm these conclusions.

2. Radial vs. Meshed Offshore Configurations

The OSW Study identifies the significant benefits of a meshed system over other network configurations. The benefits of such a meshed system likely are even higher than identified in the OSW Study because (1) it may not fully capture the availability benefit of meshing four radial lines; (2) it does not consider the benefits of controlling injections to the POI locations with the highest values (to reflect onshore congestion); and (3) it only explored meshing lines injecting into New York City, without considering networking into both Long Island and New York City (and possibly even with other state's OSW transmission into neighboring power markets).

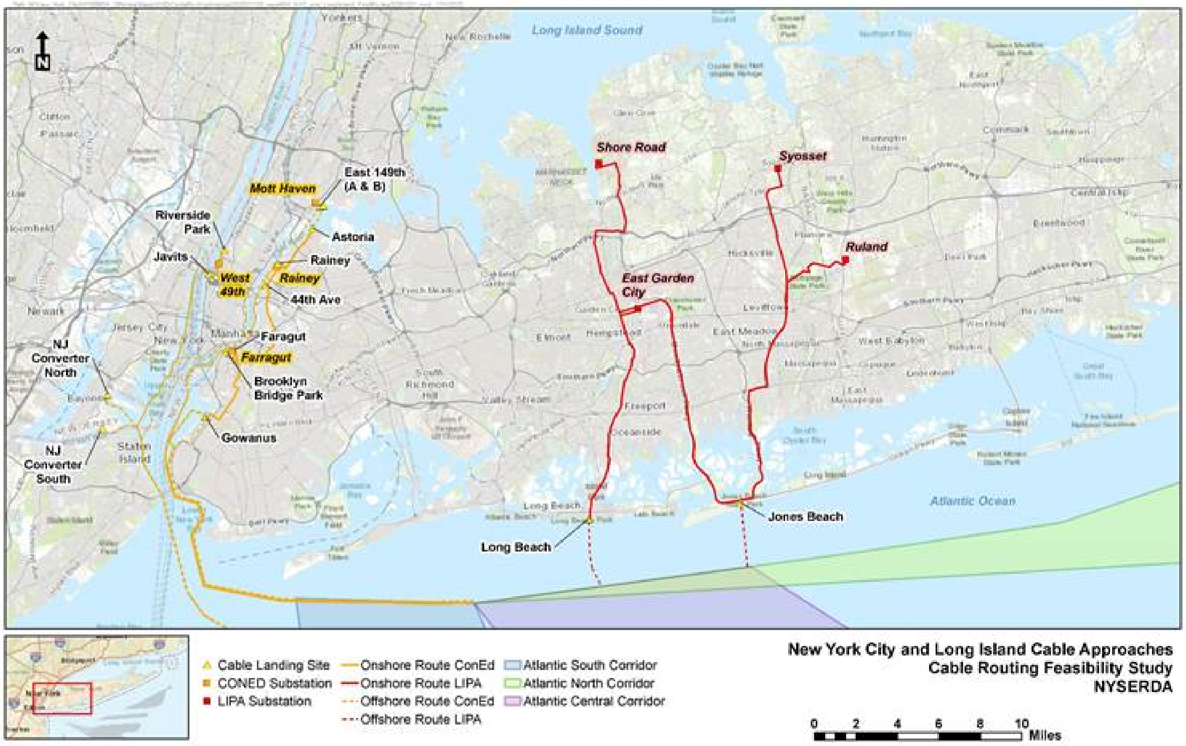
[65] Utility Study, pp. 108-109.

[66] "Offshore Wind Transmission: An Analysis of Options for New York," The Brattle Group.

Importantly, by meshing the transmission ties into New York City with lines to Long Island landing points, the offshore network would further reinforce the constrained Long-Island export limit and be able take advantage of transferring power from POIs with low LBMP (e.g., on constrained Long Island locations) to POIs with higher LBMP (in NYC) to the extent transfer capability is available at that time. In fact, the OSW Study's recommendations for future work (Section 10) notes that: "connecting strong nodes in zone K, such as East Garden City and Shore Road, with strong nodes in zone J, such as Farragut, Astoria or even Gowanus, should be explored, as such ties would offer additional benefits that would extend beyond facilitating the connection of OSW resources." This could in effect be achieved by integrating into the "offshore mesh" the offshore stations for the radial lines into Shore Road and East Garden City.

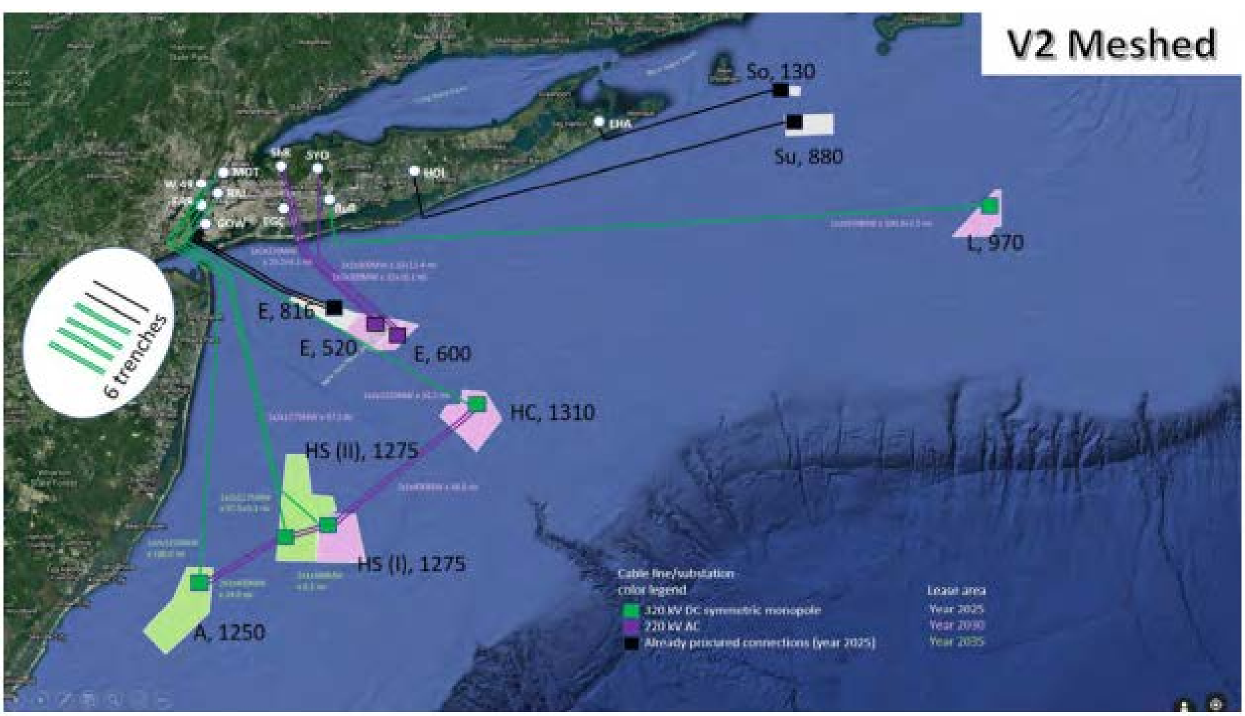
As shown in Figure 15 below, the offshore stations for E 520 and E 600 are in fairly close proximity to the HC 1310 offshore station. By extending the meshed lines to them, the offshore grid would be able to control (1) the radial injections from all off these wind locations and (2) additionally transmit power from Long Island to New York City. If one of the HVDC lines into NYC was instead routed to New Jersey, the meshed configuration would also create a new interregional link between NYISO and PJM, which could be integrated with the three existing PJM-NYISO links (Neptune, Hudson, and Linden). Moreover, the L 970 HVDC line from the New England OSW lease area into Ruland Road could be meshed with the near-by offshore substation of one or several of the HVAC and (likely future) HVDC lines into ISO-NE, thereby (1) providing reliability benefits to the OSW plants serving both regions, and (2) creating another controllable interregional link for power transfers between NYISO and ISO-NE. These potentially expanded meshed configurations warrant additional analysis.

FIGURE 14: NEW YORK CITY AND LONG ISLAND POIs AND CABLE APPROACHES



Source: OSW Study, Section 7.2 (Fig. 7-3).

FIGURE 15: "VERSION 2" MESHED MAP



Source: OSW Study, Section 7.2 (Fig. 7-3).

C. Recommendations on Bulk Transmission Needs and Potential Projects

The OSW Study and related studies do not themselves identify a short-term need for bulk transmission investments to support 9 GW of offshore wind. However, the scenarios they construct to accommodate 9 GW with the current system are idealized and optimally coordinated in several ways, notably in the precise split of 6 GW to Zone J and 3 GW to Zone K, and the operating conditions as discussed above. If development realities and grid conditions differ from those assumed and simulated, costs are likely to increase due to siting and transmission constraints, particularly limitations regarding feasible POIs and cable routes to access POIs. From that perspective, it becomes valuable to pre-emptively address the problem by adding transmission infrastructure, the need for which is almost inevitable as the State looks beyond its 9 GW minimum target and considers pathways to deepening decarbonization consistent with the goals of the CLCPA, as discussed below.

In particular, integrating 5-6 GW of offshore wind into Zone J may be more difficult and costly than anticipated. In that case, more than 3 GW of offshore wind would have to connect to Zone K to meet the 9 GW goal for 2035, if not earlier. The OSW Study estimated that, at 4 GW of OSW connected to Long Island, curtailments there could increase to 1,200 GWh per year.[67] By adding a new 345 kV tie-line from East Garden City to Dunwoodie (in Zone I), simulated curtailment decreased to 400 GWh. A new intertie could provide other benefits and options as well: (1) the new tie lines would enable more OSW to connect in Zone K, mitigating the risk associated with siting challenges and high capital costs of routing 5-6 GW into Zone J; (2) the tie line likely would reduce curtailments more than simulated; and (3) the increased transfer capability would also reduce congestion of imports to Long Island whenever offshore wind output is low.

Regarding the latter, the Zero Emissions Study finds that an additional double circuit 345 kV intertie from Long Island to Dunwoodie (and two 345-KV transformers) would be cost-effective in addressing high congestion costs that the study projects for 2040.[68] The study estimates production cost savings,[69] mostly from avoiding the use of renewable natural gas when OSW

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[67] OSW Study, Section 3.6.3.2 (Table 3-27).

[68] Zero Emissions Study, Section 1.3, Table 1-7.

[69] *See* Zero Emissions Study, Section 6.3, Table 6-1. By 2040, no fossil-fired generation would be permitted, so renewable natural gas (RNG) would be needed when wind generation is low for extended periods beyond the duration of battery storage resources. RNG is assumed to cost $23/MMBtu, which translates to over $160/MWh.

wind is insufficient to meet Long Island's entire load. Thus, additional transmission between Long Island and the mainland would have value in both directions in a future with geographic diversity from large amounts of intermittent renewable resources.

The need for a new tie-line may be inevitable in a future where offshore wind plays a significant role in New York's downstate grid. In particular, to meet the zero-emissions electricity and 85 percent reductions in greenhouse gas emissions mandates of the CLCPA, it is very likely that New York will eventually need more offshore wind than the 9 GW minimum mandate studied, as summarized in Figure 16 below. If a Zone K tie-line will be needed eventually, advancing such a project to 2030 would provide value earlier, and the cost of advancing it is only the incremental net present value of building it earlier. Doing so would expand the options for meeting the State's OSW goals, limit the risks associated with the very narrow and precise execution of interconnecting 5-6 GW into Zone J at the Study's assumed schedule and costs, and add flexibility that would support market efficiencies beyond the scope of this study.

FIGURE 16: PROJECTED OFFSHORE WIND CAPACITY BY YEAR

Source		Offshore Wind Capacity (MW)		
		2030	2040	2050
NYISO CARIS: 70x30 Scenario	[1]	6,100	-	-
Zero Emissions Study: Initial Scenario	[2]	6,000	9,800	-
Zero Emissions Study: High Demand Scenario	[3]	6,000	13,600	-
Brattle Grid Evolution Study: Reference Case	[4]	7,100	13,800	-
E3 Study: High Technology Availability	[5]	6,200	9,700	15,500

Sources and notes:
[1]: NYISO, "2019 CARIS Report," July 24, 2020, Fig. 68 at p. 79.
[2]-[3]: Zero Emissions Study, Section 4.1.2, Table 4-1 and Section 7.2.1, Table 7-3.
[4]: "New York's Evolution to a Zero Emissions Power System," prepared by The Brattle Group for NYISO Stakeholders, June 22, 2020, pp. 62, 66.
[5]: E3, "Pathways to Deep Decarbonization in New York State," June 24, 2020, pp. 35-36. Available at https://climate.ny.gov/-/media/CLCPA/Files/2020-06-24-NYS-Decarbonization-Pathways-Report.pdf

It is important to reiterate that the OSW Study is focused only on bulk transmission enhancements, assuming necessary on-ramp transmission is built at the POIs, including at the local transmission level. Local transmission upgrades needed for OSW may thus require additional investments on Long Island, such as LIPA's proposal to convert part of the 138 kV system to 345 kV, and strengthening some of the underlying 69 kV system, as presented in the Utility Study and summarized in Section **V.D**. Due to substation constraints at proposed POIs in New York City, additional local transmission upgrades may also be necessary in Zone J, such as the “Clean Energy Hubs” proposed by ConEd in the Utility Study (and discussed in Section V.B.1). Strategic deployment of substantial amounts of battery storage on Long Island and in New York City will likewise play a crucial role in integrating OSW generation helping to bring into alignment the OSW and Zero Emissions Studies results.

Finally, the OSW Study finds that the State’s current approach of procuring OSW plants with radial transmission links could be enhanced in the future by adding a meshed offshore grid, particularly for “clusters” of nearby projects. At sufficient scale, the State would reap several reliability and resiliency benefits whose value would outweigh the modest increase in upfront cost from radial to meshed designs.

D. Recommendations on Next Steps and Path Forward

The following recommendations are offered for further consideration in support of creating a cost-effective path to more reliably achieve the State’s OSW targets:

- Initiate development of proposals for a tie-line between Long Island and Zone I or J
- Continue planning and coordination of cable routes and POIs
- Create options for a meshed offshore system
- Further assess needs for onshore bulk transmission
- Review policies for optimizing storage and other system flexibilities

In addition to the above points (which are further discussed below), the state should advocate for the expeditious development of new wind energy areas that take into consideration state policy needs.

1. Develop New Transmission from Long Island

Planning for an expansion of the export capacity from Long Island by 2030 should start right away. The NYISO Public Policy Planning Process offers an effective mechanism for identifying competitive solutions to transmission needs. Such solutions may combine innovative transmission designs and non-wires alternatives. For example, the need could be specified to solicit incremental export capability from Long Island at whatever scale and by whatever methods would be the most cost-effective.

2. Continue Planning and Coordination of Cable Routes and POIs

Optimal use of New York City harbor rights-of-way and interconnection points should be studied further and expeditiously. The following planning and coordination activities should continue in earnest with deepening specificity:

- Coordinate with other stakeholders and agencies to determine and prioritize spatial constraints and opportunities more definitively, and identify creative solutions to avoid and minimize impacts, and maximize outcomes;
- Coordinate with NYISO to determine the maximum OSW injection capacity, which may be larger than the assumed 1,310 MW limit if the POI design includes redundancy or innovative use of coordinated storage to reduce the size of the single contingency;
- Examine and resolve discrepancies between the OSW Study and the Utility Study's respective findings regarding POI availabilities; and
- Plan solutions to reach at least the 9 GW OSW target and configure the onshore transmission system.

In the meantime, any new OSW transmission cables should be sized as large as possible (e.g., if feasible at the 1.3 GW single largest contingency limit), utilizing the symmetric monopole DC cable technology identified in the OSW Study.

Regarding POIs in New York City, ConEd will have to confirm that OSW Study's proposed Manhattan and Brooklyn POIs are feasible at the studied injection levels given substation space limitations and local transmission reliability criteria. If interconnecting OSW is not feasible at these substations or if capacities are more limited than the proposed MW quantities, the evaluation of cable routing through the harbor would need to be adjusted accordingly. Similarly, it will be necessary to confirm with LIPA that proposed POIs on Long Island are feasible regarding substation design, available substation space, and approach ROWs. Once feasibilities are confirmed, it may be possible for NYSERDA, LIPA, ConEd, and NYISO to coordinate efforts in identifying the most advantageous POIs for the next tranche of OSW interconnections. The coordination effort can also help inform near-term procurements so that earlier cable landings do not foreclose cost-effective options for subsequent rounds of procurements.

3. Create Options for a Meshed Offshore System

As the OSW Study explains, a meshed offshore grid would cost more to construct than individual radial connections, but it would provide several benefits. It would provide redundancy to reduce curtailments of offshore wind when a cable fails and would provide insurance against lengthy cable outages (such as experienced by Hudson or TransBay)—as long as the cables are operated with some headroom, which occurs naturally most of the time when the wind is not strong enough to maximize generation. It could also help reduce the size of the onshore contingency when a single cable fails, thus enabling larger cables and better maximizing scarce corridors and POIs and enable flowing the power to the locations with the highest LBMP.

While confirming the feasibility of a radial system for New York, **the OSW Study recommends that OSW facilities with radial transmission include the option for being later integrated into a meshed, more resilient offshore network**.

For example, bidders in NYSERDA procurements offering radial connections could be asked to include alternative bids with larger offshore transmission platforms that can accommodate the interconnections and substation configurations necessary to create a meshed network that can be used to disconnect individual gen ties and re-route the output from the directly interconnected wind generation to the rest of the meshed network. If the incremental cost of including this option is in fact modest (i.e., confirming study assumptions), it would provide a cost-effective option to build the meshed network in the future if and when fully justified. This option would also allow each OSW facility to be networked with two other New York OSW projects—which could ultimately include nearby OSW facilities serving New Jersey and/or New England with the potential to deliver additional value to New York via proceeds relating to exports or cost-sharing with neighboring states on such transmission assets. Doing so may create additional benefits in terms of trading opportunities and increased reliability by making available alternative delivery routes through neighboring system in case offshore outages should affect the direct transmission links.

4. Further Assess Needs for OSW-Related Onshore Transmission

Further study of onshore transmission needs for OSW integration is warranted, both because (1) the existing studies likely do not capture the full amount of real-world congestion and renewable curtailments that will likely be encountered and (2) bulk transmission needs may arise sooner if system conditions and renewable generation investments evolve differently from those assumed in the studies.

- NYISO could perform a complementary interconnection study for 2030 and 2035 to confirm the projected limited upgrade needs associated with 9 GW of offshore wind. This analysis may be undertaken both within the NYISO interconnection and reliability-needs study processes as well as, from a market efficiency and projected renewable curtailment perspective, within the next CARIS process.
- The feasibility and value of interconnecting OSW plants into the substations of retiring fossil plants should be considered and studied further.
- More detailed studies of real-world system conditions (e.g., considering both day-ahead forecasting errors and real-time intra-hour uncertainties) may be warranted to provide better early indicators for likely real-world congestion levels, renewable curtailments, and flexibility challenges associated with the injections of significant volumes of OSW generation.

5. Review Planning and Procurement Policies to Optimize Storage and Create Additional Grid Flexibility

As noted above, both OSW and Zero Emissions Studies show that substantial amounts of battery storage on Long Island and in New York City will play a crucial role in integrating OSW generation. The studies place 3,000 MW (by 2030) and 15,500 MW (in 2040) of storage into specific locations on the grid. For example, by 2040 over 4,000 MW of storage may be needed in New York City and over 3,000 MW of storage may be needed on Long Island. If OSW injections into the Long Island system grow faster than projected in the studies, this amount of storage will need to be procured even more quickly.

In addition, other options for increasing grid flexibility to reduce congestion and curtailments associated with increased OSW injections on Long Island should be explored. These options should include using the Neptune and Cross Sound cables in export direction during high OSW injection hours to export surplus generation on Long Island to the rest of the State by utilizing parallel paths through ISO-NE and PJM. For example, exports over the Neptune cable could be reimported into New York City by the Linden or Hudson transmission facilities. Exports over Cross-Sound Cable could be similarly re-imported into NYISO over the AC interties with ISO-NE. Under the current wholesale market design, such transactions could be scheduled hourly on a day-ahead basis or in 15-minute increments during the day prior to real-time operations. However, to fully optimize such export-and-reimport transactions during real-time market operations would require additional collaboration and coordination between NYISO, PJM and ISO-NE.

V. Zero Emissions Electric Grid by 2040: Study Findings and Recommendations

The Zero Emissions Electric Grid by 2040 study (Zero Emissions Study) is a resource planning study prepared by Siemens to analyze transmission, generation, and storage scenarios for meeting New York's goals of zero-emission electricity by 2040 and achieving interim targets of 70% renewable generation by 2030.

The study approach is organized into six steps, with the two initial steps followed by four iterative steps:

1. **Define Objectives and Assumptions:** Key objectives include reaching 70% renewable energy by 2030, reaching zero emissions by 2040, preserving the "1 in 10 years" loss of load event (LOLE) resource adequacy standard, supplying sufficient flexible resources to manage ramping needs, minimizing costs, curtailment, new transmission, and imports. Key assumptions include: (1) a new 1,250 MW DC line that provides dispatchable, renewable energy to Zone J (under the new Tier 4 procurement)); and (2) limiting dispatchable low-emission technologies to only renewable natural gas use in gas turbines.
2. **Define load and Distributed Energy Resource (DER) forecasts:** The Study drew upon the New York Decarbonization Pathways Study[70] and utilities' forecasts as input to develop the base and alternative scenarios for the load and DER forecasts (distributed behind the meter solar). The Study developed two scenarios: an "Initial Scenario" and a "High Demand Scenario."
3. **Simulate Optimal Capacity Expansion for 2030 and 2040:** Optimal capacity expansion simulations were performed using the AURORA simulation tool with zonal resolution. The planning reserve margin was kept constant over time and the different resource

[70] Energy and Environmental Economics, Inc. (E3), "Pathways to Deep Decarbonization in New York State," June 24, 2020. https://climate.ny.gov/-/media/CLCPA/Files/2020-06-24-NYS-Decarbonization-Pathways-Report.pdf#:~:text=Pathways%20to%20Deep%20Decarbonization%20in%20New%20York%20State,Protection%20Act%20%28CLCPA%29%20in%20the%202019%20legislative%20session

types' capacity values were determined dynamically, as a function of the amount of each technology on the system. To determine if a select portfolio met the 1-event-in-10-years resource adequacy standard, the study used AURORA's risk outage functionality and demand uncertainty features.[71,72] The Study methodology also estimated the ramping reserve requirements in supply portfolios based on the estimated variation in day-ahead market load projections versus actual load (load to serve minus non-dispatchable generation).[73]

4. **Transmission Reliability Assessment:** The TARA reliability study tool was used to analyze thermal and voltage violations for pre-contingency and local and design criteria contingency conditions.[74] The focus of the analysis was on the bulk transmission system 230 kV and above, although lower voltages were monitored. The analysis considered certain snapshots of conditions that resulted in heavy utilization of the transmission system based on the dispatch of the zonal runs (e.g., summer peak load with high solar, and high wind with low load).
5. **Congestion Assessment:** Nodal analysis was performed using the PROMOD production cost simulation tool to identify congestion and renewable curtailments (beyond the reliability issues determined in the above power flow analysis) with a view across all 8760 hours of a year.

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71 This functionality will randomly remove plants from service, simulating unplanned outages (such as equipment failures) or renewable energy supply lulls (such as a cloudy day for solar). The process also incorporated load uncertainty. A simulation was run incorporating both load and outage uncertainty in AURORA up to 1,000 times over select years with each iteration having a different internally generated net (demand minus supply) outage pattern for resources.

72 The study also benchmarked the results of AURORA resource adequacy analysis against a comparable analysis using the GE MARS software tool for the Initial Scenario. It was determined prior to obtaining the benchmark results that if the modeling results were similar, no further changes would be made. This was the case presented in this report.

73 A Monte Carlo approach generated sub-hourly forecast data in a probabilistic manner, allowing the capture of any extreme weather conditions, customer load behaviors, and renewable generation variability. The program generated sub hourly net load (load to serve less non dispatchable generation) and compared the hourly average levels against the sub hourly actual net load to arrive at the maximum possible deviation of sub hourly load settlements against the hourly averages. These sub-hourly deviations were then compared to available resources with appropriate ramping capabilities to assess if the portfolio was short or not. This process was repeated 100 to 1,000 times to capture extreme behavior. Once the amount of resource necessary were defined, these were then added as AURORA constraints for AURORA to select the least cost resources to meet the Ramping and Flex adequacy requirements.

74 TARA allows single contingency (N-1) and multiple contingency (N-1-1) reliability analysis and determines the limiting transmission elements considering preventive and corrective action dispatch. This procedure results in the identification of critical facilities and was expected to provide an initial view on curtailment.

6. **Define Transmission Solutions:** Transmission expansions to address reliability or congestion challenges found in prior steps were identified and their likely cost-effectiveness assessed in terms of benefit to cost (B/C) ratios.[75]

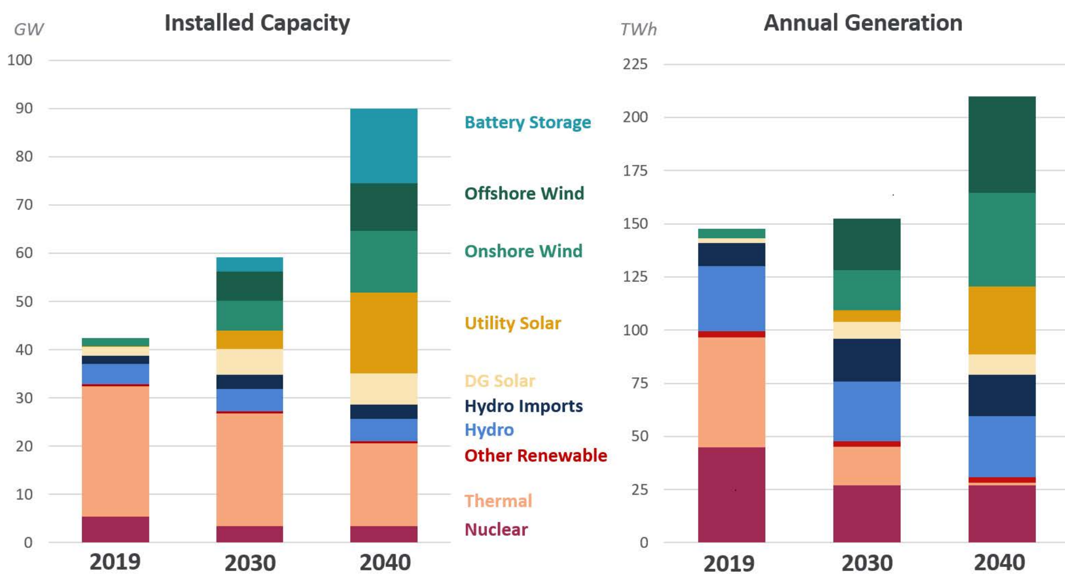
A. Summary of Zero Emissions Study Results

The Zero Emissions Study found that New York's 2030 goals could be met at low levels of curtailment and congestion without significant bulk-power transmission upgrades beyond those already planned and under development, and a new HVDC line delivering dispatchable renewable energy into New York City that is assumed to materialize as a result of the State's new Tier 4 procurement.[76] However, by 2040, high levels of congestion and some curtailments point to a need for additional bulk transmission upgrades. Figure 17 presents the Study's Initial Scenario's projected installed capacity and energy generated by technology in New York for 2030 and 2040 in comparison to 2019 levels. As shown, the share of 2040 generation from onshore wind, offshore wind, and solar is roughly equal and is complemented by battery storage (15.5 GW). In 2040, 12 GW of "other thermal" generation capacity remains operational for backup power needs but is fueled by renewable natural gas. The use of renewable natural gas, however, occurs in very few hours of the year, resulting in a 3% capacity factor for thermal capacity.

[75] These ratios measure the reduction in operating costs in terms of the Adjusted Production Costs (APC). APC accounts for sales and purchase with neighbors that the indicative transmission projects bring and divide it by its carrying costs and include return on capital, amortization, and O&M. The increase in transmission limits and their cost allocated back to the generation that would benefit from them, was then passed back to the AURORA assessment step, for an update of the plan that may include a shift in storage in response to costs.

[76] As noted in Section 1.2.1 of the Zero Emissions Study: the already-planned upgrades that are assumed to be developed "include the Western NY Empire State line 345 kilovolt (kV) project in Zone A, AC Transmission Segment A & Segment B 345 kV projects in Zone E and F as well as the Northern New York 345 kV projects in Zone D and E that were expanded to include upgrades reinforcing the connection between Porter to Edic substations at 345 KV. Additionally, there is a new 1,250 MW HVDC transmission asset delivering dispatchable renewable energy into New York City (the NYC Tx project)."

FIGURE 17. INITIAL SCENARIO: CAPACITY AND GENERATION BY TECHNOLOGY IN 2030 AND 2040



Sources: 2030 and 2040 values: Zero Emissions Study, Section 4.1.2, Table 4-1 and Section 4.2.1, Table 4-3; 2019 values are from the 2020 NYISO Gold Book.
Notes: *"Thermal" burns regular natural gas in 2030 and renewable natural gas in 2040. Legacy hydro imports are included in chart and assumed to have an effective capacity of 1,690 MW.

The Study finds low levels of curtailment and congestion by 2030. By 2040, simulated statewide curtailment increases only modestly to 1.5% and 3.4% statewide for the Initial Scenario and High Demand Scenario, respectively, without bulk transmission upgrades.[77] The Study suggests that the identified renewable curtailments and high congestion costs can be mitigated cost-effectively with transmission projects in four specific grid locations (downstream of Coopers Corner into Zone GHI, at the Millwood South Interface, at the Dunwoodie to Shore Rd cables, and at NYC and west Long Island area).[78]

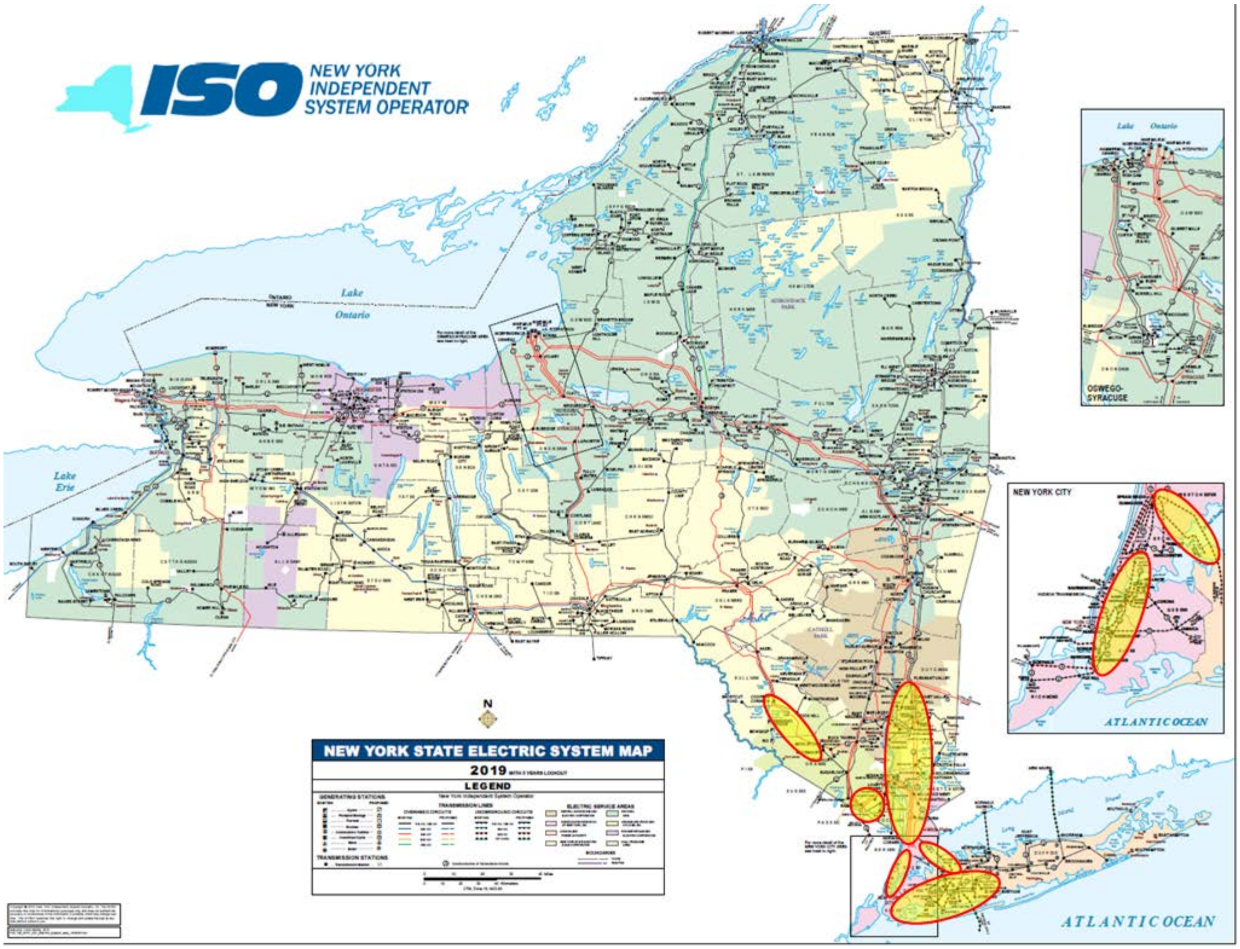
Figure 18 shows the areas where high simulated congestion costs are projected to make bulk transmission upgrades cost-effective. For the Initial Scenario, the indicative upgrades, listed in Figure 19, reduce simulated 2040 curtailment to 0.1%. In the High Demand Scenario, larger upgrades in the same locations reduce simulated 2040 curtailment to 0.8%.[79]

77 Data is from the Initial Scenario in the Zero Emissions Study, Sections 6.5.1 and 7.6.1.

78 Zero Emissions Study, Section 6.6.2, Table 6-6 and Section 7.7.1, Table 7-13.

79 Zero Emissions Study, Sections 6.6.1 and 7.7.1.

FIGURE 18. 2040 PROJECTED CONGESTION AREAS



Source: Zero Emissions Study, Section 1.2.1, Figure 1-1.

FIGURE 19. INITIAL SCENARIO: INDICATIVE COST-EFFECTIVE BULK TRANSMISSION UPGRADES

Zone	Indicative Transmission Upgrades in 2040 Upgrade Case
H/I/J	Increase Millwood South Interface transfer capability to 13000 MVA, and increase Dunwoodie South Interface transfer capability to 6000 MVA
I/K	Increase Dunwoodie—Shore Rd cable LTE rating to ~3000 MVA. (likely require two new 345 kV cables in parallel and two new 345/138kV transformers at Shore Rd)
E/G	Increase Coopers Corner—Middletown—Rock Tavern—Dolson Ave 345 kV line sections LTE rating to ~3000 MVA
G	Increase Ladentown—Ramapo 345 kV line LTE rating to ~2500 MVA

Source: Zero Emissions Study, Section 6.6.2, Table 6-6.

B. Observations, Issues, Gaps, and Comparisons with Other Studies

Future transmission needs will depend on which new resources are developed where—a major uncertainty underlying a transmission study projecting 20 years into the future. To evaluate the Zero Emissions Study's resource projections, this section compares the Zero Emissions Study's projected renewable generation investments with three similar studies: a study conducted by E3 for NYSERDA (Pathways to Decarbonization in New York State), a study conducted by Brattle for the NYISO (New York's Evolution to a Zero Emissions Power System), and the NYISO's 2019 Congestion Assessment and Resource Integration Study (CARIS). The first two studies are resource planning studies that, similar to the Zero Emissions Study, simulate the optimal growth in renewables and other resources that will be needed to meet the State's clean energy goals in 2030 and 2040. The third study, CARIS, projects resource needs only out to 2030 and is included because it was used as the basis for the LT&D analyses in the Utility Study.

A comparison of the four studies shows that there is uncertainty as to what the resource generation mix and capacities will likely be in 2030 and 2040 and where the resources will be located. This uncertainty will have implications for the grid's investment needs. Figure 20 summarizes the studies' projected renewable generation capacities in upstate Zones A-F and downstate zones G-K. Figure 21 summarizes the studies' projected generation by resource type, as well as gross load and projected renewable curtailments. A few key observations from these figures:

1. Projections of installed total renewable capacity range from 29-42 GW in 2030, and 53-66 GW in 2040. The Zero Emissions Study marks the low end of the range, with the Study's High Demand Case representing the average of the range. The Brattle-NYISO study's Reference Load Case represents the high end of this range—although unmanaged electrification would stretch this range even further. The 2030 CARIS assumptions are in the middle of the 2030 range. The differences across studies reflect differences in load (with each study meeting the required percentages of load to be met by renewable and other zero-emitting generation), as well as differences in hydro imports, nuclear generation, battery storage, and the locations in which renewable and storage resources would be developed.
2. The composition of renewable resource additions is similar across studies in 2030, except for utility-scale solar, which accounts for most of the difference in total renewables. In 2040, offshore wind also varies, from 10 GW to 14 GW across all studies and scenarios. Both cases of the Zero Emissions Study fall within the 10-14 GW range. These differences reflect

differences in load assumptions and basic uncertainties about future renewable developments.

3. Load assumptions differ substantially across studies. Cases with lower load projections include Siemens' Initial Scenario, E3's High Technology Availability Case, and the Brattle-NYISO study's Reference Load Case. Cases with higher load projects include CARIS and Siemens' High Demand Scenario. The range in load assumptions across these studies indicates the degree of uncertainty that future electrification efforts and energy efficiency programs pose.
4. Import and export assumptions also differ across studies, partially driving the capacity differences noted in point No. 1. Siemens, E3, and CARIS all assume an approximately 1,300 MW DC Tier 4 line into Zone J will be in-service prior to 2030 to provide a dispatchable clean source of energy,[80] whereas the Brattle-NYISO study does not.
5. The Study acknowledges that it does not capture the full extent of renewable curtailments and congestion due to the fact that it does not examine constraints at the lower-voltage local transmission facilities (which are analyzed in the Utility Study). In other words, the Zero Emissions Study has not estimated total 2030 and 2040 renewable curtailments. In 2030, the Study reports approximately 0.1 TWh of curtailments in both its Initial and High Demand Scenarios,[81] which is substantially lower than the 14 TWh of curtailments projected by NYISO in its recent CARIS analysis.[82] The Zero Emissions Study's transmission Upgrade case curtailments increase in 2040 but only to 0.2 TWh in the Initial Scenario and 0.8 TWh in the High Demand scenario due to modeled transmission upgrades. Curtailments are likely lower in the Zero Emissions Study results because the PROMOD production cost modeling represented transmission constraints only at 230 kV and above, whereas CARIS modeled lower voltages (e.g., 115 kV) and included higher amounts of generation. Furthermore, the Siemens study includes a model of the Northern New York (NNY) transmission project and location-optimized storage,[83] whereas CARIS does not. A more detailed discussion of bulk

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80 Designated as a Priority Transmission Project (bulk transmission projects that are needed expeditiously to meet CLCPA goals ahead of public policy projects administered through NYISO processes) in Commission order dated October 15, 2020 under Case 20-E-0197.

81 The Zero Emissions Study report 0.1% curtailment in 2030 for the Initial Scenario Base Case, which Brattle estimates to be 0.1 TWh given 105 TWh of renewable generation in 2030.

82 Note, however, that CARIS study assumptions differ in many dimensions. For example, while the CARIS analysis also included 3,000 MW of battery storage for 2030, the mix and location of renewable and storage installations was not optimized to support renewable integration.

83 Designated as a Priority Transmission Project (bulk transmission projects that are needed expeditiously to meet CLCPA goals ahead of public policy projects administered through NYISO processes) in Commission order dated October 15, 2020 under Case 20-E-0197.

transmission congestion and curtailments captured in the Zero Emissions study (and in production cost modeling generally) is provided in Section **VI.C** below.

In summary, we conclude that **the Zero Emissions Study's projected 2040 installed total renewable generation capacity and transmission needs likely are at the low end of the uncertainty range**. If more renewable generation is necessary to achieve CLCPA goals or renewable and storage development differs in mix and locations, more bulk transmission may be required than identified in the Study. In addition, the Study's results for 2040 bulk transmission infrastructure needs should be viewed as only part of the overall power grid picture, because local transmission needs and CLCPA headroom associated with local transmission are addressed in the Utility Study as discussed earlier in this report.

The Zero Emissions Study's projections for total renewable generation capacity in 2030 are closer to those made in the other studies, implying the Study's conclusions of very limited bulk transmission needs in the near term (beyond the projects already planned and under development) should be robust. The larger divergence of renewable generation and storage needs across the studies in 2040 may imply that the 2040 renewable generation levels assumed in the Zero Emissions Study may be reached prior to 2040 (even with location-optimized development of storage resources), which would imply that transmission needs identified in the Zero Emissions Study's could materialize earlier.

FIGURE 20: PROJECTED RENEWABLE CAPACITY BY ZONE GROUPS (GW)

	Zero Emissions Study: Initial Scenario		Zero Emissions Study: High Demand		E3: High Technology Availability		Brattle: Reference Load Case		CARIS: 70x30 Base Load
	2030	2040	2030	2040	2030	2040	2030	2040	2030
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Zones A-F									
Utility Solar	3.4	14.8	4.8	20.6	7.2	NR	14.3	25.6	13.0
Onshore Wind	6.2	10.8	6.8	10.6	4.7	NR	7.1	9.8	8.8
Subtotal	9.6	25.5	11.6	31.3	11.9	NR	21.4	35.4	21.8
Zones G-K									
Utility Solar	0.4	2.0	0.9	2.0	3.4	NR	0.8	4.5	2.1
Onshore Wind	0.0	2.0	0.6	2.0	0.0	NR	0.0	0.0	0.0
Offshore Wind	6.0	9.8	6.0	13.6	6.2	NR	7.1	13.8	6.1
Subtotal	6.4	13.9	7.5	17.6	9.6	NR	7.9	18.3	8.2
Total Hydro (Incl. Imports)	7.6	7.6	7.6	7.6	7.0	8.0	6.1	6.1	1.2*
Total Distributed Solar	5.3	6.4	5.3	6.4	6.0	6.0	6.1	6.2	7.5
Total Storage	3.0	15.5	3.0	14.9	4.4	10.0	5.2	11.9	3.0
Total (Excl. Storage)	**29.0**	**53.4**	**32.0**	**62.9**	**34.5**	**61.0**	**41.5**	**66.0**	**38.7**

Sources:
[1] - [4]: Zero Emissions Study, Annex A.
[5] & [6]: Energy and Environmental Economics, "Pathways to Deep Decarbonization in New York State," prepared for NYSERDA, June 24, 2020.
[7] & [8]: The Brattle Group, "New York's Evolution to a Zero Emission Power System," prepared for NYISO, June 22, 2020.
[9]: NYISO, "2019 CARIS Report," July 24, 2020.
Notes:
"NR" indicates "not reported."
* CARIS Study models but does not report hydro import capacity.
Values reported for the Zero Emissions Study correspond to the final long-term capacity expansion buildout, which accounts for both the added cost of transmission upgrades and the increase in transmission limits.

FIGURE 21: PROJECTED GENERATION BY SOURCE, LOAD, AND CURTAILMENTS (TWH)

	Zero Emissions Study: Initial Scenario		Zero Emissions Study: High Demand		E3: High Technology Availability		Brattle: Reference Load Case		CARIS: 70x30 Base Load
	2030	2040	2030	2040	2030	2040	2030	2040	2030
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Utility Solar	6	32	10	41	19*	50*	17	34	18
Distributed Solar	8	10	8	10			7	7	9
Onshore Wind	19	44	23	42	13	35	16	22	17
Offshore Wind	24	45	24	64	25	40	26	51	22
Hydro	28	29	29	28	30	30	32	32	28
Hydro Imports	20	19	20	19	18	25	13	13	20
Nuclear	27	27	27	27	27	25	17	17	27
Renewable Natural Gas	0	1	0	2	0	0	0	13	0
Natural Gas	18	0	23	0	35	0	26	0	35
Net Non-Hydro Imports	(0)	(0)	(3)	1	NR	NR	5	6	(16)
Other	3	3	3	2	3	5	0	0	3
Total In-State Generation	**132**	**191**	**146**	**217**	**152**	**185**	**142**	**176**	**160**
Gross Load	**152**	**208**	**162**	**233**	**152**	**NR**	**159**	**196****	**162**
Renewable Curtailment	**0**	**0**	**0**	**2**	**NR**	**NR**	**NR**	**NR**	**14**

Sources:
[1] - [4]: Zero Emissions Study, Section 4.2.1, Table 4-3 and Section 7.2.2, Table 7-4.
[5] & [6]: Energy and Environmental Economics, “Pathways to Deep Decarbonization in New York State,” prepared for NYSERDA, June 24, 2020.
[7] & [8]: The Brattle Group, “New York’s Evolution to a Zero Emission Power System,” prepared for NYISO, June 22, 2020.
[9]: NYISO, “2019 CARIS Report,” July 24, 2020. (See Base Load Constrained Case.)
Notes:
“NR” indicates “not reported.”
* Total solar generation, E3 does not distinguish between utility and distributed solar.
** Brattle's 2040 Gross Load contains 27 GWh of load from RNG Production.
Values reported for the Zero Emissions Study correspond to the final long-term capacity expansion buildout, which accounts for both the added cost of transmission upgrades and the increase in transmission limits.

C. Conclusions and Recommendations

The Zero Emissions Study concludes that the State could achieve its 70x30 goals with a mix of distributed energy, offshore and onshore utility-scale renewables, and energy storage, without needing bulk transmission investments beyond those already planned and a new HVDC line delivering dispatchable renewable energy into New York City that is assumed to materialize as a result of the State’s new Tier 4 procurement (as summarized above). To achieve zero emissions by 2040, however, would require many more renewable resources, flexible zero-emission resources, more storage capacity, and likely new bulk transmission investments to cost-effectively reduce congestion. Potentially high annual congestion costs by 2040 are projected to make these bulk transmission projects economical. These projects will complement the *local* transmission upgrades that the Utility Study identified as likely necessary to facilitate renewable land-based resource interconnections through 2030 and beyond. One of these bulk transmission projects—the reinforcement of the transmission interface between Long Island (Zone K) and the mainland (Zone I) has also been identified in the Offshore Wind Study as well as by LIPA (as a Phase 2 project) in the Utility Study and in its NYISO PPTN submission, as discussed above.

The Zero Emissions Study projects low average renewable curtailment levels on a statewide basis through 2040. Prior to proposed bulk transmission upgrades, modeled statewide curtailments in 2040 are low (1.5%) in the 2040 Initial Scenario; across resource types, land-based wind sees the highest curtailment (4.5%), particularly in central NY (8.7%).[84] The Study has identified four bulk transmission projects to reduce curtailment and congestion, with two projects located in central NY and two in the NYC area (see Figure 19). Projected curtailment levels would be higher if the 13,500-15,500 MW of energy storage capacity modeled in 2040 is not or cannot be developed. In that case, additional bulk transmission upgrades may become necessary to manage the higher congestion and curtailments of renewables, as indicated by CARIS.

Results from the CARIS study show that the Central-East interface, followed by the New Scotland-Knickerbocker bulk transmission facility, could experience high congestion costs in 2030, up to $577 million and $161 million respectively.[85] This indicates that despite the development of highly beneficial AC Transmission Public Policy projects, NYISO bulk facilities could face high congestion costs under the CARIS assumptions for renewable and storage siting and development, significant amounts of which are assumed to develop upstream of Central-East and Knickerbocker.[86] The more optimized locations for renewables used in the Zero Emissions study does not find these bulk system congestion impacts as it assumes more renewable development would occur in less constrained downstream locations as well as optimal energy storage placement.

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[84] Zero Emissions Study, Section 6.5.1.

[85] NYISO, 2019 CARIS Report, July 24, 2020, p. 85, Fig. 74.

[86] CARIS's 70x30 analysis developed projections for 2030 renewable siting and buildout based on the 2019 generation interconnection queue.

Additionally, future transmission reinforcements in certain upstate local transmission areas[87] that facilitate reduced renewable curtailment and higher delivery of renewable power to the bulk system can further increase loading on the bulk transmission facilities beyond what the CARIS results demonstrate. While the CARIS study has not analyzed such impacts, they should be important considerations as utilities develop proposed local transmission projects to facilitate unbottling of locally-interconnected renewables over the next decade.[88]

One of the critical assumptions of the Zero Emissions Study relates to the **coordinated development of renewable generation, storage, and transmission** in specific locations. For example, the Study indicates that over 4,000 MW of storage may be needed in New York City and over 3,000 MW on Long Island, as already discussed in the context of OSW integration above. Achieving such a high level of coordinated development of location-specific renewable generation, storage, and transmission may be challenging as these investments are currently planned by different entities and through separate procurement and regulatory processes[89]. It would require a combination of (1) careful planning and contracting that allows for the time and location-specific optimization of storage deployment; (2) updating the wholesale market rules to support this market evolution and allow storage facilities to capture the full value that they are assumed to provide in these studies; and (3) development of retail regulations that support distribution-level storage installation and allow for their contribution to wholesale market needs. This means that the current planning processes will need be enhanced toward a more coordinated and integrated generation and transmission planning process, including the planning of CLCPA-driven local transmission and distribution infrastructure.

As already noted in the context of OSW integration, we recommend that the adequacy of the storage-related planning and procurement frameworks be evaluated for their ability to achieve

[87] CARIS analysis included assessment of local transmission needs. CARIS simulations project significant local transmission constraints, which broadly divide the upstate local system into four major generation pockets: Western New York, North Country, Capital Region and Southern Tier. CARIS identified 13 "sub-pockets" or local transmission areas, within these four major generation pockets. CARIS simulation results find significant curtailment of local transmission interconnected renewables, ranging from about 10% to 48% across the four major generation pockets, with several sub-pockets experiencing even higher renewable curtailment levels. *See* NYISO, 2019 CARIS Report, p. 91, Fig. 80.

[88] To augment the market simulation analyses in CARIS, the NYISO also analyzed the 70x30 scenario from a reliability perspective in its 2020 RNA study. For example, the RNA study identified overloads at ConEd's and on O&R's transmission facilities during day peak load when LBW, OSW and UPV are in service, which confirm the same issues identified in the Utility Study.

[89] Additionally, the Climate Change Impact and Resilience Study – Phase II Study, developed for the NYISO by Analysis Group in September 2020, indicates that additional transmission development may become necessary to address reliability needs under extreme weather system condition.

this level of coordination and location-specific deployment. Taking advantage of experience elsewhere (e.g., the CPUC-CAISO joint storage regulations and market design efforts) may be useful in that effort. Relying solely on price signals from the NYISO's wholesale power market likely will not be sufficient as some of the interconnection and transmission reliability functions of storage devices co-located at OSW interconnection points will not be priced in the NYISO markets.

The Zero Emissions Study recognizes that there could be significant renewable generation curtailments at the lower-voltage, local transmission level (which the Study did not analyze). We also note, however, that the study approach will tend to not fully capture real-world bulk power congestion levels, bulk-power real-time curtailments, and intra-hour operational challenges that would increase as the State's resource mix shifts toward more intermittent renewable resources. This is because standard market simulation tools, such as those employed in this study, necessarily need to make certain simplified analytical assumptions—such as the absence of transmission outages and normalized weather conditions, assuming perfect foresight of hourly loads and renewable generation levels, and not modeling intra-hour volatility.

The study results thus reflect an optimistic view of the **congestion, curtailment, and real-time operational challenges** that system operators would face as early as by 2030. If battery storage will be developed to the scale estimated in this study (15 GW by 2040), operational challenges such as ramping to manage load and renewable generation variability may be alleviated to a large extent. However, the study only performed a cursory screening analysis of the potential operational challenges. We recommend that a more detailed operational assessment be undertaken in the future. NYISO operations will need to adequately prepare for integrating the large amounts of renewable resources that are projected to be developed over the next two decades. Such a more-detailed operational assessment would facilitate the necessary planning for future system operations.

The study retains significant amounts of thermal generation capacity to meet locational reserve margins and to provide operational flexibility through 2040. To achieve zero emissions by 2040, these plants are assumed to be fueled by **renewable natural gas (which is assumed to be significantly more expensive than fossil natural gas)**. However, significant uncertainty exists about how a zero emissions grid will evolve between 2030 and 2040. Load growth and electrification trends may differ significantly from study assumptions and possible future innovations (such as in vehicle-to-grid technologies) must be expected to change both needs and available solutions. Specific technologies, such as green hydrogen and long-duration storage, may emerge as a more cost-effective substitute for the assumed renewable natural gas technology. If so, the projected 2040 production costs and relatively high wholesale energy market prices and associated congestion costs could be lower. In such a future, the benefit of relieving congestion through bulk transmission upgrades may also be lower—though likely still justified given that the simulation approach will not fully capture real-world congestion levels.

While the Study's focus was on the bulk transmission system (facilities rated at 230 kV and above), significant congestion and or curtailment can result from **constraints on the lower-voltage transmission** facilities rated at 115/138 kV, particularly under contingencies on the bulk transmission system. This is because much of the upstate 115 kV network presents an electrically parallel path for bulk power transfers, which attract significant spikes in power flows under bulk-system contingencies. By not monitoring the lower voltage system, bulk-power congestion and upstate renewable curtailments will not be captured fully (in addition to curtailments related to local transmission on-ramp constraints). We recommend that this congestion-related issue be studied more fully, perhaps by NYISO in its next CARIS planning cycle.

As also noted earlier, both the Zero Emissions and OSW Study **models use simplified assumptions** that do not capture the full extent of real-world congestion and curtailments.[90] For example, the types of simulation models utilized in the Zero Emissions Study only capture N-1 constraints and assume that there are no further transmission system outages (planned or unplanned) that would create more severe N-1-1 constraints. In most RTO markets, however, a significant portion of congestion and curtailments relate to the more severe constraints collectively created by transmission outages, and despite the fact that on any particular constraint N-1-1 conditions may exist only during certain hours, days, or weeks of the year.[91] In

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[90] The study employed PROMOD for simulating future market operations in 2030 and 2040. PROMOD simulations are based on simplified assumptions that do not fully capture real-world market outcomes. From a wind curtailment perspective, the most impactful simplifying assumption is that PROMOD is based on deterministic inputs for all operating conditions, meaning that it is implicitly assumed that market operators would have perfect foresight of actual system conditions when they make generation unit commitment decisions on a day-ahead basis. This, however, ignores the considerable uncertainty that exists with respect to load and wind generation in real-time and makes the PROMOD simulations more akin to a day-ahead market representation. Just as there are very few wind curtailments scheduled on a day-ahead basis, PROMOD simulations yield very few wind curtailments. Under actual operating conditions, such curtailments do however exist in the real-time market, which are not captured in the study.

[91] While forced outages of any one element may be short and infrequent, the cumulative impact can be more substantial because transmission elements often depend on each other. More importantly, planned outages (to accommodate maintenance or construction activities) can last for days, weeks, and even months. Such outages, when they occur, typically cause transmission constraints to bind more frequently and significantly

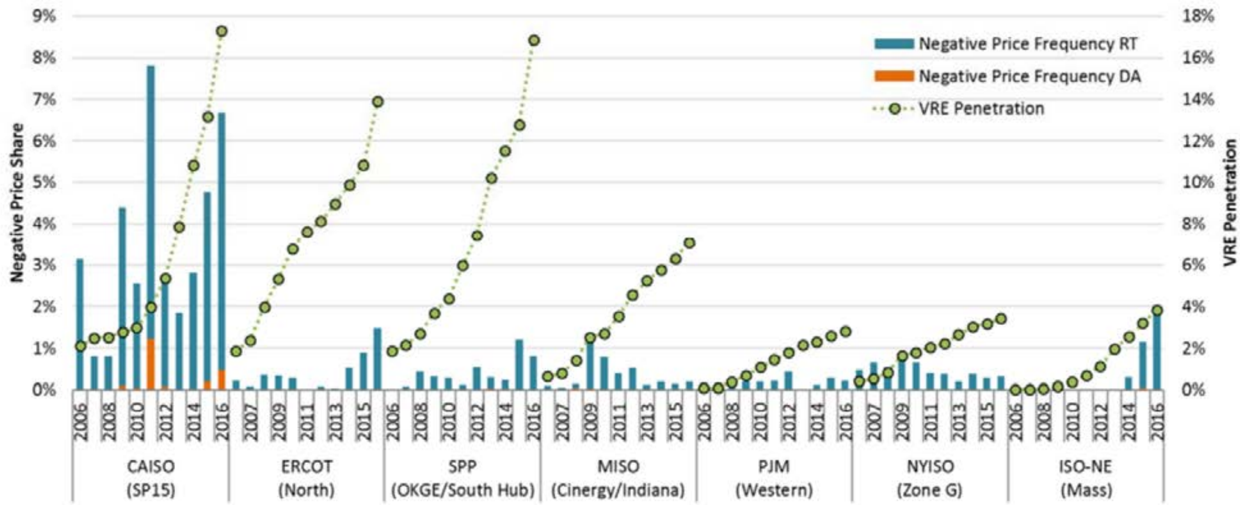
addition, the simulation models are setup to simulate only "normal" weather and load (i.e., no unusual cold snaps or heat waves), normal levels of generation outages, and representative-year wind and solar generation profiles. All of these simplifying simulation assumptions may underestimate congestion and curtailment results, which are affected by more challenging system conditions.

In addition to the necessary reliance on simplified study assumptions, simulation models also employ the benefit of perfect foresight, which makes the simulations akin to the NYISO's day-ahead market (which also treat supply and demand as deterministic). The type of simulations models employed by the Zero Emissions and OSW Studies are not designed to simulate day-ahead **forecasting uncertainty** and surprises that occur near or during **intra-hour real-time market operations**. Actual market experience with the frequency of negative pricing—which reflects congestion and is an indicator of renewable curtailment—that the frequency of negative pricing events (as an indicator of the frequency of renewable curtailment events) are significantly larger in real time than on a day-ahead market basis.[92] A 2017 Lawrence Berkeley National Laboratory study found that the frequency of negatively priced hours was much higher in real-time markets, as shown in Figure 22. Because simulation models with perfect foresight capture market conditions akin to day-ahead markets, these data indicate that the frequency and magnitude of real-world curtailments (as represented by the sum of orange and blue bars in the chart) must be expected to exceed the simulated curtailments (akin to day-ahead data represented by the orange bar in the chart).

increase transmission congestion, curtailments, and associated customer costs. For example, a 2005 study of PJM assessed the impact of transmission outages. That analysis showed that without transmission outages, total PJM congestion charges would have been 20 percent lower; the value of FTRs from the AEP Generation Hub to the PJM Eastern Hub would have been 37 percent lower; the value of FTRs into Atlantic Electric, for example, would have been more than 50 percent lower; and that simulations without outages generally understated prices in eastern PJM load zones and overall west-east price differentials. *See* Chang, Pfeifenberger, and Hagerty, "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," July 2013, pp. 37-39.
Available at: https://brattlefiles.blob.core.windows.net/files/6257_the_benefits_of_electric_transmission_-_identifying_and_analyzing_the_value_of_investments_chang_pfeifenberger_hagerty_jul_2013.pdf.

92 A recent NREL study summarized negative pricing and curtailments in U.S. wholesale markets. While the study did not explicitly compare negative pricing in day-ahead and real-time (RT) markets, the study noted "the focus on RT LMP was chosen because impacts of VRE are arguably observed more readily in this market segment" and "Sub hourly (e.g., five-minute) negative pricing may occur more frequently." *See* National Renewable Energy Laboratory *2018 Renewable Energy Grid Integration Data Book*, March 2020, pp. 9, 15.

FIGURE 22. PERCENTAGE OF ANNUAL PRICES THAT ARE BELOW $0/MWH BY MARKET



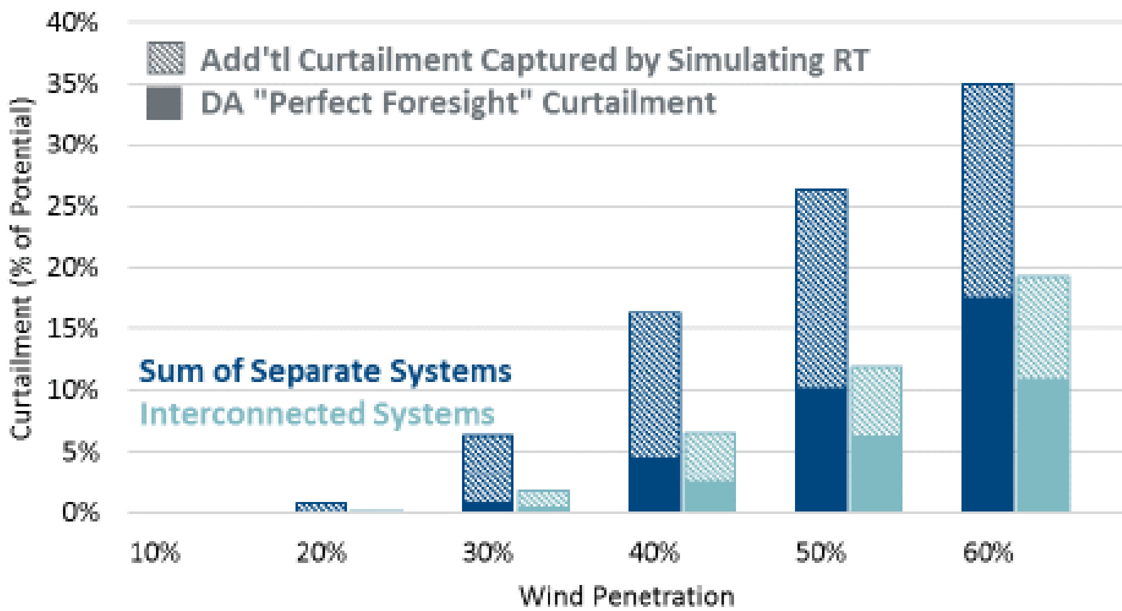
Source: Ryan Wiser, Andrew Mills, Joachim Seel, Todd Levin and Audun Botterud, "*Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing, and Costs*," U.S. Department of Energy, Lawrence Berkeley National Laboratory, November 2017, fig. 8, p. 27, https://eta-publications.lbl.gov/sites/default/files/lbnl_anl_impacts_of_variable_renewable_energy_final_0.pdf

These historical market results are consistent with the results of recent case study published by Boston University's Institute for Sustainable Energy.[93] The study found that when the uncertainty between day-ahead and hour-ahead scheduling and sub-hourly real-time operations are included in market simulations, renewable generation curtailments during real-time market operations (reflecting uncertainty and intra-hour operational challenges) significantly exceed curtailments in the (deterministic, perfect-foresight) day ahead market. Figure 23 below replicates a chart from that case study, which shows day ahead curtailments (solid bars) and additional real-time curtailments (hashed bars) for both a case before transmission upgrades (dark blue bars) and a case after transmission upgrades (light blue bars). As shown, prior to transmission upgrades (dark blue bars), the discrepancy between day-ahead and real-time curtailments is highest at lower shares of renewable generation (e.g., the total is four times higher than day-ahead curtailments at 40% renewable generation), but total real-time curtailments are still more than double day-ahead curtailments even at the much higher 60% renewable generation shares. The magnitude of this difference is an indication of the extent to which the Zero Emissions and OSW Study simulations may not fully capture real-world

[93] Johannes Pfeifenberger, Pablo Ruiz, and Kai Van Horne, "The Value of Diversifying Uncertain Renewable Generation through the Transmission System," Boston University Institute for Sustainable Energy, September 2020, http://www.bu.edu/ise/2020/09/30/the-value-of-diversifying-uncertain-renewable-generation-through-the-transmission-system/

bulk transmission congestion and curtailments (beyond the factors already discussed above) by simulating hourly market conditions under perfect foresight.

FIGURE 23: SIMULATED CURTAILMENTS DURING (PERFECT FORESIGHT, HOURLY) DAY-AHEAD AND (UNCERTAIN, INTRA-HOUR) REAL-TIME MARKET OPERATIONS



Source: Johannes Pfeifenberger, Pablo Ruiz, and Kai Van Horne, "The Value of Diversifying Uncertain Renewable Generation through the Transmission System," Boston University Institute for Sustainable Energy, September 2020, Figure 11, p. 24, http://www.bu.edu/ise/2020/09/30/the-value-of-diversifying-uncertain-renewable-generation-through-the-transmission-system/.

Given that both the Zero Emissions and OSW Studies likely will not fully capture the congestion and renewable curtailments that can be expected in actual, real-time NYISO market operations over the simulated next two decades, the NYISO should continue to undertake more detailed assessments of operational challenges, including intra-hour operational risks (e.g., during one of the NYISO's next CARIS planning cycles).

VI. Overall Power Grid Study Findings and Recommendations

A. Findings and Recommendations on Distribution, Local Transmission, and Bulk Transmission Needs

1. Local Transmission and Distribution (LT&D)

The Power Grid Study indicates that ongoing asset maintenance and reliability programs present an opportunity to capture significant CLCPA benefits. The proposed Phase 1 projects, or a similar portfolio, appear sufficient to expand the local grid's existing headroom to support the integration of the land-based renewable resources needed to meet the State's 2030 objective, and possibly beyond, from a total state-wide headroom perspective. However, the headroom created by the Phase 1 projects does not adequately address specific local transmission needs in attractive renewable development areas. To address CLCPA needs, some of the Phase 1 projects may need to be accelerated and high-priority Phase 2 projects should be considered for locations that present attractive renewable development opportunities not adequately addressed in the Phase 1 proposals.

Beyond 2030, the Utility Study does not identify specific CLCPA-driven local transmission and distribution needs beyond those that may be addressed through Phase 1 LT&D projects.

To address anticipated challenges associated with integrating 9,000 MW of offshore wind generation, the Utility Study additionally suggests the following candidate solutions:

- LIPA proposes to increase export capability from Long Island (a need that LIPA has also submitted in the NYISO Public Policy Transmission Planning Process) and related upgrades to convert a portion of its local transmission system to bulk-power voltage levels; and
- ConEd is proposing Phase 2 projects to address reliability and space constraints at New York City substations, with two offshore wind integration hubs capable of integrating 5,200 MW of additional OSW plants into its New York City system.

The Utility Study also discusses the potential for advanced transmission technologies but does not propose specific implementation strategies. Rather, the study only recommends that more coordinated research and development efforts, pilot studies, and exchange of experiences between the State's utilities be pursued.

Recommendations

- The PSC should consider implementing an expedited approval process for the proposed **Phase 1 local transmission and distribution projects** (or for a similar portfolio). Many of these projects can facilitate timely interconnection of renewable generation in constrained upstate generation pockets.
- We recommend further evaluation of the Utilities' proposed Phase 2 projects. This Phase 2 review should include (a) additional evaluation of the CLCPA benefits of certain *off-ramp* projects and (b) Phase 1 projects that can be expanded cost-effectively to provide additional CLCPA benefits. The Phase 2 projects can be evaluated under the Utilities' proposed project selection and cost-benefit framework.
- Some of the proposed **Phase 2 projects** should be prioritized as they provide unique opportunities to expand Phase 1 projects to address high-interest, high-potential renewable generation pockets, such as the Hornell and two other generation pockets. We also recommend that the PSC work with the Utilities and NYSERDA to identify and advance additional high-priority Phase 2 projects to address headroom constraints in high-interest, high-potential renewable generation development areas for which neither the proposed Phase 1 nor potential Phase 2 projects create sufficient headroom.
- Significant renewable generation potential also appears to exist in areas of the State that currently do not have access to existing transmission infrastructure. These areas are not addressed in the Utility Study (or the NYISO CARIS study, which formed the starting point of the Utility Study). The PSC may want to explore whether several such areas should be developed as **local renewable energy zones (REZ)** through the construction of new local transmission infrastructure.
- This Initial Report also identifies candidate Phase 1 projects that represent good opportunities for the application of **advanced transmission technologies**, such as dynamic line ratings that can significantly reduce renewable curtailments during much of the year (though not necessarily in all hours). Similarly, Phase 2 projects can be designed with such built-in advanced technology features to enhance the CLCPA benefits these projects are designed to provide. Additional recommendations on advanced technologies are presented in Section IV (above).

2. Transmission for Offshore Wind Generation

Review of the OSW Study and the Zero Emissions Study and their assumptions suggests that additional bulk transmission should be developed between Long Island (NYISO Zone K) and the rest of the State. The studies identify no other OSW-related bulk transmission needs. The OSW Study also finds that avoiding further bulk transmission upgrades requires the careful selection of interconnection locations and the planned colocation of 1,700 MW of battery storage at the New York City area and Long Island substations that are utilized for integrating OSW generation.[94] Overall, the conclusion that no other bulk transmission upgrades may be necessary depends on several conditions: a high level of coordination in the development of individual OSW plants and their POIs, feasible siting and permitting conditions, low congestion and curtailment conditions, no reliability impacts more challenging than during summer-peak conditions, storage developed in the specific necessary locations, and no insurmountable local transmission impacts that would change the evaluated bulk transmission solutions.

If development realities and onshore grid conditions differ from those assumed and simulated, costs are likely to increase due to siting constraints and transmission constraints. In particular, integrating 5-6 GW of offshore wind into Zone J may be more difficult and costly than anticipated. In that case, more than 3 GW of offshore wind may need to be connected to Zone K by 2035 (if not earlier) to meet the 9 GW goal, which likely would necessitate bulk transmission enhancements. Since expansion of the transmission between Zone K and the mainland is projected to be needed eventually, advancing such a project to 2030 would provide value earlier and would expand the options for meeting the State's OSW goals, thereby mitigating OSW integration risks.

From an offshore transmission perspective, a meshed network that interconnects the offshore substations of the individual OSW plants could ultimately be more valuable, more reliable, and more resilient than a system with only radial transmission from OSW plants to shore. However, a decision to actually implement a meshed system can be delayed (and perhaps should be delayed pending approval of new wind energy areas), as long as the State ensures that any projects with radial connections are constructed in ways that include the option to integrate the radial lines into a meshed system later.

94 OSW Study, Section 3.4.3.1.

Recommendations

As discussed in more detail in the discussion of the OSW Study (Section **V**), the following recommendations are offered for further consideration in support of creating a cost-effective path to more reliably achieve the State's OSW targets:

- Commence development of a tie-line between Long Island and Zone I or J so the line can be in service by approximately 2030.
- A multi-disciplinary planning and coordination effort should be initiated to support the development of cost-effective options for routing up to 6,000 MW of OSW generation into New York City and its interconnection with the city's substations.
- Confirmation of POI availabilities and resolution of any remaining discrepancies between the OSW Study and the Utility Study's respective findings to ensure OSW developers are equipped with a strong understanding of available, cost-effective interconnection solutions for the State.
- Promote options for adding transmission links between offshore substations to create a meshed offshore system if and when desirable in the future.
- Continue to assess likely needs for onshore bulk and local transmission upgrades necessary to support OSW targets through collaborative studies, including future NYISO economic planning analysis.
- Review policies for planning and developing storage and other advanced technology options to support OSW integration and increase system flexibility.

3. Other Bulk Transmission Needs

The Zero Emissions Study found that New York's 2030 goals can be met with low levels of curtailment and congestion—without significant upgrades to the existing bulk-power transmission grid beyond the projects already planned and under development and a new HVDC line delivering dispatchable renewable energy into New York City that is assumed to materialize as a result of the State's new Tier 4 procurement. However, by 2040, projections for high levels of congestion costs and some renewable generation curtailments point to a potential need for cost-effective additional bulk transmission upgrades. In particular, the Zero Emissions Study results suggest that additional bulk transmission from upstate into the New York City area (from Zone H to Zones I, J, and K) will likely become cost-effective as the State approaches 2040 and congestion costs increase. These congestion-reducing transmission investments would reduce upstate renewable generation curtailments and allow the downstate

(New York City and Long Island) area to reduce its projected reliance on backstop renewable-fuel thermal generation.

Future needs for additional bulk-power and local transmission upgrades may arise sooner than projected in the Utility, OSW, and Zero Emission Studies. Local transmission needs may arise sooner if renewable generation develops more quickly in certain areas than anticipated in the CARIS assumptions that form the basis of the Utility Study. Bulk transmission needs may arise sooner for similar reasons: land-based and offshore wind generation may not interconnect to the jointly planned locations identified in the OSW and Zero Emissions Studies. These needs may arise sooner because the OSW and Zero Emissions Studies likely understate real-world transmission congestion and renewable generation curtailments. This is the case because the two studies' simulations: (1) do not monitor and enforce all transmission constraints facilities (such as bulk-power contingency constraints on lower-voltage transmission facilities); (2) assume a well-coordinated development of storage and clean energy resources at the best system locations; and (3) do not simulate system operational challenges related to intra-hour system operations under uncertain real-time market conditions.

The State should revisit recent NYISO, NYSERDA, and other studies at regular intervals to ensure that bulk transmission needs are pro-actively identified. The NYISO's economic and public policy planning processes provide effective mechanisms for identifying such needs and developing timely solutions.

B. Recommendations on Advanced Technologies

Advanced transmission technologies can offer significant CLCPA benefits by increasing the transfer capabilities and associated renewable generation integration headroom of both the existing grid and new transmission investments during all or most hours of the year when renewable generation curtailments would be necessary otherwise. This benefit is available for both local and bulk transmission to facilitate land-based renewable generation development, as well as local and bulk transmission to facilitate OSW generation development. Because many of the advanced technologies can be implemented more quickly than traditional transmission upgrades, they can be applied rapidly to locations where the un-bottling of curtailed renewable generation is most urgent.

Advanced transmission technologies can be used to un-bottle renewable generation through a combination of: (1) permanently expanding the transfer capabilities of *existing grid facilities* as a potentially lower-cost alternative to traditional transmission upgrades; (2) temporarily expanding the transfer capability of existing transmission facilities until they can be upgraded (at which point it is often possible to redeploy the advanced transmission equipment at other grid locations); and (3) increase the transfer capability of future transmission upgrades.

The State should encourage the Utilities and other transmission owners to expeditiously evaluate and deploy advanced transmission technologies—such as dynamic line ratings (DLR), for which commercial-scale applications have demonstrated significant increases in the transfer capability of overhead transmission lines during much of the year. DLR is particularly effective in reducing (on-ramp-related) curtailments of wind energy. Several of the available advanced technologies have advanced well beyond their R&D and pilot program phase and are ready for commercial deployment in the State.

The State's utilities have experience with most these advanced technologies evaluated in the Utility Study, and many of them can be deployed to both the local and bulk-power grid more quickly and cost-effectively than traditional transmission upgrades to expand the renewable integration capability of both the existing transmission system and the proposed new projects. As an example, we identified several candidate Phase 1 projects that represent good opportunities to include advanced transmission technologies. Similarly, Phase 2 projects can be designed with such built-in advanced technology features to enhance the CLCPA benefits these projects may provide.

To identify high-priority locations where advanced technologies could quickly and cost-effectively provide un-bottling benefits on the existing grid, the planning process should provide a mechanism through which renewable generation owners and developers would be able to provide information on particularly constrained locations. This information could then be made public, such that either the utilities or advanced technology vendors could propose cost-effective solutions to address the constraints.

With respect to bulk transmission applications, planning and cost recovery for projects incorporating advanced technologies through the NYISO tariff should be possible as long as the technology are considered "transmission" solutions (e.g., similar to how PARs and FACTS devices are treated already). We note, however, that there is some uncertainty about cost recovery for "non-transmission" technologies outside the scope of the NYISO tariff and recognize that this is a topic that the PSC may decide to address. The PSC may also need to further evaluate the extent to which the traditional rate-base/rate-of-return cost recovery mechanism may create incentives that inadvertently discourage the adaption and implementation of cost-effective advanced transmission technologies.

Shared savings approaches could be used to provide additional incentives to utilities who implement advanced technologies. These incentives in part compensate for the operational complexities, risks and extra efforts associated with employing technologies that are new to a particular utility. The PSC may need to explore whether such shared savings approaches would be appropriate for the application of advanced transmission technologies in New York.

C. Recommendations for Improved Planning and Further Analyses

While the Power Grid Study is not a blueprint, it is an important first step toward planning the investments in the New York electric system that are needed to meet CLCPA goals and to provide valuable information to the State, its utilities, and transmission and renewable generation developers. The Power Grid Study component studies indicate that cost-effective transmission development and utilization of existing grid requires a great level of foresight and coordination. We recommend that the State continue to develop improved planning and procurement processes to achieve greater coordination of distribution, local transmission, and bulk-power transmission infrastructure investments.

Improved planning processes will be needed to better coordinate across LT&D upgrades that are performed by the individual utilities, the bulk-power system planning and generation interconnection processes that are led by the NYISO, and the renewable generation and storage procurement that is planned and managed by NYSERDA. For example, since some of the local transmission needs may need to be resolved by upgrading the local transmission systems to bulk transmission voltage levels, closer coordination between NYISO and local utility planning will become necessary. LIPA and ConEd's Phase 2 local transmission proposals to facilitate OSW interconnections are candidate projects that will benefit from more coordinated local and bulk-power transmission planning to achieve cost-effective overall outcomes.

The process to address **OSW-related transmission on Long Island and additional transfer capability between Long Island and the mainland** should be initiated promptly. Due to real-world challenges that will likely exceed those captured in the studies, it will be important to support the likely connection of 3,000 MW (or more) of OSW generation to Long Island well before 2035 and offset the possibility that it may take a decade to plan, permit, and construct such upgrades. Doing so now would mitigate the risk of encountering unexpected high offshore wind curtailments for years before a solution can be implemented. The NYISO's PPTPP is uniquely suited to develop and compare cost-effective solutions to this need.

A multi-disciplinary planning and coordination effort should be initiated to support the development of cost-effective **options for routing up to 6,000 MW of OSW generation into New York City** and its interconnection with the city's substations. It may also be possible to utilize the NYISO's Public Policy Transmission Planning Process as part of this effort, including for local bulk-power-level upgrades associated with interconnecting OSW to ConEd substations.

The State should also build upon existing NYISO studies to further explore the **operational challenges** not fully analyzed in the Power Grid Study, to better understand transmission needs given the likely higher real-world flexibility challenges, congestion costs, and renewable curtailments. Such studies would focus on factors not fully addressed in the OSW and Zero Emissions Studies, such as day-ahead renewable generation forecasting errors, real-time renewable generation uncertainties and associated intra-hour system flexibility needs, the impacts of planned and unplanned transmission outages, and system performance under more challenging weather conditions (such as storms, heat waves, and cold snaps).

More detailed and more consistent studies will be necessary to **quantify existing headroom** in various transmission-constrained areas on both the local and bulk transmission systems and to be able to identify high-priority, high-value locations that should be targeted with transmission upgrades. These studies should be based on both a power-flow model that better measures headroom and a production simulation model—ideally aligned with the NYISO's current Congestion Assessment and Resource Integration Study (CARIS) and future economic modeling assumptions and modeling tools—that can estimate annual congestion-cost and curtailment-avoidance benefits for local transmission and bulk transmission investments (including advanced technologies). Ideally this would also lead to local headroom estimates that will be available to renewable project developers prior to State procurement efforts.

To date, **forecasting of renewable generation development** has been based on applications for generation interconnection at the bulk power level through NYISO and at the LT&D level through individual utilities under the Department's Standard Interconnection Requirements. The forecasts on where renewable generation likely will be located in the future have significant implications for distribution and transmission infrastructure needs and the cost-effectiveness with which CLCPA targets can be achieved. These generation development forecasts can be improved by including resource mapping for solar and wind, regional econometric indicators for new development, environmental constraints, inter-regional energy exchanges, local regulations that impact greenfield development, and interconnection headroom estimates given applicable reliability standards.

Further studies will be needed to better understand **future generation and storage technology** options that may be available after 2035 to cost-effectively eliminate the residual emissions necessary to achieve a zero emissions grid by 2040 and the extent to which these technologies will impact grid investment and operational needs. The Zero Emissions Study projects that zero emissions could be achieved with 17,000-23,000 MW of thermal backstop generation fueled with landfill gas, biogas, or other renewable natural gas.[95] This option yields high congestion costs, which makes bulk-power transmission upgrades from upstate to downstate cost effective. At this point, however, this projected solution should be seen mostly as a "placeholder" until more clarity exists about available future technologies, including hydrogen and long-duration storage.

[95] Zero Emissions Study, Section 4.1.2, Table 4-1 and Section 7.2.1, Table 7-3.

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