Appendix A

(to Initial Report on the New York Power Grid Study)

Preliminary Recommendations on Local Transmission Projects

A. National Grid

In this section, we present our preliminary recommendations for National Grid's "Phase 1" projects that the Public Service Commission (PSC) could consider approving expeditiously. To arrive at our recommendations, we reviewed filing information, held discussions with the company, and reviewed the additional confidential information National Grid furnished in response to our questions and request for information.

National Grid's Phase I projects are summarized in Figure A-1 below. Figure A-1 includes project details such as cost estimates and in-service dates, as well as an indication of our recommendations to the PSC. National Grid identified 13 Phase 1 projects across seven export-constrained generation pockets. Four of these 13 projects are already in the Company's current rate case proceedings. For the other nine proposed projects, the company estimates a total cost of [redacted] (with a +200/-50 percent uncertainty at this stage of planning and design). We find that all nine projects are beneficial towards meeting the state's 70x30 CLCPA goals and recommend that immediate approval be considered for eight of the nine projects. We also ask the PSC to consider obtaining more detailed cost information, particularly for two recommended projects with high costs, to confirm the reasonableness of the estimated costs before making final approval determination. The only project for which we cannot recommend moving forward without additional analysis is a 115 kV Line Upgrade Project in the Capital Region of National Grid's service territory. The company has estimated that this project would involve refurbishment of aging facilities through [redacted], which should provide time to allow for the additional assessment of the proposed project compared to alternatives. We explain our recommendations in detail following Figure A-1.

FIGURE A-1: PHASE 1 LOCAL TRANSMISSION PROJECTS – NATIONAL GRID

Project	Zone	Generation Pocket	I/S Date	In Rate Case?	Estimated Cost	Recommend Approval?
Station/Terminal Upgrade Projects						
Colton – Boonville 115 kV Terminal Upgrades	E	Watertown/Oswego/Porter	2022	Yes	Redacted	Yes
Clarks Corners – Oneida 115 kV Terminal Upgrades	C	East of Syracuse	2023	No	$5M	Yes
Homer Hill – Bennett 115 kV Terminal Upgrades	A/C	Southwest	2023	No	Redacted	Yes
Lighthouse Hill – Clay 115 kV Clearance Limits	C/E	Watertown/Oswego/Porter	2023	No	Redacted	Yes
Coffeen – Black River 115 kV Terminal Upgrades	E	Watertown/Oswego/Porter	2023	No	Redacted	Yes
Moons Series Reactors	A	Southwest	2024	Yes	Redacted	Yes
Malone 115kV PAR	D	Watertown/Oswego/Porter	2026	Yes	Redacted	Yes
Rotterdam 69 kV Line and Station Upgrades	F	Porter/Inghams/Rotterdam	2027	Yes	Redacted	Yes
115 kV Line Upgrade Projects						
Churchtown– Pleasant Valley 115 kV Upgrades	F/G	Albany South	2025	No	$9M	Yes
Batavia – Golah 115 kV Line Upgrade	A	Southwest	2026	Partially[3]	Redacted	Yes
Rotterdam – Wolf/State Campus 115kV Line Upgrades	F	Capital Region	2027	No	$46M	RFC [1]
Dunkirk – Falconer 115 kV Line Upgrades	A	Southwest	2027	No	Redacted	Yes
Inghams – Rotterdam 115 kV Line Upgrades	F	Porter/Inghams/Rotterdam	2026-2030	Partially[3]	Redacted	Yes
Summary of Total Costs and Benefits:					**Total Cost**	**Total Headroom**
				Recommended Projects:	**$727M**	**1,130 MW**
				All Projects:	**$773M**	**1,130 MW [2]**

Source: Utility Study pp. 5, 162-164.
Notes:
[1]: RFC - Requires Further Consideration.
[2]: Headroom produced by the Rotterdam – Wolf/State Campus project not included. National Grid estimates a very large headroom of 2,590 MW; additional analyses are required to properly evaluate the benefits of this proposed project.
[3]: Batavia -- Golah and Inghams – Rotterdam projects have partial funding in the Rate Case.

1. Phase 1 Projects Preliminarily Recommended for Approval

Low-Cost Station and Terminal Upgrade Phase 1 Projects

Four of the eight terminal/station upgrade projects are already in National Grid's rate case. The other four projects cost [redacted] but facilitate, along with proposed line upgrades, renewable generation unbottling benefits ranging from 90 MW to 310 MW in the East of Syracuse, Southwest, and Watertown/Oswego/Porter generation pockets. We recommend that these low-cost terminal upgrade projects be pursued to help facilitate significant renewable generation capacity integration in constrained local generation pockets.

115 kV Line Upgrade Phase 1 Projects that Address Key Transmission Limitations for Renewable Delivery

In addition to the low-cost terminal and station upgrade projects, we recommend three 115 kV Line upgrade projects that address certain key limiting local transmission constraints. These projects are located in the Albany South, Southwest and Inghams/Rotterdam/Porter generation pockets of National Grid's local T&D service territory. These projects' costs range between [redacted] and they facilitate unbottling benefits of 150-310 MW.

- **Albany South Pocket**: The Albany South Pocket project (Churchtown-Pleasant Valley 115 kV line project) is reported to provide 280 MW of unbottling at very low upgrade cost of an estimated $9 million. This project addresses severely degraded wood structures, some of which have already been replaced. If not for its projected CLCPA benefit, the estimated need date for the project [redacted] depending on when structures fail. National Grid's proposal is to advance the project in-service date to 2025 (i.e., by approximately [redacted] Given the high CLCPA benefit-cost ratio for the project, long project development lead-time of 5 years, and fast-deteriorating asset condition, the PSC should consider immediate approval for this project.
- **Southwest and Inghams/Rotterdam/Porter Pocket:** The Southwest and Inghams/Rotterdam/Porter region projects proposed by National Grid include three major 115 kV line upgrade projects, with cost estimates ranging from [redacted] These projects are shown in Figure A-1 as Dunkirk-Falconer, Batavia-Golah and Inghams-Rotterdam 115 Line Upgrade projects. National Grid has proposed [redacted] of accelerated development for these projects, which are reflected in their proposed in-service dates of 2026-2030 shown in Figure A-1. Accelerated development allows the state to take advantage of the projects' renewable generation integration benefits in support of CLCPA goals. National Grid estimates that Dunkirk-Falconer and Batavia-Golah combine to provide 310 MW of unbottling benefits in the Southwest region, while the Inghams-Rotterdam project is estimated to provide up to 150 MW benefits in the Inghams/Rotterdam/Porter region. The base need for these projects is related to full refurbishment of aging assets, needed between 2026 and 2035. We recommend that the PSC consider immediate approval for all three of these Southwest and Inghams/Rotterdam/Porter region projects because of the large CLCPA benefits they provide. Additionally, a portion [redacted] of the Batavia-Golah project is already in the current rate case proceeding, while the Dunkirk-Falconer line is already the limiting condition for many renewable

generation development efforts in the Southwest region. We understand that a number of queued renewable projects in the project's vicinity had to withdraw from NYISO queue due to the limits imposed by this aging line.

- With respect to the Inghams-Rotterdam 115 Line Upgrade project, National Grid notes that nearly 510 MW of utility-scale solar PV projects and 155 MW of DER projects have requested interconnection to the 115 kV and 69 KV network facilities between the Inghams and Rotterdam stations, exacerbating the need for refurbishment to address asset condition deterioration.[1] A portion of the refurbishment plan is already in rate case at a cost of [redacted], while the proposed Phase 1 project upgrades an additional [redacted]. We anticipate that this project may provide greater CLCPA benefits than National Grid's estimate of 150 MW.

While we recommend that the PSC consider approval of these three 115 kV line upgrade projects, we also recommend that the PSC obtain additional project cost details of all three projects before finalizing its decision. We note that the projected cost of Dunkirk-Falconer and Inghams-Rotterdam 115 Line Upgrade projects is [redacted], which is unusually high for overhead lines at this voltage level. National Grid explained that its cost assumptions for these projects are based on the costs of the Company's recently completed Article VII rebuild projects. National Grid expects that both Dunkirk-Falconer and Inghams-Rotterdam 115 Line Upgrade projects will require the PSC's approval based on Article VII of Public Service Law requirement for the siting of major electric facilities.

2. Phase 1 Projects that Require Further Consideration

We recommend that the PSC require additional analysis related to the Company's proposed Rotterdam-Wolf/State Campus 115 kV line upgrade project before considering project approval at this time. This proposed Phase 1 project is in National Grid's Capital Region and is driven by flow-through issues resulting from higher flows into the Rotterdam area on the local and bulk transmission system. National Grid explains that the local transmission issues resolved by this proposed project are not related to a specific generator or any known group of generators, but rather to electrically farther away generation causing flow-through issues in the Capital region.

We recommend that the PSC require additional analysis to properly evaluate the full scale of CLCPA benefits offered by this project before considering project approval. National Grid estimates potential benefit of 2,590 MW, which is very large. Given that this is not directly an on-ramp issue in any of National Grid's local generation pocket, additional analyses, including the use of a different methodology—such as production cost modeling to estimate reduced renewable curtailment—is recommended to properly evaluate the benefits of this proposed project. Additionally, the expected *non-CLCPA* need date for this

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1 Utility Study, p. 17.

2 Double-Circuit Tower.

3 Single-Circuit Tower.

project is [redacted]. This means that an expeditious project approval is not necessary at this time.

B. Central Hudson Gas & Electric

Central Hudson's proposed Phase I projects are summarized in Figure A-2. The figure includes project details such as cost estimates and in-service dates, as well as an indication of our preliminary recommendations to the PSC. Central Hudson proposed a total of six Phase 1 and six Phase 2 projects. We preliminarily recommend that the PSC consider accelerated approval for five of the six Phase 1 projects. We also recommend that two of the six Phase 2 projects be considered as candidates for accelerated approval. Our project-specific recommendations are explained in detail below.

FIGURE A-2: PHASE 1 LOCAL TRANSMISSION PROJECTS – CENTRAL HUDSON

Project	Zone	Description	I/S Date	In Rate Case?	Estimated Cost	Incremental Headroom	Recommend Approval?
KM & TV Line	G	Rebuild 69 kV line	2022	Yes	$11.6M	86 MW	Yes
H & SB Line	G	Rebuild 69 kV line for 115 kV. Operate at 69 kV	2024	Yes	$58.5M	75 MW	Yes
P & MK 115kV	G	Operate P & MK at 115 kV. Install two Kerhonkson 115/69 kV auto-transformers	2024	Yes	$13.1M	102 MW	Yes
SK Line	G	Rebuild 115 kV line	2025	Yes	$4.4M	57 MW	Yes
HG Line	G	Rebuild 69 kV line	2026	Yes	$27.5M	53 MW	Yes
Q Line	G	Rebuild 69kV Line	2027	Yes	$37M	60 MW	No
				Recommended Projects Total:	**$115.1M**	**373 MW**	
				All Projects Total:	**$152.1M**	**433 MW**	

Source: Utility Study, pp. 83-84.

1. Phase 1 Projects Preliminarily Recommended for Approval

All of the recommended Phase 1 projects shown in Figure A-2 are included in the Company's 5-year capital forecast. This list encompasses all proposed Phase 1 projects, except the Q-Line 69 kV Rebuild project, which the company notes is currently in planning phase for rebuilding at 69 kV to address asset condition. The Company also notes that rebuilding this line now at a higher-rated voltage allows for addressing future renewable generation integration and delivery. Such an option would be very valuable if renewables continue to develop in this region and a need for additional headroom on the Q-Line manifests. Therefore, we recommend the PSC consider denying the approval of the Phase 1 version of the Q-line project, and instead consider for approval the proposed Phase 2 version, which would rebuild the aging line at a higher, 115 kV voltage level now. We note that the Phase 1 version of this project has an in-service date of 2027 (i.e., project would be rebuilt in-kind at 69 kV voltage by 2027 under the Phase 1 proposal). If this option were pursued now, uprating from 69 kV to 115 kV voltage later to address future renewable generation delivery needs would become more expensive.

2. Phase 2 Project Preliminarily Recommended for Approval

As explained above, the Phase 2 Q-Line project entails upgrading the 69 kV line for higher-voltage (115 kV) operation in the future. Operation of this line at 115 kV voltage in future will attract more renewable development, especially given that voltage constraints govern the 69 kV system limitations in this area. Developers siting additional future solar projects in the region would require more headroom than a 69kV system would allow. Therefore, we recommend the PSC consider approving the proposed Phase 2 version of the Q Line project, subject to the final benefit-cost assessment (BCA), in lieu of the Phase 1 version of project.

We also recommend the 10 & T-7 Line State Connections Phase 2 project proposed by the Company, based on its remarkably high project benefit-to-cost ratio. Central Hudson estimates that this project, proposed for 2030 in-service date, adds 261 MW of headroom capacity at a very low project cost. This project is designed to relieve certain equipment and station connection limitations in the Pleasant Valley/Milan pockets. It facilitates full use of the upgraded conductor as part of the NY Transco Segment B project. We note that we have recommended a similarly situated high-value project proposed by National Grid (Churchtown-Pleasant Valley 115 Upgrade). Central Hudson's 10 &T-7 project would require coordination with the National Grid.

C. AVANGRID (NYSEG and RG&E)

Our preliminary recommendations for promising "Phase 1" projects proposed by AVANGRID are discussed below. We recommend that the PSC consider these recommended projects for expeditious approval. To arrive at our recommendations, we reviewed filing information, held discussions with the company, and reviewed the additional confidential information AVANGRID furnished in response to our questions and request for information.

All together, the recommended projects would increase the capacity of renewables that can interconnect by 3,013 MW. AVANGRID categorizes components of Phase 1 projects as "Phase 1" and "Phase 1+". Phase 1 components are in AVANGRID's capital plan and are driven by reliability and/or asset condition needs. Phase 1+ components are not currently in the capital plan but are incremental additions to Phase 1 projects that provide additional renewable-integration benefits. All Phase 1+ components address constraints (overload in N-0 and N-1 conditions) that would occur in 2030 given the capacity of renewable additions projected by the CARIS 70x30 case.

We recommend seven of eight proposed Phase 1 projects as candidates for expeditious approval. All Phase 1 projects are summarized in Figure A-3 below. The figure includes project details such as project costs and in-service dates, as well as our recommendations. AVANGRID has described the proposed in-service dates as an indication of how fast the projects could be completed, assuming the projects are given immediate approval and accounting for project management (e.g., staggering of projects that are in the same area). Our project recommendations are explained in detail below.

FIGURE A-3: PHASE 1 LOCAL TRANSMISSION PROJECTS – NYSEG AND RG&E

Project	Description	I/S Date	In Capital Plan or Rate Case?	Estimated Cost	Incremental Headroom	Recommend Approval?
Lockport Area Upgrades	**Phase 1**: Rebuild Robinson Rd substation; install new transformer; reroute several lines **Phase 1**+: Reconductor 115kV line	2025	Partially in Capital Plan	$44M	530 MW	Yes
Lancaster Area Upgrades	**Phase 1**: Rebuild and upgrade Stolle Rd substation **Phase 1+**: Install new transformer	2026	Partially in Capital Plan	$53M	675 MW	Yes
South Perry Area Upgrades	**Phase 1**: Reconductor Meyer-South Perry line	2027	Capital Plan	$49M	260 MW	Yes
Hornell, Elmira & Bath Reinforcement	**Phase 1**: Build a new 230/115/34.5 kV station near Bath substation, reroute existing transmission lines to connect	2025	Capital Plan	$35M	70 MW	Yes
Binghamton Area Reinforcement	**Phase 1**: Rebuild Oakdale substation, install a 3-winding transformer and retire Westover 115 kV substation; Reroute 115 kV lines near Etna, Willet, and Clarks Corners substations; Reconductor the line between South Owego and Hillside substations **Phase 1+**: Reconductor 115 kV line	2025-2027	Partially in Capital Plan	$531M	755 MW	Yes
Ithaca Area Reinforcement	**Phase 1**: Rebuild Etna substation, upgrade Coddington substation and install capacitors **Phase 1+**: Reconductor 115 kV line	2025-2026	Partially in Capital Plan	$139M	263 MW	Yes
Oneonta Area Reinforcement	**Phase 1**: Rebuild and expand East Norwich and Jennison substations; Rebuild and expand Colliers 115 kV; Build New Morris substation and build line to Collier, Jennison, and Fraser substations **Phase 1+**:Reconductor 115 kV line, upgrade terminal equipment at multiple 115 kV substations; Install 115 kV Power Flow Control Device - Static Series Synchronous Compensator	2027-2028	Partially in Capital Plan	$629M	460 MW	Yes
Geneva Area Upgrades	**Phase 1**: Rebuild Border City 115 kV and add capacitor banks at this and Haley Rd substations **Phase 1+**: Install 115 kV Power Flow Control Device - Static Series Synchronous Compensator	2022-2026	Partially in Capital Plan	$80M	28 MW	No
			Recommended Projects Total:	**$1,480M**	**3,013 MW**	
			All Projects Total:	**$1,560M**	**3,041 MW**	

Source: Utility Study, pp. 194-196.

1. Phase 1 Projects Preliminarily Recommended for Approval

Lockport and Lancaster Areas:

Recommended Phase 1/1+ projects in these neighboring areas would enable the integration of 1,205 MW of renewables – primarily utility-scale PV – in areas that would otherwise be constrained. Recommended projects in these areas are driven by underlying reliability and/or asset condition needs, due to the aging Robinson Rd and Stolle Rd substations. Both projects also include Phase 1+ components that provide additional renewable integration benefits beyond that provided by the Phase 1 components. In the Lockport Area, the incremental Phase 1+ proposal, which involves reconductoring a 115 kV line, would provide an additional 130 MW of benefit. In the Lancaster Area, installing a new transformer under the incremental Phase 1+ proposal, would provide the majority of the overall project's 675 MW benefit. The Phase 1+ components have high renewable benefits and relatively low costs because they have been added on specifically for CLCPA benefits. Overall (considering Phase 1 and Phase 1+ components together), both projects have a low cost to renewable-benefit ratio: all together the Lockport Area Phase 1 Upgrades has a ratio of 83 $/kW and the Lancaster Area Phase 1/1+ Upgrades has a ratio of 79 $/kW of investment. Given the scale of the benefits, expectation of renewable development in the area, and low cost-to-benefit ratios, we recommend the PSC consider all components of these projects (both Phase 1 and Phase 1+) for immediate approval.

South Perry, Hornell, Elmira & Bath Areas:

Recommended Phase 1 projects in these areas would enable the integration of 330 MW of renewables – both land-based wind and utility-scale PV – in areas that would otherwise be constrained. Both projects are driven by underlying reliability and/or asset condition needs and do not include a Phase 1+ component.

- The South Perry Area Phase 1 Upgrades project proposes to reconductor a 115 kV line that will be critical for unbottling of LBW and UPV by 2030. This project would unbottle 260 MW at an estimated cost of $49 million. Given the project's base-driver needs, expectation of renewable development in the area, and moderate cost-to-benefit ratio, we recommend the PSC consider this project for immediate approval.
- The Phase 1 component of the Hornell, Elmira & Bath Reinforcement project proposes to build a new substation in the Hornell area, where there is a high degree of interest in renewable development. This new substation will provide another connection to the bulk power system at 230 kV, providing an on-ramp for renewable generators to the bulk system. Although the Phase 1 component of this project is only estimated to unbottle 70 MW of renewables, it sets up Phase 2 of the project, which has large MW benefits, with potential to unbottle additional 500 MW of wind and PV resources. Given the project's base-driver needs, expectation of renewable development in the area, and positioning for a Phase 2 project with large CLCPA benefits, we recommend the approval of the Phase 1 of the Hornell, Elmira & Bath Reinforcement project.

Ithaca, Binghamton, and Oneonta Areas:

Recommended projects in these areas would primarily enable the flow-through of renewable power from west to east. Eastward flows towards downstate are a critical component of a high renewable system in New York, since available land for renewable development is primarily upstate, while load centers are primarily downstate.

- The Ithaca Area Phase 1 Reinforcement project will in total provide 263 MW of renewable integration benefit and cost an estimated $139 million. The majority of the cost ($97 million) is for the Phase 1 reliability driven portion of the project. The Phase 1+ part of the project proposes to reconductor a 115 kV line and has a moderate cost-to-benefit ratio of 341 $/kW. If the projects are not implemented, AVANGRID's modeling predicts line overloads will occur in 2030 during N-1 conditions.
- The Binghamton Area Phase 1 Reinforcement project will in total provide 755 MW of renewable integration benefit and cost an estimated $531 million. Three of four parts of the project are for reliability and/or asset conditions needs. In the Phase 1+ part of the project, AVANGRID proposes to reconductor a 115 kV line, which is key to unbottling 230 MW of the projects' 755 MW total renewable integration benefit.
- The Oneonta Area Phase 1 Reinforcement project will provide a total of 460 MW of renewable integration benefit and cost an estimated $629 million. The bulk of the cost ($569 million) is driven by substation builds and upgrades for reliability and/or asset condition needs. Addressing these needs also provides 160 MW of "flow-through" renewable benefit. AVANGRID also proposes a comprehensive Phase 1+ add-on: reconductor a 115 kV line, upgrading terminal equipment, and installing a power flow control device. The Phase 1+ upgrades provide 300 MW of LBW or UPV integration benefit and costs $60 million for a moderate cost-to-benefit ratio of 200 $/kW.

Given the growing base-driver needs, the benefits of expanding eastbound paths for renewable power flows, and the Phase 1+ upgrades' moderate cost-to-benefit ratios, we recommend that the PSC consider approval of the Phase 1 and 1+ projects proposed in the Ithaca, Binghamton, and Oneonta Areas. However, given the high costs of the Phase 1 (base-driver) parts of these projects, we recommend the PSC seek to understand the cost details before making final decisions.

2. Phase 1 Projects Not Recommended for Approval through CLCPA Process

Geneva Area:

We do not recommend the Geneva Area Phase 1 Upgrades project for CLCPA-related approval due to its low CLCPA benefits. In the Phase 1 part of the project, AVANGRID proposes to rebuild Border City 115 kV substation and add capacitor banks at Border City and Haley Rd substations. This is estimated to cost $76 million and to yield only a 20 MW renewable integration benefit. In the Phase 1+ component of the project, AVANGRID proposes to install a Power Flow Control Device between Haley and Border City substations for a cost of $4 million and an 8 MW benefit. The Phase 1+ component is a relatively small upgrade and does not substantially bolster the project's overall CLCPA benefits. All together, the project has an unusually high cost-to-benefit ratio of 2,857 $/kW. This is a high enough ratio that we suggest the project should go through the regular rate case proceedings, but not be considered for acceleration for its CLCPA benefits.

3. Phase 2 Project Preliminarily Recommended for Approval

We preliminary recommend the Phase 2 component of the Hornell, Elmira, & Bath Reinforcement project because of its ability to provide high CLCPA benefits in an area with substantial renewable development interest. The project is estimated to increase headroom by 500 MW. We note that AVANGRID has also put forward two alternative designs for this project; these alternatives are smaller in scale. We recommend the PSC consider all three options during the approval process.

D. Orange & Rockland Utilities

Our preliminary recommendations for Phase I projects proposed by Orange & Rockland Utilities (O&R) are shown in Figure A-4 below. Figure A-4 includes additional informational details, including project description, incremental headroom benefits and in-service dates. O&R has proposed six Phase 1 projects. We recommend that the PSC consider accelerated approval for three of these six projects. Our project-specific recommendations are explained below.

O&R is seeing significant developer interest for solar PV and energy storage interconnections. Current requests in NYISO interconnection queue for PV (157 MW) and energy storage interconnections in O&R's local T&D system exceeds 500 MW. O&R notes that its service territory contains farmland and open spaces, which are well suited for siting of Solar PV and energy storage projects. These queued projects requests (when analyzed in addition to the CARIS assumptions) create bottlenecks across O&R's local 34.5 kV, 69 kV, and 138 kV system. The existing headroom across the vast majority of O&R's local T&D lines are insufficient to integrate the assumed 2030 renewable generation.

1. Phase 1 Projects Preliminarily Recommended for Approval

O&R identified six Phase 1 projects that address the impending renewable bottlenecks for a total cost of $417 million. The TL Lines 12 &13/131 project, which is included in the company's *long-term* capital plan (but not in the *2021-2030* capital plan), is proposed with an accelerated development schedule in 2027. Two other projects—Shoemaker 34.5/69/138kV Station and Western Division 34.5kV system upgrades—are part of the company's current *2021-2030* capital plan. The remaining three projects are not in the company's current or long-term plans.

- The TL Lines 12&13/131 project involves rebuilding the aging 69 kV line and replacing with larger conductor, which would unbottle current renewable projects and provide 109 MW of incremental headroom for future renewable integration.
- The Shoemaker and Western Division projects are interconnected and involve upgrading the 34.5 kV system (Western Division) and 34.5/69/138 kV station (Shoemaker) to accommodate larger conductors on O&R's Lines 4 and 6, whose existing headroom capability is under 10 MW. These projects are also needed to enable the unbottling associated with upgrading of O&R's other downstream lines. *Together*, these two projects provide 50 MW of renewable integration benefit. The Shoemaker station project also enables the unbottling of an additional 98 MW of renewables via the proposed downstream TL Lines 24/241 & 25 project.

We recommend that the PSC consider accelerated approval for these three projects, conditioned on a review of the reasonableness of the costs of each project.

2. Phase 1 Projects that Require Further Consideration

The other three proposed Phase 1 projects have delayed in-service dates, ranging from 2030-2036. While they provide large increases to headroom capability of lines with low or unavailable projected 2030 headroom, these projects are not yet in the Company's rate plan, and a few of them require the completion of upstream projects at Shoemaker and Western division to unlock renewable generation benefits. We recommend that the PSC consider these projects under the normal rate case process rather than accelerating their approval at this time.

FIGURE A-4: PHASE 1 LOCAL TRANSMISSION PROJECTS – ORANGE & ROCKLAND UTILITIES

Project	Zone	Description	I/S Date	In Capital Plan or Rate Case?	Estimated Cost [1]	Incremental Headroom	Recommend Approval?
Projects in Rate Case or Capital Plan:							
TL Lines 12 & 13/131	G	Upgrade of 69 kV Transmission Lines 12 & 13/131.	2027	Rate Case	Redacted	109 MW	Yes
Shoemaker 34.5, 69, and 13 kV Station Upgrade	G	New 139 kV and 69 kV air insulated stations	2028	Rate Case	Redacted		Yes
Western Division 34.5 kV System	G	Upgrade of 34.5 kV Western Division subtransmission system: Lines 4, 6, and 100.	2029	Capital Plan (2021-2030)	Redacted	50 MW	Yes
Projects not in Capital Plan:							
TL Line 18 to 69kV	G	Upgrade of 34.5kV Line 18 to 69kV	2030	Neither	Redacted	99 MW	RFC [2]
TL Lines 24/241 & 25	G	Upgrade of 69kV Transmission Lines 24/241 & 25	2033	Neither	Redacted	98 MW	RFC
TL Lines 26 and 261	G	Upgrade of 138kV Transmission Lines 26 and 261	2036	Neither	Redacted	144 MW	RFC
				Recommended Projects Total:	**Redacted**	**159 MW**	
				All Projects Total:	**$417M**	**500 MW**	

Source: Utility Study, p. 235.
Notes:
[1]: Data is from confidential document that Orange & Rockland Utilities shared with Brattle.
[2]: RFC - Requires Further Consideration.

E. Consolidated Edison Company of New York, Inc.

Consolidated Edison Company of New York (ConEd) identified three Phase 1 projects to address local transmission constraints in ConEd'S Astoria East/Carona and the Greenwood/Fox Hills 138 kV Transmission Load Areas (TLA). All three projects address off-ramp transmission constraints on the local 138 kV system, and they all consist of new 345/138 kV stepdown transformers with phase-angle regulator (PAR) controlled 138 kV feeders, rate-limited at 300 MW each. The lengths of the 138 kV feeders vary from 1 to 8 miles of underground cable per load pocket.

ConEd's off-ramp constraints occur on the local transmission system as electricity flows from the higher (bulk power) grid to the lower (local) voltage system. Off-ramp constraints contrasts with "on-ramp" constraints where power flows from distribution and local transmission voltages to the bulk power system. The base driver (i.e., the non-CLCPA drivers) for ConEd's Phase 1 projects, at least in part, are the New York State Department of Environmental Conservation's (DEC) new air emissions regulations for simple cycle and regenerative combustion turbines, adopted in 2019. These regulations (DEC NOx Peaker Rule or Peaker Rule) affect the operation of approximately 3,300 MW (2,000 MW in Zone J) of existing thermal generation plants as early as 2023-25.[4] ConEd's analysis assumed the retirement of all 3,300 MW of such peaking plants. All three Phase 1 projects facilitate higher imports to the 138 kV system TLAs to allow for the retirement of local peaking units. ConEd estimates a total cost of $860 million for the three proposed Phase 1 off-ramp projects.

1. Phase 1 Projects that Require Further Consideration

ConEd's proposed Phase 1 projects are needed to address the Peaker Rule's related impacts on the local transmission system. Because these projects are all off-ramp projects, they are not expected to provide CLCPA benefits in the near-term, as explained below. These projects have an estimated cost of $860 million and are currently being reviewed through ConEd's rate case process.

ConEd's proposed Phase 1 projects are all off-ramp projects that, while likely necessary to facilitate the retirement of load-pocket generation under the Peaker Rule, will not have a significant role in achieving CLCPA goals until after 2030. Before then, the output from the retiring load-pocket generators will likely be replaced by the increased dispatch of fossil-fueled bulk-power generators. Only as the state approaches 100% renewable generation will renewable generation have to be curtailed at the bulk power level due to over-generation conditions that can no longer be managed by dispatching down fossil generation. Only at that point will upgraded off-ramps reduce the curtailment of renewable generation as explained in more detail below. We thus recommend that the PSC consider off-ramp projects at a later date and require the projects' 40-year CLCPA benefits be evaluated in more detail. We recommend that the CLCPA benefit analysis for such off-ramp transmission projects assume a gradual transition from zero incremental renewable energy load-pocket imports until 2030 to 100% renewable energy imports by 2040 to determine the 40-year CLCPA benefit analysis under the benefit-cost analysis (BCA) framework for Phase 2 projects.

Allowing additional import capability into transmission load areas will reduce state-wide renewable curtailments only when the bulk system cannot absorb all renewable generation output. These conditions are unlikely to occur before 2030 (when 30% or more of the state's generation is still sourced from fossil fuels) but will occur more frequently as the state transitions towards 100% renewables by 2040 and beyond. At that point, additional import capability into the constrained TLAs will reduce bulk-power renewable curtailments, and thereby provide incremental CLCPA benefits. However, while fossil generation is still operating on the bulk power system, we expect that most of the energy from the retiring

4 Utility Study, p. 105.

load-pocket generation will be supplied by increasing the dispatch of bulk-power fossil generation. This means that renewable curtailment reduction benefits facilitated by higher import capability or off-ramp projects (such as ConEd's proposed Phase 1 projects) will not be pronounced before 2030. For these off-ramp projects, we thus propose that the full scale of the 40-year evaluation of CLCPA benefits be considered by assuming CLCPA-related renewable "unbottling" benefits associated with the added import capability to be zero until 2030, gradually increase to 100% by 2040, and remain at 100% thereafter. Only if the PSC wants to recognize the DEC NOx Peaker Rule as a state-wide initiative that warrants cost-sharing treatment similar to the projects with CLCPA benefits, could the increase in off-ramp capability be deemed to immediately provide a value equivalent to the renewable-unbottling benefit quantified in the proposed BCA framework.

2. Additional Considerations and Proposal for Expanded Analysis

ConEd's proposals for Phase 1 projects apply strictly to local transmission needs. However, ConEd's analysis has an inherent assumption of from where and how the additional renewable energy will be delivered to its local system. These assumptions will impact the scale of off-ramp challenges and the associated CLCPA benefits of the proposed projects. As noted in the Zero Emissions Study, there may be new flow patterns, for instance, with the addition of the proposed Champlain Hudson Power Express. Furthermore, the Offshore Wind Study not only considers alternate points of interconnection for radially connected offshore wind plants with a variety of ratings, but also contemplates the potential for backbone and meshed offshore transmission systems that could introduce significant flow changes in the ConEd system as well.

We recommend that these issues be analyzed by expanding the scope of ConEd's analysis to account for: (a) the impact of bulk power use changes from offshore wind and new and existing upstate interconnections, (b) further determination of potential solar and storage capacity growth within the affected load pockets (for instance, storage discharge capacity can be scheduled to fill in the required service duration and cycles), and (c) optimization of the off-ramp capacity (beyond the use of standard 300 MW off-ramp capability)[5] and location to facilitate offshore wind integration and provide increased CLCPA benefits at a lower costs per MW.

For one of the three proposed Phase 1 projects, the 2nd Rainey-Corona Feeder, ConEd identified a near-term need date (per the NYISO 2019 RNA). Given the 2023 need date for this project, we recommend that the PSC consider pursuing the review of this project through the normal rate case process. For the other two projects, the 3rd Gowanus-Greenwood Feeder and Goethals-Fox Hills Feeder, we recommend

5 In its proposal, CECONY has contemplated a set of off-ramp projects based on the standard size of transformers with PARs already used in other parts of their electric system. The advantage of having a standard transformer/PAR size is inherent in being able to stockpile standard components and spares as well as the associated engineering, operating and maintenance capabilities. On the other hand, a standardized size limits capacity upgrades to chunks of 300 MW with an associated CLCPA benefit in the 1 MW/million $ range.

that the PSC consider additional review under the expanded scope of analysis, including the evaluation of projects' 40-year CLCPA benefits as proposed above.

FIGURE A-5: PHASE 1 LOCAL TRANSMISSION PROJECTS – CONSOLIDATED EDISON

Project	Zone	Description	I/S Date	In Rate Case?	Estimated Cost [1]	Incremental Headroom	Recommend Approval?
2nd Rainey - Corona Feeder	J	New 345/138 kV PAR Controlled Feeder	2023	No		300 MW	RFC [2]
3rd Gowanus - Greenwood Feeder	J	New 345/138 kV PAR Controlled Feeder	2025	No		300 MW	RFC
Goethals - Fox Hills	J	New 345/138 kV PAR Controlled Feeder and Rebuild of Fox Hills 138 kV Substation	2025	No		300 MW	RFC
				All Projects Total:	**$860M**	**900 MW**	

Source: Utility Study, p. 113.
Notes:
[1]: Project-specific estimated costs not reported by utility.
[2]: RFC - Requires Further Consideration.

F. Long Island Power Authority/PSEG Long Island

Our preliminary recommendation of Phase I local transmission projects for LIPA/PSEG are shown in Figure A-6 below. Figure A-6 includes additional informational details such as project cost estimates and in-service dates. LIPA proposed a total of eight Phase 1 projects, of which we recommend seven as candidates to be considered for accelerated approval. These seven recommended projects have estimated costs ranging from $2 million to $162 million and estimated CLCPA benefits of 5 MW to 260 MW. Our project-specific recommendations are explained below.

1. Phase 1 Projects Preliminarily Recommended for Approval

- All the regions in LIPA's existing local transmission network (save one under peak load conditions) have low levels of existing headroom for additional generation injection. Local transmission bottlenecks have been identified for the LIPA 70x30 Scenario sensitivity light load case, and multiple violations are observed when future offshore wind generation injections of 3,116 MW are considered.
- All eight of LIPA's proposed Phase 1 projects are included in the Company's 5-year budget plan and documented within the 2019 PSEG Long Island Local Transmission Plan (LTP). These projects are prioritized to meet reliability, safety and compliance base driver needs, but are projected to also help meet CLCPA goals through reducing transmission bottlenecks/constraints.

- We recommend that the PSC consider seven of LIPA's proposed Phase 1 projects for accelerated approval. The total estimated cost of these seven projects is $334 million, and they collectively provide 605 MW of renewable generation integration benefits.
- These projects, shown in Figure A-6 below, address broadly two issues: they facilitate load-serving needs under higher future load levels, and importantly also support the power transfers on LIPA's parallel 138 kV and 69 kV local transmission networks. In LIPA, the 138kV local transmission system parallels the 69kV local transmission system. Typically, under design contingencies such as the loss of a 138kV facility, the parallel 69kV system supports the additional power transfers. The recommended LIPA projects upgrade the aging 69 kV and the 138kV system, which increase the transmission capability on the 69 kV and the 138 kV systems, and thereby facilitate the integration of renewable resources such as offshore wind and solar PV while improving energy deliverability across the LIPA bulk system.

FIGURE A-6: PHASE 1 LOCAL TRANSMISSION PROJECTS – LONG ISLAND POWER AUTHORITY

Project	Zone	Description	I/S Date	In Capital Plan or Rate Case?	Estimated Cost	Incremental Headroom	Recommend Approval?
Western Nassau Transmission Project	K	Install a new 138 kV circuit from the East Garden City substation to the Valley Stream substation.	2020	Capital Plan	$162M	70 MW	Yes
138 kV Riverhead to Canal New Circuit	K	Install a new 138 kV circuit from the Riverhead substation to the Canal substation.	2021	Capital Plan	$83M	260 MW	Yes
Wildwood to Riverhead 69 kV to 138 kV Conversion	K	Convert the existing Wildwood to Riverhead circuit from 69 kV to 138 kV.	2021	Capital Plan	$10M	160 MW	Yes
Rockaway Beach 34.5 kV New Circuits	K	Install a new 34.5 kV circuit from the Far Rockaway substation to the Arverne substation and the Rockaway Beach substation to the Arverne substation.	2022	Capital Plan	$68M	10 MW	RFC [1]
69 kV Ruland Road to Plainview New Circuit	K	Install a new 69 kV circuit from the Ruland Rd. substation to the Plainview substation.	2022	Capital Plan	$41M	40 MW	Yes
69 kV Pilgrim Bus Reconfiguration	K	Reconfigure connections to 69 kV buses at Pilgrim substation.	2023	Capital Plan	$1M	20 MW	Yes
69kV Canal to Deerfield Double Circuit Reconfiguration	K	Reconfigure Canal to Southampton to Deerfield overhead circuits.	2024	Capital Plan	$2M	5 MW	Yes
69kV Elwood to Pulaski Circuit Upgrade	K	Reconductor Elwood to Pulaski 69 kV overhead circuit	2025	Capital Plan	$35M	50 MW	Yes
				Recommended Projects Total:	**$334M**	**605 MW**	
				All Projects Total:	**$402M**	**615 MW**	

Source: Utility Study, pp. 133-134.
Note: [1]: RFC – Requires Further Consideration.

2. Phase 1 Projects that Require Further Consideration

We recommend that the PSC consider the Rockaway Beach 34.5kV New Circuits project under the normal rate case process rather than accelerating the project approval. This project, a 34.5 kV system upgrade, is projected to resolve localized load-serving related constraints on the 34.5kV network (i.e., off-ramp issue), but is not expected to support large CLCPA benefits immediately as an off-ramp solution. LIPA estimates that this project would provide only 10 MW of benefits at $68 million cost.

Appendix B

(to Initial Report on the New York Power Grid Study)

Preliminary Recommendations on Distribution Projects

A. Discussion of Recommendations

Our preliminary recommendations for promising Phase 1 and priority Phase 2 distribution projects proposed by the Utilities' are listed below in Figures B-1 through B-8. We recommend that the PSC consider these recommended projects for expeditious approval and prioritization. To arrive at our recommendations, we reviewed filing information, held discussions with the company, and reviewed the additional confidential information furnished in response to our questions and requests for information. All together, the recommended projects are estimated to increase the capacity of renewables that can interconnect the New York distribution network, by 3.2 – 3.5 GW.

As the Utilities begin to petition the PSC for approval of the specific projects recommended herein, particularly when such petitions are outside the normal rate case processes (such as when rate case cycles do not allow for sufficiently timely approval decisions), we recommend that the PSC consider requiring submission of a more detailed evaluation of how the proposed projects address the renewable unbottling needs. As explained in detail in the Initial Report to the New York Power Grid Study, we recommend that the PSC consider requiring the Utilities to submit updated data on renewable generation development activities affecting the need for the proposed projects, and additional details such as updated headroom capacity estimates reflecting a more coordinated assessment of distribution and local transmission headroom capacity. Such information, in addition to the more detailed technical information of the proposed projects, would provide additional justification for the need to act on the advancement of the proposed projects outside the normal rate case processes.

The figures below also include certain Phase 2 distribution projects that we recommend the PSC consider prioritizing for approval. We recommend the prioritization of these projects because they address potential substation and distribution feeder-related constraints that would limit the interconnection of distributed energy resources (DERs) and these projects serve areas with demonstrated DER developer interest. Examples of these projects 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.

For projects that describe general upgrades that may be deployed across many substations or distribution elements, we recommend prioritization of locations with the largest near-term need in terms of the DER development activities. For these "general upgrade" projects, utilities will need to provide additional location specific project information when petitioning the PSC for review and approval. We recommend that the PSC require that all petitions clearly define project scope and provide updated information about how immediate the project needs are based on up-to-date DER interconnection requests and development projections.

B. National Grid

FIGURE B-1: PHASE 1 DISTRIBUTION PROJECTS – NATIONAL GRID

Project	Zone	Description	I/S Date	In Rate Case?	Estimated Cost	Incremental Headroom	Recommend Approval?	Reason
Recommended projects:								
Stoner Sub	F-4	Upgrade 25MVA transformer bank with 40MVA bank to address asset condition and hosting capacity concerns	2019-2021	No	$2.5M	15 MW	Yes	Low cost-to-benefit ratio and near-term need.
Newark to Maplewood Refurb	F-4	Install a new 34.5 kV cable	2020	No	$0.7M	3 MW	Yes	Same as above
Fairdale	C-2	Replace 2.5 MVA transformer with new 5 MW transformer	2020-2021	No	$0.9M	2.5 MW	Yes	Same as above
Golah Sub TB1	B-29	Upgrade 63kV to 34 5 kV transformer from 10MVA to 25 MVA	2020-2024	No	$4.5M	15 MW	Yes	Same as above
Golah Sub TB3	B-29	Upgrade 63kV to 34 5 kV transformer from 10MVA to 25 MVA	2020-2024	No	$4.5M	15 MW	Yes	Same as above
3V0 and LTC upgrades Phase 1	Multiple	51 Pending customer and company funded 3V0/LTC upgrades	2020-2025	No	$32.5M	224 MW	Yes	Same as above
Feeder 93852	TBD	Ogdensburg 93852 HWY 37 - Rebuild	2020-2025	No	$0.1M	6 MW	Yes	Same as above
Feeder 97654	TBD	97654 Skinnerville Road - Rebuild	2020-2025	No	$0.2M	6 MW	Yes	Same as above
Feeders 0456, 0457	TBD	F0456/0457 Build feeder tie	2020-2025	No	$0.4M	3 MW	Yes	Same as above
Feeder 66954	TBD	MV-Lehigh 66954 Reconductoring	2020-2025	No	$0.6M	3 MW	Yes	Same as above
Feeder 25456	TBD	NY14 Fairdale 64 tie with 25456	2020-2025	No	$0.3M	2 MW	Yes	Same as above
Feeders 7958, 15351, 6161	TBD	Create Fdr Tie F7958-F15351&F6161	2020-2025	No	$0.1M	7 MW	Yes	Same as above
Feeder 2861	TBD	Rebuild portion of E. Otto F2861	2020-2025	No	$0.2M	2 MW	Yes	Same as above
Feeder 26552	TBD	Burdeck 26552 - Burnett St Conversion, Burdeck 26552 - Westcott / Curry Rd	2020-2025	No	$0.8M	2 MW	Yes	Same as above

Project	Zone	Description	I/S Date	In Rate Case?	Estimated Cost	Incremental Headroom	Recommend Approval?	Reason
Recommended projects (cont.):								
Feeder 3354, 10451	TBD	MSH-WOlean 3354 tie 10451 Chipmunk	2020-2025	No	$0 3M	1 MW	Yes	Low cost-benefit ratio and near-term need.
Feeder 1562	TBD	Rebuild portions of Catt. F1562	2020-2025	No	$0 3M	17 MW	Yes	Same as above
Feeder 32451	TBD	Minor Storm Hardening – 32451	2020-2025	No	$0 2M	12 MW	Yes	Same as above
Feeders 7765, 7656, 23251, 20653, 7656, 7656, 20653, 7656	TBD	(1) Middleport F7765 Tie w/Shelby 7656, (2) F23251 Create Ties with 20653&7656, (3) F7656 to relieve F20653 for Cust, (4)MSH Upgrade Limited Tie to F7656	2020-2025	No	$2.1M	8 MW	Yes	Same as above
Feeder 98352	TBD	State HWY 58 Relocation 98352	2020-2025	No	$0 5M	8 MW	Yes	Same as above
Feeder 37061	TBD	NR-Hammond 37061-T.I. Transformers	2020-2025	No	$0 5M	7 MW	Yes	Same as above
Gilbert Mills	C-2	Upgrade of transformer bank one (1) from 9.375MVA to a 15/20/25MVA transformer and includes the installation of EMS at the station.	2023-2026	No	$3M	15.625 MW	Yes	Low cost-benefit ratio, medium-term need.
Raquette Lake	E-3	Replace the existing (3)-333KVA 46:4.8kV substation transformer with 46/4.8 kV 2.5 MVA pad-mounted transformers	2020-2021	No	$0 9M	1.5 MW	Yes	Moderate cost-benefit ratio, near-term need.
Hoosick Sub	F-4	Upgrade 12.5MVA transformer bank with 25MVA bank as part of rebuild for IEC 61850 standard	2020-2024	No	$11M	12.5 MW	Yes	Same as above
Feeders 89552, 89552, 89552	TBD	89552 Crooks Road - Rebuild, 89552 Dyke Road - Rebuild, French Road Relocation 89552	2020-2025	No	$0.7M	1 MW	Yes	Same as above
Feeder 22651	TBD	Knapp Rd 22651 Feeder Tie	2020-2025	No	$0 5M	1 MW	Yes	Same as above
Feeder 98455	TBD	Dekalb 98455 Town Line rd - Rebuild	2020-2025	No	$0.6M	1 MW	Yes	Same as above
Perkins South West to DG	TBD	Reconductor 2.1 miles 34.5 kV conductor to 336.4	2020-2025	No	$1.4M	2 MW	Yes	Same as above
Buffalo Station 139	A-1	Replace Transformers. This project will replace the existing 3.75/4.687MVA transformer with a 7.5/9.375MVA transformer.	2024-2027	No	$2 9M	4.7 MW	Yes	Moderate cost-benefit ratio, medium-term need.
Altamont Sub - TB2	F-4	Upgrade 22.4MVA to 40MVA bank to address asset condition and hosting capacity concerns	2025-2030	No	$10M	17.6 MW	Yes	Same as above

Project	Zone	Description	I/S Date	In Rate Case?	Estimated Cost	Incremental Headroom	Recommend Approval?	Reason
Projects that require additional information prior to recommendation:								
New/Emerging Technologies Phase 1	multiple	Grid Modernization investments filed in rate case and IT rents	2021-2024	Yes	$520M	Requires complex analysis	Requires additional information	Headroom estimate required to assess CLCPA benefit
Cllinton Sub	E-3	Upgrade 10.5 MVA bank to address asset condition and hosting capacity concerns, size TBD	2025-2030	No	$10M		Same as above	Same as above
Projects to be considered through Rate Case process:								
Buffalo Station 32 Rebuild	A-1	Removal of all the existing equipment and the installation of four (4) new 23/4 33kV 3.75/4.687 MVA transformers	2020-2024	No	$7.6M	4 MW	Consider for approval through Rate Case process	High cost-benefit ratio and low MW benefit.
Buffalo Station 38 Rebuild	A-1	Removal of all the existing equipment and the installation of four (4) new 23/4 33kV 3.75/4.687 MVA transformers	2020-2024	No	$9.7M	4 MW	Consider for approval through Rate Case process	Same as above
Feeders 15351, 15352, 15151, 15351, 15151, 15351, 7958, 15351, 6161	TBD	(1)Create Full Tie F15351 to F15352, (2) Make Ready Fdr Tie F15151-15351, (3) MSH Create Fdr Tie F15151-15351, (4) Create Fdr Tie F7958-F15351&F6161	2020-2025	No	$1.7M	1 MW	Consider for approval through Rate Case process	Same as above
Avon to Golah	B-29	10 MW/ 20 MWh battery project at 34.5 kV	2022	No	$8M	2 MW	Consider for approval through Rate Case process	Same as above
West Adams	E-3	New second transformer bank at West Adams substation	2023-2026	No	$3 5M	1 MW	Consider for approval through Rate Case process	Same as above
Sorrell Hill	C-2	Install second 115/13 2kV 15/20/25MVA transformer at Sorrell Hill.	2023-2027	No	$5M	1 MW	Consider for approval through Rate Case process	Same as above
				Recommended Projects Total:	**$83.2M**	**415.4 MW**		
				All Projects Total:	**$648.7M**	**428.4 MW**		

Sources:
Utility Study, pp. 170-172.
Utility Transmission and Distribution Investment Working Group Report Errata (filed by National Grid), Case 20-E-0197, December 1, 2020, pp. 6, 78.

FIGURE B-2: PRIORITY PHASE 2 DISTRIBUTION PROJECTS - NATIONAL GRID

Project	Description	I/S Date	In Rate Case?	Incremental Headroom
>10 MW in Queue	12 stations in National Grid territory currently with over 10MW of DG in queue above the nameplate rating of the bank include 44 South Park, Berry Rd, Brockport, Cattaraugus, East Pulaski, East Watertown, Hudson, Lawrence Ave, Lisbon E. S., North Carthage, Salisbury ES, and W Hamlin.	2025-2030	No	15-330 MW
3V0 and LTC Upgrades	Additional 3V0/LTC upgrades	2025-2030	No	498 MW
			Total Benefit:	**513 - 828 MW**

Source: Utility Study, p. 172.
Note: Locations with the largest near-term need in terms of the DER development activities should be prioritized. National Grid needs to provide additional location-specific project information.

C. Central Hudson Gas & Electric

FIGURE B-3: PHASE 1 DISTRIBUTION PROJECTS – CENTRAL HUDSON

Project	Zone	Description	I/S Date	In Rate Case?	Estimated Cost	Incremental Headroom	Recommend Approval?	Reason
Recommended projects:								
5 kV Aerial Cable Replacement	G	Replace cable or convert 5 kV to 13.2 kV operation	Ongoing	No	$2 5M	14 MW	Yes	Low cost-benefit ratio, and near-term need.
Copper Wire Replacement Program	G	Replace #4 and #6 copper with higher capacity ACSR	Ongoing	No	$3.6+M	23 MW	Yes	Same as above
Coxsackie Transformer Replacement	G	Replace with 22 MVA	2021	No	$2.1M	10 MW	Yes	Same as above
Knapps Substation Replacement	G	Station Rebuild – high capacity circuit exits	2022	No	$1M	18 MW	Yes	Same as above
New Baltimore Transformer Replacement	G	Add a 2nd 12 MVA transformer	2023	No	$1.6M	12 MW	Yes	Same as above
Greenfield Road Transformer and Circuit Exits	G	Replace existing transformers	2023	No	$1.5M	10 MW	Yes	Same as above
Coxsackie DEC Peaker Regulation Project	G	Add a 2nd transformer and DVAR	2024	No	$4M	22 MW	Yes	Same as above
South Cairo DEC Peaker Regulation Project	G	Add a 2nd transformer and DVAR	2024	No	$4.1M	12 MW	Yes	Same as above
4800V & 4 kV Replacement Programs	G	Upgrade 4800 V and 4kV to 13.2 kV eliminating stepdown transformers	Ongoing	No	$17.6+M	11 MW	Yes	Moderate MW benefit and has a near-term need, but has high cost-benefit ratio
Projects that require additional information prior to recommendation:								
DA/DMS	G	Distribution Automation and Distribution Management System – foundational investments	Ongoing	No	$14.2M		Requires additional information	Headroom estimate required to assess CLCPA benefit
Operating Infrastructure	G	Infrastructure	Ongoing	No	$25.3M		Same as above	Same as above
Storm Hardening	G	Harden mainline zones of protection	Ongoing	No	$59.5M		Same as above	Same as above
				Recommended Projects Total:	**$38M**	**132 MW**		
				All Projects Total:	**$137M**	**132 MW**		

Source: Utility Study, p. 86.

D. AVANGRID (NYSEG and RG&E)

FIGURE B-4: PHASE 1 DISTRIBUTION PROJECTS – NYSEG AND RG&E

Project	Zone	Description	I/S Date	In Rate Case or Capital Plan?	Estimated Cost	Incremental Headroom	Recommend Approval?	Reason
Recommended projects:								
Station 49	B	115/34 5kV transformers upgrade	2021	Capital Plan	$19M	20.1 MW	Yes	Low cost-benefit ratio, large MW benefit, near-term need
Amenia Substation	G	12kV circuit upgrade	2021	Capital Plan	$13M	23.7 MW	Yes	Same as above
Hilldale Substation	E	Transformer upgrade / replacement	2024	Capital Plan	$32M	25.7 MW	Yes	Large MW benefit and near-term need, though high cost-benefit ratio
Station 46	B	34.5kV transformers upgrade; 12kV circuit upgrade	2025	Capital Plan	$49M	23.7 MW	Yes	Same as above
Dingle Ridge Substation	G	Transformer upgrade / replacement	2021	Capital Plan	$16M	8 9 MW	Yes	Moderate MW benefit and near-term need, though high cost-benefit ratio
Station 43	B	34.5kV transformers upgrade; 12kV circuit upgrade	2026	Capital Plan	$47M	24.2 MW	Yes	Large MW benefit and medium-term need, though high cost-benefit ratio
Sloan Substation	A	12kV circuit upgrade; Additional 12kV circuits; 34.5kV transformer upgrade	2027	Capital Plan	$28M	26.6 MW	Yes	Same as above
Projects to be considered for next Rate Case:								
Station 117	B	13.2kV circuit upgrade	2026	Capital Plan	$25M	12.9 MW	Consider for approval through rate case	High cost-benefit ratio, moderate MW benefit, medium-term need
				Recommended Projects Total:	**$204M**	**152.9 MW**		
				All Projects Total:	**$229M**	**165.8 MW**		

Source: Utility Study, pp. 225-226.

FIGURE B-5: PRIORITY PHASE 2 DISTRIBUTION PROJECTS – NYSEG AND RG&E

Project	Description	I/S Date	In Rate Case or Capital Plan?	Incremental Headroom
Kanona Substation	Transformer Upgrade	2025	No	8.9 MW
Limestone Substation	Flexible Interconnection Capacity Solution (FICS) for DG. Battery Energy Storage Solution	2023	No	5.5 MW
Keeseville Substation	Complete 12kV Substation & Circuit Upgrade and Conversion	2025	No	26.1 MW
Guildford Substation	Complete 12kV Substation & Circuit Upgrade and Conversion	2025	No	26.1 MW
Woods Corners Substation	Complete 12kV Substation & Circuit Upgrade and Conversion	2025	No	21.7 MW
			Total Benefit:	**88.3 MW**

Sources: Utility Study, pp. 226-227.

E. Orange & Rockland Utilities

FIGURE B-6: PHASE 1 DISTRIBUTION PROJECTS – ORANGE & ROCKLAND UTILITIES

Project	Zone	Description	I/S Date	In Rate Case or Capital Plan?	Estimated Cost	Incremental Headroom	Recommend Approval?	Reason
Recommended projects:								
Blooming Grove Substation	G	Upgrade existing 25MVA single bank substation with provisions for modular utility owned storage.	2023	Rate Case	Redacted	51 MW	Yes	Moderate cost-to-benefit ratio, large MW benefit, and near-term need.
Woodbury Substation	G	New Substation to support load growth, reliability and hosting capacity in the Harriman Area (Monroe, Blooming Grove, Woodbury, Harriman).	2025	Rate Case	Redacted	76 MW	Yes	Same as above
Shoemaker Substation	G	Construct new 138kV transmission yard and upgrade existing 35MVA single bank substation	2028	Capital Plan	Redacted	41 MW	Yes	Same as above
Westtown Second Bank/UG Exits	G	Improve reliability for loss of Bank 1103 and increase hosting capacity in this area (bank limitation reached).	2029	Capital Plan	Redacted	18 MW	Yes	Low cost-to-benefit ratio and moderate MW benefit.
Conditionally recommended projects:								
Bullville Substation	G	Upgrade existing 25MVA single bank substation with provisions for modular utility owned storage.	2027	Rate Case	Redacted	33 MW	Conditional yes	Yes if Western Division 34.5 kV project is approved. Moderate cost-to-benefit ratio.
Wurtsboro Substation	G	Upgrade existing 5MVA single bank substation and convert 4.8kV area	2029	Capital Plan	Redacted	30 MW	Conditional yes	Same as above
Bloomingburg Substation	G	Upgrade existing 20MVA single bank substation	2030	Capital Plan	Redacted	38 MW	Conditional yes	Same as above
Rio Substation	G	Upgrade existing 18MVA single bank substation	2030	Capital Plan	Redacted	21 MW	Conditional yes	Yes if Line 18 local transmission project is approved. Moderate cost-to-benefit ratio.
Projects that require additional information prior to recommendation:								
Woodbury Batteries	G	Utility owned batteries to support area growth that could potentially have mobile capability to interconnect into future substations.	2023	Rate Case	Redacted		Requires additional information	Headroom estimate required to assess CLCPA benefit
				Recommended Projects Total:	**Redacted**	**308 MW**		
				All Projects Total:	**$155.7M**	**308 MW**		

Source: Utility Study, pp. 245-246.

F. Consolidated Edison Company of New York, Inc.

FIGURE B-7: PHASE 1 DISTRIBUTION PROJECTS – CONSOLIDATED EDISON

Project	Description	I/S Date	Rate Case or Capital Plan?	Estimated Cost	Incremental Headroom	Recommend Approval?	Reason
Recommended projects:							
DSP Programs	Investments to improve distribution system safety, reliability, resiliency, efficiency, and automation	2020+	Approved in rate case	$107M		Yes (Already approved)	Already approved in rate case
Communications Infrastructure	Systems to manage data exchange across systems, applications, and devices	2020+	Approved in rate case	$50M		Yes (Already approved)	Same as above
Vinegar Hill Distribution Switching Station	Distribution switching station to add capacity and provide operational flexibility	2022	Approved in rate case	$215M	240 MW	Yes (Already approved)	Same as above
Fox Hills Energy Storage Project	Energy Storage at Area Substation to facilitate DER interconnection and provide system support	2022	Approved in rate case	$22M	7.5 MW	Yes (Already approved)	Same as above
EV Make-Ready Investments	Investments as approved by the Commission	2025	Approved in rate case	$395M		Yes (Already approved)	Same as above
Conditionally recommended projects:							
Newtown Extension	Expansion of planned NWS to install new transformer and sub-transmission line	2025	Capital Plan		120 MW	Conditional yes	Conditional on cost estimate which has not been provided by the Utility Study.
Energy Storage Program	Five projects to provide a range of operational and CLCPA-related benefits	2025	Capital Plan		50 MW	Conditional yes	Same as above
Projects that require additional information prior to recommendation:							
DSP Incremental Programs	Incremental investment in the DSP	2024	Capital Plan			Requires additional information	Headroom and cost estimates required to assess CLCPA benefit.
			Recommended Projects Total:	**$789M**	**417.5 MW**		
			All Projects Total:	**$789M**	**417.5 MW**		

Source: Utility Study, p. 117.

G. Long Island Power Authority/PSEG Long Island

FIGURE B-8: PHASE 1 DISTRIBUTION PROJECTS – LONG ISLAND POWER AUTHORITY

Project Name/Description	Location	I/S Date	In Rate Case or Capital Plan?	Estimated Cost	Incremental Headroom	Recommend Approval?	Reason
Recommended projects:							
Flowerfield replace 6.25 MVA bank with 69/13 kV 33 MVA banks, switchgear & C&R	Flowerfield	2020	Capital Plan	\$11.4M	23 MW	Yes	Low cost-benefit ratio, large MW benefit, and near-term need
Upgrade 14 MVA transformers to 33 MVA transformers	Far Rockaway	2021	Capital Plan	\$9.3M	32 MW[1]	Yes	Same as above
Install new transformer and switchgear	Rockaway Beach	2021	Capital Plan	\$11.3M	24 MW	Yes	Same as above
Install new third bank and switchgear	Bridgehampton	2022	Capital Plan	\$11.1M	28 MW	Yes	Same as above
Upgrade existing distribution transformers	Peconic	2023	Capital Plan	\$7M	34 MW	Yes	Same as above
Upgrade substation from 23 kV to 33 kV	Hero	2023	Capital Plan	\$0.7M	3 MW	Yes	Low cost-benefit ratio and near-term need.
Construct new 69/13 kV substation	Lindbergh	2020	Capital Plan	\$54.5M	56 MW	Yes	Moderate cost-benefit ratio, large MW benefit, and near-term need
Rockaway Beach convert all 4 kV feeders to 13 kV	Rockaway Beach	2021	Capital Plan	\$11.3M	20 MW	Yes	Same as above
Install new 138/13 kV transformer and switchgear	Roslyn	2021	Capital Plan	\$21.9M	28 MW	Yes	Moderate cost-benefit ratio, large MW benefit, and near-term need
Install new 138/69 kV transformer and switchgear	Ronkonkoma	2021	Capital Plan	\$19.7M	28 MW	Yes	Same as above
Construct new substation 69/13 kV bank and two feeders	Round Swamp	2021	Capital Plan	\$30.2M	56 MW	Yes	Same as above
Install new transformer and switchgear	Brightwaters	2022	Capital Plan	\$20.4M	28 MW	Yes	Same as above
North Bellmore install 33 MVA bank, switchgear, feeders & C&R	North Bellmore	2023	Capital Plan	\$21.9M	28 MW	Yes	Same as above

Project Name/Description	Location	I/S Date	In Rate Case or Capital Plan?	Estimated Cost	Incremental Headroom	Recommend Approval?	Reason
Recommended projects (cont.):							
Expand 69/13 kV substation & distribution circuits	New South Road	2022	Capital Plan	$21.2M	28 MW	Yes	Moderate cost-benefit ratio, large MW benefit, and near-term need
Construct new 69/13 kV substation	Brooklyn Ave.	2023	Capital Plan	$32.6M	56 MW	Yes	Same as above
Upgrade substation from 23 kV to 33 kV	Culloden Point	2022	Capital Plan	$6.2M	9 MW	Yes	Moderate cost-benefit ratio, moderate MW benefit, and near-term need
Upgrade substation from 23 kV to 33 kV	Hither Hills	2024	Capital Plan	$13M	18 MW	Yes	Same as above
Upgrade substation from 23 kV to 33 kV	Amagansett	2022	Capital Plan	$15.7M	12 MW	Yes	Moderate MW benefit, near-term need, though high cost-benefit ratio
New Navy Road substation	Navy Road	2023	Capital Plan	$31.7M	18 MW	Yes	Same as above
			Recommended Projects Total:	**$351.1M**	**520 MW**		

Source: Utility Study, pp. 148-149.
Note: [1]: Estimated benefit for this project has been corrected by LIPA/PSEG after the Utility Study was published.

FIGURE B-9: PRIORITY PHASE 2 DISTRIBUTION PROJECTS – LONG ISLAND POWER AUTHORITY

Project Name/Description	I/S Date	In Rate Case or Capital Plan?	Incremental Headroom
Additional Breaker Cubicles for DER Feeders	2021-2030	No	108 MW
Grounding protection for transmission buses[1]	2021-2030	No	600 MW
Voltage regulation for DER feeders	2021-2030	No	48 MW
		Total Benefit:	**756 MW**

Source: Utility Study, p. 151.
Note:
[1]: The MW value is estimated across 135 transmission buses and can be realized only if the other constraints are addressed.
[2]: Locations with the largest near-term need in terms of the DER development activities should be prioritized. LIPA needs to provide additional location specific project information.

Appendix C

(to Initial Report on New York Power Grid Study)

Utility Transmission & Distribution Investment Working Group Study

Utility Transmission and Distribution Investment Working Group Report

November 2, 2020

Respectfully Submitted,

Central Hudson Gas & Electric Corp.
Consolidated Edison Company of New York, Inc.
Long Island Power Authority
Niagara Mohawk Power Corporation d/b/a National Grid
New York State Electric & Gas Corporation
Orange & Rockland Utilities, Inc.
Rochester Gas and Electric Corporation

Contents

STATE OF NEW YORK

PUBLIC SERVICE COMMISSION

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

Executive Summary

On May 14, 2020, the New York Public Service Commission (Commission) issued the initiating order (May Order) in this proceeding[1] in response to environmental policy objectives and related requirements set forth in the Climate Leadership and Community Protection Act (CLCPA)[2] and the Accelerated Renewable Energy Growth and Community Benefit Act (AREGCB Act).[3] The CLCPA establishes aggressive targets for the reduction in greenhouse gas (GHG) emissions, renewable and emissions-free electric generation, and development of off-shore wind. The AREGCB Act directs the Commission to take specific actions to ensure that New York's electric grid will support the State's climate mandates. These actions include, among other things, initiating a proceeding to establish a planning process to guide future investments in local transmission and distribution (sometimes referred to here as LT&D) and establishing a LT&D capital plan for each utility. This Report contains the Utilities'[4] proposals and recommendations on these matters, in fulfilment of the requirements of the May Order.[5]

The AREGCB Act and the May Order distinguish between distribution, local transmission, and bulk transmission assets. For the purposes discussed in this Report, local transmission refers to "transmission line(s) and substation(s) that generally serve local load, and transmission lines

1 Case 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act* (Transmission Planning Proceeding), Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (issued May 14, 2020) (May Order).

2 New York Public Service Law, § 66-p.

3 New York Public Service Law §§ 162, 123 and 126.

4 The Utilities include: Central Hudson Gas & Electric Corp. (Central Hudson); Consolidated Edison Company of New York, Inc. (CECONY); Long Island Power Authority (LIPA); Niagara Mohawk Power Corporation d/b/a National Grid (National Grid); New York State Electric & Gas Corporation (NYSEG); Orange & Rockland Utilities, Inc. (O&R); and Rochester Gas and Electric Corporation (RG&E) (collectively, Utilities). Throughout this document, when referring to a single or generic company the term "utility" will not be capitalized.

5 Transmission Planning Proceeding, May Order.

The Commission noted in the May Order that "prior to the enactment of the [AREGCB Act], the Department of Public Service had already established working groups in collaboration with the utilities to address the policy, planning, and technological challenges to meeting the CLCPA targets. These proactive efforts are productive and useful, and this order intends to build on those efforts, as well as provide direction for future initiatives." This Report was prepared by the Utilities in collaboration with other members of the working groups, which include the Department of Public Service(DPS) Staff, the New York Independent System Operator, Inc. (NYISO), the New York Power Authority (NYPA), and the New York State Energy Research and Development Authority (NYSERDA).

The utility working groups were originally ordered to file the proposals on process and ratemaking matters discussed in this Report on October 5, 2020. On September 1, 2020 the Commission Secretary granted an extension of the filing date to November 1, 2020 to align these recommendations with the filing of analyses related to potential distribution and local transmission upgrades to facilitate CLCPA compliance, which can be found in Part 2 of this Report.

which transfer power to other service territories and operate at less than 200 kV," as defined by the Commission in the May Order.[6] Bulk power transmission facilities (BPTF) are planned and operated by the NYISO.

The recommendations made in this Report contemplate two categories of LT&D projects based on project readiness and the complexity of regulatory issues that remain to be resolved:

- *Phase 1* projects are immediately actionable projects that satisfy Reliability, Safety, and Compliance purposes but that can also address bottlenecks or 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 pipeline. Phase 1 projects will be financially supported by the customers of the utility proposing the project.
- *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 described in Part 1, below.

Project investment criteria and prioritization recommendations are presented with additional regulatory considerations in ***Part 1*** of this Report. The Utilities focus on adaptation of existing LT&D planning processes and consider opportunities to accelerate select projects to facilitate achievement of CLCPA objectives. Achievement of clean energy mandates will require expansion of the Utilities' planning objectives and therefore changes to the planning processes. It will also require adaptation of decision-making tools and integration of insights gained from additional stakeholder involvement. Furthermore, achieving requirements of the CLCPA and the AREGCB Act will also require changes to existing practices concerning cost allocation and cost recovery. Certain benefits of necessary and appropriate LT&D investments will accrue not only to customers within, but also outside, the investing utility's service area. Regulatory approval outside a Utility's normal rate case may be both required to advance Phase 1 LT&D projects in the timeline required to achieve CLCPA mandates, and to recover costs of Phase 2 costs from customers throughout New York. Specific proposals and recommendations on these matters include the following.

6 Transmission Planning Proceeding, May Order, p. 3 Note 4.

CLCPA Investment Criteria and Project Prioritization

- The Utilities recommend a set of local transmission and distribution investment criteria designed to meet CLCPA mandates, including:
    - Cost effectiveness of local transmission and distribution investments;
    - Greater renewable energy utilization (*i.e.*, to reduce curtailments and increase renewable power delivery to New York customers);
    - Streamlined renewable energy project deployments to deliver benefits more quickly;
    - System expandability to interconnect renewable generation;
    - Improved system flexibility to manage intermittent resources; and
    - Firmness of renewable generation projects that would be facilitated by the proposed local transmission and distribution investments.
- Use of these criteria would allow the Utilities to identify CLCPA-driven projects along with traditional Reliability, Safety, and Compliance projects.
- The Utilities recommend that these approaches be integrated with existing local transmission and distribution planning processes going forward.

Benefit Cost Analysis

The Utilities recommend that the Commission accept a set of local transmission-related BCA guidelines for CLCPA projects. These guidelines will comprise a simple, consistent, repeatable mechanism to allow local transmission owners to efficiently prioritize CLCPA-related investments.

Stakeholder Engagement

The Utilities recommend annual engagement with stakeholders through robust dialogue and data exchange built as a supplement to existing mechanisms that already provide transparency in transmission and distribution planning. Recommended stakeholder engagement opportunities specific to local transmission planning are informed by existing NYISO processes but would be conducted outside of NYISO structures (i.e., by each New York jurisdictional utility).

Cost Allocation and Cost Recovery

State CLCPA and AREGCB Act mandates to incorporate an increasing share of renewables into local transmission and distribution activities will require additional costs. Clear cost allocation and recovery processes are imperative to ensure timely implementation and cost-effective project deployment. The Utilities make the following recommendations:

1) Cost sharing measures should not impede project development.
2) Beneficiaries must include all customers throughout the State to ensure equitable cost allocation.
3) The incremental cost of utility projects prioritized to support CLCPA mandates should be eligible for load ratio share cost allocations.

4) The Commission should determine, as part of its overall authorization of utility local projects, those projects for which costs should be shared and which should not, recognizing that regional planning differences that benefit a region are also needed to facilitate CLCPA mandates. The Commission should track individual utility CLCPA project costs and consider whether costs are incurred equitably across the State when determining the need for cost sharing.
5) Where necessary, the Commission should leverage as much as possible the existing utility rate case process to expedite CLCPA projects.
    - The Commission should authorize project cost recovery outside of rate case processes to expedite projects.
6) Utilities must have certainty on cost allocation and recovery before projects can begin.

Public Service Law, Article VII

CLCPA benefits described herein will not be realized until the LT&D improvements identified through the planning processes are sited, designed and built. Accordingly, the Utilities conclude Part 1 with an outline of potential opportunities for improving the timeliness and predictability of the transmission siting process for major electric transmission facilities under Public Service Law Article VII.

Part 2 identifies a number of potential LT&D upgrades that the utilities recommend as necessary or appropriate to accelerate progress toward achievement of the CLCPA renewable energy mandates. These include actionable local system upgrades (*i.e.*, new facilities or enhancements to existing transmission or distribution facilities) that will facilitate greater interconnection and use of clean energy resources throughout New York State. Each of the Utilities has identified Phase 1 and Phase 2 projects that can be pursued immediately following Commission approval to proceed.

The analyses presented in Part 2 are based on projected system conditions in 2030. The Utilities have evaluated LT&D capabilities required to support the CLCPA goal of delivering 70% of the State's electric energy needs from renewable sources by 2030.[7] Pursuant to the May Order, the Utilities:

- Evaluated the local transmission and distribution system of the individual service territories, to understand where capacity "headroom" exists today;
- Identified existing constraints or bottlenecks that limit energy deliverability;
- Considered synergies with traditional capital expenditure projects (i.e., aging infrastructure, reliability, resilience, compliance market efficiency, operational flexibility, etc.);
- Identified least-cost upgrade projects to increase the capacity of the existing system;

[7] New York is simultaneously evaluating bulk transmission facilities needed to support the CLCPA's goal of 100% renewable generation by 2040. Therefore, the assumptions that serve as the foundation of the Utility Study have been coordinated with both the 2040 and Offshore Wind (OSW) Studies.

- Identified potential new or emerging solutions that can accompany or complement traditional upgrades;
- Identified potential new projects that would increase capacity on the local transmission and distribution system to allow for interconnection of new renewable generation resources; and
- Identified the possibility of fossil generation retirements and the impacts and potential availability of those interconnection points.[8]

Figure 1 and Figure 2, below, summarizes the range of projects proposed for LT&D development in Phase 1 and Phase 2.

Figure 1: Phase 1 LT&D Proposed Project Estimates

Project Name	Projects (No.)	Estimated Project Cost	Estimated Project Benefit (MW)[9]
Central Hudson			
Transmission	6	$152M	433
Distribution	12	$137M	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	$633M	367.1+
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	$6,800M	8,162
Transmission Total	**52**	**$4,164M**	**6,619**
Distribution Total	**61**	**$2,636M**	**1,543**

* $789 million of investment (reflecting 5 of 8 projects) have already received funding approval. Incremental Phase 1 distribution costs for CECONY are $341 million.

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8 Ownership of interconnection points is largely covered by FERC-approved NYISO tariffs, outside of the control of the Utilities.

9 MW Benefit is provided as an indicator of the relative benefit of each project. Once the BCA methodology outlined in Part 1, Section III is approved, the Utilities will work to update this metric for Phase 2 projects.

Figure 2: Phase 2 LT&D Proposed Project Estimates (Conceptual)

Project Name	Projects (No.)	Estimated Project Cost*	Estimated Project Benefit (MW)
Central Hudson			
Transmission	6	$138M	766
Distribution	7	$55M	222
CECONY			
Transmission	6	$4,050M	7,686
Distribution	2	$1,300M	360
LIPA			
Transmission	6	$1,281M+	1,830
Distribution	8	$167.2M	937
National Grid			
Transmission	13	$1,371M	1,500
Distribution	7	$510M-$1,206M	1,162-2,141+
NYSEG/RG&E			
Transmission	11	$780M	943MW
Distribution	5	$125M	88.3MW
Total	71	$9,7777-$10,428M	15,494-16,473
Transmission Total	**42**	**$7,620**	**12,725**
Distribution Total	**29**	**$2,157-$2,853M**	**2,769-3,748**

* In general, the Phase 2 projects included by the Utilities are in early stage development, without completed, detailed designs and/or engineering. Therefore, costs provided in this figure should be considered conceptual estimates.

Part 3 summarizes progress that has been made in the development of plans to study, evaluate, pilot, demonstrate, and deploy new and/or underused technologies and innovations that can increase electric power throughput, increase electric grid flexibility, increase renewable energy hosting capacities, increase the electric power system efficiencies and reduce overall system costs. These plans were developed to answer the following questions:

- Are there existing technologies that can improve the efficiency of the grid that are being underutilized?
- Are there research and development opportunities for new or emerging technologies?
- How should the State's research and development efforts be organized?
- How should the Utilities coordinate with other New York research and development stakeholders (Electric Power Research Institute (EPRI), universities, national labs, Department of Energy (DOE), Advance Research Projects Agency Energy (ARPAe), etc.)?

The Utilities emphasize the need to alleviate transmission system bottlenecks to allow for better deliverability of renewable energy throughout the State. In particular, there is a need to unbottle constrained resources to allow more hydro and/or wind imports, a need to reduce system congestion, a need to optimize use of existing transmission capacity and rights of way, and a need to increase circuit load factor through dynamic ratings. The Utilities have developed a set of potential technology solutions that include: transformer, cable and transmission line monitoring systems; advanced sensor placement tools; advanced transmission and sub-transmission voltage regulation systems; dynamic line and equipment rating systems; energy storage for grid services; advanced high-temperature, low-sag conductors and new composite conductors; new compact tower designs; power flow controllers; global information system utilization; sulfur hexafluoride monitoring and alternative systems; modular solid state transformers and other advanced grid control devices; and improved ability of transmission lines to redirect flow to underused lines.

The Utilities' recommendations and proposals that appear throughout this Report represent a plan to deploy facilities that will accelerate achievement of the mandates codified in the CLCPA and the AREGCB Act. The Utilities look forward to collaboration with the Commission, DPS Staff, and stakeholders to meet these requirements and the State's policy objectives in a timely, efficient, and cost-effective manner.

Part 1: Transmission Policy Working Group Report

I. INTRODUCTION

On May 14, 2020, the New York Public Service Commission (Commission) issued the initiating order (May Order) in this proceeding[10] in response to environmental policy objectives and related requirements set forth in the Climate Leadership and Community Protection Act (CLCPA)[11] and the Accelerated Renewable Energy Growth and Community Benefit Act (AREGCB Act).[12] The CLCPA establishes aggressive targets for the reduction in greenhouse gas (GHG) emissions, renewable and emissions-free electric generation, and development of off-shore wind. The AREGCB Act directs the Commission to take specific actions to ensure that New York's electric grid will support the State's climate mandates. As noted by the Commission, the integration of clean generation in New York State will require a "restructuring and repurposing"[13] of New York's electric local transmission and distribution (referred to as LT&D) infrastructure. These actions directed by the AREGCB Act include:

1) Conduct a comprehensive study to identify distribution system upgrades, local transmission upgrades, and investments in the bulk transmission system as necessary or appropriate to achieve the CLCPA targets ("power grid study"), and issue an initial report of findings and recommendations on or before December 31, 2020;
2) Initiate a proceeding to (a) establish a distribution and local transmission capital plan for each utility (with utility proposals to be filed on or before November 1, 2020)[14] and (b) establish a distribution and local transmission planning process to guide future investments; and
3) Develop a state-wide plan to develop and implement bulk transmission-level investments that are necessary or appropriate to achieve the CLCPA targets using the NYISO's Public Policy Planning Process or, for projects the Commission determines must proceed expeditiously to meet CLCPA targets, designating NYPA to develop, alone or in collaboration with others.

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10 Case 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act* (Transmission Planning Proceeding), Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (issued May 14, 2020) (May Order).

11 New York Public Service Law, § 66-p.

12 New York Public Service Law §§ 162, 123 and 126.

13 Transmission Planning Proceeding, May Order, p. 2.

14 Transmission Planning Proceeding, May Order. The utility working groups were originally ordered to file the proposals on process and ratemaking matters discussed in this Report on October 5, 2020. On September 1, 2020 the Commission Secretary granted an extension to the filing date to November 1, 2020 to align these recommendations with the filing of analyses related to potential distribution and local transmission upgrades to facilitate CLCPA compliance, which can be found in Part 2 of this Report.

The AREGCB Act and the May Order distinguish between distribution, local transmission, and bulk transmission assets. For the purposes discussed in this Report, "local transmission" refers 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 200 kV, as defined by the Commission in the May Order.[15] BPTF are planned and operated by the NYISO, pursuant to its tariff approved by the Federal Energy Regulatory Commission (FERC).

In the May Order, the Commission focused on the AREGCB Act's requirements related to D&LT systems and directed the Utilities to develop proposals for:

1. A transparent planning process, to be implemented by the utilities with as much consistency and interoperability as possible, that will identify additional projects on the distribution and local transmission systems that support achievement of CLCPA goals;
2. An approach to account for CLCPA benefits in the utilities' planning and investment criteria;
3. An approach to prioritizing any such recommended projects in the context of the utilities' other capital expenditures and the CLCPA time frames;
4. A benefit/cost analysis to apply in assessing potential investments in CLCPA upgrades to the distribution and local transmission systems, as well as any other criteria the utilities believe should be applicable to evaluating these investments; and
5. Cost-containment, cost recovery, and cost allocation methodologies applicable to these investments and appropriate to the State's climate and renewable energy, safety, reliability, and cost-effectiveness goals.[16]

The recommendations made in the sections within this Part 1 reflect the Utilities' response to the May Order's directives and their recommended approach for timely and efficient achievement of the CLCPA and AREGCB Act mandates. Consistent with the Order, the Utilities focus on adaptation of existing distribution and local transmission planning processes and consider opportunities to identify and accelerate or develop select projects to facilitate achievement of CLCPA objectives. This filing does not address the NYISO BPTF planning process.

The existing end-to-end distribution and local transmission and distribution planning process consists of the following multiple steps:

- Establishing planning objectives;
- Specifying investment criteria, including reliability and safety standards that must be maintained to provide reliable service;
- Identifying preferred solutions, including a review of estimated costs; and

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[15] Transmission Planning Proceeding, May Order, p. 3 Note 4. The May Order also includes the following caveat to the definition included here: "…However, as the Utilities consider the issues outlined in this order, we recognize that an alternative definition may emerge."

[16] Transmission Planning Proceeding, May Order, pp. 7-8.

- Evaluating alternative solutions, including local transmission and distribution projects and non-wires solutions, where appropriate or possible.

Achievement of clean energy mandates will require modification of the Utilities' planning objectives, and therefore changes to the system planning and project prioritization processes, decision-making tools, and stakeholder involvement. As acknowledged in the May Order, fulfilling CLCPA and the AREGCB Act may also require changes to existing practices concerning cost allocation and cost recovery, as certain benefits of the necessary or appropriate Utility T&D investments will accrue not only to customers within, but also outside, the investing Utility's service areas. For projects that support the CLCPA, regulatory approvals outside a Utility's normal rate case may be required to recover costs from customers across the state.

The Commission indicates that it seeks input and proposals on several specific elements of the planning process, including, "[a] benefit/cost analysis to apply in assessing potential investments in CLCPA upgrades to the distribution and local transmission systems, as well as any other criteria the Utilities believe should be applicable to evaluating these proposals."[17] Benefit/Cost Analysis (BCA) is currently applied selectively by the Utilities for certain customer programs (*e.g.*, energy efficiency programs, non-wire alternatives, and large investment programs such as advanced metering infrastructure). In Section IV, below, the Utilities address adaptation of the current BCA framework and consider its merits for comparing competing projects to achieve CLCPA mandates.

Finally, the Utilities understand that the Commission will consider overall costs to customers of achieving the CLCPA. The cost of implementing local T&D upgrades is one element of the costs associated with CLCPA achievement, which will also require much more significant investments in bulk transmission, large scale renewables, and other resources to balance the system. The CLCPA and the May Order recognize that *all* of these costs and clean energy opportunities must be considered together, holistically.[18] The Utilities firmly believe that regardless of the pathway the State decides on to meet the State's clean energy and clean air mandates, local transmission and distribution investment can help create the flexible system necessary to meet the mandates cost-effectively.

A. Principal Recommendations

The Utilities stand ready to work with the Commission to identify cost effective local T&D projects that support achievement of the CLCPA. The Utilities make the following

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17 Case 20-E_0197 - May Order at p. 7.

18 E.g., the CLCPA statute grants the Commission the discretion to suspend or temporarily modify any element of programs to meet the law's mandates after a hearing and a finding that (1) the program "impedes the provision of safe and adequate electric service," (2) the program "is likely to impair existing obligations and agreements," and/or (3) "there is a significant increase in arrears or service disconnections" that the Commission determines is related to the program.

recommendations and proposals on process and ratemaking matters in support of this critical State objective in the sections that follow in Part 1, below:

Section II: CLCPA Investment Criteria and Project Prioritization

- The Utilities recommend a set of local transmission and distribution investment criteria designed to meet CLCPA mandates, including:
  - Cost effectiveness of local transmission and distribution investments;
  - Greater renewable energy utilization (*i.e.*, to reduce curtailments and increase renewable power delivery to New York customers);
  - Streamlined renewable energy project deployments to deliver benefits faster;
  - System expandability to interconnect renewable generation;
  - Improved system flexibility to manage intermittent resources; and
  - Firmness of renewable generation projects that would be facilitated by the proposed LT&D project(s).
- Use of these criteria would allow the utilities to identify CLCPA-driven projects along with traditional Reliability, Safety, and Compliance projects.
- The Utilities recommend that these approaches be integrated with existing local transmission and distribution planning processes going forward.

Section III: Benefit Cost Analysis

The Utilities recommend that the Commission accept a set of local transmission-related BCA guidelines for CLCPA projects. These guidelines will comprise a simple, consistent, repeatable mechanism to allow local transmission owners to efficiently prioritize CLCPA-related investments.

Section IV: Stakeholder Engagement

The Utilities recommend annual engagement with stakeholders through robust dialogue and data exchange built as a supplement to existing mechanisms, which provide transparency in distribution planning. Recommended stakeholder engagement opportunities specific to local transmission planning are informed by existing NYISO processes but would be conducted outside of NYISO structures (*i.e.*, by each New York jurisdictional utility).

Section V: Cost Allocation and Cost Recovery

State CLCPA and AREGCB Act mandates to incorporate an increasing share of renewable generation into local transmission and distribution activities will mean additional costs. Clear cost allocation and recovery processes are imperative to ensure timely implementation and cost-effective project deployment. The Utilities make the following recommendations:

1) Cost sharing measures should not impede project development.
2) Beneficiaries must include all customers throughout the state to ensure equitable cost allocation.

3) The incremental cost of utility projects prioritized to support CLCPA mandates should be eligible for load ratio share cost allocations.
4) The Commission should determine, as part of its overall authorization of utility local projects, those projects for which costs should be shared and which should not, recognizing that regional planning differences that benefit a region are also needed to facilitate CLCPA mandates. The Commission should track individual utility CLCPA project costs and consider whether costs are incurred equitably across the State when determining the need for cost sharing.
5) The Commission should leverage as much as possible the existing utility rate case process to expedite CLCPA projects.
   - The Commission should authorize project cost recovery outside of rate case processes to expedite projects.
6) Utilities must have certainty on cost allocation and recovery before projects can begin.

Section VI: Public Service Law, Article VII

Even with the transmission policy and ratemaking improvements outlined above, CLCPA benefits will not be realized until the transmission and distribution improvements identified through the planning processes are sited, designed and built. Accordingly, the Utilities conclude this Report with an outline of potential opportunities for improving the timeliness and predictability of the transmission siting process for major electric transmission facilities under Public Service Law Article VII.

II. CLCPA INVESTMENT CRITERIA AND PROJECT PRIORITIZATION PROCESS

A. Introduction

The May Order recognizes that local transmission and distribution planning processes must evolve to accommodate CLCPA mandates as an explicit planning objective. Modified planning processes to facilitate compliance with the CLCPA must be transparent and consistently applied across utilities, while recognizing that regional differences do exist. The outcome of the utility T&D planning will be a portfolio of proposed projects that reflect multiple system objectives: reliability and safety, adherence to environmental standards, and cost-effectiveness.[19] Current processes are examined and proposals to enhance these processes for CLCPA adherence are described below. Section B below provides context on the current planning processes. Section C focuses on the criteria utilities will use to identify CLCPA-driven projects (or parts of projects). Section D discusses how the planning criteria will be incorporated into utility capital plans. Section E provides clarification on prioritization and approval processes, and Section F concludes with the Utilities' recommendations regarding CLCPA investment criteria and project prioritization processes.

B. Context: Current Planning Processes

i) NYISO Transmission Planning Process

The Utilities collaborate with the NYISO in evaluating, planning, and implementing transmission projects to provide reliable operations and meet forecasted needs. In general, the NYISO is responsible for identifying and resolving reliability needs on the BPTF; the Utilities are responsible for reliable operations within their transmission system footprints. The utilities are also responsible for evaluating the potential impacts of BPTF on their local transmission system and applying transmission planning criteria to select necessary infrastructure investments on the local transmission and distribution systems, coordinating as appropriate with the NYISO and neighboring utilities.

These transmission planning processes are performed in accordance with federal rules and the NYISO's Open Access Transmission Tariff.[20]

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[19] CLCPA will accelerate the deployment and interconnection of intermittent, renewable resources, which may challenge the planning and operation of local transmission and distribution systems. While standards established by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the New York State Reliability Council (NYSRC) may evolve as the State's energy resource portfolio transitions, this Report assumes that compliance with existing NERC, NPCC, and NYSRC standards will remain a paramount and guiding utility concern.

[20] On April 24, 1996, the FERC issued Order No. 888, which requires jurisdictional utilities to provide access to transmission service under terms that are comparable to those that apply to the utility itself. These terms are formalized in an Open Access Transmission Tariff (OATT).

The NYISO evaluates the BPTF through its Comprehensive System Planning Process (CSPP). The CSPP includes the quarterly Short-term Reliability Process (STRP), the biennial Reliability Needs Assessment (RNA), and Comprehensive Reliability Plan (CRP). These processes identify and solicit solutions for bulk electric reliability needs. The Congestion Assessment and Resource Integration Study (CARIS) evaluates benefits of projects designed to relieve congestion, and the Public Policy Transmission Planning Process (PPTPP) identifies and solicits projects to satisfy public policy needs.[21]

In their role, the Utilities plan for both the BPTF and the non-BPTF for their service territories based on all applicable planning criteria. The Utilities' Local Transmission Plans (LTPs) and local upgrades are an input to the NYISO's determination of BPTF system needs. Local transmission needs are assessed based on applicable utility planning criteria (discussed below) and may also consider inputs from Public Policy Requirements.[22] In addition to the reliability standards, a utility may implement specific planning and investment criteria to satisfy local needs or planning directives.

ii) Current Utility Local Transmission and Distribution Planning Process

Local transmission needs are currently driven by several factors including:

- Reliability, safety, and compliance;
- System capacity/load growth;
- Customer requests including Distributed Energy Resources (DER) access and public requirements;
- Asset condition/aging infrastructure, resiliency; and
- Environmental impacts.

The *current* planning process for utility local transmission and distribution facilities varies based on planning needs and investment drivers, and consists of two project categories:

1) Reliability, Safety, and Compliance investments include:
   - *Transmission Proactive Reliability*: The Utilities propose projects to address reliability and other needs that are identified in periodic transmission planning studies (Reliability Studies). Reliability Studies assess the current and planned transmission system for compliance with applicable industry reliability standards that apply to voltage, thermal, and stability criteria among other requirements.[23]

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[21] Proposals and recommendations related to the identification and prioritization of transmission projects discussed in this Report pertain only to those projects that may accelerate achievement of CLCPA mandates. Changes to the NYISO planning processes are out of scope.

[22] The NYISO OATT allows a transmission utility to include in its LTP a project driven by a public policy need. All costs would be allocated to the utility's customers, consistent with all LTP projects.

[23] These standards include but are not limited to NERC Standard TPL-001 reliability standards, NPCC Regional Reliability Reference Directory #1, NYSRC Reliability Rules, and TO-specific reliability guidelines.

- *Interconnection or Public Requirements*: Certain transmission projects focus on designing the most appropriate and efficient solution to address needs other than compliance. These may include customer interconnections and public requirements.[24]
- *Facility Damage or Failure*: Unplanned and unforeseeable events must be addressed if and when they occur.

2) Projects required to maintain or enhance an asset condition or maintain resiliency include:
   - *Asset Condition projects*: transmission investments, such as replacement of the elements of overhead circuits, underground cable, or substation equipment. Overhead circuit investments are performed in compliance with National Electric Safety Code (NESC) requirements.
   - *Resiliency investments*: transmission investments that increase the resiliency of the transmission network against extreme weather events (*i.e.*, storm hardening).

Throughout the remainder of this filing, the term "Reliability, Safety, and Compliance" includes the concepts of asset condition and resiliency. That is, Reliability, Safety, and Compliance projects include projects that are pursued to respond to transmission proactive reliability, interconnection and public requirements, facility damage or failure, asset conditions, and resiliency needs.

Planning processes vary by project category. The outcome of the utility T&D planning is a portfolio of proposed projects that reflect the objectives identified above. All proposed projects are identified in a utility's Capital Expenditure Plans, and all proposed projects, with estimated capital spending, are identified in each utility's rate case filings. In certain cases, an application for a certificate of environmental compatibility and public need may need to be prepared and approved by the Commission before construction of a proposed project can begin.[25] Each utility retains the flexibility to organize, prioritize and deliver projects included in a rate plan based on current system needs and conditions. Cost recovery typically occurs over many years in alignment with the depreciable lives of the various capital investments. Individual projects with long implementation time frames may be developed in phases and addressed in multiple rate cases.

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[24] *E.g.*, responding to a request by a municipality.

[25] Public Service Law Article VII requires the Commission to review and make findings concerning the environmental compatibility and public need of major electric transmission facilities in New York State. Major electric transmission facilities are generally defined in Article VII to include transmission lines with a design capacity of 125 kV or more that extend one mile or more, and lines 100kV or more that extend 10 miles or more. See Public Service Law §§ 120 and 121.

The Utilities continue to perform Reliability Studies throughout the year and make adjustments for a variety of evolving factors.[26] These changes can impact the timing and cost estimates for planned projects.

C. Incorporating CLCPA into the Utility T&D Planning Process

The CLCPA mandates the transformation of the State's energy supply portfolio. Integration of such large quantities of clean energy resources to local transmission and distribution facilities will require each utility to determine how to accommodate such resources and deliver the power to loads with local transmission and distribution investments that meet technical and economic criteria.

Going forward, the Utilities propose to use new investment drivers that address the unique operational attributes of renewable and intermittent resources when conducting studies that will identify "necessary or appropriate" local transmission and distribution investments. These incremental CLCPA investment criteria[27] can be incorporated into the transmission planning process and project-specific analyses. These criteria will address:

1. *Renewable Utilization* (including renewable energy unbottling and delivery) – enabling greater utilization by enabling generation connected to the local system to move renewables into the bulk system ("on-ramps"), as well as flows from the bulk system into the local transmission and distribution system where it can be used by customers ("off-ramps");
2. *Timing* –accelerate or expand a project to accommodate CLCPA targets;
3. *Expandability* – ability to help accommodate future project expansion;
4. *Cost Effectiveness* – contribution to lowering costs of achieving CLCPA targets;
5. *Improve System Flexibility to Accommodate Greater Intermittency* – does the project improve reliability in the face of rapidly increasing intermittency; and
6. *Firmness* – does the project enable existing or new renewable generation in a region? Are the renewable generation proposals in a utility or NYISO interconnection queue sufficiently firm to justify the transmission investment?

These investment criteria are discussed in greater detail, with examples, below.

i) Renewable Utilization (unbottling and delivery)

Renewable Utilization encompasses unbottling (*i.e.*, moving power from generation to the bulk transmission system) and usability (*i.e.*, bringing renewable generation to load centers).

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26 *E.g.*, changes to assumptions, constraints, project delays/accelerations, weather impacts, outage coordination, permitting/licensing/agency approvals, changes to system operations, performance, safety, any customer-driven needs that may arise.

27 The term CLCPA investment Criteria is used throughout this Report to mean criteria that are not driven by traditional planning concepts (*i.e.*, reliability, safety, compliance). Instead, CLCPA investment Criteria are driven by the requirement that 70 percent of energy consumed in New York come from clean resources by 2030, and 100 percent by 2040.

The concept recognizes the role of local transmission infrastructure as the between the BPTF and the distribution system.

Unbottling Renewables (Relieving Constraints Downstream of Renewables)

Explanation Improves the pathways for renewable generation to reach the bulk electric system / reduces curtailment of renewables in a given region or across New York transmission system.

Metric Annualized unbottled energy (calculated over 40 years[28])

Case Study National Grid's Multi-Value Transmission Methodology

National Grid created what it called its Multi-Value Transmission (MVT[29, 30]) project to address both National Grid system needs and New York policy and system needs. MVT projects are designed to improve system reliability while also enabling the delivery of renewable resources.

National Grid applied a production cost model to evaluate the deliverability of two separate pockets of renewable generation in National Grid's transmission system. One analysis looked at proposed solar generation in an area, located between National Grid's substations near Utica. The model included a total of 510 MW of dispatchable Large-Scale Renewable (LSR) solar generation connected to the 115kV transmission and the 69kV subtransmission networks in the study area. The model also included 156 MW of non-dispatchable Distributed Energy Resource (DER) solar connected to distribution stations throughout the study area. A second analysis looked at wind generation in Western NY. The model included a total of 207MW of existing wind and an additional 200MW of expected future wind. Initial production cost models were used to determine annual renewable curtailment for the base cases in each study. From these simulations, National Grid created a list of the most-binding elements. Subsequent models evaluated the curtailment impact of addressing the binding elements individually and in combination for each study.

The Utica area analysis found that constraints within the local network resulted in 136 gigawatt hours (GWh) of annual solar curtailment. It was found that addressing the most binding elements in the area provided 115 GWh of annual relief (addressing 85% of the renewable curtailment). The Western NY

28 The useful life of local transmission and distribution investments is generally 40 years or longer. We adopt 40 years as a reasonable proxy for a potential useful life for a given element of system equipment. See Section III, below.

29 The term MVT was created by National Grid over the years to describe a new type of project. National Grid's projects were the first in NY to be described this way. We have adapted and adopted that term in this section of this Report and others to mean transmission driven by both reliability and public policy mandates.

30 This project is described in more detail in National Grid's current, pending rate case before the New York Public Service Commission, Docket 20-E-0380.

analysis found that constraints posed by series reactors on a transmission line result in 77 GWh of annual wind curtailment. It was found that relocating the reactors provided 61 GWh of annual relief (addressing 79% of the renewable curtailment). Both transmission solutions sought to relieve the highest amount of renewable curtailment in the most cost-effective manner. Both proposed solutions also provide significant reliability and operational flexibility benefits that are difficult or infeasible to accurately quantify.

Renewable Delivery ("Off-ramps")

Explanation In addition to improving the deliverability of renewables to the bulk transmission system, utilities may need to unbottle Transmission Load Areas (TLAs, i.e. load pockets) so more renewable generation can be delivered into previously constrained load pockets. Deliverability of renewables to the bulk system and from the bulk system into constrained load pockets should be measured using the same metrics.[31] Regulatory requirements, wholesale electricity market conditions, and dynamic system topologies will likely play a role in the way these projects are prioritized.[32]

Enhancing renewable delivery may carry an ancillary benefit of emissions reduction. Renewable curtailments that persist due to transmission constraints may result in the need to dispatch fossil units to compensate for curtailed renewable generation. Relieving the transmission constraint may allow renewables to displace fossil fuel generation in load pockets.

Metric Annualized unbottled energy

Case Study Unbottling New York City Load Pockets

In New York City, generation was built in close proximity to load, requiring fewer long transmission lines to serve local customers. As a result, CECONY's service territory is made up of seventeen TLAs. In CECONY's system load pockets must be served by the combination of generation located within the pocket and imports from external generation. However, imports are limited by the transmission capability to move power into and out of the load pocket. In many of New York City's load pockets, planning and operational criteria require generation inside the pocket to generate power to meet the load in that pocket. Today, the generation in New York City and inside of CECONY's

31 See Section III, Benefit Cost Analysis for a more comprehensive discussion of the benefits of reducing curtailments.

32 A utility seeking to use this criterion would have to demonstrate the energy flowing through the solution would displace local fossil generation.

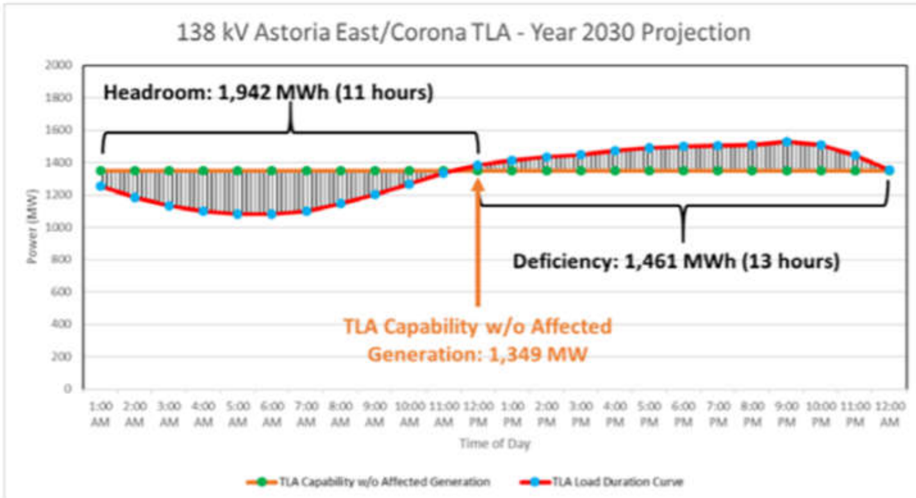
load pockets is predominantly fossil generation. This fossil generation is required to run to serve customers in the load pockets.

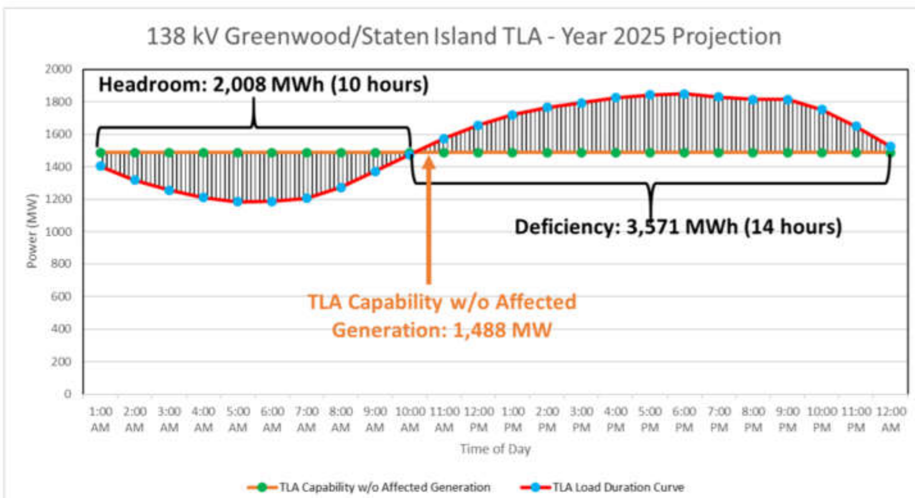
Most, if not all, of the existing natural gas and oil-fired generation within these load pockets will need to be retired to achieve the mandates in the CLCPA. Storage and non-wires alternatives (NWA) may reduce the need to run fossil generation in load pockets. However, such solutions by themselves are unlikely to be sufficient. New York City has several load pockets with peak loads that reach levels 200 MW to 500 MW higher than the existing transmission facilities can provide capacity to move power into the load pocket. The large magnitude of this gap as a proportion of the peak load in these load pockets creates prolonged deficiencies in the ability to meet load without running generation inside the pocket. This lack of sufficient transmission into the load pocket can require generating resources inside the pocket to provide up to 15 hours of support for several consecutive days. An energy storage solution applied to such a load pocket could be required to discharge for fifteen consecutive hours and then charge in the remaining nine hours for consecutive days. Since energy storage resources do not generate energy, their discharge capability is ultimately limited by the time and energy available to charge, storage technology.

CECONY has completed studies on the local system impacts of existing generator compliance plans with new emissions limitations for peaking units.[33] Those studies revealed that removal of the impacted generation resulted in deficiencies extending over 10 to 13 hour periods in the Astoria East/Corona load area, and over 14 hours in the Greenwood Fox Hills load area, as shown in Figure 3, below.

33 For more information, see https://www.nyiso.com/documents/20142/13200831/03%202020%20RNAConEd%20Local%20System%20Base%20Case%20Assessments%20Results.pdf/17424cd7-3cef-3637-2388-5a27654af266

Figure 3: Transmission Load Area Capability in Two Constrained Regions in CECONY's Service Territory





CECONY's transmission study (in Part 2 of this Report) identifies local transmission solutions to enable the generators located within these load pockets to comply with new emissions regulations. These solutions would also facilitate achievement of the CLCPA mandates.

ii) Timing

Explanation This investment criterion asks how local transmission and distribution investments should be accelerated or prioritized to deliver renewables within CLCPA mandate timelines.

Metric	Construction Timeline vs. Potential Interconnection Timelines vs. CLCPA Mandates
Example	*A project slated for later implementation by a Utility is moved up in its capital plan and expanded to provide renewable delivery benefits earlier, in addition to the project's baseline Reliability, Safety, and Compliance benefits.*

iii) Expandability

Explanation	The ability of a project to be expanded to accommodate additional renewable development in a region of a utility service territory.
Metric	Incremental headroom created for expected renewable development
Example	*When conducting an asset condition assessment, a utility notices significant generator interest in the region. That utility then builds in elements that allow for future upgrade buildout that would make renewables deliverable; e.g. adding additional bays in a substation.*
Case Study	New York City Clean Energy Hubs

To meet the CLCPA's mandate of 9,000 MW of offshore wind, these resources must connect to New York City and Long Island. Connecting to either area will pose challenges from both a routing and permitting perspective. However, a benefit of connecting to New York City is direct access to customers there.

The two projects selected by NYSERDA in its 2019 RFP were both larger than 800 MW, and it is expected that future projects will seek to connect at a similar scale. Such interconnections are best made directly onto the 345 kV system to make them available to reach all customers in the City and potentially to be exported for use of customers in other regions. However, the transmission system in New York City offers limited available points of interconnection for new generation to connect. Of those interconnection points that are available today, many would require substantial upgrades to make the interconnecting generation deliverable to loads. Due to the dense population in New York City and the locations of high voltage transmission lines, there are limited locations to build new transmission substations.

CECONY is exploring the opportunity to create Clean Energy Hubs in New York City that would: (1) connect and fully deliver new resources such as offshore wind; (2) solve identified bottlenecks or constraints on the local system to enable loads to be served by renewable energy; and (3) address future load growth from electrification (due to CLCPA), while also improving the resiliency of the company's local system.

iv) Cost Effectiveness

Explanation	Allows renewable generation to serve loads in a cost-effective manner.

Metric Net Benefits and Benefit/Cost Ratio (over 40 years)[34]

Example *The cost of a local transmission upgrade is compared against the cost of procuring additional constrained renewable generation to allow for the achievement of CLCPA mandates. In this case, the project is a multi-value project that is an expansion of a project that is justified under existing planning criteria, but when the scope of the project is expanded will (1) reduce curtailments of existing renewable generation, and/or (2) allow new renewable generation to be delivered to load without significant curtailment of the renewable generation due to local transmission constraints. The Utilities will utilize the BCA methodology described in Section III, below, to demonstrate that the benefits of the project, when combined with other non-monetary benefits applied through the proposed planning process, justify investment in the project.*

Case Study NYSEG Geneva Area Upgrade

The scope of the CLCPA beneficial Geneva Area Upgrade project includes a modest expansion of an existing planned NYSEG substation project (the Border City 115 rebuild and capacitor additional project). In addition to the substation expansion, power flow control devices, and a storage device could together provide significant renewable generation congestion relief to this area.

In this case, the incremental substation expansion work, power flow control devices, and storage system would not be justifiable under the current planning practices. However, with the introduction of CLCPA investment planning criteria, these components can be considered based on their cost and beneficial effect in unlocking renewable resources in support of the State's CLCPA objectives. The cost effectiveness calculation would include a comparison of the amount of renewable energy that could be curtailed with and without the upgrades. The differences of the renewable energy that can be dispatched before and after the upgrades is the MWh benefit from the unbottling renewable energy, which is then utilized in the calculation of Net Benefits and Benefit/Cost Ratio. The annual revenue requirement of the incremental cost of the power flow control equipment and storage is used as the cost for BCA calculations.

34 See Section III: Local Transmission Benefit-Cost Analysis.

v) Improve System Flexibility to Accommodate Greater Intermittency

Explanation The ability to operate local transmission and distribution system reliably and efficiently in regions with high penetration of intermittent renewables.

Metric When non-firm renewable generation[35] penetration levels in the region begin to dominate the local generation mix a Utility could trigger a LT&D project to prevent loss of load event triggered by most or all of the non-firm renewables in that region.

Example The sudden loss of 300 MW of solar generation due to unforeseen cloud formation in a specific region could trigger a local loss-of-load event. A Utility project may develop a solution[36] to improve system flexibility and eliminate this reliability risk. Such an investment will likely include resiliency, reliability, or expandability benefits as well.

vi) Firmness

Explanation Firmness represents the certainty of interconnection of renewables in a given region of a Utility's system. Firmness where sufficiently demonstrated should be a criterion that can drive the need for upgrades to a utility system.[37]

Metric Incremental, future renewable delivery. There are a number of criteria that a utility can utilize to determine how likely a generator is to reach commercial operation, or that generator's Firmness.

Example *A utility is notified that NYSERDA's Build Ready solicitation has closed and NYSERDA has identified three sites in a region of the company's service territory. Generators have signed contracts to develop their project at the site they were awarded. A Utility may then rely on a local transmission or distribution investment to permit interconnection of the clean energy resources.*

Case Study Build Ready Program

NYSERDA's Build Ready program[38] proposes to create opportunities for new renewable development at high potential sites across the New York LT&D system. NYSERDA will conduct formal and detailed assessments to identify brownfield, and other similarly underutilized parcels of land. Those parcels will

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35 Non-firm renewable generation as used here means: an intermittent generator NOT coupled with energy storage, and therefore unable to generate due to changes to weathers.

36 A transmission or distribution solution may include storage or other advanced transmission technologies.

37 Under federal rules, any new or expanded points of interconnection would need to be made available to any prospective generators consistent with open access principles. However, given the State's clean energy policies, it is not expected that there will be many future applications from fossil-fueled generators.

38 Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard* (CES Proceeding), Order Approving Build-Ready Program (Issued October 15, 2020).

be studied by NYSERDA from siting, interconnection, and cost of development perspectives. After identification and study NYSERDA will auction these 'Build Ready' sites to the developers prepared to make renewable energy investments in New York.

These Build Ready sites, once successfully auctioned, provide high quality and reliable data points for the Utilities to consider when conducting short and long-term capital planning processes. A handful of approved and auctioned Build Ready sites in a region will support cost-effective investment by the local and interconnection utility.

D. Classification and Prioritization of LT&D Projects

Clean energy enablement projects deliver value that should be reflected in a utility's portfolio of projects. The portfolio will continue to include Reliability, Safety, and Compliance projects that are required under existing planning criteria. This Report proposes a two-phased approach to integrating CLCPA values into the Utilities project portfolios.

- *Phase 1* projects are immediately actionable projects that satisfy Reliability, Safety, and Compliance purposes but that can also address bottlenecks or 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 pipeline. Phase 1 projects will be financially supported by the customers of the utility proposing the project.
- *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 described in Section III, below.

As a first step (Phase 1), the Utilities propose to apply the supplemental CLCPA Investment Criteria to identify ready opportunities to accelerate or progress Reliability, Safety, and Compliance projects to provide additional CLCPA benefits (i.e., Multi-Value projects). Part 2 of this Report provides a list of projects that are ready for immediate implementation that satisfy traditional investment criteria and that unleash CLCPA benefits. Figure 4 describes an initial classification scheme for local transmission and distribution projects. Phase 1 will consist of Multi-Value projects

Phase 2 projects will include those that are (1) purely CLCPA driven, and (2) modifications or additions to Multi-Value projects that increase CLCPA target achievement.

Figure 4: Illustrative Local Transmission and Distribution Project Types

T&D Project Type	Description
Reliability, Safety, and Compliance	Projects driven by asset condition, reliability, resiliency, cybersecurity, safety, or compliance directive from regulatory bodies including, but not limited to: Commission, NERC, NYSRC, EPA, NY DEC, FERC, NPCC. Reliability, Safety, and Compliance projects can be broken down further to include mandatory and discretionary projects.
Multi-Value	Projects that have both Reliability, Safety, and Compliance *and* CLCPA benefits.
CLCPA-Driven	Projects identified as needed to achieve CLCPA statutory requirements and CLCPA-related resiliency project.

i) Reliability, Safety, and Compliance Projects

The Utilities currently rely on Reliability, Safety, and Compliance planning criteria to inform the investments that are included in rate cases. These planning criteria are largely similar across the Utilities, but how each company applies them, and which criteria are most important to each Utility differs.

These criteria are set by myriad planning, safety, and environmental bodies as noted above and include critical infrastructure regulations and cyber security rules. Reliability, Safety, and Compliance projects relating to reliability and/or transmission system security must continue to be prioritized investments within all Utilities' capital plans.

In the process of designing and evaluating these projects, each will be assessed for any Multi-Value potential, as discussed below. The analysis of possible CLCPA benefits should have no effect on the need or value of the Reliability, Safety, and Compliance project itself.

Reliability, Safety, and Compliance projects will not change in their priority need.

ii) Multi-Value Projects

Multi-Value projects have a Reliability, Safety, and Compliance component driven by traditional planning criteria, but also serve a CLCPA planning purpose. Should a Reliability, Safety, and Compliance project present the opportunity for expansion to capture additional CLCPA-related benefits, the incremental portion of the project will be assessed using the CLCPA metrics described above in a BCA to determine whether the modification is beneficial.[39] For example, a utility may need to replace an aging transmission line, but through applying the CLCPA investment criteria, finds that it can unbottle additional renewables and move them onto

[39] This process does not apply to Phase 1 projects, which will not be assessed in a BCA.

the bulk electric system by replacing the line with a larger conductor. Now the project has at least two value streams: (1) reliability and (2) helping New York meet its renewable mandates.[40]

To the extent that a Reliability, Safety, and Compliance project presents Multi-Value potential,[41] the BCA described in the next section should apply only to the incremental benefits portion of the project can be utilized as an input to the prioritization process. Once the full metrics of incremental value have been determined, the utility will compare the project's benefits to the full range of potential within a portfolio of projects. Adjustments and prioritization will be made based on all applicable timing factors as well as the criteria discussed above.

The benefit of the incremental CLCPA component of this transmission project accrue not only to the utility's own customers, but to all customers in New York. Accordingly, the incremental cost of the CLCPA component of this Multi-Value project may be eligible for cost allocation to customers outside its service territory, as discussed further in Section V, below. The costs of the conventional Reliability, Safety, and Compliance component continues to be charged to the individual utility's customers.

iii) CLCPA-Driven Projects

This category of projects pertains to LT&D projects that a utility would only include in a rate case or capital plan based on the project's ability to meet the new CLCPA investment criteria described above. Each Utility will use a clear methodology based on the principles in this Report to determine how and why it included a CLCPA-Driven project in its rate case, accompanied by a justification as to how and why the project should be eligible for cost allocation to customers outside its service territory (where appropriate). An example of a CLCPA-Driven project would be a set of local transmission upgrades required to improve delivery of assumed renewable generation in a region of a Utility's service territory to the BPTF for a significantly higher percentage of the 8,760 hours in a given year(s).

CLCPA-driven projects will be designed specifically to achieve CLCPA mandates and will function as cost-effective investments to accelerate progress towards the CLCPA mandates and their attendant metrics. CLCPA projects will be selected using the supplemental CLCPA investment criteria described here, including relative cost-effectiveness in meeting CLCPA mandates using the Net Benefits and BCA calculations described in Section III. CLCPA projects will be organized within a total portfolio so as not to displace or compromise Reliability, Safety, and Compliance projects. Instead, that prioritization will allow for the most efficient deployment and recovery of benefits identified in the BCA and evaluation stages of this process. The benefit of CLCPA projects accrue not only to the utility's own customers, but to all customers in New

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40 See the National Grid MVT project description above.

41 This applies to Phase 2 and beyond.

York. Accordingly, costs attributable to these projects may be eligible for cost allocation to all benefiting customers.

E. Prioritization and Approval of Local Transmission and Distribution Projects

To use the CLCPA investment criteria described above, the Utilities will need to build on their existing capital planning processes. There are four basic inputs to the evaluation process:

- Existing planning criteria (e.g., reliability);
- Incremental CLCPA investment criteria:
- Expected incremental clean energy value; and
- Expected investment costs.

The Utilities plan to approach these inputs in a transparent manner and will appropriately consider stakeholder input in developing project queues.

Each Utility will stage and prioritize Multi-value and CLCPA-Driven local transmission and distribution projects based on the prioritization process described below. The BCA was developed to apply only to those projects (or portions of projects) identified based in the incremental CLCPA investment criteria, and not to projects identified based on existing planning criteria (such as reliability). Reliability, Safety, and Compliance projects are needed to maintain the integrity of the electric system. Any public policy benefits they provide should be acknowledged but performing a full BCA on such projects is not necessary for decision-making. The Utilities therefore recommend that the Commission only require application of the BCA to CLCPA-Driven projects and components of a Multi-Value project that are CLCPA-driven.

Projects identified based on CLCPA drivers and incremental portions of Multi-Value projects attributable to CLCPA drivers should be evaluated against the CLCPA Investment Criteria described above and undergo the BCA, although neither would be dispositive of whether a project proceeds.[42] For example, there may be projects that do not deliver the highest BCA evaluation score as one criterion, but can still be justified based on other factors not assessed, or impossible to accurately assess in the BCA. See the BCA section of this paper to understand how that analysis assigns monetary value to a transmission project's ability to enable New York State energy mandates and renewable delivery.

The processes for selecting and prioritizing projects under this approach are illustrated in Figure 5, below.

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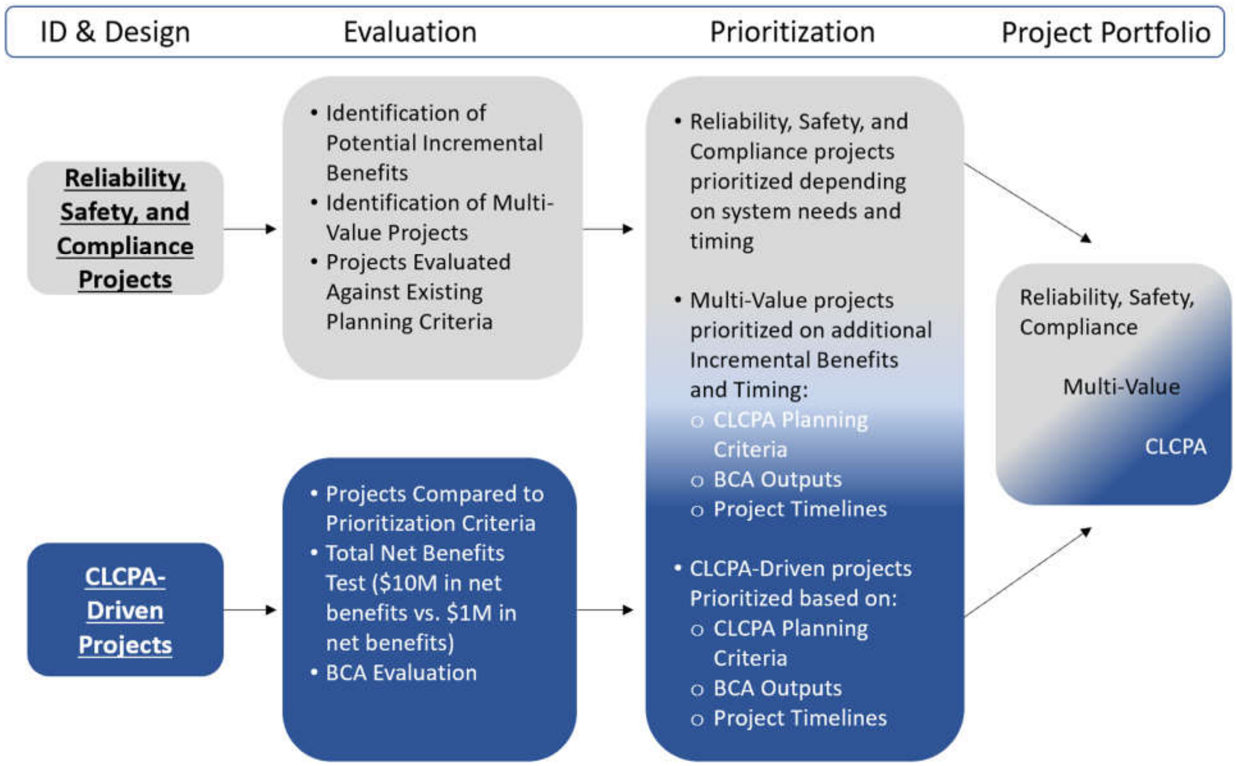
[42] The Utilities' proposals related to BCA for local transmission projects are described in Section III, below.

Figure 5: Illustration of Prioritization Process



F. Summary of Recommendations

The modifications to utility planning practices described above rightfully bring planning paradigms and practices that have been standard practice for decades into the CLCPA era. LT&D planning must evolve to develop cost-effective investment to support New York State's bold energy policies, in addition to continuing to meet all reliability, safety, and compliance criteria. These CLCPA Investment criteria and the prioritization process reflect the Utilities' recommended initial steps to drive the investment necessary to deliver renewable energy to load centers and support New York's electric customers' clean energy preferences, without sacrificing reliability.

Specifically, the Utilities recommend that the Commission approve a set of local transmission and distribution investment criteria designed to meet CLCPA mandates, including: 1) renewable energy utilization (*i.e.*, to reduce curtailments and increase renewable delivery to load pockets); 2) improved timing of renewable projects to deliver benefits faster; 3) grid access expandability to interconnect renewables; 4) cost effectiveness of local transmission and distribution investments; 5) improved intermittency management; and 6) firmness of renewable generation projects. Designation of local transmission and distribution projects by type will streamline classification, prioritization, and approval of CLCPA-driven projects and Reliability, Safety, and Compliance projects. Finally, the Utilities recommend that these approaches be integrated with, and additive to existing local transmission and distribution planning processes going forward (*i.e.*, for Phase 2 and beyond), but not replace or undermine any existing planning criteria or imperatives.

III. LOCAL TRANSMISSION BENEFIT COST ANALYSIS

A. Objectives

This section describes the Utilities' proposed approach to applying a benefit-cost analysis (BCA) to Multi-Value and CLCPA-Driven transmission projects.[43] The May Order notes the Commission's expectation that "the utilities will have to define the benefits of such a project in a way that is fair and objectively quantifiable."[44] Further, the May Order notes that the application of a BCA "presents novel issues, including how to identify who benefits from these CLCPA-targeted investments and by how much."[45]

A BCA is a key factor in project screening and prioritization, and specifically addresses benefits that are quantifiable in dollar terms. The Utilities propose a BCA approach here that can be applied to the full range of potential local transmission projects that have the potential to unlock CLCPA benefits. The approach described below focuses on CLCPA-related metrics, and uses a simple, repeatable methodology.

B. BCA Framework Approach

The Utilities' proposed BCA methodology for local transmission projects (the LT BCA) is designed to address the principles articulated in the BCA Framework Order[46] and Whitepaper.[47] It considers several principles, including:

1) Transparency: The LT BCA provides assumptions, methodologies, descriptions and quantifications of all benefits and costs considered, including those that are localized and as granular as possible.
2) Benefits and Costs Allocation: Care is taken to avoid combining or conflating CLCPA benefits and costs with those associated with Reliability, Safety, and Compliance. The benefits and costs of local transmission to achieve CLCPA objectives (through a focus on avoided renewable curtailments and alternative means of avoiding or making up the renewable energy of these curtailments) are distinctly separate from those of Reliability, Safety, and Compliance projects.

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43 The current planning process for conventional capital investment in local transmission does not require application of a benefit cost analysis (BCA) in all cases. (*E.g.*, projects pursued to address reliability requirements or constraints are not assessed using a BCA today.) A BCA is applied to assess specific customer programs and large investments.

44 Transmission Planning Proceeding, May Order, p. 9.

45 Transmission Planning Proceeding, May Order, p. 9.

46 Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* (REV Proceeding), Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding (BCA White Paper) (filed July 1, 2015).

47 Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* (REV Proceeding), Order Establishing the Benefit Cost Analysis Framework (BCA Framework Order) at 2 (Issued January 21, 2016).

3) Portfolio Perspective: The LT BCA provides a basis for comparing the relative cost-effectiveness of local transmission projects in meeting CLCPA mandates. This allows the Utilities to develop portfolios of investments that best satisfy the investment criteria set forth in Section II.
4) Lifecycle and Sensitivity Analysis: The Utilities' net present value approach considers a 40-year value stream for the alternative approach used for comparison.[48]
5) Comparison to Traditional Investments: The LT BCA compares the levelized cost of local transmission investments needed to reduce renewable energy curtailments to the addition of supplemental renewable energy that would otherwise be needed offset to offset curtailments to achieve the CLCPA mandates. This focuses on the societal cost of each, which is a key feature of the approach the Commission requires the Utilities to use in other contexts.[49]

There are some overlaps between this LT BCA and the approaches described in utility-specific BCA Handbooks, which apply to distribution assets. This LT BCA methodology was developed for the specific purpose of evaluating the relative cost effectiveness of local transmission projects in meeting CLCPA mandates.[50, 51] When applying this framework to local projects, it is necessary to:

1) Provide a basis for evaluating the relative cost of local transmission projects in the context of the benefits they provide in meeting CLCPA targets, both in terms of the magnitude of net benefits and the ratio of benefits to costs;
2) Allow the Utilities to perform initial benefit/cost analysis on a large number of CLCPA-related projects quickly and consistently; and
3) Distinguish incremental CLCPA investments from those that would proceed under Reliability, Safety, and Compliance drivers.

This LT BCA methodology presents a streamlined approach to assessing the benefits and costs of reducing renewable curtailments by adding local transmission.

Simplicity is essential to conduct the analysis necessary to expeditiously meet CLCPA objectives, considering the number of benefit/cost analyses that the Utilities will be required to perform in the relatively compressed time period specified by the Commission and required in the AREGCB Act. To that end, this proposed LT BCA relies on data already available and used in other Utility benefit/cost analyses. Specifically, the environmental value of each MWh of unbottled renewable energy is based on the most recent Renewable Energy Credit (REC) and

[48] This LT BCA approach is a departure from the distribution-level BCA Handbook in order to align timelines used for local transmission benefit-cost analyses with the NYISO's approach for bulk transmission.

[49] Transmission Planning Proceeding, May Order, p. 7.

[50] Note that the LT BCA methodology provides Utilities the option to incorporate on scenarios that consider different inputs or parameters.

[51] LIPA believes that the Commission should also consider the alternative of statewide cost allocation for distribution investments with the objective of spawning distributed renewable generation investment through reducing interconnection costs new distributed renewable generators will face.

Offshore Wind Renewable Energy Credit (OREC) prices as posted or estimated by NYSERDA.[52] The energy value attributable to CLCPA projects is represented by the forecasted Location Based Marginal Price (LBMP) based on the NYISO's Congestion Assessment and Resource Integration Studies (CARIS) Study (using a renewable energy buildout consistent with CLCPA mandates), as utilized in the benefit/cost framework for NWAs. In the 2019 CARIS assessment, the NYISO studied 2029 in a 70 x 30 CARIS sensitivity case and has proposed to extend the CARIS 2 analysis through a 2060 forecast period. The BCA will use the CLCPA forecast in the most current NYISO CARIS public policy scenarios), with extrapolation for future years based on the price trends in the CARIS cases.[53] Utilities may also utilize Installed Capacity ("ICAP") prices forecasted by DPS.

This framework is best viewed as a tool to be used in conjunction with other non-monetary criteria to screen and prioritize investment opportunities for further in-depth design and study. On its own, the LT BCA will not be used to make go/no-go decisions or provide for a ranking of projects solely on benefit/cost metrics. To meet the mandates set forth above, the LT BCA will produce two primary metrics:

1) Net Benefits: Simple measure of net benefits calculated as the discounted 40-year stream of benefits minus the discounted 40-year stream of costs (both beginning at a project's in-service date), with the understanding that project cost recovery may occur over a period longer than 40 years. The net benefit metric will demonstrate the magnitude of net benefits and allow for prioritization of projects that provide the most meaningful contributions to meeting CLCPA mandates. The aggressiveness of CLCPA mandates are such that achieving scale in the selection of projects is crucial for success.
2) Benefit/Cost Ratios: The second metric is a benefit/cost ratio measured as the discounted 40-year stream of benefits divided by the discounted 40-year stream of costs. The benefit/cost ratio is a commonly used metric that shows the relative cost-effectiveness of projects irrespective of size.

Transmission projects have an economic life substantially in excess of 40 years, so this methodology provides a conservative valuation of the long-term benefits of the projects.

i) LT BCA Overview

The benefit/cost metrics were selected based on cost effectiveness in achieving CLCPA targets. The CLCPA and the AREGCB Act are focused on delivering renewable generation to load. As such, the primary metric for the LT BCA is a quantitative valuation of renewable energy that can be unbottled by a project and delivered to customers in New York.

Renewable energy is bottled (curtailed) when transmission limitations prevent renewable energy from serving load. Local transmission investments can reduce these curtailments,

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52 NYSERDA. "Clean Energy Standard: 2020 Compliance Year."

53 New York ISO. "2019 CARIS Report: Congestion Assessment and Resource Integration Study. July 2020. Available here.

increase the flow of renewable energy to customers, and decrease electric sector emissions. There are two general categories of projects:

- On-ramp projects: Local transmission projects developed in areas where local customer load and current transmission export capacity is not sufficient for existing and/or new renewable generation, and where investment is needed to allow for the deliverability of excess renewable energy to the BPTF for delivery to load centers elsewhere in the State.
- Off-ramp projects: Local transmission projects developed to enable renewable energy that is injected into the BPTF to be delivered to local loads where local transmission is insufficient to absorb all renewable energy generated, and renewable energy would otherwise be curtailed.

Examples of on-ramp and off-ramp projects are shown in **Error! Reference source not found.**C. This proposed LT BCA has the flexibility necessary to evaluate both types of projects.

The benefits of unbottling renewable energy are estimated based on the assumption that, in the absence of a transmission project, the energy (MWh) curtailed would need to be replaced by construction of additional renewable energy generation to displace the curtailed energy during other hours of the year when the constraint is not binding. The replacement generation is needed in order to meet the CLCPA mandate that 70% of the State's energy needs be generated by renewable energy sources by 2030 and 100% from emissions-free energy sources by 2040. In that case, the added renewables would increase megawatt-hours of renewable energy during periods where load is sufficient, and when the transmission system has headroom, while accepting more curtailments during periods where renewables are already constrained by load and no headroom exists. For example, if renewable energy is curtailed 20% of the time due to transmission constraints, additional renewable energy can be added that produces enough renewable energy during the 80% of hours where curtailments do not occur to make up for the quantity of renewable energy that is curtailed during 20% of the time. This approach would allow for the production of sufficient renewable energy to meet CLCPA mandates, but at an additional cost. Therefore, the value of unbottled renewable energy is the levelized cost of adding a new renewable energy resource to replace the curtailed energy, accounting for the "spillage" of expected curtailment of the new resource. Because the basic value of a new megawatt-hour of renewable energy in New York, absent curtailment, is the projected market value of renewable energy per MWh (energy and capacity) plus the projected value for a REC or OREC[54], the value of new renewable energy from unbottling curtailed

[54] There are other potential revenue streams, but they are either de-minimis compared to energy and REC prices, or not focused specifically on CLCPA-related benefits.

renewable resource is the (LBMP + ICAP[55] + REC or OREC price)/(1- curtailment percentage)[56]. The calculation above is the primary calculation of benefits for both the Net Benefits and Benefit/Cost calculations (when expressed over a 40-year period)[57]. For both calculations, the cost is calculated as the 40-year revenue requirement for the transmission project.

The LT BCA aims to address constraints and curtailments from a generation pocket to the bulk power system under two options.[58] The first option adds more renewables during unconstrained periods to compensate for curtailment periods, and the second adds transmission to eliminate constraints. Figure 6 is a graphical representation of renewable energy being curtailed when the quantity of renewable energy production in an area with transmission constraints exceeds the total load within that area plus export capability out of the area.

Figure 6: Renewables Constrained from a Generation Pocket or Into a Load Pocket

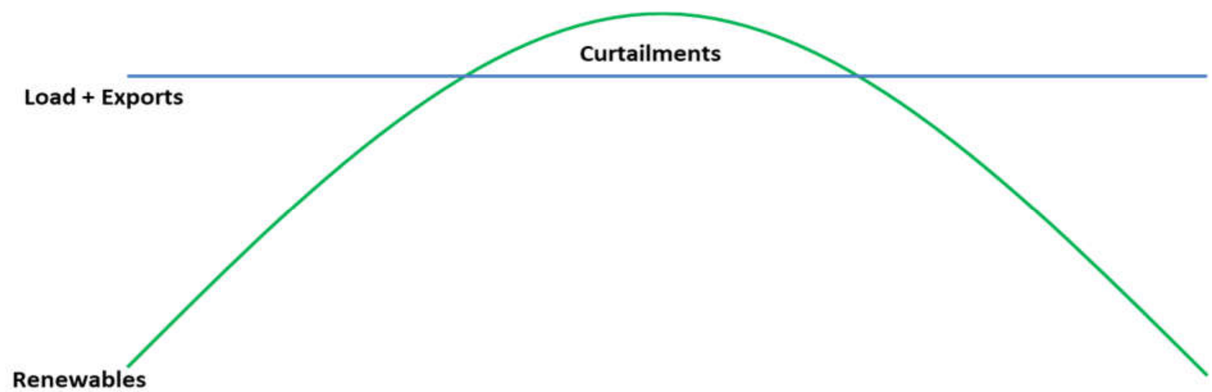


Figure 7 and Figure 8 below illustrate the two options for addressing the curtailment of renewable energy.

Under Option 1, additional renewables are added to the system during unconstrained periods to make up for renewable energy spilled during periods of curtailment. (*See* Figure 7.) As discussed above, this approach would add additional renewable energy, but also exacerbate constraints. The unit cost of the new renewables would need to increase to compensate for

55 The inclusion of ICAP is optional and may be used at a Utility's discretion.

56 The levelized cost of a renewable facility that is unconstrained assumes that the market value is received for all production. If a resource is expected to be curtailed, the unit rate received from the market needs to be grossed up to account for lost sales during periods of constraint. In addition, , the inclusion of an ICAP component is optional.

57 The Utilities considered applying a loss factor, but because the renewable facility used in the benefits calculation is a generic renewable facility with no specific location (either generic upstate or generic offshore wind), the use of a loss factor may introduce a complexity that does not result in any meaningful differentiation between project BCA scores.

58 A similar analysis can be applied for transmission constraints from the bulk power system into a load pocket in instances where renewable curtailments are occurring on the bulk power system. For clarity, this example focuses on bottled generation.

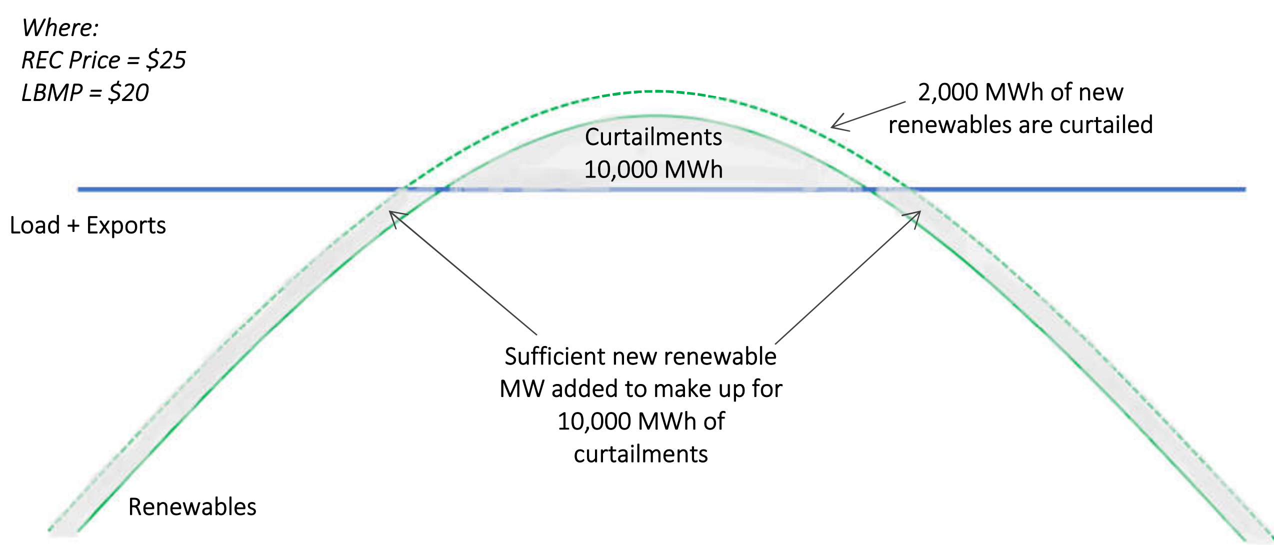
curtailment-related revenue reductions. This entails determining the levelized unit cost of the renewable additions after factoring in the financial impact of constraints. This is calculated as the (REC Price + LBMP +ICAP)/(1-curtailed MWh %). For example, if 16.67% of the new renewable MWh would be expected to be curtailed, the unit cost is:

(REC Price + LBMP + ICAP)/(1 – 16.67%).

The cost implications of each option are distinct as well. For Option 1, it takes 12,000 MWh of new renewables in the export-constrained generation pocket to make up for the curtailment of 10,000 MWh (16.67% curtailment of the renewable additions). Thus, assuming for simplicity that ICAP earnings are zero:

Net Cost = ($25 + $20)/(1-16.67%) = $54.00/MWh.

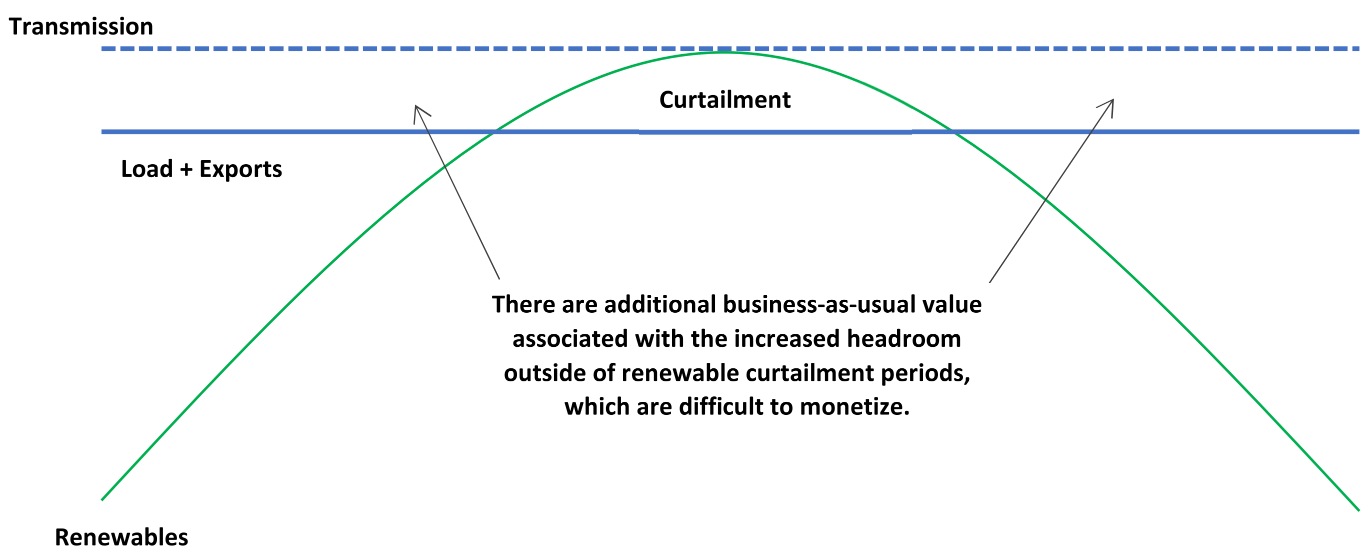
Figure 7: Option 1 (Add Renewables)



Under Option 2, transmission is added to eliminate constraints. (See Figure 8.) The avoided new renewable cost is approximated as the: (REC Price + LBMP +ICAP)/(1-curtailed MWh %) *[i.e. Option 1]*. If the cost of transmission is less than the avoided renewable cost, the B/C Ratio > 1.

Opting instead to construct transmission results in an annual benefit[59] of $54.00 x 10,000 MWh = $540,000. Assuming an annual transmission revenue requirement of $400,000, the B/C Ratio = $540,000/$400,000 = 1.35.

Figure 8: Option 2 (Add Transmission)



The value of choosing Option 2 extends beyond the Net Benefits and Benefit/Cost Ratio calculations. Transmission additions can create additional value during periods without curtailments. For example, by allowing more efficient generating sources to be dispatched and displace higher emissions from less efficient fossil generating sources. This results in additional value in the form of reduced production costs, congestion, and emissions not captured in the LT BCA. It can also provide for increased resiliency and operational flexibility. For simplicity, this BCA does not attempt to quantify these benefits.

The Net benefits and benefit/cost ratio calculations are described below.

ii) Benefit Calculations

The ***Net Benefits*** metric is calculated using the following formulae:

1. For a project that will be built specifically to meet CLCPA targets, and would not otherwise be built, this formula applies:

PV (MWh x RE) + *PV(Other Value) – PV(Project Rev Req)*

[59] This assumes the same prices as are used in the prior example.

2. For a project that is built as an expansion/improvement to a Reliability, Safety, and Compliance project (i.e., a Multi-value Project), this formula applies:

PV (Inc MWh x RE) + *PV(Other Value) – PV(Inc Project Rev Req)*

The ***Benefit/Cost Ratio*** is calculated using the following formulae:

1. For a project that will be built specifically to meet CLCPA targets, and would not otherwise be built, this formula applies:

$$\frac{\text{PV (MWh x RE)} + \textit{PV(Other Value)}}{\text{PV(Project Rev Req)}}$$

2. For a project that is built as an expansion/improvement to a Reliability, Safety, and Compliance project (i.e., a Multi-value Project), this formula applies:

$$\frac{\text{PV(Inc MWh x RE)} + \textit{PV(Other Value)}}{\text{PV(Inc Project Rev Req)}}$$

Where:

"RE" = the levelized cost (in dollars per Megawatt hour) of new constrained renewable energy resources. This is calculated as the:

(REC + LBMP + ICAP)/(1 – curtailment percentage)

Where the curtailment percentage is the expected statewide[60] percentage of MWh of renewable production that would be curtailed in a 70% renewable energy by 2030 case without expansion of the transmission system (i.e., as estimated in the CARIS 70x30 scenario).

"PV" = present value over the period using average after-tax Weighted Average Cost of Capital ("WACC") for the Utilities.[61]

"MWh" = Megawatt hours of unbottled renewable energy calculated by the transmission owner using the Unbottled Renewable Energy Calculation Methodology (described in detail in Appendix A).

60 Note that because renewable energy can be added outside of the zone where the transmission constraint is being solved, use of a statewide percentage of curtailments is more appropriate for assessing the renewable alternative than using the percentage of curtailed renewable energy within the constrained zone, which remains the relevant metric for the transmission alternative.

61 The average of all Utilities' WACC is used because CLCPA benefits are societal, and not specific to any individual Utility's customers.

"Inc MWh" = MWh of unbottled renewable energy attributable to an expansion or modification of a Reliability, Safety, and Compliance project (i.e. does not include MWh of unbottled renewables attributable to the Reliability, Safety, and Compliance project, only to the incremental investment to be made for CLCPA purposes).

"REC" = Societal value of each MWh of unbottled renewable energy, represented by the forecasted REC price or OREC price as applicable to the type of resource producing unbottled renewable energy. REC and OREC prices are the most recent REC and OREC prices posted or estimated by NYSERDA.

"LBMP" = Energy market value of each MWh of renewable energy in the load zone of the transmission project, based on a NYISO CARIS forecast that includes a buildout of renewables consistent with CLCPA mandates, with extrapolation or interpolation as needed to prices that fall outside of the years of CARIS outputs.

"ICAP" = Capacity market value (if any) of the incremental renewable investment compared against the transmission project, converted from dollars per kilowatt-month to dollars per MWh assuming a standard capacity factor for the renewable resource. The ICAP conversion formula is as follows:

Step 1: MW Nameplate x Unforced Capacity Percentage[62] = MW ICAP Value
Step 2: MW Nameplate x Annual Capacity Factor (excluding constraints) x 8,760 annual hours = MWh Energy
Step 3: MW ICAP Value x ICAP Price ($/kW-month) X 1,000 (Kw to MW conversion) x 12 months = ICAP Revenue
Step 4: ICAP Revenue/MWh Energy = ICAP Price in $/MWh

The Utilities will use ICAP price forecasts contained in the NYDPS' ICAP Spreadsheet Model[63]. For renewables with a REC price, the "NYCA" ICAP price is to be used. For renewables with an OREC price, the weighted average of the NYC, LI, and Lower Hudson Valley prices are to be used. Prices will be extrapolated beyond the forecast period based on the price trend.

"Other Value" is an optional benefit category that can be used by a utility only for the purpose of comparing projects within its own service territory (subject to COMMISSION approval of specific benefit metrics). These benefits may be specific to a particular utility in differentiating between its own projects.

"Project Rev Req" = the first 40 years of a project's revenue requirement developed using the Utility's WACC.

"Inc Project Rev Req" = the incremental revenue requirement over the initial 40-year analysis period of a project's lifecycle for a Reliability, Safety, and Compliance project that is

62 NYISO ICAP Manual Section 4.5(b).

63 The ICAP Spreadsheet Model is identified in Attachment A of Appendix C to the Commission's January 21, 2016 Order in Case 14-M-0101.

expanded or modified to fulfill CLCPA targets (i.e. based on only the CLCPA-related incremental project cost)

iii) Benefit Inputs

As is discussed above, the LT BCA will use REC and OREC prices, as applicable, as proxies for the societal value of these reduced renewable curtailments.[64] Since the State values customer payments for the environmental attributes of the renewable energy REC or OREC price (as applicable), the environmental value of reduced renewable energy curtailments are valued at the REC or OREC price for purposes of the LT BCA.

Another proxy for the societal value of avoided renewable curtailments might be the social cost of carbon or other effluents. However, the fact that state-approved contract payments for renewables are based on REC or OREC prices provides a very clear dollar per MWh basis for valuation, whereas valuation based on a social cost of carbon would be more complex and depend, to some extent, on exogenous factors other than the reduced curtailments of renewable generation. For the purpose of developing a simple, replicable framework for analysis, the REC or OREC price fits best.

The LT BCA also accounts for the LBMP as a required revenue stream for a renewable energy project. As in the NWA analysis, the LT BCA will use the CARIS forecast of a statewide average LBMP for renewable projects using a REC price and load-weighted average J and K zonal LBMPs[65] for OREC-derived renewable projects. The forecasted LBMP is also in theory the marginal production cost of the last MWh of energy dispatched including bulk power system losses, so there is an additional rationale for the use of the LBMP. When the LBMP is positive, it is implied that the marginal production cost is associated with a generator that has a fuel source, and thus a marginal cost of energy production that can be avoided by the reduced curtailment of renewables.

iv) Valuation Specifics

The valuation criteria include a Benefit/Cost ratio and Net Benefit sum. Each component of the formula is a 40-year stream of benefits and/or costs, with present valuation performed using the average statewide Utility WACC, consistent with the NWA BCA analysis.[66] For ease of

64 The BCA also recognizes changes in the marginal cost of energy brought about by renewable energy that is unbottled as described below.

65 Zone J refers to Kings, Queens (except the Rockaway peninsula), Richmond, New York, and Bronx counties. Zone K refers to Nassau and Suffolk counties and the Rockaway peninsula in Queens County.

66 There are a variety of metrics used in the NWA that are not utilized in the base benefit/cost analysis project comparison framework, although as noted above could be included in a utility specific project justification. Some NWA metrics were excluded because of de minimis impacts, some due to complexity given the number of analyses needed, and some because they are less relevant to meeting CLCPA targets.

this comparison between projects, all present values should be expressed in present value dollars as of the year of the analysis, not the year of the project in-service date.

The Benefit/Cost ratio provides some indication of the value proposition of an improvement but does not indicate the magnitude of savings made possible by the project, an important consideration in meeting CLCPA integration mandates quickly. The sum of Net Benefits fulfills this role, indicating the quantity of net benefits each project could deliver.

Reliability, Safety, and Compliance projects that would be built by the Utilities without modification or acceleration of development irrespective of this process may have CLCPA-related benefits. In this case, the benefit/cost ratio is effectively infinite because the CLCPA-related value is received at no incremental cost. Thus, those mandatory projects would be assumed to have been built anyway and will not be subject to an LT BCA.

For CLCPA-Driven projects (i.e. projects under development to fulfill CLCPA mandates), the value is the full benefit stream for the project, and the cost is the full project cost.

For Reliability, Safety, and Compliance projects that are expanded and/or improved to meet CLCPA mandates, the value is the incremental CLCPA-related value of the project (beyond the value of the Reliability, Safety, and Compliance project). Likewise, the cost is the incremental cost in excess of the Reliability, Safety, and Compliance project cost. Essentially, for these projects, the Net Benefit and Benefit/Cost Ratio metrics are based only on *incremental* CLCPA-related benefits and *incremental* costs.

Reliability, Safety, and Compliance projects that are justified later in the planning period in the absence of CLCPA-related benefits may be cost effective to advance and implement earlier when CLCPA benefits are considered. In this case, the incremental benefits (e.g. reduced renewable curtailments), will be considered throughout the planning period. Progressing such a project to an earlier date, in the absence of CLCPA benefits, would yield a negative incremental net present value (i.e. net cost increase). This will be considered the incremental net present value cost of the CLCPA related schedule changes.

C. Recommendations

The Utilities recommend that the Commission accept the BCA methodology for CLCPA projects proposed herein. Given the pace with which local transmission upgrades will need to be developed to satisfy 2030 and 2040 CLCPA mandates, a simple, consistent, repeatable BCA method is needed to allow the transmission owners to efficiently prioritize CLCPA-related investments. What is most relevant for this process is how cost-effectively the various projects will deliver CLCPA benefits, and this proposed LT BCA methodology is designed to do that with specificity. The Utilities also recommend that the Commission acknowledge that a) transmission projects have economic lives substantially longer than the 40 year analysis period, which results in additional benefits that are not captured by this analysis; and b) that additional non-quantifiable benefits are likely to be associated with the expansion of local transmission in the state, such as market efficiency and resiliency, and for these reasons, projects need not have a Benefit/Cost Ratio greater than 1 to be ranked for relative cost-effectiveness.

IV. STAKEHOLDER ENGAGEMENT

A. Stakeholder Engagement Overview

Gathering input and feedback from stakeholders and the development community on potential projects and their respective locations that can be fed into local transmission and distribution investment plans is crucial to ensuring the system is built out to appropriately integrate clean energy resources. Utilities communicate with stakeholders and gather input about both local transmission and distribution development plans using a variety of channels. The communication channels that apply to each category of development are designed to illustrate system needs and limitations and to focus development on local transmission and distribution projects that will provide the greatest benefit to customers. These channels are intended to facilitate collaboration with third parties.

i) Local Transmission Stakeholder Engagement

The Utilities recommend that stakeholder engagement in the local transmission planning process build on— but operate completely independent from— the utility LTP presentation process at the NYISO. The NYISO Open Access Transmission Tariff (OATT) provides that Utilities comply with federal regulatory rules governing transparency and stakeholder input for local planning, as set forth in FERC's Order No. 890,[67] and for public policy requirements, as required by FERC's Order No. 1000.[68] As required under NYISO OATT provisions, each utility posts its current Local Transmission Plan (LTP) on its website and is required to provide information on a variety of inputs to LTP plans:

- Identification of the planning horizon covered by the LTP;
- Data and modeling assumptions;
- Reliability needs, needs driven by Public Policy Requirements, and other needs addressed in the LTP;
- Potential solutions under consideration; and
- A description of the transmission facilities covered by the plan.

Under the OATT, the Utilities present their LTP to stakeholders at NYISO Electric System Planning Working Group (ESPWG) and Transmission Planning Advisory Subcommittee (TPAS) meetings. The Utilities make these presentations at a minimum every two years at the start of the ISO's biennial reliability planning cycle. NYISO stakeholders that typically attend these meetings include generators, developers, end-use consumers, environmental parties, and government agencies. Stakeholders are provided the opportunity to provide input and ask

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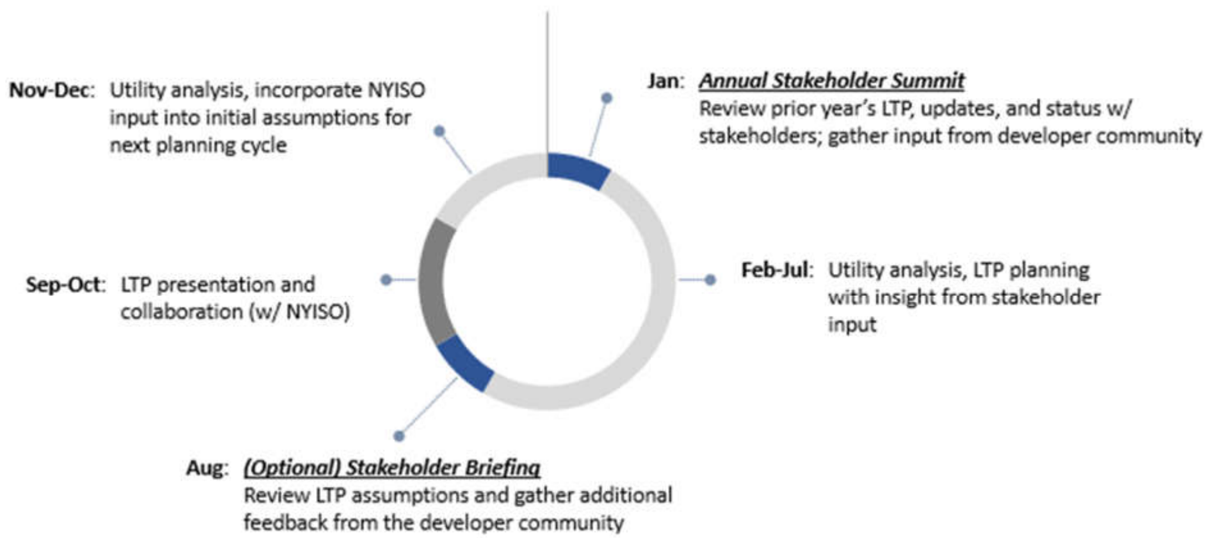
[67] FERC Order No. 890.

[68] FERC Order No. 1000.

questions. While the Tariff only requires the Utilities to present every two years, in practice the Utilities typically present to stakeholders more frequently as their LTP or projects change.

The utilities propose to build on the current LTP process by holding an additional annual meeting to gather feedback from the developer community on local transmission planning considerations.[69] Figure 9 illustrates the proposed stakeholder engagement opportunities throughout a generic LTP process, assuming an approximately annual update cycle.[70] The primary purpose of these meetings is for Utilities to gather information about developers' plans, so that this input can be considered in utility LTPs. These opportunities include an annual Stakeholder Summit designed to facilitate the flow of information and input from the developer community to the Utilities. Later in the year, Utilities may hold an additional Stakeholder Briefing, in which they can explain changes in assumptions and gather additional feedback from the developer community.

Figure 9: Hypothetical Annual Utility LTP Cycle (sample)



ii) Distribution-level Stakeholder Engagement

Utilities currently employ a variety of engagement strategies to apprise third parties of investment plans and to collaborate with stakeholders concerning distribution-level development. There are opportunities for stakeholders to learn about distribution-level system needs through information exchanges, procurement programs, and other regulatory processes.

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69 Information shared in these forums will need to consider limitations imposed by Critical Energy Infrastructure Information (CEII) designations and considerations for NYISO competitive processes.

70 This approximately annual update cycle does not change the reporting frequency to NYISO ESPWG. This stakeholder input opportunity is separate from that process.

Figure 10, below, illustrates many of these approaches, which apply across utilities with subtly different implementation practices from one utility to the next.

Figure 10: Venues that Provide Distribution Planning Transparency, Opportunities for Stakeholder Engagement, and Involvement

Stakeholder Engagement Opportunities	Information Gathering	Stakeholder Input Opportunity	Description
Governance, Information Sharing			
Joint Utilities Advisory Group	✓	✓	The Advisory Group (AG) is an open forum for stakeholders who are actively engaged in the REV process and the Distributed System Implementation Plan (DSIP) filings to advise the Joint Utilities of New York (JU) on a productive and collaborative stakeholder engagement process.
DSP Enablement Newsletters	✓		These newsletters are circulated quarterly and posted to the Joint Utilities of New York website.
System Data & Hosting Capacity Portals	✓		The Joint Utilities of New York website contains links to a variety of system data resources and portals for exploring hosting capacity throughout distribution systems.
Company websites, Joint Utilities website	✓		Companies share information related to a variety of distribution-infrastructure programs (e.g., EV charging locations; EV Make-Ready project implementation plans, NWA opportunities, etc.) The Joint Utilities of New York website contains a wealth of resources related to DSIP filings, stakeholder collaboration opportunities, program implementation strategies, procurement opportunities, etc.
PSEG Long Island Interconnection Working Group	✓	✓	LIPA's service provider PSEG Long Island conducts an Interconnection Working Group, including industry and utility representatives, that provides a forum for joint discussions and recommendations on matters affecting the interconnection of solar and other distributed energy resources to LIPA's electric system.
Regulatory Processes			
Rate Cases	✓	✓	Utilities initiate rate cases approximately every three years
Distributed System Implementation Plans	✓	✓	The Joint Utilities publish detailed implementation plans for distribution system-based investments. The DSIPs, which describe five-year technology and system deployment planning processes and objectives are updated every other year. *(LIPA files a similar plan, called the Utility 2.0 Long Range Plan & Energy Efficiency and Demand Response Plan.)* The Utilities each conduct stakeholder outreach sessions to present the DSIP in each two-year cycle.
Procurement Programs, Opportunities			
Non-Wires Alternatives	✓		Utilities provide information concerning Non-Wires Alternative opportunities for DER providers on company websites.

Stakeholder Engagement Opportunities	Information Gathering	Stakeholder Input Opportunity	Description
Energy Storage Solicitations	✓		Some of the Utilities plan to conduct supplemental solicitations for energy storage resources pursuant to the December 2018 Energy Storage Order in Case No. 18-E-0130.
EV Make-Ready	✓		The Utilities have published implementation plans and associated resources related to EV site Make-Ready opportunities on the Joint Utilities of New York website.
NYSERDA Build-Ready Program	✓	✓	The Commission has approved a new clean energy resources development and incentives program to encourage expedient siting and development of community and environmentally compatible renewable energy facilities to address CLCPA objectives.

B. Recommendations

Today, the Utilities provide transparency in distribution and local transmission planning through the existing mechanisms, many of which are described above. The Utilities recommend that these mechanisms be continued and strengthened to ensure that there are meaningful opportunities to gather input from the developer community that can be considered in local transmission and distribution planning processes and support integration of clean energy resources onto the local system.

V. COST ALLOCATION AND COST RECOVERY

A. Objectives

The Utilities propose methods of cost allocation and recovery for local transmission investments, and CLCPA-related distribution investments not otherwise subject to a utility's distribution cost recovery framework,[71] either entirely or partly within the rate case framework, which will form the basis of a Commission-established "distribution and local transmission capital plan" for each utility. Accordingly, cost allocation and cost recovery for "bulk transmission" (as defined in the AREGCB Act) and distribution upgrades covered under a utility's distribution cost recovery framework are not addressed here.

This section identifies:

1. Potential cost recovery pathways (including current cost recovery processes)
2. Comparison of regulatory pathways and evaluation of benefits and challenges
3. Cost recovery pathway examples
4. Utilities' recommendations to the Commission on cost allocation and cost recovery mechanisms

As stated earlier, the Utilities recommend that the Commission authorize projects in phases, with Phase 1 projects to be those that could proceed through individual utility rate cases, and Phase 2 projects consisting of CLCPA-Driven projects that may require new regulatory mechanisms to facilitate equitable cost sharing across the state.[72] In considering a staged approach, however, the Commission should avoid unnecessary delay between the successive phases, as such delay could risk compliance with the CLCPA's target of achieving 70% renewable energy by 2030.

B. Cost Allocation and Recovery Overview

The Utilities have considered four principal pathways for cost allocation and recovery:

1) Rate Case-Based Approach: Traditional utility rate cost recovery and consideration of potential new Commission-based regulatory mechanisms.

[71] On October 29, 2020, the Interconnection Policy Working Group (IPWG), which consists of the Utilities, DPS Staff, and other participants, filed a proposal related to recovery of CLCPA-oriented distribution project costs in Case 20-E-0543. Proposals related to distribution cost recovery described here and in the IPWG's proposal are limited to the utility rate case approach, and do not contemplate the allocation of costs to other utilities' customers. The IPWG proposal contains cost allocation and cost recovery mechanisms for both utility driven upgrades, including multi-value synergies between a utility's capital plan and opportunities for increasing hosting capacity, and market driven upgrades triggered by DG in queue. The proposal shifts from a first mover payment concept to a pro rata concept where projects contribute to costs based on the amount of capacity they use from substation upgrades.

[72] Refer to this filing's Executive Summary for a discussion of the distinctions between Phase 1 and Phase 2 projects.

2) **Voluntary agreements:** Voluntary co-tenancy agreements or voluntary FERC-jurisdictional participant-funding agreements (recovered through rate proceedings).
3) **NYSERDA payments:** NYSERDA reimbursement to Utilities for CLCPA-driven local transmission projects through regional System Benefits Charges (SBCs) or similar charging mechanisms can be used to fund new transmission.[73]
4) **Renewable Generator Sponsorship:** Renewable generation owner/developer agreement to pay for transmission costs (based on wholesale transmission rates).

The Utilities describe four potential pathways in this section. Figure 11 provides an overview of each pathway.

Figure 11: Proposed Cost Allocation and Cost Recovery Mechanisms

	Rate Case-Based Approach	Voluntary Agreement	NYSERDA Payment	Renewable Generator Sponsorship
Jurisdiction / Legal Framework	Commission	Commission and FERC	Commission and potentially FERC	Commission and FERC
Applicability to Local Transmission Projects	All types of Multi-Value and CLCPA-driven projects, subject to rate case constraints	All types of Multi-Value and CLCPA-driven projects identified by Commission for cost-sharing	All types of Multi-Value and CLCPA-driven projects identified by Commission for cost-sharing	Only projects with benefits that can be attributed to discrete generators
Ability to Enable Alternate Cost Allocation Framework	• Local cost allocation only • Need to consider cost equity across districts	• Cost allocation methodology based on beneficiaries of CLCPA • LIPA not able to participate in a co-tenancy arrangement	• Costs allocated to load serving entities (LSEs) on volumetric basis (consistent with NYSERDA's collection of the Systems Benefit Charge from LSEs) • Need to address participation from LIPA and other non-jurisdictional entities	• Costs allocated to renewable generation project developers (on voluntary basis)
Milestones to Effectiveness	• Existing process • May need interim cost recovery for utilities in the midst of multi-year rate plans	• Time required to negotiate agreements between utilities • FERC approvals required	• Need to create new NYSERDA process to administer payments • Could require FERC approval	• Requires generator agreement • Requires certainty of REC/OREC mechanism to attract generator financing
Key Stakeholder Groups	• Utilities • Commission • DPS Staff • Rate case intervenors	• Utilities • Commission • DPS Staff • Rate case intervenors • FERC	• Utilities • Commission • DPS Staff • NYSERDA • FERC	• Utilities • Commission • DPS Staff • Renewable project developers • Existing generators • NYSERDA • FERC • NYISO

[73] CES Proceeding, Order Adopting Modifications to the Clean Energy Standard (Issued October 15, 2020), p. 91.

i) Status Quo Cost Recovery Under Commission Rate Case Proceedings

New York's investor-owned utilities recover local transmission and distribution costs through bundled rates filed with the Commission.[74] Utility costs for new facilities and upgrades to existing transmission facilities 69 kV and above (including 230 and 345 kV facilities), and in some cases lower voltage facilities down to 34.5 kV, are recovered as part of the revenue requirement approved in utility rate cases from all delivery customers within a utility's service territory. Historically, projects included in the rate case have generally been identified based on utility local system needs, and the revenue requirement of each utility's rate case has been charged only to the utility's local customers. Introduction of CLCPA drivers (and the societal benefits associated with such drivers) into utility planning processes raises a novel issue: the need to consider the revenue requirement of other utilities in the context of an imputed statewide cost allocation.

Utility rate plans may cover three years, if achieved through a negotiated joint proposal (the most typical outcome in recent years), or one year, if adjudicated. Once approved, the utility makes capital decisions through its capital planning process. The utility typically has discretion to prioritize and manage its investment plans.

1. Rate Case Limitations

As noted above, Commission jurisdictional rate cases provide for the recovery of a utility's costs from customers within its service territory, and the Commission has not implemented alternate cost arrangements for local transmission projects that may benefit other utility franchise areas or the state as a whole. FERC has exercised authority in this area and has approved formulas in the NYISO OATT for regional cost allocation of projects selected through the NYISO's planning processes. Regulatory frameworks to enable regional cost allocation other than through a NYISO planning process may require FERC approval.

Utilities have used co-ownership structures – including tenancy-in-common or co-tenancy arrangements – to partner on transmission or generation projects and charge their share of costs to their respective delivery customers in their rate cases. This was used for generation prior to deregulation and for transmission lines. For example, NYPA and National Grid own discrete assets that comprise a circuit, with National Grid owning the structures and NYPA owning the 345 kV line conductor.

Depending on the geographic distribution and magnitude of transmission investments throughout the State, allowing each utility to recover costs of its own investments through its individual utility rate case might result in customers bearing a similar proportion of statewide transmission CLCPA costs as if all transmission CLCPA investments were collectively shared statewide, pursuant to a regional cost allocation formula. In the context of this effort, achieving a

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[74] National Grid is an exception; it maintains a FERC formula rate for transmission investment.

similar outcome to statewide cost-sharing may be sufficient. However, cost allocation precision should be balanced against the need to move projects forward expeditiously to achieve the requirements of the CLCPA. The rate case cost recovery path can offer an expedient and simple approach to implementing projects needed to support the CLCPA while minimizing execution risk. These are important considerations given the statute's time sensitive targets.[75]

ii) Proposed Regulatory Frameworks for Equitable Cost Recovery of CLCPA Projects

The Utilities have identified four potential regulatory frameworks that, alone or in combination, can facilitate an equitable cost allocation for Phase 2 utility projects that support the CLCPA:

1) Rate cases;
2) Voluntary utility agreements;
3) NYSERDA payments; and
4) Renewable generator sponsorship.

Each of these frameworks is described in more detail below.

1. Rate Case-Based Approach

Rate Case Benefits

- Simple, existing process
- Easy to implement
- Nimble, providing ability to tackle a specific problem
- Multi-party process, inclusive dialog between DPS, interveners, and utilities
- Maintains LIPA's ability to use tax exempt bond financing

Rate Case Challenges

- Rate pressure
- Cost allocation challenges
- Competing priorities in rate case
- Limited ability to optimize across utilities
- Lack of coordination (e.g., utilities are, generally, on 3-year rate plans on different calendars)
- Cost shift from generators to customers

Transmission investment cost recovery through individual utility rate cases may result in equitable regional cost sharing as though all transmission investments were shared according to a regional cost allocation formula, but only if the geographic distribution and magnitude of investment throughout the State reasonably reflects the load each utility serves. Under a Rate Case-Based approach, each utility would include its Multi-Value or CLCPA-driven project in its LTP. Costs would be recovered in the utility's state rate case, from customers in its service territory, as they are today. A mechanism to account for such projects across the Utilities is recommended to safeguard reasonably equitable distribution of costs paid by customers across the state.

The process for inclusion of CLCPA projects in the rate case would be as follows:

[75] Climate Leadership and Community Protection Act ("CLCPA"), A.8429 (Englebright)/S.6599 (Kaminsky) (N.Y. 2019), available at: https://legislation.nysenate.gov/pdf/bills/2019/S6599.

1. A utility identifies and prioritizes projects based on CLCPA and traditional planning criteria (as described in the Section II, above).[76]
2. The utility would work with DPS Staff and rate case intervenors to identify a final list of projects for inclusion in its rate plan.[77]
3. The utility would implement the projects agreed to in the rate case through its capital budget and planning process.

An important consideration to this proposal is an imputed load ratio share cost allocation among the Utilities for CLCPA projects. Commission authorization should also consider the timing of future projects that may impact the cost allocation outcome. The costs incurred by the Utilities could be reviewed and subject to true-up as part of the Commission's regular review of its actions taken pursuant to the AREGCB Act, which requires reevaluation every four years. Such timing would allow a holistic review of project costs across the state.

While identification of relevant projects would eventually become part of the utility rate case and capital planning processes, separate Commission approvals outside the rate case may be appropriate to expedite the development of projects in between Utility rate cases, to avoid disrupting existing three-year rate plans. For example, at the time of an expected Commission Order authorizing projects in Q1 2021, the Utilities will be in the middle of approximately three-year rate plans scheduled to expire as follows:

- Orange and Rockland – end of 2021
- CECONY - end of 2022
- NYSEG/RG&E – April 2023 (currently under Commission review)
- National Grid – July 2024 (currently under Commission review)
- Central Hudson - August 2024 (currently under Commission review)

To expedite projects in the near-term, the Commission should authorize project cost recovery outside of the normal utility rate case process, as necessary, to enable projects to proceed. Specifically, the Commission should issue an Order in the first quarter of 2021, identifying initial projects and authorizing their costs to be recovered through utility rate cases, separate from the budgets currently effective under each utility's governing three-year rate plan.

Each utility seeks Commission approval to develop its portfolio of proposed transmission and distribution projects that are immediately actionable and, in their estimation, will enable meaningful progress towards CLCPA objectives. In the event such CLCPA projects are not currently contemplated in utility rate plans, once the project is placed into service and deemed to be used and useful, the utilities would notify the Commission and begin to accrue a carrying

76 Planning criteria for reliability, asset management, and compliance remain fundamental drivers for utility capital planning and identification of rate case projects.

77 In the case of LIPA, projects would be subject to LIPA's budget approval and ratemaking mechanisms as set forth in its Tariff and the LIPA Reform Act.

charge[78] (including return on the amount placed in service and related depreciation expense) at its current allowed weighted average cost of capital and recover such costs on a monthly basis through a surcharge until base rates are reset as described below. To the extent a carrying charge on the average electric plant in service balances would otherwise be deferred for customer benefit under the utility's rate plan,[79] such carrying charge would be applied as a credit against the surcharge recovery. To the extent a carrying charge on the average electric plant in service balances that would otherwise be deferred for customer benefit under the utility's rate plan is higher than the surcharge recovery calculation, the net difference will be deferred for the benefit of customers.

Unless an alternate rate recovery mechanism applies, the rate treatment of capital projects should generally be handled within rate proceedings whenever possible, consistent with the manner capital projects are typically handled. Given, however, that the utilities are currently in varying states of their own rate case development (with some utility rate cases currently pending, others soon to be filed and others not to be filed for several years), the Commission should permit the utilities to recover the carrying costs, including depreciation, associated with the construction of approved CLCPA projects when such projects are placed in service.

To the extent that any Phase 1 or other (as applicable) projects are not currently contemplated in utility rate plans, the Commission should permit the utilities to submit a petition for Commission approval of timely cost recovery of the carrying costs through a transmission surcharge (or other applicable pass through clauses). The surcharge would be designed to allow the utility to recover its CLCPA projects' carrying costs, including depreciation, until its next rate case, at which time the investment would be reflected in base rates.

The alternative regulatory pathways described below all take time and expense to implement, require regulatory approvals, potentially from both the Commission and FERC, and therefore involve greater risk. While these challenges can be overcome, the Utilities recommend that these pathways be reserved for cases where (a) reasonable equity between districts cannot otherwise be substantially achieved through rate case recovery, *and* (b) the cost disparity in absolute dollars is substantial enough to justify the time and expense associated with implementation. To the extent that cost recovery through the rate case provides a reasonable, but not perfect, cost allocation outcome, this approach may still be preferable to enable projects to move forward expeditiously, consistent with the aims of the AREGCB Act.

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78 The accounting profession (and the SEC) has interpreted the automatic recovery mechanism approved by the regulator in an order, is required for a regulated utility to accrue a carrying charge on an asset including the weighted average cost of capital.

79 Commonly referred to as "net plant reconciliation" in utility rate plans.

2. Voluntary Utility Agreements

Voluntary Agreements Benefits

- Enables cost allocation to beneficiaries
- Potential to optimize projects - may enable larger projects that are more cost-effective (as compared to smaller projects that would be approved in rate case)

Voluntary Agreements Challenges

- Rate pressure
- Voluntary
- Time to negotiate agreements
- Potential for challenges during PSC rate case negotiations
- LIPA unable to participate in co-tenancy agreements
- Aspects of contract require FERC approval, or entire rate for participant-funding
- Cost shift from generators to customers

Utilities could voluntarily agree to share the costs of CLCPA-driven transmission projects through either (1) voluntary co-tenancy arrangements, or (2) voluntary FERC-jurisdictional participant-funding agreements. While the two approaches differ in their legal framework and rate recovery mechanism, implementation of both would involve voluntary agreement among the Utilities to share costs.

Utilities may use co-ownership arrangements to partner on CLCPA-driven transmission projects and charge their share of costs to their respective delivery customers in their Commission rate cases. Under this approach, a utility would commit capital for an undivided interest of a local transmission project that supports CLCPA mandates (incremental to portions of the project driven by Reliability, Safety, and Compliance criteria) and that is available to other electric transmission utilities for investment. Each utility's delivery customers would fund the project in proportion with its ownership share, and each utility would recover its proportion of investment costs through its state rate case. Aspects of the agreements governing the co-tenancy arrangement that do not pertain to cost recovery (*e.g.*, handling of operations and maintenance (O&M), among other things) would likely need to be filed with FERC.

In addition, a co-tenancy arrangement would not work for NYPA, as it would be unable to pass on costs of such a voluntary agreement to its many customers with long-term contracts. However, because NYPA's customers predominately take delivery service from the Utility in whose service territory they are located, including these CLCPA costs, a co-tenancy agreement among the Utilities would ensure that NYPA customers contribute to these facilities.

Conversely, a participant-funded rate would involve the Utilities voluntarily agreeing on behalf of their customers to fund the costs of other utilities' projects. Unlike with a co-tenancy agreement, the Utilities would agree to share the costs of projects without the corresponding exchange of equity. The rate agreed to by the Utilities, if any, would be FERC-jurisdictional (as opposed to only certain elements of the agreement), and utility costs would be recovered at FERC rather than under the Commission's rates. Finally, there is no statutory limitation on any New York State LSE's ability to enter agreement to share costs.

For either approach, the process for establishing voluntary arrangements among the Utilities to facilitate cost-sharing of CLCPA projects could work as follows:

1. Utilities identify a list of projects at specified times in the future as directed by the Commission.
2. A Commission Order identifies projects to proceed and directs the Utilities to make a subsequent filing demonstrating the CLCPA benefits of those projects whose costs should be regionally allocated.
3. The Utilities propose appropriate cost allocation/recovery framework(s) for projects subject to regional cost allocation. In addition to projects that may be approved for immediate construction, consideration should also be given to the likelihood of projects that may be approved in the future.
4. Cost recovery would proceed through the relevant Commission or FERC procedure, as appropriate:
    a. Voluntary co-tenancy agreement: For projects for which the Utilities propose voluntary co-tenancy, the Commission would approve co-tenancy arrangements through an interim Order authorizing cost recovery through each utility's retail T&D rates. Aspects of the co-ownership agreements (e.g., handling of O&M) would likely be filed with FERC.
    b. Voluntary FERC participant-funded rate: For projects for which the Utilities propose to participant fund, the Utilities would file at FERC for a participant-funded rate. The rate terms (such as ROE, incentives, etc.) and cost allocation would be subject to settlement discussions at FERC.[80] A separate rate would be needed for each utility that has projects that require regional cost allocation.
5. The agreement(s) would be revisited on a regular cycle on a looking-forward basis, aligned with the Commission's schedule (established under the CLCPA) for reviewing its progress every four years, as planning progresses to include additional projects, based on an aligned schedule among the Utilities for identifying such projects. Each utility's agreement to the additional projects would continue to be voluntary.

Achieving voluntary agreement among the Utilities may require time and effort to negotiate and may not be successful. In the event the Utilities cannot successfully conclude such agreement(s), costs would be recovered through individual utility rate cases, or alternatively, if cost allocation is deemed necessary to ensure equity of cost responsibility among customers, the Commission may request the Utilities to negotiate participant funding agreements. Consideration of multiple utilities' projects together, rather on an individual project basis, could potentially address some of the challenges.

[80] Although LIPA is generally FERC non-jurisdictional, this would not preclude it from participating in such an agreement. But the agreement would need limiting language to protect LIPA's non-jurisdictional status and reflect the fact that the revenue requirement and cost recovery for LIPA projects is subject to approvals under New York state law. Such an approach would be consistent with other joint agreements filed at FERC to which LIPA is a signatory, such as the NYISO Transmission Owners Agreement as well as the structure of LIPA cost recovery mechanisms which have been incorporated into the NYISO Tariff.

LIPA Limitations

Statutory limitations on LIPA's ownership of transmission and related facilities outside of its service area would preclude LIPA from participating in any co-tenancy cost sharing arrangements. In addition, LIPA's participation in any regional cost sharing arrangements beyond the traditional rate case, especially those involving multi-party agreements, would require the approval of LIPA's Board of Trustees and possibly the New York State Comptroller.

LIPA also generally finances capital projects with tax-exempt bonds, which are subject to restrictions mandated by Internal Revenue Service rules. These restrictions include a general prohibition on the use of these funds for "private business use" or for projects owned by third parties. Because LIPA uses tax-exempt bond financing, it enjoys a significantly lower cost of capital compared to many other utilities and passes these savings on to its customers. Accordingly, LIPA's participation in any regional cost sharing arrangement would need to be carefully assessed in the context of its statutory legal authority and its preference to finance investment with tax-exempt bonds. Should LIPA be required to finance these projects with non-tax-exempt bonds, or a combination of funds, there would be implications for the aggregate cost of CLCPA projects and LIPA's customers.

3. NYSERDA Payments

Under this approach, NYSERDA would reimburse utilities for local transmission projects that support CLCPA mandates through revenues collected from the System Benefits Charge (SBC) (expanded, if necessary). Issues related to the applicability of the System Benefits Charge to LIPA, NYPA, and non-jurisdictional municipal power entities would need to be addressed, perhaps through the establishment of a separate charge. The Commission would identify the projects for which NYSERDA should issue payments, and the payments would be calculated based on the first 40 years of the revenue requirement of the project (or portion) that provides societal benefits over that same 40-year period by supporting the CLCPA. Under-collections (due to load used in the calculation of the SBC being lower than forecasted) would be addressed periodically via changes to the SBC rate.[81]

NYSERDA Payments Benefits

- Enables cost allocation to beneficiaries
- Potential to optimize projects - may enable larger projects that are more cost-effective (as compared to smaller projects that would be approved in rate case)
- Standardized
- Public authorities can participate

NYSERDA Payments Challenges

- Rate pressure
- New mechanism, would take time to implement
- FERC approvals for NYSERDA payment to utility could be required
- Creates administrative burden for NYSERDA
- Cost shift from generators to customers

[81] In addition to the SBC, NYSERDA may support certain transmission development projects through alternative mechanisms. *See* CES Proceeding, Order Adopting Modifications to the Clean Energy Standard (Issued October 15, 2020), pp 91-92.

A NYSERDA payment approach could be implemented as follows:

1. The Utilities propose appropriate cost allocation/recovery framework(s) for projects subject to regional cost allocation.
2. For projects for which the Utilities propose the NYSERDA cost allocation/recovery framework, a Commission Order directs the Utilities to begin development of projects, and NYSERDA to pay utilities for the costs of the project monthly.
3. NYSERDA collects funds via the SBC or adding a new NYSERDA payment mechanism in support for local transmission that deliver significant benefits to CLCPA objectives.
4. Utilities may recover costs through state rate cases initially. However, revenues a utility receives from NYSERDA are reconciled and imputed into future rate case requests (payments by NYSERDA are an offset to base rates).
5. If pre-approved by the Commission, the Commission may direct NYSERDA to develop appropriate NYSERDA payment mechanism for the collection of new local transmission projects beyond 2021, as they are approved by the Commission. This could be scheduled to occur on a four-year cycle, consistent with the Commission's obligation to periodically review its actions taken pursuant to the CLCPA.
6. Over-collections (due to customer load exceeding NYSERDA's forecast) will be refunded to customers or retained by NYSERDA to fund future shortfalls.

This construct would need to be developed in a manner that assists NYSERDA in managing its administrative and financial impacts. For example, the volume of payments flowing in and out of NYSERDA could be reduced to reflect only the difference between the costs the Utilities actually recover through their rate cases and the amount for which their delivery customers *should* be held responsible pursuant to a load ratio share cost allocation of all CLCPA transmission investments statewide. That is, only those adjustments to a utility's rate case recovery necessary to achieve an equitable regional cost allocation (*i.e.,* overages and underages) need be processed through NYSERDA's clearinghouse. Such an approach could create efficiencies, if software systems are created and implemented to accurately track and report CLCPA projects and the costs incurred and recovered by each utility. Recovering the cost for new transmission through a NYSERDA payment model could raise several federal jurisdictional questions.[82]

[82] LIPA does not support the NYSERDA payment approach.

4. *Renewable Generator Sponsorship*

Under this model, the renewable generation owner or developer would voluntarily agree to pay for the cost of transmission to unbottle and deliver energy for its projects.[83] The Utilities have considered imposing this cost burden upon all generators on a mandatory basis, but several issues make this option difficult to implement.[84]

Whether voluntary or mandatory, any charge to generators for transmission would likely be a wholesale transmission rate requiring FERC approval, and could be administered under the NYISO Tariff. On a voluntary basis, the agreement with the generator could work as follows:

Generator Sponsorship Benefits
- Costs remain with developers
- Achieves cost allocation to beneficiaries through RECs/ORECs
- Maintains locational pricing signals

Generator Sponsorship Challenges
- Rate pressure
- Voluntary, but no guaranteed delivery for generators
- FERC approval for rate required
- Additional parties involved – potential for disagreement between generators
- Risk of utility customers bearing the cost of unsubscribed capacity

1. The utility works with existing generation owners or prospective generators to identify a project to unbottle their projects.
2. The utility and generators enter into an agreement and file a rate at FERC, consistent with the agreement, for recovery of the costs of the projects from the relevant generators.
3. When the renewable generator enters service, or when the transmission project comes into service (whichever last occurs), the generator is charged for costs commensurate with its usage of the new transmission facilities, as reflected in the agreement filed at FERC.
4. If the transmission commences construction prior to a renewable generation's in-service date, the utility recovers its costs from its delivery customers through its Commission rate case. The renewable generator begins payments (and utility customer payments end, to the extent the transmission is fully used) when its project enters service, and local

83 This proposal differs from current requirements in the NYISO interconnection process because projects would consider energy deliverability, whereas the NYISO interconnection process only considers capacity deliverability (i.e., deliverability during the peak hour of the year as compared to all 8760 hours in a year). In addition, voluntary agreements may enable transmission projects to be built ahead of time, rather than waiting for the interconnection process, saving time in the overall process.

84 Precedent for such a requirement does exist. FERC approved a "Location Constrained Resource Interconnection" (LCRI) construct in the CAISO Tariff, to plan for and recover costs of transmission to "location constrained" (i.e., renewable) resources in advance of their construction. The entity proposing the transmission facility must demonstrate a minimum level of interest of 60% of the capacity of the transmission facility for a project to proceed. Once constructed, generators pay their proportionate share of the transmission facility cost (on a per-MW basis), and the costs of transmission capacity not initially subscribed is recovered in utility transmission rates until generators come online.[84] Implementing such an approach in New York would require changes to the NYISO OATT (subject to stakeholder vote), and FERC approval.

utility customers are refunded to the extent of their prior payments as generator payments are made.

5. To the extent a transmission line is not fully subscribed, the utility continues to recover the costs attributable to the unsubscribed capacity from its delivery customers through its Commission rate case.

Unlike the other three options, this approach would result in the cost burden of projects being directly assigned to unbottled generators. Cost allocation would still be regional, to the extent that generators recover the transmission investment costs they incur to utilities through the REC or OREC payments or NYISO market revenues (energy, capacity, and ancillary services, as applicable) they receive. However, this approach could raise free ridership concerns, as a generator may benefit from a project funded by another generator, and, unlike other ISOs such as PJM Interconnection Inc., the NYISO does not administer any firm transmission rights to guarantee delivery.

C. Evaluation of Regulatory Pathways

Each of the four regulatory pathways involves a tradeoff between its ease of implementation and its ability to facilitate equitable statewide cost-sharing of utility projects. In order to provide a consistent basis for comparison, the Utilities have thus far identified five key considerations against which to evaluate the cost recovery pathways: legal framework, applicability, beneficiaries pay allocation, milestones to effectiveness, and roles of stakeholder groups. In weighing these considerations, the Utilities will consider how the Commission can leverage expeditious, proven methods to enable projects to proceed swiftly to meet the CLCPA mandates, as required by the CLCPA. As noted above, the Utilities believes that, absent a gross disparity in statewide cost burdens, the greatest weight be given to the individual utility rate recovery pathway due to its ability to timely achieve CLCPA's mandates. The key considerations are described further below.

i) Legal Framework

1. Description of Consideration:

Under existing law, both the Commission and FERC have roles in transmission cost recovery. There is a need to clarify the legal framework (existing or new) for the socialization of costs within the State's jurisdiction. Without a clear legal framework, implementation of projects may be subject to risks and delays.

2. Evaluation of Pathways:

The roles of the Commission and FERC are different under each regulatory pathway:

- Rate Case: Utility costs continue to be recovered through each utility's bundled T&D rate with the Commission. Costs across utilities would need to be monitored and assessed on a regular cycle to confirm that regional equity in cost allocation is generally being achieved to the satisfaction of the Commission and stakeholders. FERC approvals are not required.

- Voluntary utility agreements: Under a co-tenancy approach, utility costs continue to be recovered through each utility's bundled T&D rate with the Commission, with aspects of the agreements requiring filing with and approval by FERC. Under a participant funded model, utility costs are recovered under a FERC participant-funded rate, subject to FERC's rate settlement procedures.
- NYSERDA payments: Likely requires FERC approval of the rates paid to the Utilities, which are subject to FERC's rate settlement procedures.
- Renewable generator sponsorship: Likely requires FERC approval of the rates paid to the Utilities.

ii) Applicability

1. Description of Consideration:

Whether the cost recovery mechanism can address cost recovery for the different types of projects likely to be identified by the Utilities.

This consideration relates to both the project's characteristics (*e.g.*, reconductoring a line) as well as the CLCPA driver that led to identification of the project (*e.g.*, enabling the interconnection/deliverability of 9,000 MW of offshore wind). In considering both aspects of a project, the Utilities recognize that regional differences should be considered in order to assess the impact on proposals meant to facilitate the CLCPA's mandates of delivering renewable power to New York's customers, reducing the reliance on fossil generation, and reducing emissions in environmental justice communities. Accordingly, this consideration acknowledges that types of transmission (*i.e.,* overhead vs underground) and the needs addressing CLCPA mandates (*i.e.,* "on-ramps" – moving renewable energy onto the 345 kV system vs "off-ramps" – moving renewable energy from the bulk power system to loads) will vary across the state. However, in the future the Utilities may need to work together to reach agreement on cost allocation schemes for projects addressing different need cases, driven by different local planning standards and approved by the Commission.

To provide further clarity on the distinction between transmission investments that are Reliability, Safety, and Compliance and those that are proposed solely to facilitate CLCPA mandates, the Utilities propose that a Reliability, Safety, and Compliance project should be any project that would have been identified and prioritized for inclusion in a utility's rate case over the near- or long-term based on traditional considerations, including good utility practice (*e.g.*, aging asset replacements). Projects that a utility would ultimately identify or have identified in a long-term system plan that can be accelerated to provide incremental CLCPA benefits can be considered for equitable cost treatment (*e.g.* load ratio or imputed load ratio share), but only to the extent of the incremental cost of acceleration (*i.e.,* the delta of costs incurred presently compared to the Reliability, Safety, and Compliance component). By contrast, a project that a utility identified based on the CLCPA Investment Criteria alone would be a CLCPA-driven project.

2. Evaluation of Pathways:

Under all approaches, Reliability, Safety, and Compliance projects and the Reliability, Safety, and Compliance components of Multi-Value projects would continue to be recovered from a utility's local customers under the Rate Case-Based Approach. However, compared to the other three approaches, which provide flexibility as to the types of projects that are eligible for cost recovery, the renewable generator sponsorship approach would only be applicable to those projects (i.e., CLCPA-only projects) serving generators that are unbottled by the transmission upgrades.

iii) Beneficiaries Pay Allocation

1. Description of Consideration:

The degree to which the costs of new or incremental CLCPA-driven transmission projects can be allocated on a "beneficiaries pay" basis.

Because the CLCPA establishes state-wide mandates, the costs of utility projects that support those mandates should be shared equally across the state (*i.e.,* based on load-ratio share). A load-ratio share cost allocation is the cost allocation formula used to implement numerous New York State mandates, including NYSERDA's Zero Emissions Credit ("ZEC"), Renewable Energy Credit ("REC"), and Offshore Wind Renewable Energy Credit ("OREC") programs.

Per the directives in the May Order, any cost allocation methodology must distinguish between projects (or portions of projects) that are identified based on traditional planning criteria (*e.g.,* reliability) and those that support renewable integration, deliverability and usability or other CLCPA mandates. The May Order directed that projects (or portions thereof) identified based on Reliability, Safety, and Compliance drivers be recovered through utility rate cases, while projects (or portions thereof) that expand or accelerate Reliability, Safety, and Compliance projects to include CLCPA benefits would be eligible for regional cost sharing.[85] Projects that are included in a utility's capital plan due to the CLCPA (i.e., "CLCPA-driven" projects) would be eligible for cost sharing.

2. Evaluation of Pathways:

Each of the four regulatory pathways considered could facilitate a cost allocation outcome consistent with the principles described above:

Rate Case-Based Approach: Costs would continue to be allocated to customers in the utility's service territory. Depending on locations and costs of identified projects

[85] The May Order refers to Reliability, Safety, and Compliance projects that can be expanded to realize renewable resource benefits as "Multi-Value." The Commission stated that costs of only that incremental portion of Multi-Value projects that brings CLCPA benefit should be eligible for regional cost allocation.

throughout state, cost recovery or each utility's project(s) through its own utility rate case may provide an overall result similar to that attained if all CLCPA projects were regionally cost allocated. Computer systems or software could be installed to track and account for such projects and their payment by delivery customers to inform equitable cost sharing.

Voluntary utility agreements and NYSERDA Payments: Costs could be allocated to all CLCPA beneficiaries, consistent with state policy.

Renewable generator sponsorship: Regional cost allocation would be achieved (*i.e.,* to the extent that generators recover the costs of the transmission projects through their REC/OREC and/or the NYISO market revenue payments), but the cost of transmission investments may exceed the amount generators are willing to pay, leaving a shortfall for local delivery customers to pay.

iv) Milestones to Effectiveness

1. Description of Consideration:

Whether a cost recovery pathway can enable projects to proceed expeditiously to support achievement of the state's policies, as directed by the AREGCB Act.

Leveraging rate cases may provide for quicker near-term action compared to establishing a new cost recovery pathway. Further, using mechanisms entirely within the Commission's jurisdiction that do not require new authorizing legislation may provide the State with greater control than mechanisms that require federal approvals or the creation of new processes. Another consideration is the time and complexity to develop and implement new regulatory frameworks (or contractual agreements between or among the Utilities) to implement cost sharing, and the potential for legal challenge and corresponding delays associated therewith.

2. Evaluation of Pathways:

Compared to the rate case, each of the other regulatory pathways poses more significant implementation challenges:

- Voluntary utility agreements: Under a co-tenancy approach, time would be required to negotiate agreements between or among the Utilities. While a master agreement could potentially be negotiated in advance, specific projects would need to be identified to be subject to the agreement and challenges associated with the State authorities' participation would need to be understood and resolved. Significant issues would need to be addressed in the agreements, including NERC compliance, environmental liabilities, cost overruns, governance, etc. Cost recovery would also need to be coordinated with the Utilities' three-year rate plan cycles, which are not aligned in timing. Finally, parts of the agreement would require FERC approval, adding another step to the process before cost recovery could proceed. In contrast, negotiations between the Utilities may be less complex for a participant-funded rate but the process for establishing cost recovery at FERC may be more protracted if other affected parties protest the application before FERC.

- NYSERDA payments: Requires the creation of a new process at NYSERDA to administer the payments, and possible FERC approval of the rate paid by NYSERDA to the Utilities (e.g., a participant funding agreement that would be filed at FERC).
- Renewable generator sponsorship: Requires a willingness of generators (who may be sensitive to the magnitude and timing of their payment obligations relative to their receipt of revenues), and possible approval from FERC. Administration could be left to the individual utilities or pursuant to the NYISO OATT.

In contrast to the challenges described above, the rate case is an existing process that could be used immediately to authorize cost recovery for the identified projects. While identification of CLCPA projects would eventually become part of a utility rate case and capital planning processes, separate Commission approval outside of the rate case likely will be needed, at least in some cases, in order to expedite the development of projects without disrupting currently operating three-year rate plans.

v) Roles of Stakeholder Groups

1. Description of Consideration

How the interaction of stakeholders may affect the viability of a given pathway.

2. Evaluation of Pathways:

Each pathway would bring engagement of the various stakeholders that are typically involved in utility rate cases, transmission planning, and the NYISO markets:

- Rate case: Utilities, DPS Staff, and rate case intervenors would need to consider CLCPA-driven projects alongside the projects typically considered. Renewable generation owners and developers may also become more interested in utility rate case proceedings, to the extent projects to unbottle their existing or planned generation are included.
- Voluntary utility agreements: Under co-tenancy, the nature of rate case negotiations could change to the extent they newly address cost recovery for projects outside of the utility's service territory that are administered under a co-tenancy agreement. Utilities may also take a greater interest in other utilities' rate cases, to the extent those proceedings have implications for cost recovery of projects covered under agreements between or among the Utilities. There would also be a role required for FERC, compared to under the rate case, to approve the co-tenancy agreements between the Utilities. A voluntary participant-funded rate would involve a larger role for FERC in approving cost recovery for the Utilities. It would also require the Utilities and their intervenors to file and participate in two separate rate proceedings (at the Commission and at FERC) for cost recovery of their projects.
- NYSERDA payments: This approach would similarly involve a role for FERC, as well as create a new and potentially burdensome role for NYSERDA to administer the cost-sharing program, though constructs can be created to reduce those burdens.

- Renewable generator sponsorship: In addition to involving FERC, this approach would *directly* impact existing and new generators, as they would be paying the costs of the transmission projects. There may also be disagreement *between* generators, as projects voluntary funded by one generator may bring benefits to another (creating a free ridership problem).

D. Example Pathways

The appropriate regulatory pathway(s) to facilitate cost recovery of CLCPA-driven local transmission projects will depend on the locations and costs of projects identified throughout the state and authorized to proceed by the Commission in early 2021. Given that uncertainty, the Utilities have not presently identified a single pathway for the Commission to pursue. Rather, this paper is intended to provide an overview of available approaches that have been considered to date and outline the circumstances under which each approach may be appropriate, as well as the potential challenges associated with implementation.

To the extent that regional equity in cost allocation can be achieved through cost recovery under each utility's rate case, this would be the most immediately executable, sure approach to authorizing cost recovery for projects needed to support the CLCPA. However, doing so requires alignment in timing of utility planning studies, and tracking of CLCPA-related projects, to compare across utility districts. As noted above, this could be done as part of the Commission's obligation to review its actions under the AREGCB Act every four years. In addition, to expedite projects in the near-term, the Commission may need to authorize cost recovery for projects outside of the rate case process to enable projects to proceed in a timely manner. For example, as noted above, to the extent that any Phase 1 or other projects (as applicable) are not currently contemplated in utility rate plans, the utilities may need to submit a petition for Commission approval of timely cost recovery of the carrying costs through a transmission surcharge (or other applicable pass through clauses). The surcharge would be designed to allow the utility to recover its CLCPA projects' carrying costs, including depreciation, until its next rate case, at which time the investment would be reflected in base rates.

While the Utilities have not identified a single optimal regulatory pathway among these alternatives at this time, the following illustrative examples describe situations where each cost recovery pathway may be appropriate. Once the Commission identifies the projects that should proceed, the Commission should further direct the Utilities to file a subsequent recommendation on appropriate cost sharing for those projects. In the interim, the Utilities provided a set of conceptual recommendations for the Commission's consideration, as highlighted at the beginning of this paper.

i) Examples

These illustrative examples represent a range of potential outcomes, showing a potential appropriate cost recovery strategy under each scenario pending a final proposal. As these examples illustrate, some of the regulatory pathways may be used in combination (e.g., rate case and renewable generator developer sponsorship) to achieve the desired cost allocation.

1. *Example 1: Cost Recovery for Phase 1 Reliability, Safety, and Compliance Project with CLCPA Benefits*

A utility identifies a Reliability, Safety, and Compliance project that also provides CLCPA benefits. In this case, alternative cost-sharing arrangements are not required. Projects identified based on Reliability, Safety, and Compliance drivers would continue to be recovered through individual utility rate cases.

2. *Example 2: Cost Recovery with Roughly Equal Distribution of Costs Across State*

Utilities A, B, and C comprise roughly 20%, 30%, and 50% of statewide load, respectively, and thus equitable cost allocation in those proportions. The Commission authorizes one $19M project for Utility A, two projects of $16M each for Utility B, and a $17M and $32M project for Utility C. If each utility recovers its costs through its rate case, then Utilities A, B, and C would incur 19%, 32%, and 49% of the costs of implementing the projects in support of the state mandates. Though the outcome does not perfectly align with the intended cost allocation, it is sufficiently close that the Commission could rely on cost recovery through individual utility cases. The time and cost to implement a new, alternative pathway to facilitate "perfect" cost-sharing is unwarranted based on the distribution of projects throughout the state and well-established "beneficiaries pay" principles. It could also frustrate timely achievement of the state's environmental mandates.

3. *Example 3: Cost Recovery with Unequal Distribution of Costs Across Utilities*

For the same scenario as example 2, Utility B identifies an additional $50M project that would unbottle two existing renewable generators located in its service territory. Adding this project would result in Utility B bearing 55% of the overall costs of $150M, compared to its intended cost allocation share of 30%. In this scenario, the NYSERDA payment or renewable generator sponsorship approaches could achieve the desired cost allocation outcome.

Under the NYSERDA payment approach, NYSERDA would only be reimbursing Utility B for project costs that would not otherwise be equitably allocated through recovery in individual utility rate cases (i.e., the $50M incremental project). This would minimize the administrative and financial burden on NYSERDA, as it would only be reimbursing Utility B for its additional project (representing its customers' excess cost burden), but not all the Utilities for all of their projects, as the desired cost allocation can be achieved through each utility included those projects in its own rate case.

Alternatively, under the renewable generator sponsorship approach, Utility B could work with the two generators that would be unbottled to negotiate a rate (on a voluntary basis). The two generators would, in turn, recover their costs through incremental REC, OREC and/or NYISO market revenue payments, socializing the costs. Because this project unbottles existing renewables, the renewable generator sponsorship approach may be the more appropriate approach in this case. Since the renewable generator would be the financial beneficiary of the unbottling project (through increased REC revenues), it may be best positioned to judge the benefits and costs of a transmission project to unbottle its generation. Of course, placing the cost responsibility on the generator in this way would minimize risk to customers.

In contrast, the voluntary co-tenancy agreement approach is not likely to be expedient here, as only one utility has a project for which cost-sharing outside of the rate case is required, and because Utility B would need to relinquish 70% of the equity in its project (if it were the only project subject to agreement) to achieve the desired cost allocation outcome.

4. *Example 4: Cost Recovery with Unequal Distribution of Costs Across Utilities*

Building on example 3, Utility C identifies an additional $60M project to improve delivery of renewables within its service territory. Adding this project to Utility B and C's rate cases, respectively would result in Utilities A, B, and C bearing 9%, 39%, and 52% of the total project costs throughout the state, compared to their intended cost allocation shares of 20%, 30%, and 50%, respectively.

In this example, a voluntary co-tenancy agreement may be an effective regulatory pathway to share costs. Allocating the costs of Utility C's project to renewable generators is not workable because the project cannot be attributed to an identified set of generators. The NYSERDA Payment approach could also be used to reimburse both utilities, though the volume of payments administered by NYSERDA may increase.

To achieve the intended cost allocation, Utilities B and C could both offer their additional projects, costing $50M and $60M, respectively, for sharing under a co-tenancy agreement or participant funding agreements with all the Utilities. A co-tenancy agreement could be formulated such that each utility retains majority ownership over its project, but the ultimate cost allocation is consistent with the desired distribution of costs, as shown in Figure 12 below.

Figure 12: Cost Allocation Example

Project Share	Utility A Share	Utility B Share	Utility C Share
Utility B Project ($50M)	$12M	$26M	$12M
Utility C Project ($60 M)	$10M	$7M	$43M
Total Share of Costs	$22M	$33M	$55M
Total Share of Costs (%)	20%	30%	50%

E. Cost Containment

The Commission's May Order directed the Utilities to provide input and proposals for "cost-containment, cost recovery, and cost allocation methodologies applicable to these investments and appropriate to the State's climate and renewable energy, safety, reliability, and cost-effectiveness goals." The current state regulatory paradigm in New York already includes cost containment through approved capital investments and associated costs. Under the current rate case structure, utilities are awarded a defined capital budget to fund infrastructure investment over the term of the rate plan. Utilities must manage their capital needs to the agreed upon budget. In this way, the Commission's current rate recovery practices, with cost containment achieved through capital budget management and not through creation of additional risks for the Utilities, strike an appropriate balance between allowing for budget management flexibility while holding utilities to the capital budgets approved in the rate case, and compensating risks through a return on equity commensurate with such risks. The introduction of mandatory cost containment measures on top of the current process will create asymmetric risk for the Utilities and could serve to deter rather than incent the type of investment needed to expeditiously reduce transmission constraints.

Commission policies should continue to provide utilities flexibility to address changing circumstances on the system while managing to the capital budgets approved in the rate case.

F. Recommendations

As described in this Report, the Utilities provide the following recommendations related to cost allocation and cost recovery for local transmission projects that support achievement of the CLCPA for the Commission's consideration.

1. The AREGCB Act's overriding aim is to expedite construction of transmission needed to achieve the CLCPA mandates. Any alternative cost recovery pathway selected to facilitate cost sharing among the Utilities should not impede the rapid advancement of projects to meet CLCPA mandates.
2. For the purpose of defining an equitable cost allocation outcome for transmission projects that support achievement of the CLCPA, "beneficiaries" should be defined to include all customers across the state. Consistent with the state-wide policy mandates and the cost allocation method used by NYSERDA in its renewable energy program, a load-ratio share cost allocation should apply to CLCPA projects.
3. Utility projects (or the costs of incremental additions to, or acceleration of, projects) that are identified and prioritized due to their ability to support the CLCPA mandates should be eligible for load ratio share cost allocation.
4. The Commission should determine, as part of its overall authorization of utility local projects, those projects for which costs should be shared and which should not, recognizing that regional planning differences that benefit a region are also needed to facilitate CLCPA mandates.
5. The Commission should use the utility rate case process for consideration of CLCPA project costs, to the extent a reasonably equitable statewide cost allocation outcome can be achieved, even if not perfect. The rate case is the simplest, most efficient cost recovery pathway to consider project cost recovery.

6. The Commission should consider authorizing projects in phases, with the first phase of projects to be those that could proceed through individual utility rate cases, and later phases consisting of those projects that may require new regulatory mechanisms to facilitate equitable cost sharing across the state. In considering a staged approach, however, the Commission should avoid unnecessary delay between the successive phases, as such delay could risk compliance with the CLCPA's target of achieving 70% renewable energy by 2030.
7. To expedite projects in the near-term, the Commission should consider authorizing project cost recovery outside of the normal utility rate case process, through a surcharge, as appropriate, to enable projects to proceed. Specifically, in the first quarter of 2021, we recommend the Commission issue an Order identifying initial projects and authorizing their costs to be recovered through each respective utility's rate case, separate from the budgets currently governing the Utilities' rate plans. Note that Phase I projects will not require a LT BCA but require a rate case-type approach. Conversely, Phase II projects will address benefits and costs in more specificity and would be eligible for alternative regulatory mechanisms.
8. An important consideration to this proposal is that to structure an imputed load ratio share cost allocation for CLCPA projects recovered through individual utility rates, any Commission approval authorizing such action should be based on the most comprehensive estimated and actual cost information available at the time, and subject to adjustment to ensure that cost allocation remains fair to all customers.
9. If (a) reasonable cost equity among districts cannot otherwise be largely achieved through rate case recovery, *and* (b) the dollar amount of such disparity is substantial enough to warrant the potential implementation delay and expense to achieve such equity, then the Commission should direct the Utilities to follow up with a specific recommendation to effectuate cost sharing pursuant to one of the pathways identified herein (voluntary utility agreements, NYSERDA payments, or generator sponsorship), or another pathway not yet identified. It is recommended that the Commission reserve for itself the right to request the Utilities to enter into FERC-jurisdictional participant funding agreements should the Utilities be unable to agree on a cost allocation mechanism. To the extent an alternate pathway is required to achieve reasonable cost equity for projects in later phases, the Utilities will need certainty on cost allocation and recovery before projects can proceed.

VI. ARTICLE VII OF THE NEW YORK STATE PUBLIC SERVICE LAW

A. Objectives

In the May Order the Commission did not specifically direct the Utilities to provide recommendations for processes related to siting, construction, and commissioning of local transmission and distribution projects. It did, however, note that the directives of the CLCPA require a revisit of the "traditional decision-making framework that the Commission and the Utilities have relied on up to now for investing in transmission and distribution infrastructure."[86] Once projects with CLCPA benefits are identified, planned, justified through a BCA analysis, and approved by the Commission it is critical to ensure that development of these projects will occur unimpeded so that clean energy resources can be brought online without delay. With that objective in mind the Utilities provide recommendations related to the siting process for local transmission development codified in Article VII of the Public Service Law (referred to here as Article VII). These recommendations represent opportunities to expedite progress in reaching CLCPA requirements.

B. Standardization

The Commission seeks "a transparent planning process, to be implemented by the utilities with as much consistency … as possible."[87] The Utilities agree that consistency in the siting process will provide reasonable expectations for developers, investors, the Utilities, and regulators.

Standardization in siting processes offers a mechanism to formalize this consistency. The Utilities recommend that DPS Staff supplement its Article VII process guidelines to provide specific direction to applicants. Updated guidelines will help foster consistency among transmission projects, reduce data repetition within the process, and manage expectations. The guidelines should be comprehensive, incorporate specific detailed requirements, and include guidance for applications for local transmission siting approval as well as the Environmental Management and Construction Plan (EM&CP). Through these guidelines, DPS Staff can identify what must be included in an application and what should be provided in the EM&CP.

C. Local Transmission Siting Review Process

i) Siting Applications

The Utilities recommend that DPS Staff review siting application requirements to determine which remain useful and continue to provide data that are necessary to reach siting determinations on environmental compatibility and public need. The adoption of official guidance document(s) would help eliminate unnecessary steps and delays, ultimately speeding

86 *Id.*

87 Transmission Planning Proceeding, May Order, p. 7.

up the siting review process. For example, the Utilities recommend the removal or revision of application requirements that are determined to serve no useful purpose or are routinely waived. For example, some Utilities have found that regulatory requirements that specify the scale of maps and the timeliness of aerial photos in siting applications are excessively rigid and frequently result in unnecessary effort, time and expense for the applicant to obtain waivers.

If necessary, the application content regulations should be revised to accomplish these recommendations.

ii) Application Review

Revised regulations could expedite review processes by restricting the scope of necessary project reviews. For example, archeological resource studies should be limited to areas to be newly disturbed by the proposed project, such as new substations, laydown yards, and new rights of way (ROW). Existing ROW and access roads should be assumed to have been previously disturbed and not require testing or concurrence from the New York State's Historic Preservation Office (SHPO).

Consistency within comment periods for projects should also be set forth. In some cases, requests for extensions for the comment period have been granted inconsistently, for varying periods of time, and without sufficient justification. Beyond adoption of revised regulation, official guidance documents would, ensure all participants have an understanding and proper expectation of the length of time for comments.

iii) Conditions and Deficiencies

Conditions of siting approval contained in an Article VII certificate should be standardized where possible and adopted by the Commission. The Utilities recommend removing any certificate conditions that should be covered by the EM&CP, and move any certificate conditions that identify what should be included in the EM&CP to the EM&CP specification documents that will be attached to any Joint Proposal or Order. Applicants can then be directed to identify conditions that do not apply to a specific project to expedite review.

Common deficiencies in siting applications and EM&CPs should be identified and addressed in DPS Staff guidance document(s) to improve the quality of submittals and cut down on agency review time. At the very least, new guidance document(s) should be adopted that would list information and studies that are required of applicants. This would benefit applicants preparing responsive documentation and assist DPS Staff reviewing applications to determine whether any deficiency exists.

Site visits are also recognized as a productive means to share information with parties. These should be held timely and frequently, recognizing the need to accommodate staffing constraints. To promote site visits, the use of EM&CP drawing drafts should be sufficient at this stage.

iv) EM&CP

The EM&CP contain a set of procedures for the development of Article VII transmission projects to ensure environmental protection.[88] Each EM&CP contains sub-sections designed to mitigate environmental impacts of transmission construction. An EM&CP also finalizes the design of the transmission facility (e.g., pole locations, work pad sizes, access roads, culvert replacements, *etc.*).

To promote timing and decrease repetition of data required in different documents, an official guidance document should specify what information should be added to the EM&CP, and not included in other documents in the Article VII process, like the application. For example, the guidance should allow the EM&CP to be submitted and reviewed together with a draft Storm Water Pollution Prevention Plan (SWPPP), rather than waiting for the approved local approval of the SWPPP. Concurrent submittal and review of the draft SWPPP and draft EM&CP would assist in providing information in a timely manner and would allow any necessary conforming changes to be made before the time of final siting approval. Moreover, the final EM&CP could be used for the review and approval of the SWPPP. Additionally, the required vegetation impact review should be included under the environmental impact section within the EM&CP.

DPS Staff should work to promote coordination of agency guidance documents such as DEC's Wetlands and Waterbodies Specifications. Finally, since multiple agencies have a hand in the siting process, their input should be sought and considered in the creation of DPS Staff guidance document(s).

v) Settlement Process

The Working Group has additional suggestions to make the negotiations process more efficient. For example, the Utilities recommend that the ALJ hold the parties to a settlement negotiation schedule to maintain forward momentum and progress. Additionally, parties could be held to more frequent negotiation conferences, including all-day events if necessary. Starting settlement negotiations earlier in the process would also serve to identify issues promptly, which would give the applicant time to be responsive to requests for additional information or to cure deficiencies. An initial pre-application meeting could be a productive means to identify such issues at the onset of the process. Providing early opportunities to identify issues should prevent such concerns from arising later in the process. With opportunities to identify issues earlier in the process, an ALJ could limit issue spotting after a certain period in the negotiations, and could potentially reject late objections that are raised late in the process, such as after a joint filing is proposed. The raising of issues late in the process unnecessarily creates confusion and delay in

[88] These procedures apply to, for example: erosion and sediment controls; clearing and slash disposal; stream and wetland protections; general clean-up and restoration; access of roads and maintenance; invasive species controls; protections for rare and endangered flora and fauna, and significant natural communities; inspection and monitoring; pollution prevention; and project construction.

finalizing a settlement, particularly when parties had ample opportunity to raise such issues earlier. An actively involved ALJ would increase the likelihood of maintaining a focus and procedural schedule. Any conditions needing changes, and the reasons for those changes, should be identified at the initiation of the settlement process.

In sum, the above recommendations would promote prioritization CLCPA investments and ensure they are constructed and commissioned in a timely fashion.

Part 2: Technical Analysis Working Group

I. INTRODUCTION

This Part 2 (also referred to as the Utility Study) provides the results of analyses undertaken at the Commission's direction[89] to identify local transmission and distribution upgrades necessary or appropriate to accelerate progress toward achievement of the Climate Leadership Community Protection Act (CLCPA) renewable energy mandates. This Utility Study identifies actionable local system upgrades (i.e., new facilities or enhancements to existing transmission or distribution facilities) that will facilitate greater interconnection and use of clean energy resources throughout New York State.

The Utilities note that timely achievement of New York's clean energy and environmental requirements will require innovative electric system investment planning and execution. Significant and continued expansion of the local transmission[90] and distribution systems will be necessary to achieve CLCPA renewable energy goals in a cost-effective manner. This Report identifies the earliest opportunities to prioritize and accelerate local transmission and distribution projects that meet traditional Reliability, Safety, and Compliance requirements, but that also simultaneously contribute to CLCPA target achievement by allowing developers to deploy clean energy projects and give those projects access to the load (Phase 1 projects). This Report also identifies projects that are primarily justified by enabling achievement of the CLCPA targets, but may require additional design engineering, benefit/cost analysis, or cost recovery considerations (Phase 2 projects). A more detailed definition of Phase 1 and 2 projects are provided in Section B below.

This Utility Study and the analytical results described here form one component of the comprehensive "power grid study" required by the AREGCB Act to be completed by the end of 2020.[91] The other two components of the power grid study initiated by NYSERDA address high voltage system upgrades necessary to accommodate: (1) the State's 2035 offshore wind target

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[89] Transmission Planning Proceeding, May Order, pp. 6-7.

[90] Transmission Planning Proceeding, 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. However, as the Utilities consider the issues outlined in this order, we recognize that an alternative definition may emerge."

[91] Pursuant to the AREGCB Act, the "power grid study" is to be produced by the Commission in consultation with other state agencies and authorities, the Utilities, and the NYISO to inform the identification of distribution upgrades, local transmission upgrades, and bulk transmission investments "that are necessary or appropriate" to facilitate the timely achievement of CLCPA targets.

(the "OSW Study"); and (2) the CLCPA goal that New York's electric system be emissions-free by 2040 (the "2040 Study").[92]

A. Utility Study Scope

The Utility Study is based upon projected system conditions for year 2030, as New York State moves towards achieving the CLCPA goal. It evaluates transmission and distribution capabilities in each of the Utilities' service territories that will be required to support the CLCPA goal of delivering 70% of the State's electric energy needs from renewable sources by 2030. New York is simultaneously evaluating bulk transmission facilities needed to support the CLCPA's goal of 100% renewable generation by 2040. Therefore, the assumptions that serve as the foundation of the Utility Study have been coordinated with both the 2040 and OSW Studies. However, the Utility Study is focused on local transmission and distribution development required to meet CLCPA targets, not upgrades to the bulk power system.[93] The Commission plans to initiate a separate proceeding for bulk power system investments needed to achieve CLCPA targets.

With the Utility Study's scope in mind, the May Order established a series of considerations for the Utilities to address:

1. Evaluate the local transmission and distribution system of the individual service territories, to understand where capacity "headroom" exists today;
2. Identify existing constraints or bottlenecks that limit energy deliverability;
3. Consider synergies with traditional capital expenditure projects (*i.e.*, aging infrastructure, reliability, resilience, market efficiency, operational flexibility, etc.);
4. Identify least-cost upgrade projects to increase the capacity of the existing system;
5. Identify potential new or emerging solutions that can accompany or complement traditional upgrades;
6. 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
7. Identify the possibility of fossil generation retirements and the impacts and potential availability of those interconnection points.

Working within this uniform set of considerations, the Utilities have each prepared individual local system studies to describe the utility's unique system needs. These individual analyses are included in sections II-VII, below.

B. Utility Study Overview

The Utilities each provide study methodologies and initial results in separate sections below to account for significant differences among local transmission and distribution systems,

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92 Transmission Planning Proceeding, May Order, p. 5.

93 See Footnote 2.

local planning processes and design criteria. However, each of the Utilities has based its work on a set of common assumptions and considerations.

Each utility's report includes an introduction and discussions of the following topics:

1. Description of each utility's Service Area;
2. Any utility-specific assumptions (i.e., deviations from common assumptions shared by all of the Utilities), and description of its local design criteria;
3. Existing capacity "headroom" within the utility's local transmission and distribution facilities; and
4. Bottlenecks or constraints that limit energy deliverability within the utility's system.

These descriptions of the utility's service territory and unique features are followed by study results, which are separated into two distinct categories.

Phase 1 projects are immediately actionable projects that satisfy Reliability, Safety, and Compliance purposes but that can also address bottlenecks or 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 pipeline. Phase 1 projects will be financially supported by the customers of the utility proposing the project.

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 described in Part 1 of this filing.

The Study will not address all aspects of Operational and Power System Design issues with 70% by 2030 Renewable Generation Mix (with Energy Storage) including but not limited to:

a. Spinning Reserves / Ramping Requirements
b. Voltage Control
c. Stability Control
d. Protection Coordination
e. System Restoration

These issues will be required to be addressed in future studies. Subsequently, a review of existing Reliability Rules will have to be initiated based upon ongoing lessons learned in order to accommodate the goals of CLCPA.

To build on the work each utility has already completed and described in their DSIPs, each utility assessed the alignment between the 5-year forecasts and capital plans included in each utility's DSIP and the forward-looking CLCPA targets and scenarios detailed by both NYISO and NYSERDA.[94, 95] As part of this analysis, each utility specified the inputs and assumptions for its scenario development that reflected achievement of the CLCPA goals, including for electric vehicles, space heating electrification, solar PV, energy efficiency, and energy storage.

Supported by the forecast, each utility categorized two types of distribution system projects that are necessary to meet CLCPA goals. Distribution Phase 1 projects are those that each utility had previously identified in its DSIP filing, capital plans, or rate cases that will improve the company's ability to broadly support DER integration and DSP enablement and can be accelerated based on incremental CLCPA benefits. Phase 1 projects also may have already received approval as part of a rate case and can be expanded to achieve CLCPA goals. These projects also have benefits for reliability, safety, or compliance.

Distribution Phase 2 projects are specifically designed to close gaps between the DSIP forecast and achievement of CLCPA goals. For example, projects that increase hosting capacity can be proposed or accelerated following Commission approval of the CLCPCA planning criteria presented in Part 1 of this filing. A benefit cost-analysis of such projects has not yet been undertaken and may be impacted by any changes in cost sharing requirements.

If applicable, for the proposed distribution projects listed in this Report to meet the CLCPA goals, each utility's BCA handbook[96] should be applied. However it is possible that modifications may need to be made in the near future[97] to the BCA handbooks to define, capture, or modify key benefits attributed to meeting the CLCPA goals for explicit application to the proposed list of projects in this Report.

The Utilities have made significant progress on plans to modernize the electric grid's distribution system to accommodate the State's climate and clean-energy goals. Existing plans for modernization on the distribution system are described in each utility's Distributed System Implementation Plan (DSIP) filing[98] that cover a future five year period and, in the case of PSEG

94 2019 CARIS 70x30 Scenario: Preliminary Constraint Modeling, Nuclear Sensitivity and Additional Results.

95 NYSERDA White Paper on Clean Energy Standard Procurements to Implement New York's Climate Leadership and Community Protection Act.

96 Updates to BCA Handbooks are filed every two years at the same time as the updated Distributed System Implementation Plans are filed.

97 The next BCA Handbook updates for each utility are due end of June 2022

98 *See* the Joint Utilities' recent DSIP filings in Case 16-M-0411, *In the Matter of Distribution System Implementation Plans.* http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101

Long Island,[99] its June 30, 2020 Utility 2.0 Long Range Plan.[100] As described in these filings, the Utilities continue to invest in modern, cost-effective solutions to support CLCPA goals through the deployment of advanced technologies to optimally manage distributed energy resources, which continue to be deployed on the distribution system across New York at a rapid rate. Those distribution projects described in the DSIP/Utility 2.0 Long Range Plan filings may be accelerated as needed

To build and expand upon each utility five-year DSIP each utility conducted a detailed study of the distribution system to identify all Phase 1 and Phase 2 projects required to meet the CLCPA 2030 goals. As part of this analysis the Joint Utilities aligned on two common 2030 forecast scenarios, that being 1) the detailed bottom up type forecasts as described in detail in the DSIPs and 2) forecasts that align with the NYISO 70X30 bases cases. As part of this analysis, each utility specified the inputs and assumptions for its scenario development that reflected achievement of the CLCPA goals, including for electric vehicles, space heating electrification, solar PV, energy efficiency, and energy storage.

The many distribution projects provided in this Report, especially the Phase 2 distribution projects are based on traditional wire-based capital projects. However, all the utilities have NWA, DLM/DR and energy storage programs[101] and associated criterion, whereby the traditional wire projects would be considered for such procurements, potentially leveraging DER as an alternative solution.

C. Summary Results

Sections II through VII, below contain more detailed assessments prepared by each of the Utilities as described above and pursuant to the May Order. Figure 13, below, summarizes the Utilities' Phase 1 projects. Figure 14 summarizes Phase 2 projects.

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[99] PSEG Long Island LLC, through its operating subsidiary Long Island Electric Utility Servco LLC, has managerial responsibility for the day-to-day operation and maintenance of, and capital investment to, the electric transmission and distribution system owned by LIPA under the Amended and Restated Operations Services Agreement between Long Island Lighting Company d/b/a LIPA and PSEG Long Island LLC dated as of December 31, 2013.

[100] PSEG Long Island Utility 2.0 Long Range Plan & Energy Efficiency and Demand Response Plan - 2020 Annual Update - Prepared for Long Island Power Authority; filed by PSEG Long Island on behalf of LIPA on June 30, 2020, dated July 1, 2020. Filed under Case 14-01299, http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-01299&submit=Search

[101] Case 18-E-0130, *In the Matter of Energy Storage Deployment Programs,* Order Establishing Energy Storage Goal and Deployment Policy (issued December 13, 2018).

Figure 13: Utilities' Phase 1 (Immediately Actionable) Projects

Project Name	Projects (No.)	Estimated Project Cost	Estimated Project Benefit (MW)[102]
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	$633M	367.1+
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	$6,800M	8,162
Transmission Total	**52**	**$4,164M**	**6,619**
Distribution Total	**61**	**$2,636M**	**1,543**

* $789 million of investment (reflecting 5 of 8 projects) have already received funding approval. Incremental Phase 1 distribution costs for CECONY are $341 million.

[102] MW Benefit is provided as an indicator of the relative benefit of each project. Once the BCA methodology outlined in Part 1, Section III is approved, the Utilities will work to update this metric for Phase 2 projects.

Figure 14: Utilities' Phase 2 Projects (Conceptual)

Project Name	Projects (No.)	Estimated Project Cost*	Estimated Project Benefit (MW)
Central Hudson			
Transmission	6	$138M	766
Distribution	7	$55M	222
CECONY			
Transmission	6	$4,050M	7,686
Distribution	2	$1,300M	360
LIPA			
Transmission	6	$1,281M+	1,830
Distribution	8	$167.2M	937
National Grid			
Transmission	13	$1,371M	1,500
Distribution	7	$510M-$1,206M	1,162-2,141+
NYSEG/RG&E			
Transmission	11	$780M	943MW
Distribution	5	$125M	88.3MW
Total	71	$9,7777-$10,428M	15,494-16,473
Transmission Total	**42**	**$7,620**	**12,725**
Distribution Total	**29**	**$2,157-$2,853M**	**2,769-3,748**

* In general, the Phase 2 projects included by the Utilities are in early stage development, without completed, detailed designs and/or engineering. Therefore, costs provided in this figure should be considered conceptual estimates.

II. CENTRAL HUDSON GAS & ELECTRIC

Central Hudson Gas & Electric Corporation is a regulated transmission and distribution utility serving approximately 307,000 electric customers and 82,000 natural gas customers in New York State's Mid-Hudson River Valley. Central Hudson delivers natural gas and electricity in a defined service territory that extends from the suburbs of metropolitan New York City north to the Capital District at Albany. Central Hudson supports policies that will help to cost-effectively reduce carbon emissions while continuing to provide resilient and affordable energy to the Mid-Hudson Valley.

Central Hudson owns approximately 75 substations containing power transformers with an aggregate transformer capacity of 5.5 million kilovolt amps. Central Hudson's electric system consists of approximately 9,400 pole miles of transmission and distribution lines, as well as customer service lines and meters.

The transmission system operates at nominal voltages of 69 kilovolts, 115 kilovolts and 345 kilovolts. The distribution system operates at nominal voltages of 13.8 kilovolts, 34.5 kilovolts, 4.8 kilovolts, and 4.16 kilovolts. The distribution system also encompasses sub-transmission systems that nominally operate at 13.8 kilovolts in the three urban areas of our service territory, feeding into secondary networks.

A. Local Transmission

i) Central Hudson Study Assumptions and Description of Local Transmission Design Criteria

Central Hudson analyzed its transmission system to determine Load Serving Capability (LSC), Load Headroom and Generation Headroom to identify constraints and bottlenecks to the siting of Distributed Energy Resources (DERs). The MW headroom values for each proposed project were also calculated.

Central Hudson performs system Load Serving Capability (LSC) analyses for both the existing Transmission System as well as the Transmission System with known planned upgrades/reinforcements included. For "looped" local transmission systems with two transmission inputs, the transmission line with the lowest summer Long Term Emergency (LTE) rating typically sets the LSC for the area. For looped transmission systems, however, the LSC may be set by a more limiting internal element or by a voltage limit/constraint.

Central Hudson has calculated the Load Headroom and Generation Headroom values for the fourteen transmission areas[103] within our service territory. The Load Headroom value is used to determine margin for both load growth and energy storage charging capacity prior to requiring upgrades. Load Headroom is defined as the LSC less the 2019 peak load served less the defined charging capacity of energy storage in queue. The Generation Headroom value is used to determine how much generation or injection of energy storage resources may be sited in a transmission area prior to requiring upgrades. Generation Headroom is defined as the LSC plus the 2019 minimum load served less installed generation and the defined energy storage injection in queue.

Central Hudson calculated MW headroom value increases for the proposed projects based on the local transmission area or the ratings of a single transmission line; hosting capacity may be limited by the system external to the upgraded area. The sum of these MW headroom values will be less than the benefit to the transmission system as a whole.

ii) Possible Fossil Generation Retirements; Impacts and Potential Availability of Interconnection Points

Central Hudson's service territory includes two fossil generation plants. These plants are located along the Hudson River near locations with minimal open land to site PV installations. Central Hudson cannot speculate if these locations could be used for DER installations in the future if these plants are retired.

[103] Note that not all substations are within a transmission area.

iii) Existing Capacity "Headroom" within Central Hudson System

In Figure 15, Load Headroom and Generation Headroom[104] totals are calculated for each transmission area on the Central Hudson System. The generation and energy storage totals include DER projects in-service, projects in-queue and project pre-applications. For projects following the NY State Standardized Interconnection Requirements (SIR) process, only Community Distributed Generation (CDG) projects were included in the generation totals.

Figure 15: Transmission Area Load Headroom and Generation Headroom (note that nested areas may be limited by the larger area it is included in)

<table>
<tr><th colspan="2">Transmission Area</th><th>Load Serving Capability (MW)</th><th>2019 Peak Load (MW)</th><th>2019 Minimum Load (MW)</th><th>Generation (MW)</th><th>Energy Storage (MW)</th><th>Load Headroom (MW)</th><th>Generation Headroom (MW)</th></tr>
<tr><td colspan="2">Northwest 115/69kV</td><td>142</td><td>128</td><td>40</td><td>226</td><td>160</td><td>-146</td><td>-204</td></tr>
<tr><td></td><td>Westerlo Loop 69kV</td><td>85</td><td>62.6</td><td>11.2</td><td>173</td><td>40</td><td>-17.6</td><td>-116.8</td></tr>
<tr><td colspan="2">Kingston-Rhinebeck 115kV</td><td>175</td><td>83.7</td><td>25.4</td><td>4.8</td><td>20</td><td>71.3</td><td>175.6</td></tr>
<tr><td colspan="2">Ellenville 115/69kV</td><td>234</td><td>67.6</td><td>14.9</td><td>64.5</td><td>0</td><td>166.4</td><td>184.3</td></tr>
<tr><td></td><td>Ellenville 69kV</td><td>125</td><td>25.7</td><td>7.5</td><td>50.3</td><td>0</td><td>99.3</td><td>82.2</td></tr>
<tr><td colspan="2">69kV WM Line</td><td>60</td><td>45.1</td><td>5.7</td><td>52.7</td><td>0</td><td>14.9</td><td>13.1</td></tr>
<tr><td colspan="2">115kV RD-RJ</td><td>144</td><td>97.3</td><td>29.1</td><td>15.1</td><td>20</td><td>26.7</td><td>138</td></tr>
<tr><td colspan="2">Mid-Dutchess 115kV</td><td>230</td><td>114</td><td>44</td><td>17.9</td><td>40</td><td>76</td><td>216.1</td></tr>
<tr><td colspan="2">Pleasant Valley 69kV</td><td>107</td><td>70.7</td><td>14.3</td><td>12.9</td><td>10</td><td>11.3*</td><td>98.4</td></tr>
<tr><td></td><td>69kV E Line</td><td>77</td><td>30.1</td><td>7.2</td><td>5</td><td>10</td><td>21.9*</td><td>69.2</td></tr>
<tr><td></td><td>69kV Q Line</td><td>73</td><td>52.9</td><td>3.6</td><td>10.8</td><td>10</td><td>10.1</td><td>55.8</td></tr>
<tr><td></td><td>69kV G Line</td><td>99</td><td>37.9</td><td>3.5</td><td>7</td><td>10</td><td>51.1</td><td>85.5</td></tr>
<tr><td colspan="2">Myers Corners Supply</td><td>44</td><td>24.9</td><td>7.3</td><td>0</td><td>0</td><td>19.1</td><td>51.3</td></tr>
<tr><td colspan="2">Southern Dutchess</td><td>211</td><td>128.1</td><td>40.2</td><td>0.075</td><td>0</td><td>82.9</td><td>251.1</td></tr>
<tr><td colspan="2"></td><td colspan="7">* Includes effect of 15 MW flow to New England</td></tr>
</table>

To date, three transmission areas in the Central Hudson service territory have experienced higher levels of DER interest. The Northwest 115/69kV transmission area will exceed its headroom capacity for siting any additional DERs as shown in Figure 15. This area serves load to the North Catskill, Saugerties, Woodstock, Lawrenceville, South Cairo, Freehold, New Baltimore, Westerlo and Coxsackie substations. The system is supplied from two 115 kV sources (Central Hudson and National Grid's '2' line and 'T-7' line) and a 69 kV source (SB Line). The 69kV SB Line is the main constraint serving this area; the rebuild of this line is currently planned within Central Hudson's five-year capital plan. The project is in the Article VII process with the Settlement Joint Proposal signed by all parties.

[104] Generation Headroom based on thermal constraints only. Potential voltage constraints, short circuit issues, and stability issues are not considered.

The Westerlo Loop 69kV transmission area is a sub-area of the Northwest 115/69kV transmission area. This area serves load to Lawrenceville, South Cairo, Freehold, Westerlo, New Baltimore and Coxsackie Substations. There has been significant interest from developers in siting DERs along this 55-mile 69kV transmission loop. The 69kV operating voltage and conductor sizes are the main constraints of this system.

The 69 kV E Line transmission area also has seen some interest from developers siting DERs. The 69 kV E Line is supplied from the Pleasant Valley Substation and feeds the Hibernia, Stanfordville, Smithfield, Pulvers Corners and Millerton substations. The other inputs to this system are the 690/FV Line to Eversource's Falls Village Substation and the normally open SA Line to NYSEG's Amenia Substation. For the N-1 loss of the Pleasant Valley 69kV source, the area transmission system could be supplied radially from the ISO-NE system. For this condition, ISO-NE would not have the ability to dispatch area generation, and participation in NYISO markets may not be allowed.

iv) Bottlenecks or Constraints that Limit Energy Deliverability within the Central Hudson System

Central Hudson performed steady state load flow analysis on the NYISO's 2020 RNA 70x30 scenario load flow cases. The Utility T&D Investment Working Group Technical Analysis Subgroup determined that it was most appropriate to perform the analysis on Case 1: Peak Load (30,000 MW), Case 3: Light Load (12,500 MW) and Case 6: Shoulder Load (21,500 MW) of the cases provided. In these cases, the NYISO placed generation at Central Hudson's Hurley Avenue 115kV, Modena 115kV and North Catskill 115kV substations as shown in Figure 16, below.

Figure 16: 2020 RNA 70x30 Central Hudson Generator Locations

Substation	Generator (MW)	Generation Dispatched		
		Case1 (MW)	Case 3 (MW)	Case 6 (MW)
Hurley Avenue 115kV	213.87	96.2103	0	85.579
Modena 115kV	213.87	96.2103	0	85.579
North Catskill 115kV	213.87	96.2103	0	85.579
North Catskill 115kV	106.94	48.1074	0	42.791
North Catskill 115kV	213.87	96.2103	0	85.579
North Catskill 115kV	213.87	96.2103	0	85.579
North Catskill 115kV	213.87	96.2103	0	85.579
North Catskill Total	962.42	432.948	0	385.107

Figure 17 and Figure 18 below show the results for Case 1 and Case 6. There were no constrained elements identified in Case 3 for N-1 analysis. The N-1 analysis flow data is listed for the worst-case contingency.

Figure 17: 2020 RNA 70x30 Case 1

Monitored Facility	kV	Ratings (MVA) Normal	LTE	Base Flow (MVA)	Base Flow (%)	N-1 Flow (MVA)	N-1 Flow (%)
#10 Line – Milan to Pleasant Valley	115	124	139	169.1	136.4	212.8	153.1
#5 Line – North Catskill to Churchtown	115	129	183	173.5	134.5	238	130.1
T-7 Line – Milan to Blue Stores	115	166	185	220.3	132.7	282.6	152.7
H Line – North Catskill to Saugerties	69	130	150	127.3	97.9	220.8	147.2
SB Line – Hurley Avenue to Saugerties	69	130	150	96.5	74.2	155.6	103.7
#2 Line – North Catskill to Feura Bush	115	116	120	59.8	51.6	160.9	134.1
North Catskill Transformer #5	115/69	112	129	89.8	80.1	257.6	199.7
North Catskill Transformer #4	115/69	112	129	93.8	83.8	172.5	133.7
I Line – Boulevard to Hurley Avenue	69	61	67	54.1	88.7	89.7	133.9
N Line – Boulevard to Sturgeon Pool	69	45	47	25.5	56.7	46.1	98.0

Figure 18: 2020 RNA 70x30 Case 6

Monitored Facility	kV	Ratings (MVA) Normal	LTE	Base Flow (MVA)	Base Flow (%)	N-1 Flow (MVA)	N-1 Flow (%)
#10 Line – Milan to Pleasant Valley	115	124	139	175.9	141.9	216.5	155.8
#5 Line – North Catskill to Churchtown	115	129	183	160.3	124.2	216.6	118.3
T-7 Line – Milan to Blue Stores	115	166	185	229.5	138.3	282.8	152.9
H Line – North Catskill to Saugerties	69	130	150	126.7	97.5	211.5	141.0
SB Line – Hurley Avenue to Saugerties	69	130	150	107.3	82.5	191.8	127.9
#2 Line – North Catskill to Feura Bush	115	116	120	52.3	45.1	143.7	119.8
North Catskill Transformer #5	115/69	112	129	79.7	71.1	230.4	178.6
North Catskill Transformer #4	115/69	112	129	85.9	76.71	154.7	119.9
I Line – Boulevard to Hurley Avenue	69	61	67	52.3	85.7	92.2	137.7
N Line – Boulevard to Sturgeon Pool	69	45	47	27.2	60.4	50.9	108.3

Due to the large amount of generation placed at the North Catskill 115kV bus, there were thermal overload issues identified on the nearby transmission lines and 115/69kV step-down transformers. The H and SB lines are constrained by their 69 kV operating voltage and conductor size. The existing #10 line (Milan to Pleasant Velley), and part of the T-7 line (North Catskill to Milan) are scheduled to be rebuilt by NY Transco with high temperature conductor which increases the summer and winter conductor ratings to 390 and 415 MVA, respectively. The conductor on the North Catskill to New Churchtown section of the T-7 Line (to be renamed the 5 line), however, will not be replaced and the existing ratings will remain. These rebuilt lines, however, will be limited by substation connections and tap transmission spans.

As described previously, loss of the Pleasant Valley source to the 69 kV E Line could result in this system being supplied from ISO-NE. For this condition, ISO-NE would not have any capability to dispatch area DER thus potentially precluding those resources from participating in the NYISO markets. To allow such NYISO market partition, an additional transmission input from the NYCA transmission system would be required.

v) Transmission Projects that would Address Bottlenecks or Constraints that limit Energy Deliverability within the Central Hudson System

From the study results presented in section iii above, Phase 2 projects that address bottlenecks and constraints that limit energy deliverability are listed in Figure 19 below. These proposed projects are in addition to the projects already approved in the Central Hudson's 5-year electric capital forecast. These projects are dependent on Commission approval of the CLCPA planning criteria proposed in the Policy Working Group.

Figure 19: Phase 2 Transmission Projects that Address Bottlenecks and Constraints

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost Estimate	MW Headroom
H & SB Line	G	Hurley Avenue	North Catskill	Change Operating Voltage from 69kV to 115kV	2030	$11.8M	100
NC Line	G	North Catskill	Coxsackie	Rebuild and Operate 69kV line for 115kV	2030	$29.1M	147
New Smithfield Area Line	G	Milan	Pulvers Corners	New Milan to Pulvers Corners Transmission Line	2030	$25.2M	95
Q Line	G	Rhinebeck	Pleasant Valley	Rebuild 69kV for 115kV*	2027	$15.0M**	60
					Total	$81M	402
* Line to be initially operated at 69 kV. Project would replace Q Line Phase 1 project listed in Figure 20. ** Incremental cost to build at 115 kV.							

In Figure 19, the H & SB Lines and NC Line projects proposed address constraints on the Northwest 115/69kV and Westerlo 69kV Loop transmission areas. These projects together would upgrade a significant portion of the 69kV transmission system to 115kV.

The H and SB lines are in Central Hudson's 5-year capital forecast to be rebuilt for 115kV operation to address future needs. The lines will be operated at 69kV until the upgrade to 115kV is required. The H and SB Line project proposal expedites the conversion of the operating voltage to 115kV and would provide a third 115 kV transmission line input into the transmission area. This project would require at least one new 115/69kV autotransformer to be installed at Saugerties Substation to feed the 69 kV SR Line to Woodstock.

The NC Line project addresses headroom constraints on the Westerlo Loop 69kV transmission area. The NC Line project proposal would rebuild and operate the existing 69kV line from North Catskill to Coxsackie substations for 115kV. This project would also include installing a 115/69kV autotransformer at Coxsackie.

The New Smithfield Area Line project addresses the 69 kV E Line transmission area. This project proposal includes building a new Milan to Pulvers Corners transmission line to provide a second NYCA transmission source to the area. This would allow DERs to be dispatchable by the NYISO under N-1 conditions.

The Q Line project was proposed to address future expandability of renewable energy resources. The 20.5-mile 69kV line from Rhinebeck to Pleasant Valley is in the planning stages to be rebuilt for 69kV operation. Central Hudson's 69kV operating voltage is often a significant constraint when siting large renewable generation interconnections. This project proposes to rebuild the Q Line for 115kV operation instead even though it is currently not justified by other needs. The incremental cost to build the line for 115kV operation as part of the rebuild project would be significantly less than the cost of a complete rebuild in the future if developers were to site DER projects that would require more headroom than a future 69 kV system in this area would allow.

vi) Projects that would Increase Capacity on the Local Transmission System to allow for Interconnection of New Renewable Generation Resources within the Central Hudson System

Projects in Central Hudson's 5-year electric capital forecast to address load growth, new business, compliance, day-to-day business management and infrastructure replacement will also increase capacity on the local transmission system to allow for new renewable generation resources. The capital forecast is developed each year using the most recent planning studies, customer and sales forecasts, corporate demand forecasts, and other corporate trends. Figure 20 lists Phase 1 projects that are included in the 5-year electric capital forecast that increase energy deliverability.

Figure 20: Phase 1 Transmission Projects included in 5-Year Capital Forecast

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost Estimate	MW Headroom
KM & TV Line	G	Knapps Corners	North Chelsea	Rebuild 69kV Line	2022	$11.6M	86
H & SB Line	G	Hurley Avenue	North Catskill	Rebuild 69kV Line for 115kV Operate at 69 kV	2024	$58.5M	75
HG Line	G	Honk Falls	Neversink	Rebuild 69kV Line	2026	$27.5M	53
Q Line	G	Rhinebeck	Pleasant Valley	Rebuild 69kV Line	2027	$37M	60
SK Line	G	Knapps Corners	Spackenkill	Rebuild 115kV Line	2025	$4.4M	57
P & MK 115kV	G	Modena	Kerhonkson	Operate P & MK at 115kV Install (2) Kerhonkson	2024	$13.1M	102
		Sturgeon Pool	Kerhonkson				

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost Estimate	MW Headroom
				115/69 kV Auto-XFMRs			
					Total	$152.1M	433

From the study results presented in section iv above, Phase 2 projects that increase system capacity are listed in Figure 21, below. These proposed projects are in addition to the projects already approved in the Central Hudson's 5-year electric capital forecast. These projects are dependent on Commission approval of the CLCPA planning criteria proposed in the Policy Working Group.

Figure 21: Phase 2 Projects that Increase Transmission System Capacity

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost Estimate	MW Headroom
10 & T-7 Line Station Connections	G	Pleasant Valley	Milan	Upgrade Station Connections to not Limit Line Conductor	2030	$0.9M	261
Northwest Reinforcement	G	New Baltimore	Westerlo	New Substation 345/115kV Auto-XFMR 115/69kV Auto-XFMR NW & CL lines at 115kV	2030	$56.0M	103
					Total	$57M	364

In Figure 21, the proposed 10 & T-7 Line Station Connections project addresses the capacity constraints on the 115kV #10 Line and the segment of the T-7 line between New Churchtown and Milan. The proposed project would replace station connections and associated limiting equipment at Pleasant Valley and Milan substations to not limit the new conductor that will be installed as part of the NY Transco Segment B project. Since the entire T-7 Line between North Catskill and New Churchtown will not be replaced as part of the NY Transco Segment B project, the existing conductor would need to be replaced to increasing area hosting capacity. This project would have to be coordinated with National Grid and NY Transco for feasibility.

The proposed Northwest Reinforcement project addresses overloads in the vicinity of North Catskill substation. This potential project proposes to build a new 345/115/69 kV substation where National Grid's 345kV '94' Line intersects the 115kV '2' Line, 115kV '8' Line and 69kV NW Line. The new substation would provide another source into the Westerlo Loop 69kV transmission area. This project does not alleviate the North Catskill overloads in the 2020 RNA

70x30 load flow case. From the DER projects in-service, projects in-queue and project pre-applications, developer interest in siting renewable generation is distributed throughout the Northwest 115/69kV and Westerlo Loop 69kV transmission areas and not located directly at North Catskill where 962 MW of renewables was placed in the 2020 RNA 70x30 load flow case. This project would provide substantial benefits to these transmission areas. The proposed Northwest Reinforcement project requires additional analysis and study work before it can be implemented; the exact configuration of the project would be highly dependent on where DER develops.

B. Distribution

i) Review and Identification Phase 1 Distribution Projects

The purpose of this section is to describe the review of the Company's current capital plans and other existing long range system plans to identify where existing Substation and Distribution projects that have load or generation headroom benefits as designed or with modifications.

Within the Company's current capital plan, the vast majority of the Company's Capital spend is for non-discretionary (new business, restoring service, safety repairs, compliance, road rebuilds/relocations) type work or to maintain system standards (equipment replacement based on condition assessment, correct existing planning/design violations and equipment replacement based on obsolescence). Over the last several years, the Company's service territory has experienced declining to stagnant electric load growth; as a result, no significant load growth-based projects are included within the Electric Capital Budgets. The Capital program is predominately infrastructure projects to ensure system integrity and customer reliability going forward.

Specifically, the Company's current capital plan for Substation and Distribution is comprised of predominately condition based infrastructure projects. As part of the Company's planning process, alternative analyses are completed to determine the appropriate replacement strategy (i.e. replace in-kind; replace with higher rated equipment; and replacement with alternative solution/ equipment/ location). Current interconnection queue data is utilized as an input in this analysis to facilitate the identification of near-term hosting capacity needs. While these projects are primarily for non-discretionary type work or to maintain system standards, a number of the projects have load or generation headroom benefits as designed or with modifications. The Figure 22 below identifies the existing projects that have load or generation headroom benefits as designed or with modifications.

Figure 22: Phase 1 Distribution Projects included in 5-Year Capital Forecast

Project Name	Zone	Substation	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost Estimate	MW Headroom
DA/DMS	G	System Wide	Distribution Automation and Distribution Management System – Foundational Investments	Ongoing	$14.2M	**
Operating Infrastructure	G	System Wide	Infrastructure	Ongoing	$25.3M	**
Knapps Substation Replacement	G	Knapps Corners	Station Rebuild – high capacity circuit exits	2022	$1.0M	18MW
Coxsackie Transformer Replacement	G	Coxsackie	Replace with 22 MVA	2021	$2.1M	10MW
Coxsackie DEC Peaker Regulation Project	G	Coxsackie	Add a 2nd Transformer and DVAR	2024	$4M	22MW
South Cairo DEC Peaker Regulation Project	G	South Cairo	Add a 2nd Transformer and DVAR	2024	$4.1M	12MW
New Baltimore Transformer Replacement	G	New Baltimore	Add a 2nd 12 MVA Transformer	2023	$1.6M	12MW
Greenfield Road Transformer and Circuit Exits	G	Greenfield Road	Replace existing Transformers	2023	$1.5M	10MW
5 kV Aerial Cable Replacement	G	System Wide	Replace cable or convert 5 kV to 13.2 kV Operation	Ongoing	$2.5M	14MW
Copper Wire Replacement Program	G	System Wide	Replace #4 and #6 copper with higher capacity ACSR	Ongoing	$3.6M+	23MW
4800V & 4 kV Replacement Programs	G	System Wide	Upgrade 4800 V and 4kV to 13.2 kV eliminating stepdown transformers	Ongoing	$17.6M+	11MW
Storm Hardening	G	System Wide	Harden mainline zones of protection	Ongoing	$59.5M	**
				Total	$137 M	132MW

** The MW Headroom for the Distribution Improvement – Operating / Infrastructure Condition, Storm Hardening and Grid Modernization (including DMS/DA) programs is not identified within the table. These programs are larger in scale and can encompass a range of project types and geographic areas. Based on the nature of these programs, the MW headroom improvements will be distributed across our service territory and is difficult to forecast.

The Distribution Improvement – Operating / Infrastructure Condition program includes a mixture of conversions, polyphasing, reconductoring, closing circuit gaps, and rebuilding older infrastructure in poor condition. There are almost 50 projects specifically identified for 2021-2025 within this category.

Storm hardening efforts include reconductoring three-phase mainline zones of protection as well as lateral lines. Additional electronic reclosers will also be placed in strategic locations throughout the service territory as an incremental component to Central Hudson's DA/DMS initiative.

Through its Grid Modernization Program, the Company is taking significant steps to accommodate DERs and model the system impacts of DERs in order to preserve distribution system safety and reliability. Critical to these efforts are a set of foundational investments that will support DSP capabilities. Central Hudson's Grid Modernization Program is comprised of six critical projects:

1. Distribution Automation (DA) – automated devices, distribution infrastructure (poles and wires)
2. ESRI System Model Geographic Information System (GIS) – provides a single consolidated mapping and visualization system
3. Distribution Management System (DMS) – the centralized software "brains"
4. Distribution System Operations (DSO) – the organization responsible for monitoring and controlling the electric distribution system through the use of the DMS
5. Network Communications Strategy (NS) – the two-way communication system between the DA devices and DMS
6. Substation Metering Infrastructure– Substation feeder metering upgrades required for accurate ADMS power flow calculations.

Over 800 Intelligent Electronic Devices (IED; e.g. electronic reclosers, switched capacitors and voltage regulating devices) and sensors are being installed through DA and other projects. These devices provide real time data to the DMS, which enables it to make centralized decisions based on current system conditions rather than anticipated peak loads. DERs also must be monitored, and in some cases, controlled, as a critical input to the DMS. The Network Communications Strategy equipment enables communication between the DA equipment and the DMS. GIS enables new capabilities for Central Hudson, including developing accurate distribution grid models (potentially down to the customer meter) and enabling calculation and visualization of DER installations and hosting capacity.

Distribution System Operations staff will utilize DA devices to regularly feed live electrical system data into the DMS, GIS will support a number of DMS capabilities, including:

- Greater operational efficiency with improved automation management;
- Preservation of safety and reliability in real-time operations through integration of disparate data sources; and
- Improved interaction with SCADA devices, including distribution feeder breakers, substation load tap changers and DERs.

The continued implementation of these supporting technologies and systems will enable Central Hudson to produce more robust system models that incorporate the impact of DERs and ultimately allow it to utilize DERs better to provide value to the grid and customers. In the near term, Central Hudson's Grid Modernization Program aims to accommodate DERs through increased monitoring and, in some cases, control. Over the longer term, Central Hudson may seek to dispatch DERs in real time to preserve distribution system safety and reliability or provide other services of value to the grid.

ii) 70 X 30 Distribution Study Objectives

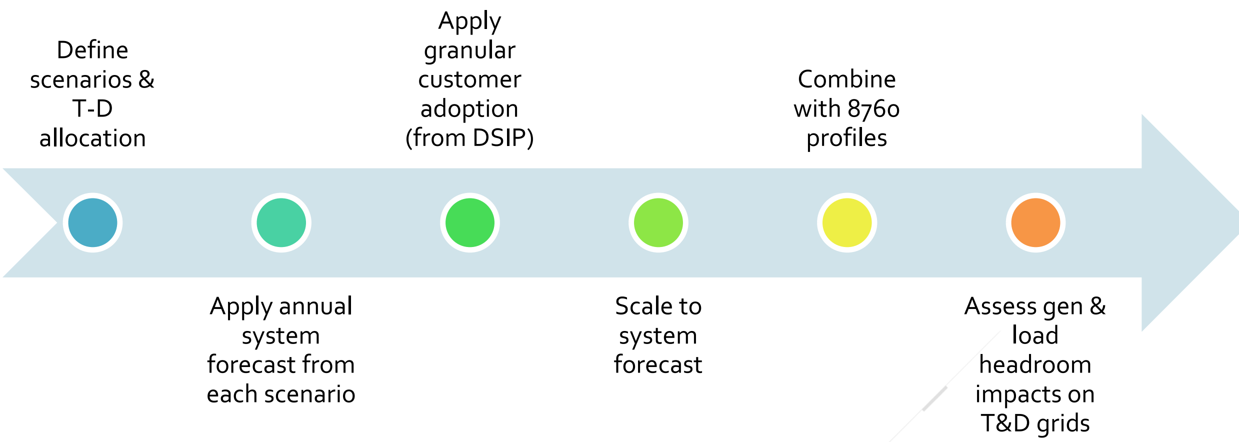
The purpose of this analysis is to identify areas within Central Hudson's territory where distribution upgrades are necessary and appropriate, and to assess the impacts of the CLCPA renewable energy and electrification goals on distribution constraints and costs. Specifically, this Report expands the forecasts and analysis of the 2020 DSIP and addresses the first evaluation scenario of the May Order, and seeks to evaluate the capacity headroom available on Central Hudson's distribution system through 2030 for the identification of Phase 2 Distribution projects. The analysis seeks to answer three main questions:

- Where is the solar capacity likely to be located within Central Hudson territory?
- What is the year-by-year capacity headroom assuming the solar capacity needed to meet the 2030 goals?
- What are the costs of the upgrades necessary to achieve the climate goals?

iii) Methodology

Figure 23 provides a high-level overview of the process for evaluating local area capacity needs and constraints under multiple scenarios.

Figure 23: 70x30 Analysis Overview



The analysis process can be summarized in six steps. These steps are:

1. **Define scenarios and T&D allocation**. Central Hudson selected three scenarios representing different levels of CLCPA goal achievement. These scenarios range from a business-as-usual scenario, where Central Hudson continues to work towards the goals outlined in their 2020 Distributed System Implementation Plan (DSIP), to a scenario where CLCPA renewable energy and electrification goals[105] are fully implemented and achieved by the target year. These scenarios incorporate T&D capacity allocation following allocations established in the NYISO CARIS 70x30 Scenario[106].
2. **Apply annual system forecast from each scenario**. Annual forecasts through the target year 2030 are defined for each scenario to align with either the DSIP or CLCPA goals, as applicable. This definition includes allocation between the ten Central Hudson transmission areas and the distribution system. CLCPA goals for renewable resources were defined at the 115 kV bus level and were spread down to substations including those connected to the 69 kV transmission system based on proximity and connection to transmission lines in the specified areas of the 115 kV system.
3. **Apply granular customer adoption (from DSIP)**. In the 2020 DSIP, loads and DER adoption (solar, storage, EE, EV, heat pumps) were estimated for each transmission area and substation. These forecasts are leveraged in this analysis to define adoption at the local level. The same proportional adoption dispersion was

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105 "White Paper on Clean Energy Standard Procurements to Implement New York's Climate Leadership and Community Protection Act"; DPS and NYSERDA; JUNE 18, 2020.

106 "2019 CARIS 70x30 Scenario: Preliminary Constraint Modeling, Nuclear Sensitivity and Additional Results"; NYISO Electric System Planning Working Group; March 16, 2020.

used for the scenarios applying the DSIP or the CLCPA goals for behind the meter resources.

4. **Scale to system forecast**. For each year, the local adoption forecasts are then scaled up to the aggregate forecast, with the goal of accurately reflecting the expected growth or loss in headroom on a year-by-year basis.
5. **Combine with 8760 profiles**. The system year-by-year forecast is then combined with 8760 load profiles for distributed energy resources that were developed for the 2016 DSIP to understand the overall load impact DER adoption on distribution and transmission loads. Production profiles used for solar[107] and storage[108] production were different than those used for the DSIP given the focus of this analysis on identifying headroom constraints.
6. **Assess generation and load headroom impacts on T&D grids**. The aggregated load shapes and local level load and DER adoption forecasts are combined to estimate the generation and load headroom impacts of the different scenarios on the T&D grid, for each year and local area. Generation headroom is reported for the minimum net load hour. Load headroom is reported for the maximum net load hour.

iv) Headroom Calculation Definitions

This analysis explores two different types of "headroom", or the available capacity in MWs, existing in each local area of the grid – generation headroom and load headroom.

Generation headroom refers to the available capacity for additional generation or injection of energy at a transmission area prior to requiring upgrades. Resources that increase energy consumption, such as gross load or beneficial electrification, increase generation headroom, while new generation sources and consumption-reducing resources (such as energy efficiency) decrease the available capacity for generation. Figure 24 illustrates the various factors in the generation headroom equation. For the purposes of this analysis, battery storage is assumed to be unmanaged by the utility – that is, the developers and end user have full control of the battery storage. As a result, planning for storage is based on the scenario of battery storage fully discharging at the minimum load hour. Generation headroom is reported for the minimum net load hour, and battery storage is assumed to be fulling discharging at the minimum load hour.

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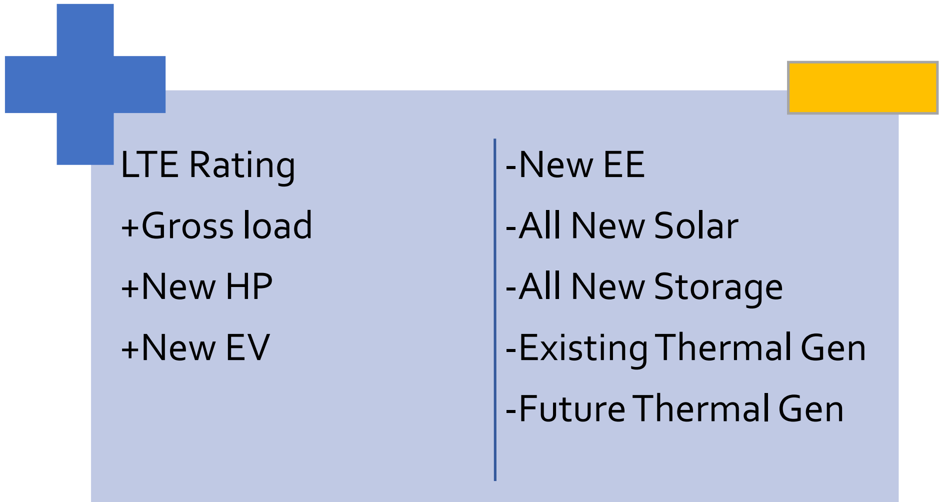
[107] The DSIP analysis focused on typical 1-in-2 impacts for which an average monthly solar production profile was used. The key objective of the CLCPA 70x30 analysis is to identify grid constraints under minimum net load and maximum net load conditions so the peak monthly production profile was used.

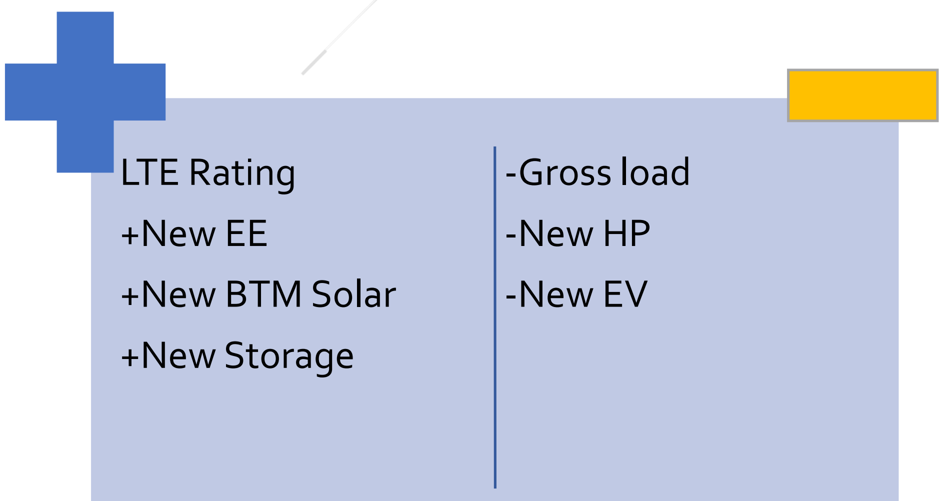
[108] The DSIP analysis focused on typical 1-in-2 impacts for which a market driven charge / discharge profile was used. The key objective of the CLCPA 70x30 analysis is to identify grid constraints under minimum net load and maximum net load conditions so the nameplate capacity was applied to all hours.

Figure 24: Generation Headroom Definition



Load headroom refers to the available capacity for load growth on the system area before requiring upgrades. Resources that reduce net load, such as behind the meter renewable energy generation and energy efficiency, effectively increase load headroom, while resources that increase energy consumption decrease load headroom. Load headroom is the inverse of generation headroom. The key difference is that it does not include front-of-the-meter solar production or any thermal generation since the focus is on load, not generation. Figure illustrates the load headroom equation. Load headroom reported for day and hour with the maximum net load, with battery storage assumed to be fully charging at the maximum net load hour.

Figure 25: Load Headroom Definition



CLCPA goals will affect both sides of the equation, for both generation and load headroom. Beneficial electrification efforts will increase loads, while energy efficiency measures will reduce them. Investments in solar generation and storage systems will increase available load capacity on the system. Central Hudson will need to balance the effects of these various changes across the transmission and distribution system in order to provide reliable electric service to its customers, while maintaining equilibrium on the electric system.

v) Scenario Definitions

This analysis explores generation and load headroom year-by-year through 2030, across three scenarios with various degrees of renewable energy and DER adoption. Figure 26 compares the three scenarios across three categories – solar and storage capacity, transmission and distribution capacity split for solar and storage, and energy efficiency, EV, and heat pump capacity.

Figure 26: Scenario Comparison

Scenario	Solar/Storage Capacity Goals	T&D Split for Solar/Storage	EE/EV/HP Capacity Goals
1	DSIP	DSIP	DSIP
2	CLCPA 70x30	NYISO 70x30	DSIP
3	CLCPA 70x30	NYISO 70x30	CLCPA 70x30

Scenario 1 is the business-as-usual baseline case, which assumes that Central Hudson continues with the goals outlined in their 2020 Distributed System Implementation Plan. Under this scenario, Central Hudson achieves the capacity goals set for solar, battery storage, energy efficiency, electric vehicle, and heat pump adoption set in the DSIP. It also includes all existing and in queue transmission connected thermal generation, solar generation, and storage capacity.

Scenario 2 explores generation and load headroom using the achievement of CLCPA goals related to generation but using the loads consistent with Central Hudson's 2020 DSIP filing. It assumes that CLCPA solar and storage capacity goals are achieved, but energy efficiency, EV, and heat pump goals from the DSIP are maintained. Since the CLCPA does not establish a specific goal transmission versus distribution connection resources, the NYISO 2019 CARIS 70x30 Scenario is used to, on a broad basis, define the allocation across the system. Capacity was subsequently allocated to substations, including those connected to the 69 kV transmission system, based on proximity and connection to transmission lines in the areas specified by the NYISO. In addition, resources were assumed to be split evenly between transmission and distribution connections. Scenario 2 is a hybrid of DSIP and CLCPA conditions and was intended to test the outcome of adding CLCPA incremental renewables without the incremental electrification goals.

Scenario 3 assumes that CLCPA renewable energy and electrification goals are achieved by the 2030 target year. It uses the same allocation methodology for connected as scenario 2 for the transmission and distribution allocation on the system and split between transmission and distribution for solar and storage capacity.

Figure 27 compares Central Hudson's DER goals under the DSIP and CLCPA. It provides a sense of the range between the business-as-usual scenario and the CLCPA scenario. While storage capacity goals are the same in both scenarios, capacity goals for all other DERs are significantly higher under the CLCPA. In particular, the solar capacity goal under CLCPA conditions is nearly four times higher than the DSIP forecast, which was based on historical adoption pattern and solar in the interconnection queue.

Figure 27: DSIP and CLCPA 2030 Goals

2030 Goals	BAU (DSIP)	CLCPA
Total Solar (MW)	479	1,872
Total Storage (MW)	620	620
EE (GWh)	446	729[109]
EV (Vehicles)	19,600	60,000[110]
Heat Pumps (GWh)	30	60[111]

vi) Other Key Assumptions

In order to calculate year-by-year minimum net load generation and load headroom at the transmission area and substation levels, the analysis incorporates granular load and DER adoption forecasts from the 2020 Central Hudson DSIP:

- Gross hourly load forecasts match the DSIP forecast through 2025 and were simply extended to 2030.
- Hourly load profiles for load modifying DERs developed for the DSIP were also used for this analysis.
- Central Hudson also assumed that the allocation of distribution connected solar, energy efficiency, and heat pumps was the same as the allocation developed for the DSIP.

A few key modifications of the DSIP framework were made to better align with the goals of this analysis:

- Loading factors reported for the DSIP were a ratio of gross loads and LTE ratings. Given the focus on understanding avoided T&D costs, load modifying DERs (energy efficiency, heat pumps, electric vehicles, solar, and storage) were not

[109] Increases from the DSIP based on an increase of EE on a gross statewide basis of 34700 GWH to 56700 GWH.

[110] Based on CHGE territory share of light duty vehicles and the statewide goal of 850,000 by 2025 and 2 million by 2030.

[111] Based on a doubling of the HP GHW load from the DSIP to estimate the CLCPA impact.

included in load forecasts. As such load headroom calculated for this study is not comparable for to DSIP loading factors.

- Heat pumps were included as part of energy efficiency for the DSIP but were broken out for the CLCPA given the different goals and because heat pumps contribute incremental load in months where heating is needed.
- The DSIP analysis focused on typical 1-in-2 impacts for which an average monthly solar production profile was used. The key objective of the CLCPA 70x30 analysis is to identify grid constraints under minimum net load and maximum net load conditions so the peak monthly production profile was used.
- The DSIP analysis focused on typical 1-in-2 impacts for which a market driven battery storage charge / discharge profile was used. The key objective of the CLCPA 70x30 analysis is to identify grid constraints under minimum net load and maximum net load conditions so the nameplate capacity was applied to reflect a scenario where battery storage is not managed by the utility, but managed by developers and customers. It is possible that battery storage could be operated under conditions which align with local need, thereby increasing headroom. However, for planning purposes battery storage is assumed to be operated by the battery owner or developer. In effect, because battery storage is not operated by the utility it could be managed to align with other needs such as ancillary services which may be misaligned with local needs.

vii) Distribution Substation Results

1. Generation Headroom

There are 62 load serving distribution substations located in Central Hudson's territory. Figure 28 shows the generation headroom available under each planning scenario at the distribution substation level, for the 10 substations with the least available headroom in 2030. Generation headroom at the distribution level mirrors the results of the transmission area analysis, with the largest constraints in the Westerlo and Northwest 69 kV Areas. Notably, three Westerlo substations have significant generation capacity needs by 2025 in the CLCPA scenario.

Figure 28: Generation Headroom in MW by Distribution Substation, 2025 and 2030

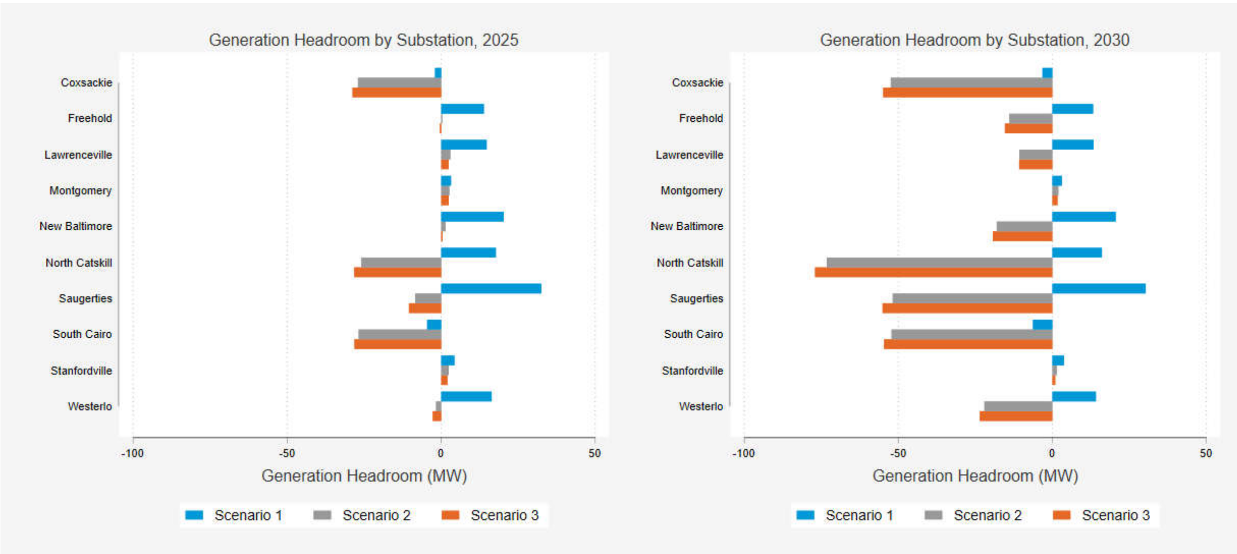


Figure 29 shows the generation headroom available as a percent of the substation's LTE rating, for the same group of 10 substations. For the substations with the lowest generation headroom, projected generation capacity needs in 2030 are approximately one to three times the current LTE ratings.

Figure 29: Generation Headroom as Percent of LTE Rating by Substation, 2025 and 2030

Figure 30 shows the generation headroom for the same set of substations, broken down by modifying factor for the business-as-usual and CLCPA scenarios in 2030. While planned bulk storage capacity additions are the largest contributor to generation needs in the business-as-usual scenario, bulk solar capacity additions are the primary driver of generation constraints under CLCPA conditions.

Figure 30: Generation Headroom Breakdown by Modifying Factor – Substation Level

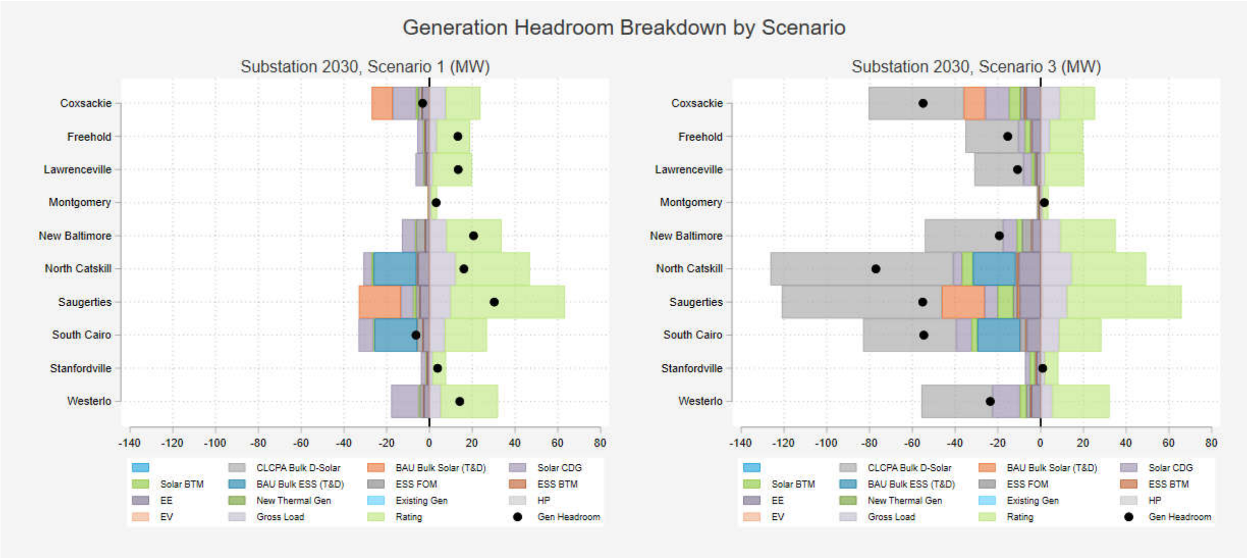
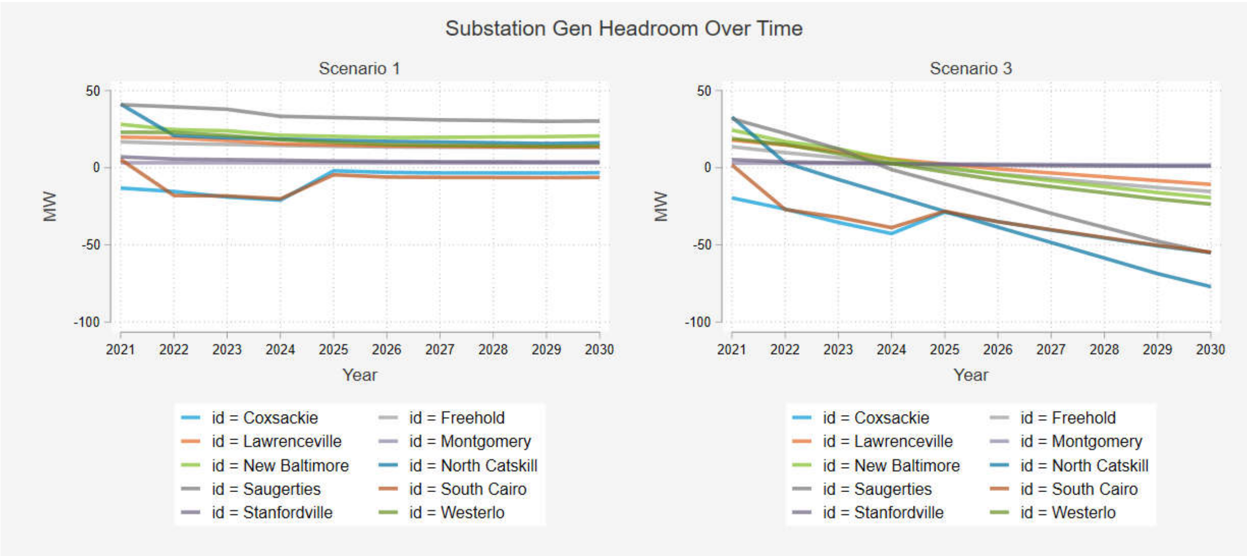


Figure 31 shows the significant impact of CLCPA goals on generation capacity needs at the distribution level. In the business-as-usual scenario, generation headroom is largely stable across the planning period, with two exceptions. The battery installation in the Northwest 115-69 kW Area decreases generation headroom available at the North Catskill and South Cairo substations, and predicts a generation constraint at the South Cairo substation from 2022-2024. In 2024, planned generation retirements increase available headroom at the South Cairo and Coxsackie substations. Under CLCPA planning conditions, most substations experience a sharp decline in generation headroom that tracks the deployment of the CLCPA. The only exceptions are the Stanfordville and Montgomery substations, which remain stable with marginal generation headroom available throughout the planning period.

Figure 31: Generation Headroom Timeline by Distribution Substation & Scenario



2. *Load Headroom*

Figure 32 shows the load headroom available for each scenario at the distribution substation level, for the 10 substations with the least available headroom in 2030. Load constraints at the distribution level are similar across scenarios and years. Note that this subset of ten substations is different from the ten lowest substations in terms of generation headroom, although three substations appear on both lists – Montgomery, North Catskill, and South Cairo.

Figure 32: Load Headroom in MW by Distribution Substation, 2025 and 2030

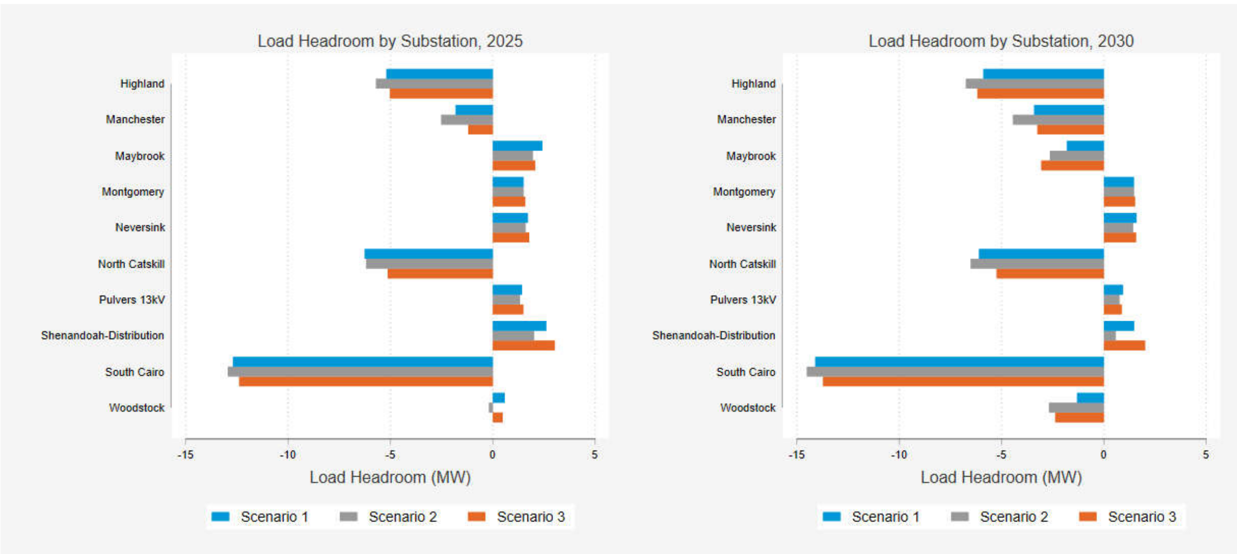


Figure 33 shows the load headroom available as a percent of each substation's LTE rating. Load constraints at the substation level are significantly smaller compared to LTE ratings than generation constraints, with deficits around 15-20% of ratings. The only exception is South Cairo, where loads are projected to exceed the substations LTE rating by 60% across scenarios and years. South Cairo has an LTE rating around 20 MW, which is low given the additional 20 MW of planned bulk storage capacity addition in the area.

Figure 33: Load Headroom as Percent of LTE Rating by Substation, 2025 and 2030

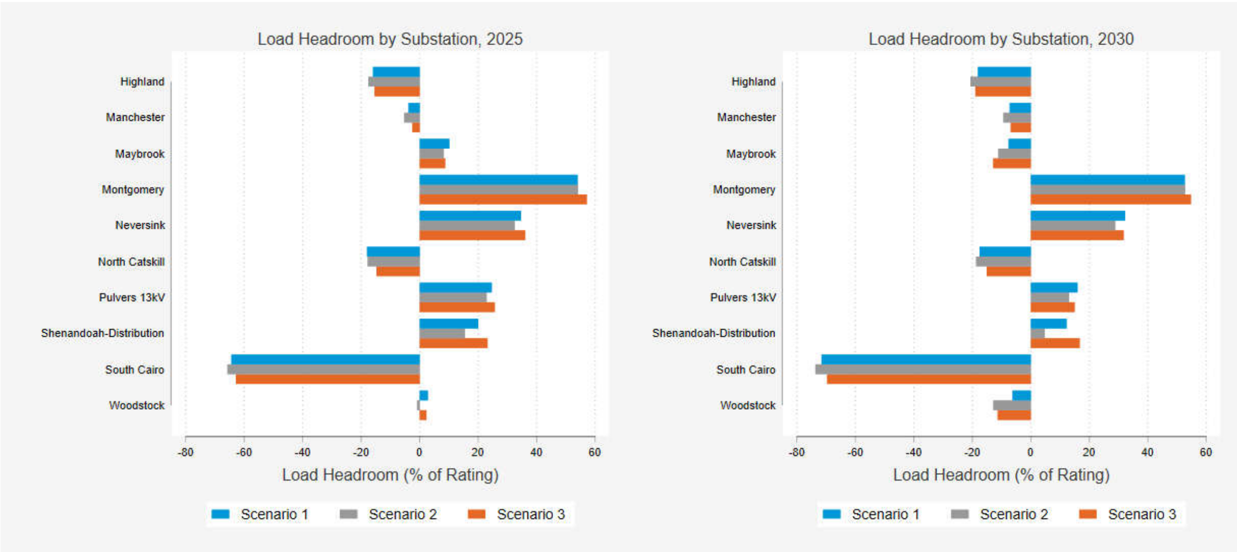


Figure 34 shows the load headroom for each substation, broken down by modifying factor for the business-as-usual and CLCPA scenarios in 2030. The black triangle indicates the overall load headroom available for each substation and year. Load deficits in both scenarios are driven by high bulk storage capacity relative to substation LTE ratings. Highland, Manchester, North Catskill, and South Cairo receive most of the impact of the 100 MW bulk storage addition that will come online in 2022.

Figure 34: Load Headroom Breakdown by Modifying Factor – Substation Level

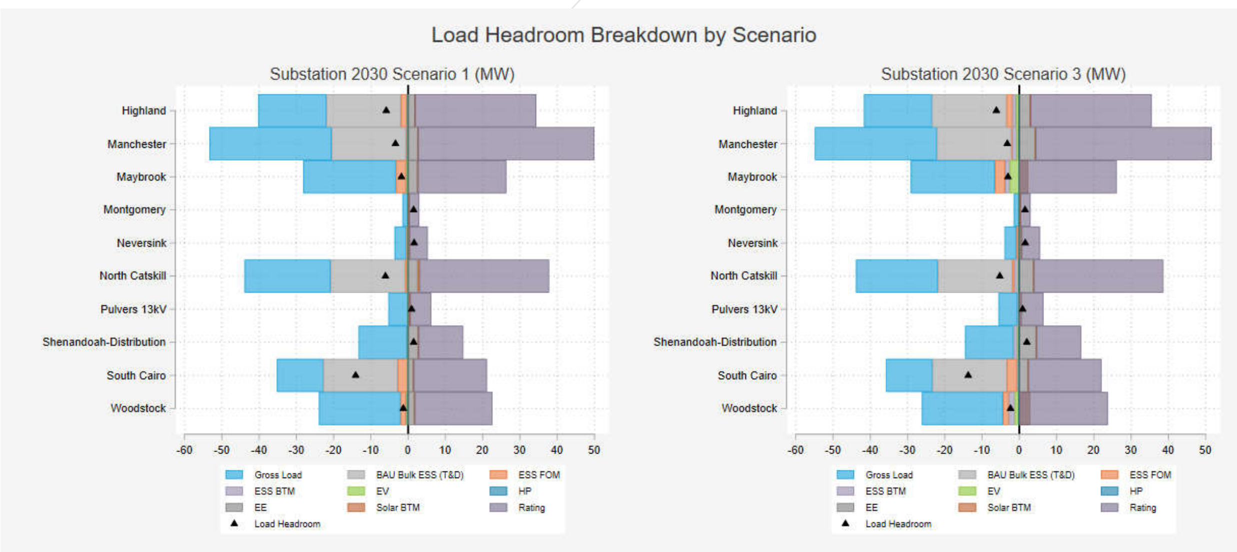
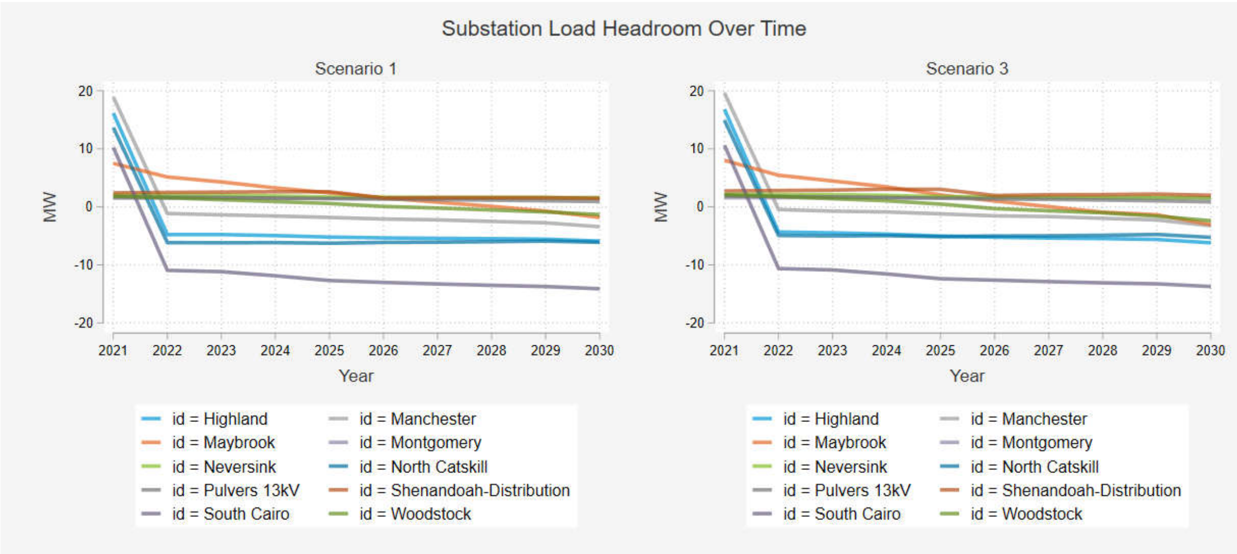


Figure 35 highlights the impact of the bulk storage capacity addition on these four substations. There is a sharp decrease in load headroom between 2021 and 2022. After the shortfall due to storage additions, load headroom remains relatively stable for these substations through 2030. For the other six substations, load headroom is generally steady across the planning period under both scenarios.

Figure 35: Load Headroom Timeline by Distribution Substation & Scenario



viii) Distribution Areas requiring Capacity Investments

Figure 36 shows projected capacity constraints in Central Hudson's territory for the business-as-usual and CLCPA scenarios in 2030, by distribution substation. Under the business-as-usual scenario, only two substations experience generation capacity constraints, due to planned thermal generation retirements. With the deployment of the CLCPA, six additional substations become constrained, concentrated in the northern part of Central Hudson's territory.

Figure 36: Capacity Constraints Across Central Hudson's Territory, by Distribution Substation

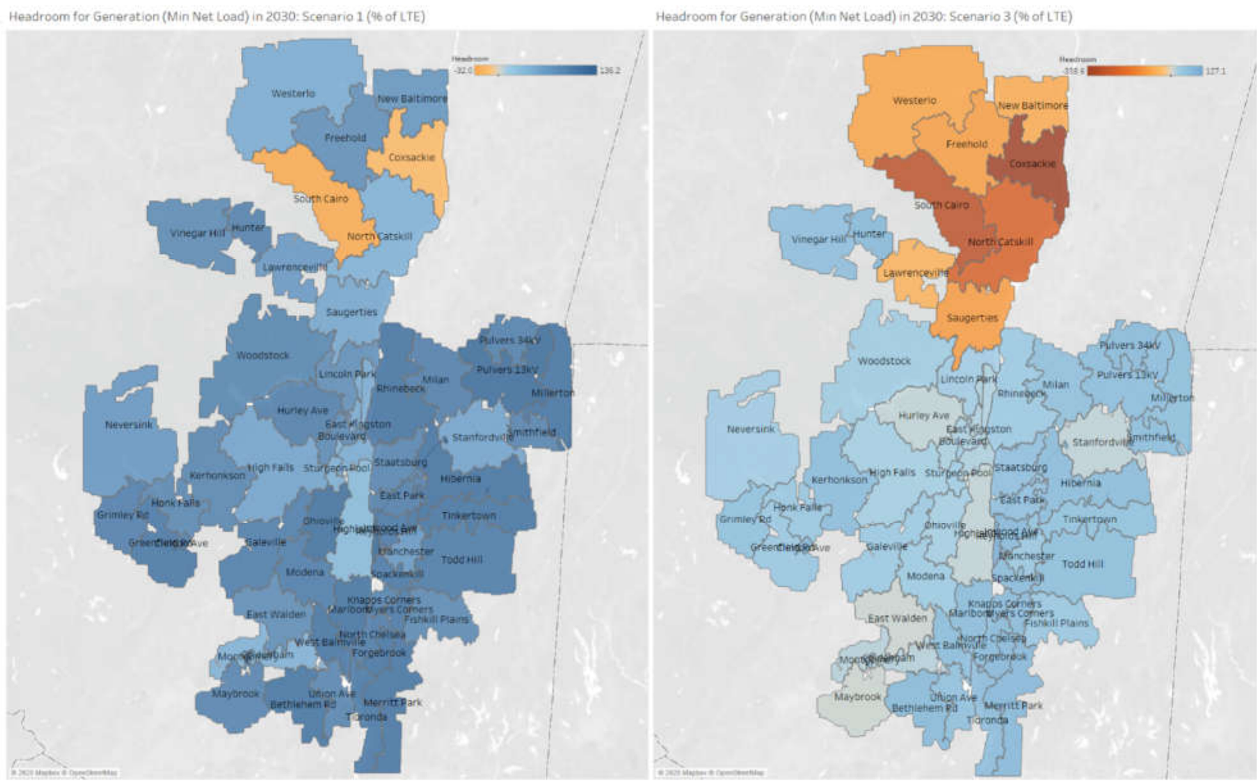


Figure 37 shows the eight substations in need of upgrades for 2020. For all eight substations, bulk solar additions that will be deployed under the CLCPA are a key driver of constraints. North Catskill and South Cairo will experience additional constraints due to bulk storage projects in queue for the Northwest 115-69 kV and Westerlo Areas. South Cairo and Coxsackie will experience a boost in generation headroom available after a planned thermal retirement in 2024. Six of the eight substations will require updates by 2025, under CLCPA planning conditions.

Figure 37: Distribution Substations with Generation Headroom Needs

Substation	Transmission Area	2030 Rating Including NWAs (MW)	2030 Incremental Generation Headroom Needed (MW)	Key Drivers of Constraints
Coxsackie	Westerlo Loop	16.2	55.0	BAU bulk solar and CLCPA bulk solar (helped by 2024 thermal retirement)
Freehold	Westerlo Loop	15.5	15.4	CLCPA bulk solar
Lawrenceville	Westerlo Loop	18.3	10.8	CLCPA bulk solar
New Baltimore	Westerlo Loop	25.8	19.3	CLCPA bulk solar
North Catskill	Northwest 115-69 Area	34.7	77.1	BAU bulk storage and CLCPA bulk solar

Substation	Transmission Area	2030 Rating Including NWAs (MW)	2030 Incremental Generation Headroom Needed (MW)	Key Drivers of Constraints
Saugerties	Northwest 69kV Area	53.6	55.2	BAU bulk solar and CLCPA bulk solar
South Cairo	Westerlo Loop	19.7	54.7	BAU bulk storage and CLCPA bulk solar (helped by 2024 thermal retirement)
Westerlo	Westerlo Loop	26.7	23.6	BAU CDG solar and CLCPA bulk solar

Figure 38 shows the four substations in need of upgrades to address load constraints. The figure includes numbers for the CLCPA scenario, although load constraints for these substations are similar under business-as-usual and CLCPA scenarios. The load capacity needs in these substations are the result of bulk storage capacity additions already in queue. The Maybrook and Woodstock substations exhibited similar, small load constraints under both the business-as-usual and CLCPA scenarios. Although these needs could potentially be addressed with renewable energy solutions, Central Hudson analyzed these substations in the 2020 DSIP and assessed that these needs can be met temporarily through lower-cost distribution load transfers that may defer the need for infrastructure investment in these areas.

Figure 38: Distribution Substations with Load Headroom Needs

Substation	Transmission Area	2030 Rating Including NWAs (MW)	2030 Incremental Load Headroom Needed (MW)	Key Drivers of Constraints
Highland	N/A	32.6	6.2	BAU bulk storage
Manchester	Mid Dutchess	47.3	3.3	BAU bulk storage
Maybrook	WM Line	23.8	3.1	Small need similar for BAU and CLCPA. Slightly worsened by CLCPA EVs and BTM ESS
North Catskill	Northwest 115-69 Area	34.7	5.2	BAU bulk storage and CLCPA bulk solar
South Cairo	Westerlo Loop	19.7	13.7	BAU bulk storage and CLCPA bulk solar (helped by 2024 thermal retirement)
Woodstock	Northwest 69kV Area	120.9	2.4	Small need similar for BAU and CLCPA. Slightly worsened by CLCPA EVs and BTM ESS

ix) Distribution substation projects that address load and generation headroom constraints

From the study results presented above, Figure 38 shows a list of substation projects that include both new substations and substation expansions that will increase load and generation headroom to meet the 70x30 CLCPA goals.

Figure 39: Phase 2 Projects that Increase Distribution System Capacity

Project Name	Zone	Substation	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost Estimate	MW Headroom
Coxsackie	G	Coxsackie	New 2 Transformer Station	2030	$12M	44MW
Freehold	G	Freehold	2nd Transformer	2030	$4M	12MW
Lawrenceville	G	Lawrenceville	2nd Transformer	2030	$4M	12MW
North Catskill	G	North Catskill	New 3 Transformer Station	2030	$15M	66MW
Saugerties	G	Saugerties	3rd Transformer	2030	$4M	22MW
South Cairo	G	South Cairo	New 2 Transformer Station	2030	$12M	44MW
Westerlo	G	Westerlo	2nd Transformer	2030	$4M	22MW
				Total	$ 55M	222MW

C. Conclusion

Central Hudson identified local transmission and distribution projects necessary and appropriate to timely achieve the CLCPA's objectives. Central Hudson evaluated load and generation headroom metrics within the local transmission and distribution system and identified projects to address these constraints. Central Hudson also analyzed the NYISO's 2020 RNA 70x30 scenario load flow case to identify future constraints and proposed projects to address these constraints.

III. CONSOLIDATED EDISION COMPANY OF NEW YORK, INC.

A. Local Transmission

Consolidated Edison Company of New York's (CECONY) principal business operations are its regulated electric, gas and steam delivery businesses. CECONY provides electric service to approximately 3.5 million customers in all of New York City (except a part of Queens) and most of Westchester County, an approximately 660 square mile service area ("Service Area") with a population of more than nine million. In addition, CECONY delivers gas to approximately 1.1 million customers in Manhattan, the Bronx, parts of Queens and most of Westchester County. In addition, CECONY operates the largest steam distribution system in the United States, producing and delivering approximately 19,796 MMlb of steam annually to 1,589 customers in parts of Manhattan.

i) CECONY's Study Assumptions and Description of Local Transmission Design Criteria

1. Study Assumptions

The Utility Study is based upon the database established and used by the NYISO for the 2020 Reliability Needs Assessment (RNA) 70x30 CLCPA Scenario. The Utility Study is limited to a transmission security assessment only. In the case of CECONY, the Utility Study is limited to its Service Area.

The NYISO provided three base cases that allow transmission security assessment under steady state at various dispatches of renewable resources and at different load levels. These base cases are: (1) Day Peak Load of 30,000 MW (where the net load reflects Behind-the-Meter (BtM) solar reduction); (2) Shoulder Load of 21,500 MW (where the net load reflects BtM solar reduction) ; and (3) Light Load of 12,500 MW (where the net load reflects BtM solar reduction). The load is modeled based on the 2020 Gold Book forecast for 2030 with the noted adjustments for BtM solar. The renewable resource mix (using nameplate MW) included in the database consists of: (1) 6,098 MW Off-Shore Wind (OSW); (2) 8,772 MW Land Based Wind (LBW); and (3) 15,150 MW Utility based photovoltaic (UPV), for a total of 30,020 MW of renewables capacity. As it relates to CECONY's Service Area, the database includes a 1,310 MW HVDC tie from Hydro Quebec to New York City (Zone J) modeled as in-service. In addition, all Peaking Units affected by the DEC NOx Peaker Rule were removed from the database. Additional fossil fuel power plants were removed, as needed, based upon their age (oldest first).

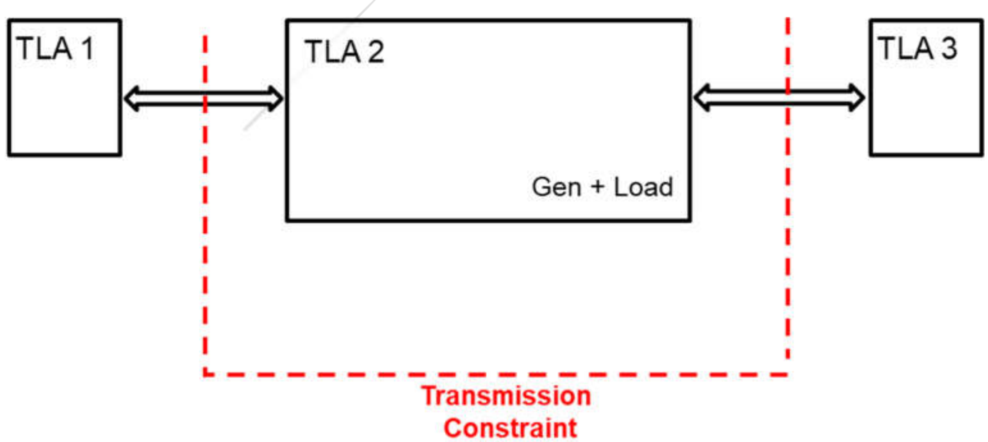
CECONY modified the provided database to (1) increase OSW from 6,098 MW to 9,000 MW, maintaining the distribution between Zones J and K based on load ratio share; and (2) modify Points of Interconnection (POI) of various assumed renewable resources based upon CECONY's knowledge of its Transmission System coupled with optimized energy delivery to load. While the CLCPA target requires 9,000 MW OSW by 2035, the Utilities determined it reasonable to model 9,000 MW interconnected by 2030 to capture the full impact of the state goal in the Utility Study.

2. Description of Local Transmission Design Criteria

System expansion and the incorporation of new facilities must follow published CECONY Transmission Planning Criteria (Specification TP-7100)[112]. Specification TP-7100 describes the planning criteria to assess the adequacy of CECONY's Bulk Electric System (BES) and certain non-BES 138 kV and 69 kV systems (collectively, the "Transmission System") to withstand design contingency conditions in order to provide reliable supply to all CECONY customers, throughout the planning horizon. The specification establishes Fundamental Design Principles and Performance Criteria. These two components complement each other and adherence to both is required by all new projects proposed by CECONY and by independent developers that connect to CECONY's Transmission System. In addition to Specification TP-7100, all facilities – generation and transmission – must be designed to conform with and adhere to all applicable North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and New York State Reliability Council (NYSRC) Reliability Rules, including NYSRC Local Reliability Rules, as well as applicable CECONY specifications, procedures and guidelines.

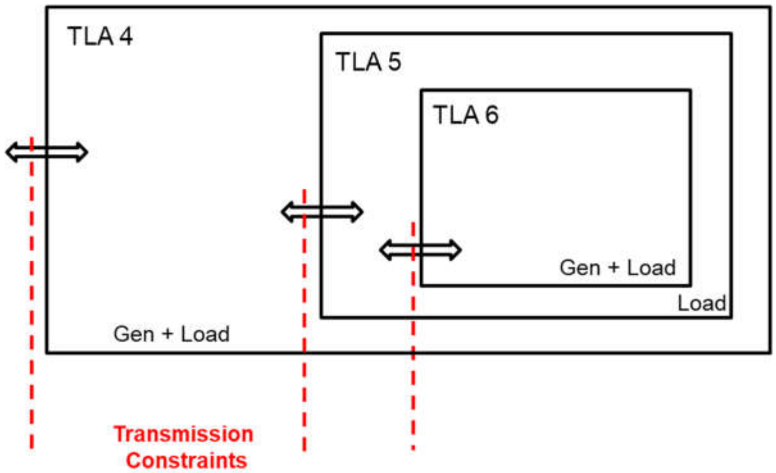
CECONY's Transmission System is comprised of seventeen (17) Transmission Load Areas (TLA). These TLAs were designated based on the identification of existing Transmission System constraints, where supply internal to the TLA is insufficient to meet the internal TLA load, hence the TLA is dependent on the transmission to balance supply and load. There are "Stand Alone" TLAs, where only one constraint exists between the area and the rest of the system (See Figure 40), and there are "Imbedded" TLAs, where one TLA is located within a larger TLA, which in turn is located in yet another TLA resulting in multiple constraints (See Figure 41).

Figure 40: "Stand Alone" TLA



112 Publicly available at: https://www.coned.com/-/media/files/coned/documents/business-partners/transmission-planning/transmission-planning-criteria.pdf?la=en

Figure 41: "Imbedded" TLA



CECONY's TLAs are designed as follows: (1) those supplied by 345 kV are designed to Second contingency (i.e., N-1/-1/-0); (2) a list of specific 138 kV TLAs are also designed to Second contingency (i.e., N-1/-1/-0); and (3) the remaining 138 kV TLAs are designed to First contingency (i.e., worst of N-1 or N-1/-1). Specification TP-7100 identifies CECONY's TLAs with their designation as First or Second contingency design.

ii) Discussion of a Possibility of Fossil Generation retirements and the Impacts and Potential Availability of those Interconnection Points

There are currently 10,700 MW (nameplate) of fossil generation located within CECONY's service territory. Most, if not all, of the existing natural gas and oil-fired generation will need to be retired to achieve the mandates in the CLCPA. Because CECONY does not own a majority of the fossil generation on its local system (other than limited units to support its steam system), it does not have control over the fossil generation retirements. Further, availability of Points of Interconnection (POI) upon unit retirement is governed by NYISO tariffs and subject to FERC's open access rules.

Nevertheless, initial fossil generation retirements in CECONY's service territory will include those affected by the New York State Department of Environmental Conservation's (DEC) new air emissions regulations for simple cycle and regenerative combustion turbines ("Peaking Units"), which it adopted in 2019. The regulation, referred to as the "Peaker Rule," complements the CLCPA and supports its objectives by reducing nitrogen oxide (NOx) emissions from fossil generation during the summer Ozone Season, which is disproportionately located in neighborhoods already overburdened by pollution, such as the South Bronx, Sunset Park in Brooklyn, and other Environmental Justice Communities. The Peaker Rule phases in compliance obligation between years 2023 and 2025 and impacts approximately 3,300 MW of existing facilities located in downstate New York, with approximately 2,000 MW of these facilities located in New York City (Zone J). Owners of the impacted units have submitted compliance plans indicating their intention to either retire the units or operate them seasonally (outside of Ozone Season).

Many of the Peaking Units are located in already constrained areas, and so their retirement/unavailability will only exacerbate these constraints. In its analysis, CECONY assumed that all Peaking Units affected by the DEC NOx Peaker Rule were removed from the database. CECONY also assumed that none of the POI would be available for any of the assumed renewable additions. This assumption is based upon the following:

1) While existing POIs are grandfathered from current compliance obligations, any material change at the POI (*i.e.,* retirement of a fossil facility replaced by an Energy Storage System) must conform with and adhere to the latest applicable NERC, NPCC, and NYSRC Reliability Rules, including NYSRC Local Reliability Rules, as well as applicable CECONY specifications, procedures and guidelines, requiring such significant investment to utilize the existing POI that alternative POI options that are physically feasible maybe be more economical;

2) Existing POIs are located in already constrained areas and/or low voltage areas where, for example, a typical size of an OSW project would be un-deliverable due to bus equipment and/or outlet capability limitations and where local upgrades would be simply infeasible or cost prohibitive, and

3) CECONY does not own the POIs, and rules governing the use of POIs are established by the NYISO and FERC.

Finally, in addition to the Peaking Units POI, CECONY assumed in its analysis that none of the non-Peaking Units POI (e.g. Steam Electric and Combined-Cycle units) were available, since CECONY does not own these POIs and these non-Peaking Units may continue to be in-operation after 2030.

iii) Discussion of Existing Capacity “Headroom” within CECONY’s System

The existing capacity ‘headroom’ on CECONY’s Transmission System is not easily identifiable. On the Overhead (OH) portion of the Transmission System, the Right of Ways (ROWs) are fully utilized. For example, there are no double circuit towers ROW that has only one circuit strung. The Underground (UG) portion of the Transmission System is already optimized, and no simple upgrades, such as replacements of a disconnect switch, are possible to increase a feeder’s carrying capacity. Most of the bus positions within CECONY’s transmission substations are occupied; and expandability of these substations may not be feasible or cost effective. Further, due to Transmission System bottleneck or constraints, a renewable resource interconnected to an area (such as a TLA) may be deliverable only within that limited area before its flow is impeded by an upstream constraint.

For the purpose of this Report, CECONY identified Capacity “headroom” as the amount of interconnection of resources possible in a TLA before the first constraint binds and assuming no other constraints within the TLA. Thus, the listed “Headroom” values are overestimated.

CECONY's approach to identify existing Capacity "headroom" was to calculate local load – existing generation + outlet capability, under N-1 transmission conditions, both for the peak load and light load cases. These are approximate MW values. Physical feasibility and external constraints to the local TLA may preclude achieving these MW. Figure 42 identifies approximate Capacity "headroom" based on 2030 system conditions.

Figure 42: Approximate Capacity "Headroom"

Transmission Load Area	Projected Load		Existing Generation (MW)		Outlet Capability under N-1 (MW)		"Headroom" (Under N-1)	
	Peak Load	Light Load	Peak Load	Light Load	Peak Load	Light Load	Peak Load	Light Load
Staten Island 138 kV	596	232	395	401	627	738	828	569
Greenwood / Fox Hills 138 kV	1472	566	126	1244	949	1077	2295	399
Corona / Jamaica 138 kV	1242	475	414	420	1366	1536	2194	1591
Brooklyn / Queens 138 kV	3319	1273	2452	3673	1438	1660	2305	-740*
Eastern Queens 138 kV	1520	562	1169	1259	906	1044	1257	348
The Bronx 138 kV	1391	536	0	0	1671	1917	3062	2453
Dunwoodie South 138 kV	303	118	0	0	694	873	997	991
Dunwoodie North / Sherman Creek 138 kV	579	223	0	0	1270	1517	1849	1740
Eastview 138 kV	709	275	0	0	1167	1458	1876	1733
Millwood / Buchanan 138 kV	234	91	52	53	418	477	600	514
East River 138 kV	388	147	486	524	353	438	255	61
Vernon / Queensbridge 138 kV	1309	501	1106	1143	1657	1909	1860	1267
Astoria West / Queensbridge 138 kV	945	357	1220	1286	573	655	299	-274*
Astoria East / Corona 138 kV	1068	385	755	839	918	1064	1231	611
East 13th Street 138 kV	1021	385	640	723	1829	2159	2210	1821
West 49th Street 345 kV	2119	801	1210	1382	3562	4053	4471	3472
New York City 345/138 kV	11373	4316	8821	10392	3651	3974	6203	-2102*

*Negative Headroom under Light Load Conditions means that this amount of existing generation must be curtailed.

iv) Discussion of Bottlenecks or Constraints that Limit Energy Deliverability within CECONY's System

CECONY has identified the following TLAs where the current transmission capability will limit the amount of renewable generation that can be imported into the TLA and will require the continued operation of fossil fuel power plants in the TLA. If renewable resources cannot access the load located in these constrained TLAs, there will be excess renewable energy external to the local area providing zero value to these local customers and may result in curtailment. Figure 43 identifies these constrained TLAs.

Figure 43: Constrained TLAs

Transmission Load Area	Load Served (Peak)	Design Designation
Staten Island 138 kV	596	N-1/-1
Greenwood / Fox Hills 138 kV	1,472	N-1/-1
East River 138 kV	388	N-1/-1/-0
Vernon / Queensbridge 138 kV	1,309	N-1/-1/-0
Astoria West / Queensbridge 138 kV	945	N-1/-1/-0
Astoria East / Corona 138 kV	1,068	N-1/-1/-0
East 13th Street 138 kV	1,021	N-1/-1/-0

Transmission investments will be needed to address these bottlenecks or constraints and enable the State to meet the clean energy goals in the CLCPA. If renewable energy cannot serve customers within a load pocket, then fossil generation within the load pocket would continue to be required to run to serve the load, challenging the State's ability to achieve the CLCPA target of 70% renewable energy by 2030 and ultimately 100% emissions-free energy by 2040. The bottlenecks can be solved by load reductions and/or load transfers (i.e., load to be transferred out of the local constrained TLA to an unconstrained TLA), by local transmission additions, by renewable resource or energy storage additions within the TLA, or by a combination of these solutions. As large renewable intermittent resource additions connect to the 345 kV system, the constraints defining the TLAs must be addressed to enable the local loads within the constrained TLAs to be served by renewable supplies. This is especially true for New York City, where limited physical space in each of the 17 TLAs virtually forecloses the addition of utility scale PV or challenges large Energy Storage Systems within the TLAs. In addition, storage within the TLA would only partially address reliability needs, as the load pocket deficiencies extend over 10 to 14-hour periods, often over consecutive days. Energy Storage System technology to date would have difficulty responding for the duration of the reliability need period. The expansion of the Transmission System, by establishing "off-ramps" to connect the mostly free flowing 345 kV system to CECONY's 138 kV TLAs, would provide for the most effective utilization of renewable resources.

In addition to unbottling load located within TLAs, OSW will need to connect to New York City and/or Long Island to meet the CLCPA goal of 9,000 MW OSW by 2035. CECONY, in coordination with the Long Island Power Authority (LIPA), is designing an optimal plan to accommodate the injection of OSW into the two service territories, considering local transmission constraints. CECONY has identified transmission constraints for the injection of OSW into the overall New York City 345 kV / 138 kV TLA. These constraints, if not addressed, would limit OSW energy deliverability within CECONY's system, especially during off peak conditions. Given the typical size of an OSW project, connecting OSW directly to the free flowing 345 kV system is most sensible. However, because the existing Transmission System in New York City is limited in its expandability, with limited bus positions in existing substations, and limited locations to construct additional transmission substations, substantial upgrades will be required to interconnect new generation to the 345 kV system. Further, local constraints will need to be addressed to enable the OSW to both connect onto the 345 kV system and to reach bottled loads in the TLAs.

v) Discussion of Potential Projects that would Address Bottlenecks or Constraints that limit Energy Deliverability within CECONY's System

In order to meet CLCPA goals, Transmission System bottlenecks or constraints need to be eliminated to enable loads renewable resources to access and serve the load, especially when those renewable resources are connected outside the local area. Therefore, the local Transmission System should be expanded to provide both "on-ramps" (*i.e.,* moving renewable energy onto the 345 kV system highway) and "off-ramps" (*i.e.,* moving renewable energy off the 345 kV system highway down to the load areas, which would otherwise be served by fossil fuel power plants).

CECONY has identified potential projects that address the bottlenecks or constraints that limit energy deliverability. In identifying these projects, CECONY primarily seeks to meet the CLCPA targets, while simultaneously ensuring continued reliability and resilience of service to customers. For example, CECONY explored if a potential project would: (1) address reliability impacts of the DEC NOx Peaker Rule; (2) connect and fully deliver new resources such as OSW and new upstate renewables; (3) solve identified bottlenecks or constraints on the local system to enable loads to be served by renewable energy; and (4) address future load growth from electrification (due to CLCPA), while also improving resilience on CECONY's local system. Thus, these would be considered multi-benefit projects.

1. Addressing Constraint for the Astoria East / Corona 138 kV TLA

CECONY identified constraints on the Astoria East / Corona 138 kV TLA boundary feeders. These constraints are exacerbated by the retirement of local Peaking Units driven by DEC's NOx Peaker Rule. To address both the constraint and the need, CECONY is planning the installation of a 6-mile-long, 345 / 138 kV Phase Angle Regulator (PAR) controlled feeder. The new feeder will be placed in commercial operation by Summer 2023, to meet reliability needs identified in NYISO's 2020 RNA and the 2020 Quarter 3 STAR arising by that date, and coinciding with the first deadline by which Peaking Units must comply with the DEC NOx Rule's new emissions standards. The new feeder will electrically connect CECONY's 345 kV Rainey substation with CECONY's

Corona 138 kV substation creating the first of several 345 to 138 kV "off ramps" that will be necessary to support a clean energy future. The proposed feeder will have a nominal capability of approximately 300 MW. Therefore, it will enable 300 MW of renewable supply to access the load. The feeder will address the identified constraints on the Astoria East/Corona 138 kV TLA boundary feeders, and additionally allow renewable resources to access the load on CECONY's 138 kV system, eliminating the dependency on local fossil fuel power plants to maintain local reliability.

2. *Addressing Constraint for the Greenwood / Fox Hills 138 kV TLA (Including the Staten Island 138 kV TLA)*

CECONY identified constraints on the Greenwood / Fox Hills 138 kV TLA boundary feeders. These constraints are exacerbated by the seasonal unavailability and/or retirement of local Peaking Units driven by DEC's NOx Peaker Rule. In addition, CECONY identified constraints on the neighboring Staten Island 138 kV TLA if the local fossil fuel power plant(s) becomes unavailable or retires.

Due to the size of the constraint (370 MW) CECONY is planning to install two new feeders. The first feeder is planned to be an approximate 1-mile-long, 345 / 138 kV Phase Angle Regulator (PAR) controlled feeder. The feeder will be placed in commercial operation by Summer 2025, to meet reliability needs promulgated by the DEC NOx Peaker Rule and identified in NYISO's 2020 RNA arising by that date and coinciding with the second deadline by which Peaking Units must comply with the DEC NOx Rule's second set of new emissions standards. The new feeder will electrically connect CECONY's 345 kV Gowanus substation with CECONY's Greenwood 138 kV substation, creating another 'off-ramp' to support the pathway to deliver clean energy supplies.

The second feeder is planned to be an 8-mile-long, 345 / 138 kV Phase Angle Regulator (PAR) controlled feeder that will also be placed in commercial operation by Summer 2025 to meet local system reliability needs, and additionally address a portion of the bulk system reliability needs, promulgated by the DEC NOx Peaker Rule and identified in the RNA arising by that date. The new feeder will electrically connect CECONY's 345 kV Goethals substation with CECONY's Fox Hills 138 kV substation, installing a third such "off-ramp" on the CECONY's Transmission System. The existing Fox Hills 138 kV substation will be re-configured as a 138 kV Ring Bus. This will not only ensure compliance with the latest applicable specifications, procedures and guidelines but will also alleviate many of the limitations imposed by the current straight bus design that limits transfer capability between substations, imposes constraints on planned outages, results in the loss of multiple facilities for a single outage and could require curtailment of renewable resources during planned or unscheduled transmission facility outages. Both feeders will have a nominal capability of approximately 300 MW each. Therefore, it will enable 600 MW of renewable supply to access the load. Not only will the feeders address the identified constraints on the Greenwood / Fox Hills 138 kV TLA boundary feeders but they will also allow approximately 600 MW of renewable resources to access the load on CECONY's 138 kV system, decreasing the dependency on local fossil fuel power plants to maintain local system reliability. Further, the Goethals to Fox Hills feeder will un-bottle some of the existing (and future) resources connected to Staten Island's 345 kV and 138 kV system.

3. *Addressing Constraint for the East River 138 kV TLA, East 13th Street 138 kV TLA, and Vernon / Queensbridge 138 kV TLA*

CECONY identified constraints on the East River 138 kV TLA "Imbedded" within the East 13th Street 138 kV TLA, and on the "Stand Alone" Vernon / Queensbridge 138 kV TLA boundary feeders. Although these TLAs are mostly independent of each other, CECONY identified a potential single cost-effective project that addresses these three constrained TLAs and also creates POIs for new resource interconnections, such as OSW (for about 2x750 MW connection or approximately 1,500 MW total). The project, referred to herein as New York City Clean Energy Hub #2, is a conceptual project that will require more detailed engineering studies. The project will transfer load from the constrained 138 kV system to a 345 kV substation within New York City while simultaneously create new POIs for clean energy and/or new technology resources. Initial load un-bottling is estimates to be approximately 440 MW, with additional load unbottling estimated at an incremental 240 MW.

Renewable resources will be able to access the un-constrained load transferred out of the constrained CECONY's 138 kV system and reduce the load's dependency on local fossil fuel power plants to maintain local system reliability. CECONY is estimating that this project can be placed in commercial operation by Summer 2029.

4. *Addressing Constraint for the Astoria West / Queensbridge 138 kV TLA*

CECONY identified constraints on the Astoria West / Queensbridge 138 kV TLA boundary feeders. This TLA currently depends on three base load fossil power plants to be on-line (at peak and at certain levels of off-peak) for the TLA to meet its N-1/-1/-0 planning and operational requirements. CECONY identified a potential cost-effective project that will address the identified constraint through load transfers. That is some load will be transferred out of the local constrained TLA to an unconstrained TLA. Specifically, CECONY would propose transferring 406 MW out of the constrained 138 kV system to be supplied by an existing 345 kV substation. Thus, the project would enable renewable resources to access the un-constrained load that is transferred out of the constrained CECONY's 138 kV system, and also reduce the local system's dependency on local fossil fuel power plants to maintain reliability. CECONY estimate that this project can be placed in commercial operation by Summer 2030.

5. *Addressing Constraints for the overall New York City 345 / 138 kV TLA*

To meet the CLCPA goal of 9,000 MW OSW by 2035, OSW will need to interconnect to New York City and/or Long Island. CECONY, in coordination with LIPA, is designing an optimal plan to integrate the injection of OSW into the two service territories, considering local transmission constraints. In addition, there will be a need to construct transmission to redistribute the renewable intermittent power throughout CECONY's local Transmission System to both supply local loads and export to upstate load areas to prevent OSW's curtailment.

In the analysis, confirmed by the Utility Study, CECONY has identified transmission constraints for the injection of OSW into the overall New York City 345 kV / 138 kV TLA. These constraints, if not addressed, would limit OSW's integration onto the local 345kV system to deliver to upstate loads, as well as limit its deliverability within CECONY's system, especially during off peak conditions. CECONY identified three potential local cost-effective 345 kV feeders (NYC Feeder 1, 2 and 3) that will address the identified constraints. Each local feeder, located wholly within CECONY's service territory and rated at approximately 700 MW, will also allow upstate renewable resources access to downstate loads, thus facilitating the unbottling effect of those supplies from northern New York State. Just as importantly, these three feeders will enable the redistribution of the OSW throughout the local Transmission System so that it can be effectively utilized during peak and off peak periods, as well as exported during periods that would otherwise lead to curtailments. CECONY estimate that the first feeder can be placed in commercial operation by Summer 2027, and that the remaining two feeders can be placed in commercial operation by Summer 2030.

While the primary driver of these three local feeders is the integration of OSW (that is, they would not have been identified "but for" the CLCPA driver), as noted above they will provide a number of additional benefits to facilitate achievement of the CLCPA goals and as well as improve the resilience and operation of the local system.

vi) Discussion of Potential Projects that would Increase Capacity on the Local Transmission and Distribution System to allow for Interconnection of New Renewable Generation Resources within CECONY's System

CECONY assessed potential projects that could increase capacity on CECONY's Transmission System to allow for connection of new resources. Most of the bus positions within CECONY's Transmission Substations are occupied, and expandability of many substations may not be feasible or cost effective. CECONY explored the ability to upgrade existing or construct additional local transmission substations to connect new OSW, Energy Storage Systems, or other new, clean resources. Such projects are designed to be "multi-benefit," providing the benefits associated with achieving the goals of CLCPA, and simultaneously providing operational and resiliency benefits to CECONY's local Transmission System.

In addition to the potential project described under V.3. - New York City Clean Energy Hub #2 – CECONY has identified a another potential cost-effective project that would create POIs for new resource interconnections, such as OSW (for approximately 4x750 MW connections or 3,000 MW total). The project, referred to herein as New York City Clean Energy Hub #1, is a conceptual project that will require detailed engineering studies CECONY estimates that the project can be placed in commercial operation by Summer 2027, prior to the New York City Clean Energy Hub #2.

vii) Conclusion

Consistent with the May Order, this Report presents the results of CECONY's transmission security assessment identifying potential local system upgrades that will facilitate meeting CLCPA goals, as required by the AREGCB Act. Figure 44 identifies Phase 1 projects with Order of Magnitude (OOM) Cost Estimates. Additionally, Figure 45 identifies Phase 2 projects with Order of Magnitude (OOM) Cost Estimates.

Figure 44: Phase 1 Immediately Actionable Projects

Project Name	Zone	Terminal A	Terminal B	Project Description	Estimated Project Benefit (MW)	Proposed In-Service Date	Order of Magnitude (OOM) Cost Estimate
2nd Rainey – Corona Feeder	J	Rainey	Corona	New 345 / 138 kV PAR Controlled Feeder (~6 Miles UG)	300	2023	-
3rd Gowanus – Greenwood Feeder	J	Gowanus	Green-wood	New 345 / 138 kV PAR Controlled Feeder (~1 Miles UG)	300	2025	-
Goethals – Fox Hills	J	Goethals	Fox Hills	New 345 / 138 kV PAR Controlled Feeder and Rebuild of Fox Hills 138 kV Substation (~8 Miles UG)	300	2025	-
						Total:	$860M

Figure 45: Phase 2 Additional Potential Projects

Project Name	Zone	Terminal A	Terminal B	Project Description	Estimated Project Benefit (MW)	Proposed In-Service Date	Order of Magnitude (OOM) Cost Estimate
NYC Clean Energy Hub #1	J	TBD	TBD	Clean Energy Hub to provide additional POIs into local system	3,000	2027	-
NYC Clean Energy Hub #2	J	TBD	TBD	Clean Energy Hub to provide additional POIs into local system and enable load transfer	2,180	2029	-
NYC Feeder 1	I, J	TBD	TBD	Each is a new local Feeder to unbottle renewable supplies	700	2027	-
NYC Feeder 2	J	TBD	TBD		700	2030	-
NYC Feeder 3	J	TBD	TBD		700	2030	-
Load Transfer	J	TBD	TBD	Rebuild 2 Area Stations; Load Transfer	406	2030	-
						Total:	$4.05B

As listed in Figure 44, CECONY has identified three immediately actionable projects that are needed to give renewable resources access to the load, and unbottle load currently served by fossil generation while also enabling compliance with the DEC NOx Peaker Rule. CECONY is currently planning to file a petition with the Commission by the end of the year seeking approval to recover the costs of such projects and will provide each individual project's cost estimate for inclusion in the petition. Further, while CECONY proposes to recover costs for these projects through its rate plan capital budget due to the timing of when the projects are expected to be in service (*i.e.*, the first project will be in service in 2023), CECONY requests herein that the Commission consider the significant regional environmental benefits these three immediately actionable projects provide. Specifically, while the projects are needed to meet local system reliability needs, the Commission should recognize that such needs arise as a result of State action, taken as an initial step towards the achievement of CLCPA's climate goals, to reduce polluting emissions from the older peaking units located in New York City, many of which are in or near disadvantaged communities. Because these projects satisfy reliability needs while also facilitating the State's ultimate goal of replacing the State's combustion powered peaking units with clean energy sources, CECONY requests that:

1. The Commission approve cost recovery of the identified Phase 1 projects in this case, and approve recovery of the costs of these three projects;[113]
2. The Commission acknowledge that projects that result from the Peaker Rule qualify as CLCPA projects; and
3. The Commission credit to CECONY the costs of such projects, should the Commission develop and implement a future accounting framework to balance the CLCPA-related costs incurred by the utilities statewide, as described in the policy recommendations set forth elsewhere in this Report.

Further, in Figure 45 CECONY has identified six additional Phase 2 potential projects with broad regional CLCPA benefits that can be implemented by 2030, and which are necessary to integrate 9,000 MW of OSW feasibly and cost-effectively into New York City and Long Island. Although not proposed in Phase 1, timely approval and construction of these projects is necessary to provide offshore wind developers with needed certainty regarding viable interconnection locations, facilitate the most competitive and efficient response to any future offshore wind solicitations, and satisfy the CLCPA's renewable and offshore wind goals in a timely, and the most cost effective and efficient manner. Accordingly, for the foregoing reasons, CECONY requests that:

1. The Commission confirm in its Order adopting policies, or in its Order establishing utility capital plans implementing identified distribution and local transmission upgrades, that

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[113] As noted above, CECONY may also file a separate petition for cost recovery of these projects, as contemplated by its current rate plan. See Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service (Case 19-E-0065) (2019). CECONY will consult with DPS Staff regarding the need to file this separate petition.

each of the projects identified in Figure 45 is a local transmission project, within the meaning of the AREGCB Act and the May Order;

2. The Commission approve each of the six projects identified in Figure 45 for cost recovery, and direct the construction of such projects, starting first with the NYC Clean Energy Hub #1. In evaluating Phase 2 projects, NYC Clean Energy Hub #1 should be among the first projects to advance, due to the need to create POIs[114] in advance of generation to produce the most cost effective, efficient solutions for all New Yorkers; and
3. The Commission implement a cost allocation framework that allocates the costs of these Phase 2 projects statewide on a load ratio share basis, consistent with the policy recommendations elsewhere in this Report and with the statewide CLCPA benefits such projects provide.

B. Distribution

i) Introduction

Meeting the CLCPA targets, including 3,000 MW of storage by 2030 and 9,000 MW of offshore wind by 2035, will require significant investment in transmission to address existing bottlenecks and constraints and interconnect new renewable resources. While transmission represents a critical path for meeting CLCPA goals, the distribution system also plays an important role in delivering power to end users, serving as a distribution system platform (DSP) for customer products and services, and maintaining system safety and reliability by balancing supply and demand at the local level using tools such as demand response and energy storage.

In response to the Reforming the Energy Vision (REV) initiative and in line with industry trends, CECONY is investing approximately $1.1 billion over the 2020-2025 period[115] to build the DSP and modernize the electric grid. These ongoing investments are resulting in a grid that is flexible and adaptable to the changing resource mix, agile in the face of more dynamic grid operations, and capable of effective coordination between the wholesale market and distribution system operation. Through these investments, as well as innovations in system design and organizational efficiencies, CECONY is actively preparing for a clean energy future characterized by accelerated growth of distributed energy resources (DER) and electric vehicles (EVs). Additionally, increased system visibility, flexibility, and agility will help CECONY manage the shift to electric space heating and the resulting increase in winter load.

CECONY has already enabled the interconnection of approximately 300 MW of distributed solar generation and 11 MW of energy storage, and CECONY expects even higher penetration of these resources in the future. In anticipation of evolving system needs, CECONY

114 POIs are subject to FERC Open Access rules.

115 This includes projects approved as part of CECONY's 2020-2022 rate case, approved during a prior rate case but with investment spanning into this timeframe, or included in CECONY's five-year capital plan.

has employed a programmatic approach to create distribution system flexibility by integrating non-utility-owned assets into the Company's system planning and performance evaluation. As a result of this approach, which also incorporates clean energy drivers, CECONY's planning process has effectively prepared the Company for forecasted needs until 2030. Additionally, in contrast to other New York distribution utilities that are more likely to face distribution system constraints due to significant solar, storage, and wind penetration, CECONY's future distribution system constraints are most likely to arise due to significant increases in electrification, which the Company forecasts is likely to transpire after 2030.

ii) Phase 1 Projects

The Company's distribution system Phase I initiatives represent significant progress toward the CLCPA's vision of a decarbonized grid begun under the REV initiative. The Company is committed to executing its approved investment plans, including adding at least 50MW of distribution-connected storage and investing $395 million in EV make-ready programs through 2025. The Company has also identified opportunities where existing investment programs can be expanded and accelerated to advance CLCPA goals, such as adding funding to modernize a larger percentage of network protector relays to increase hosting capacity and extending the Newtown Non-Wires Solution ("NWS") energy storage system to help prepare the Glendale/Newtown load area for EV adoption and electrification, enable greater integration of DER and energy storage, and provide additional resilience benefits.

CECONY's DSP, grid modernization, and REV initiatives promote a cleaner, more sustainable energy future, enhance the customer experience, and build the capabilities necessary for integrating DER. These efforts include working towards a transformative and scalable DSP that enables the bi-directional flow of energy and greater utilization of DER to meet system needs. Implementing these projects and programs will position the Company to meet evolving customer expectations, as well as make progress toward meeting the State's clean energy policy goals.

As shown in Figure 46, the Phase I projects total approximately $1.1 billion over the 2020-2025 period and include those already funded or represented in the Company's five-year capital plan. Many of the currently budgeted projects extend beyond the three-year timeframe of the Company's last rate case, with future phases to be described as part of the Company's next rate request. The Company continues to execute these investment programs, which are already providing customer benefits.

Figure 46: Phase 1 Project Portfolio

Project Name	Project Description	MW Impact	Proposed In-Service Date	Order of Magnitude Cost Estimate ($000s)[116]
DSP Programs	Investments to improve distribution system safety, reliability, resiliency, efficiency, and automation	-	2020+	$107,000*
DSP Incremental Programs	Incremental investment in the DSP	-	2024	-
Communications Infrastructure	Systems to manage data exchange across systems, applications, and devices	-	2020+	$50,000*
Newtown Extension	Expansion of planned NWS to install new transformer and sub-transmission line	120	2025	-
Vinegar Hill Distribution Switching Station ("DSS")	Distribution switching station to add capacity and provide operational flexibility	240	2022	$215,000*
Energy Storage Program	Five projects to provide a range of operational and CLCPA-related benefits	50	2025	-
Fox Hills Energy Storage Project	Energy Storage at Area Substation to facilitate DER interconnection and provide system support	7.5	2022	22,000*
EV Make-Ready Investments	Investments as approved by the Commission	-	2025	$395,000*
		Phase 1 Total		$1,130,000

* Denotes projects already funded (totaling $789 million).

1. Grid Modernization and DSP Investment Programs

As authorized in CECONY's last rate case, CECONY is investing an average of approximately $36 million per year over the 2020-2022 rate period to develop or enhance capabilities that improve the safety, reliability, resiliency, efficiency, and automation of the electric distribution system. Together, these expanded capabilities are creating a next-generation grid that can support CLCPA and REV goals.

As described in CECONY's 2020 Distributed System Implementation Plan ("DSIP"), many of these investments provide multiple customer benefits, simultaneously supporting decarbonization, increasing resilience to extreme weather events and climate change, enabling DER growth, and improving the customer experience. As authorized in the Company's last rate case, CECONY is investing approximately $107 million over the 2020-2022 rate period to build a DSP and develop or enhance capabilities that improve the safety, reliability, resiliency, efficiency, and automation of the electric distribution system. CECONY plans to continue funding the DSP in

116 The budget for Phase I projects represents amounts already approved by the New York Public Service Commission through CECONY's 2020-2022 rate case period or included in CECONY's five-year capital plan. The budget for Phase 2 projects represents total expected future costs associated with each project.

future rate filings Together, these expanded capabilities are creating a next-generation grid that can support CLCPA and REV goals.

For example, CECONY is on track in its installation of modernized protective relays ("MNPRs") and supervisory control and data acquisition ("SCADA"), with 600 microprocessor relay upgrades and 200 SCADA-enabled locations scheduled per year for 2020-2022. This is part of a program to upgrade the Company's underground network protectors to have bi-directional capabilities, which minimizes trips from backfeed due to DG or energy storage discharge, increases available hosting capacity, and enables lower-cost interconnection, while also providing greater grid edge visibility and shorter response time to system operators.

These programmatic investments are part of a broader grid modernization initiative that includes a Geographic Information System ("GIS," which is not included in the Phase 1 Projects), smart sensors and other tools to facilitate situational awareness, and associated communications and applications. Smart sensors, Distributed Energy Resource Management System ("DERMS"), MNPRs and other technologies depend on communications infrastructure to manage data exchange across systems, applications, and devices and maximize the value of these other investments. CECONY is approved to spend $50 million on communications infrastructure over the three-year period, with work extending into future years.

In addition to these investment programs, CECONY plans to continue investing in NWS, such as DG, energy storage, and energy efficiency ("EE") projects, to address capacity constraints as they arise on the system. Previously used to avoid transmission and distribution buildout, CECONY will use NWS in complementary portfolios that include traditional upgrades and meet the expected increased loading from electrification.

Consistent with this evolution in philosophy driven by CLCPA, CECONY will evaluate an extension to the existing Newtown NWS scope—which aims to address projected overloads in the Vernon to Glendale/Newtown/Amtrak load pocket—to defer traditional infrastructure upgrades. Following the NWS, CECONY plans to install a fourth 138/27 kV area station transformer at the Newtown substation (93.3 MVA) and new sub-transmission line to feed the fourth bank from the Vernon 138 kV substation. The project could be implemented as early as 2025.

The Newtown Extension will help prepare CECONY for achievement of multiple CLCPA objectives. First, it will prepare the Glendale/Newtown load area for greater levels of EV adoption, building electrification, and intrinsic load growth in the future. Second, it will allow for additional system capacity to integrate increasing levels of DG and energy storage. Finally, the project will add more resilient substation capacity in the Long Island City network area and provide additional contingency capability for supply of the Amtrak power facility at Sunnyside Yards.

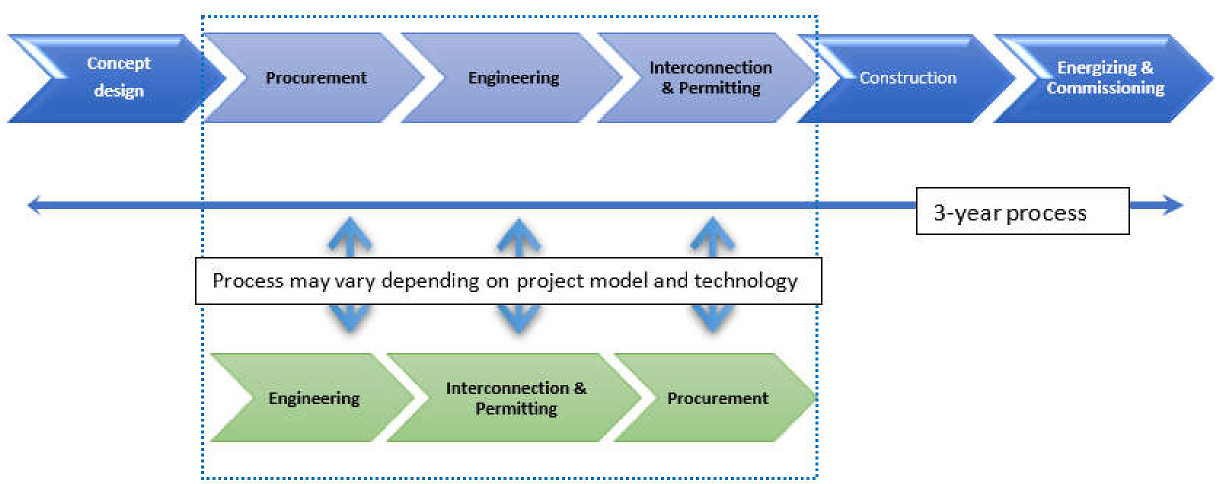
To develop an effective solution for a separate Water Street/Plymouth Street NWS, the Company is leveraging a combination of EE programs, DG, and storage to address near-term load relief needs through 2021 and enable a longer-term traditional solution—a less expensive DSS—at Vinegar Hill that will add capacity and provide operational flexibility. The DSS project, totaling approximately $215 million over the current three-year rate period, includes two new 138/27 kV transformers (supplied from 138 kV Hudson Ave East Transmission station), which will increase Plymouth Street's capability from 382 MW to 502 MW and Water Street's capability from 377 MW to 497 MW. The project is expected operational in 2022.

CECONY expects NWS to continue to benefit customers by reducing demand and spurring third-party investment. The experience the Company has gained through implementing its NWS portfolio will be valuable as the Company explores optimizing NWS with traditional solutions to serve expected load growth from electrification. For example, because of CECONY's unique network topology, CECONY can leverage NWS with advanced switching plans and bi-directional network protector relays to expand available system capacity. The Company can target these innovative solutions to areas most likely to see load growth from electrification, such as EV adoption and heating oil conversions in outer boroughs, as well as to diversify resources and increase resilience in critical areas. The ability to use technology to relieve feeder loading and add capacity takes on added significance considering CECONY's dense urban environment with limited physical space for larger-scale solar and storage installations.

2. Energy Storage Program

The Company, through a combination of its last rate case and current five-year capital plan, will be investing in five energy storage projects aimed at providing a range of benefits aligned with the CLCPA, including accommodating greater penetration of intermittent renewables and electrification while also providing greater resilience in high-need areas. These projects, which will be in Staten Island, Brooklyn, Queens, Bronx, and Westchester, will introduce at least 50 MW of new storage capacity onto the distribution system and be in service by 2025.

Figure 47: Prototypical Energy Storage Development Timeline



3. *EV Make Ready Investments*

The New York Public Service Commission's ("Commission") July 16, 2020 Order authorized CECONY to incent customers up to $287 million through 2025 as part of "a multi-year approach to develop and deploy the minimum critical infrastructure necessary to support the EV charging market and EV adoption."[117] In addition, CECONY estimates $93 million dollars in corollary new business developments, which results in $380 million towards EV make-ready programs. When coupled with the Nevins Street Energy Storage and EV Make-Ready project, the total EV make-ready investment is $395 million. As described in the Company's EV Make-Ready Program Implementation Plan,[118] the Company will incent make-ready infrastructure for new Level 2 and Direct Current Fast Charging ("DCFC") EV charging stations for light-duty vehicles in the Company's service territory. This includes utility electric infrastructure needed to connect and serve the load associated with new EV chargers that would have otherwise been paid by the installing customer, such as step-down transformers, overhead or underground service lines, and utility meters.

iii) Phase 2 Projects

To more closely align the distribution system's capabilities with CLCPA goals and timelines, CECONY scoped potential new projects, referred to as Phase 2 projects, that will be necessary to meet CLCPA goals and prepare for a future characterized by significant DER and renewables penetration. As described below, CECONY's distribution evaluation identified two projects that will help it prepare for prospective system changes due to achievement of CLCPA objectives.

Figure 48: Phase 2 Projects

Project Name	Project Description	MW Impact	Proposed In-Service Date	Order of Magnitude Cost Estimate ($000s)
New Area Substation	New substation and sub-transmission feeders to pick up load from nearby network	235	2030+	-
Energy Storage Projects	Six individual projects to provide a range of benefits	125	2030	-
			Total	$1,300,000

117 Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure* ("EVSE&I Proceeding"), Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (issued July 16, 2020) ("EV MRP Order"), p. 18.

118 EVSE&I Proceeding, Con Edison Electric Vehicle Infrastructure Make-Ready Program Implementation Plan (September 14, 2020).

iv) Distribution Needs Evaluation

As part of the Transmission Planning Working Group, CECONY aligned its annual system forecasting activities with the broader effort to incorporate CLCPA assumptions into the Company's system performance analysis. The Company aligned NYISO 70x30 projections with the "bottoms up" network forecasts and area substation load relief plans, comparing existing area station capability against CLCPA-related drivers on a 10- and 20-year basis. The technical analysis afforded the Company an opportunity to evaluate its system planning activities against 2030 and 2040 CLCPA goals, which underscore the likely impacts and resulting need for system expansion in CECONY's service territory due to load growth from increased electrification and EV adoption.

Through the REV initiative, the Company has taken steps to adjust business-as-usual ("BAU") planning to incorporate clean energy drivers into system forecasting and performance evaluation. CECONY accounts for BAU adoption of clean energy resources (*i.e.*, DG, demand response, and EE) as load modifications against the system peak by applying a coincidence factor. NWS have also been used as a viable means for system planners to address planning issues due to load growth within the Company's network areas.

To date, the most significant challenge to DG interconnection in the CECONY service territory has been minimum load conditions within the secondary network given the effect of reverse power flows on network protector relays. As a result, the Company has adopted a programmatic and multi-value approach to modernize protective relays and replace older, more sensitive equipment with modernized relaying capable of delineating fault current from steady DG backfeed. Through this effort, the Company also realizes additional benefits by gaining insight into the real-time performance of the distribution system as well as having the ability to remotely operate these devices. This type of system evolution has driven the Company to implement programmatic approaches that create distribution system flexibility by integrating non-utility-owned assets into system planning and performance evaluation. The Company intends to continue funding and employing programmatic approaches, where feasible, as they can easily be incorporated into traditional planning criteria and allow for system reinforcement and project design that can incrementally address changing system conditions over a longer timeframe.

Additionally, ongoing efforts related to hosting capacity analysis—including an October 2020 refresh of the Company's hosting capacity maps—continue to refine minimum load models to identify areas where DG penetration has the potential to create system constraints. CECONY evaluated the DG queues to establish areas where programmatic approaches to system design would not be sufficient to address longer-term penetration challenges. Currently, the Company's protective relay modernization program targets areas of high DG penetration within the CECONY network systems, alleviating issues stemming from DG backfeed under minimum load conditions. The Company prioritizes these relays using evaluations of current DG queues and expected growth rates of DG within the network system.

Separately, the Company continues to utilize the Network Reliability Index ("NRI") to prioritize investments. This simulation ranks network areas by the probability of a cascading event occurrence. CECONY prioritizes networks with a lower NRI for capital investment used to improve resiliency and reliability. This process exists as a parallel effort to traditional primary and secondary system reinforcement analysis that is an output of the Company's annual planning cycle.

The Company also evaluated the transmission projects identified through the technical analysis to align on a multi-value approach where applicable. The Company identified areas where proposed transmission investment may complement distribution system design through resiliency, future prepping, and enablement of electrification. CECONY evaluated scenarios where it may need projects to supplement transmission infrastructure or could incrementally add them to existing distribution project plans. Finally, the Company evaluated currently funded projects and programs as well as investments currently included in the Company's capital forecast for potential changes or incremental additions that could provide additional benefits for achieving CLCPA objectives.

1. Project Descriptions

CECONY identified two Phase 2 projects totaling $1.3 billion that will enable the Company to more effectively prepare for a future distribution system characterized by significant DER and renewables penetration and increased load levels due to meeting CLCPA objectives. Since these projects are driven by currently forecasted future conditions assuming achievement of CLCPA objectives, in the future CECONY will monitor changing market conditions and distribution capacity to possibly revise the specific scope and funding levels for each project in response to changing market conditions and transmission capacity.

The proposed Phase 2 projects reflect a long-term view based on the CLCPA timeline trajectory and consider the whole electric system, including interdependencies between transmission and distribution system investments. In its analysis, the Company sought opportunities wherever possible to both build in optionality, such that projects are designed for and anticipate future expansion, and to maximize benefits, including addressing the three primary investment drivers shown in Figure 49 below: carbon-free generation, electrification, and resilience.

Figure 49: Three Primary Investment Drivers

These identified projects make sense under a range of scenarios. However, because some of the Phase 2 projects are in response to post-2030 system needs, the Company will continue to evaluate emerging trends and may modify or propose new projects as warranted. Similarly, significant engineering design work will need to take place prior to project implementation, which will firm up project specifications and cost.

a) New Area Substation

This project will include the installation of a new area substation and four 138 kV sub-transmission feeders in one of the faster growing outer boroughs of New York City that is also primarily located in a low elevation flood prone area. This new area station will serve to create a new network by picking up load (via load transfers) from two nearby networks. The project has an estimated cost of approximately $1 billion and will be implemented sometime after 2030 depending on the speed of electrification from transportation and heating.

The New Area Substation project will also help prepare the Company for achievement of CLCPA objectives in multiple regards. First, the project improves resiliency by improving reliability in both networks from which load is transferred from and creating a new network with higher reliability than the original networks that comprise it. Second, this project prepares the area, with a relatively larger number of commuters who drive for use of EVs in support of CLCPA's clean energy goals. Third, it is anticipated that this project will increase headroom in the substations that will provide optionality to install energy storage at the new substation and add further resiliency to the area.

b) Energy Storage Projects

The Company has identified six energy storage projects that will help it prepare for meeting CLCPA objectives, totaling up to a combined 125 MW in capacity. These projects will provide a range of benefits, including increased headroom to integrate a growing penetration of offshore wind, DG, EVs and building electrification, targeted locational peak load reductions and voltage support, and enhanced resilience to future heat waves and flooding. While the Company will need to address potential challenges to deploying these projects, such as receiving New York City and Fire Department of New York ("FDNY") permits, they will directly support achievement of CLCPA objectives. All projects will be in service by 2030.

IV. LONG ISLAND POWER AUTHORITY/PSEG LONG ISLAND

Long Island Power Authority ("LIPA") respectfully submits this Report in accordance with the Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (AREGCB Act) issued by the New York Public Service Commission ("Commission") on May 14, 2020 ("May 14 Order"). This Report provides results of LIPA's portion of the Utility Study to identify distribution and local transmission upgrades necessary or appropriate to timely achieve the State's climate goals as set out in the Climate Leadership and Community Protection Act ("CLCPA").

LIPA provides electric service to approximately 1.1 million customers in Nassau and Suffolk Counties and on the Rockaway Peninsula in Queens. LIPA's service territory covers about 1,230 square miles, encompassing nearly 90 percent of Long Island's total land area. The area closer to Queens County in New York City is more urbanized and the area to the eastern portion is rural. Three small independent municipal electric systems - Freeport, Rockville Centre, and Greenport - are located within the LIPA service territory. The LIPA owned transmission and sub-transmission system includes approximately 1,400 miles of overhead and underground lines with voltage levels ranging from 23 kV to 345 kV.

A. LIPA Transmission System

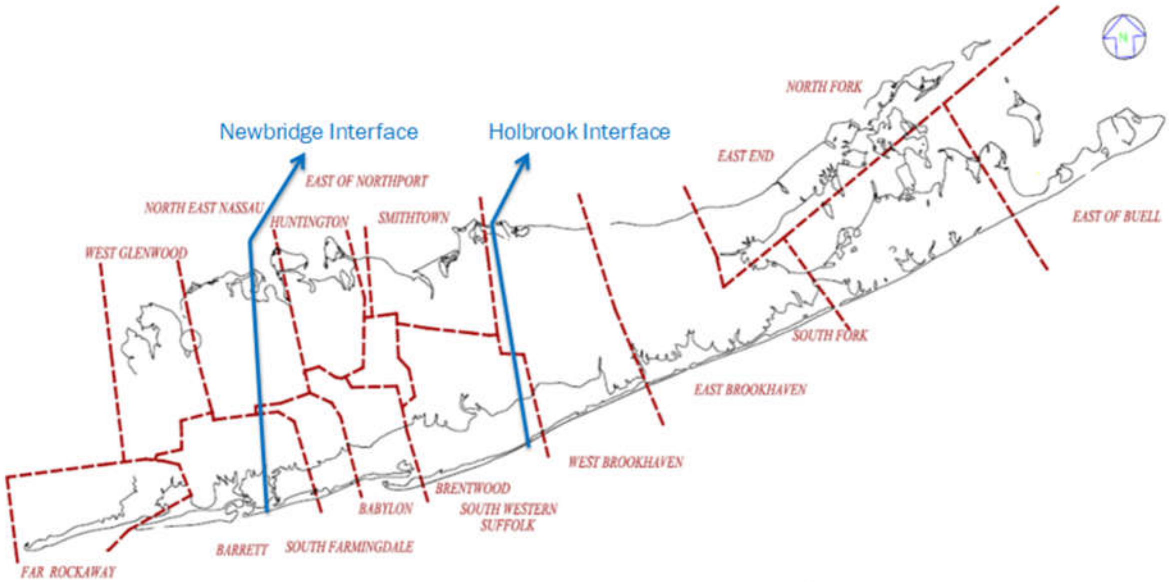
The LIPA transmission system consists of 138 kV and 345 kV voltage levels and the LIPA sub-transmission system consists of 23 kV, 34.5 kV and 69 kV voltage levels. The LIPA transmission system has limited electrical interconnections to CECONY, ISO-New England and PJM, via inter-ties.

The LIPA 138kV transmission backbone primarily runs from west to east (from the Nassau/Queens border in the west to Riverhead in the east). Transfer of power from the western part of the system to the eastern part of the system, and vice versa is primarily supported by the LIPA 138kV transmission backbone in addition to underlying 69kV sub-transmission circuits.

LIPA Internal Interfaces

The primary path for bulk power deliveries to LIPA's load center is across three internal bulk transmission interfaces defined as: Newbridge Road, Northport, and Holbrook interfaces. These interfaces divide Long Island into three separate regions: West of Newbridge, Central, and East of Holbrook regions. The largest amount of load is located in the Central region bounded by the Newbridge Road and Holbrook interfaces. Figure 50 below provides a high-level view of the LIPA internal transmission interfaces.

Figure 50: LIPA Internal Interfaces



These interfaces, which consist primarily of 138kV and underlying 69kV paths, are important for analytical purposes in determining the ability to transfer power and deliver generating capacity across the LIPA system. The interface definitions can be found in the PSEG Long Island Transmission System Planning Criteria[119] document.

i) LIPA Study Assumptions and Description of Local Design Criteria

To assist working group efforts in performing analysis for both the existing system and the high renewable injection into the system, NYISO provided two sets of base cases.

1. Steady State Study Cases

a) System As-Found cases

For the As Found base cases, the representation for the NYCA and LIPA system is based on the 2020 NYISO RNA Year 2030 peak case ("Summer As Found Case") and Year 2025 light load case ("Light Load As Found Case"). The Summer as Found Case's load level assumption was based on the 2020 Gold Book Table I-4a Zone K Non-Coincident 2030 Peak Demand with additional modifications consistent with internal study practices. The Light Load As Found Case load level was set to 1800 MW based on historical yearly load curves for the LIPA system. Historical data shows about 10% exposure to load levels less than 1800 MW.

[119] PSEG Long Island Transmission Planning Criteria; Issued July 1, 2016 https://www.psegliny.com/aboutpseglongisland/-/media/9EFC22D5FA1246F0B5E5371EA6A96AD3.ashx

b) *70x30 Scenario cases*

For the 70x30 Scenario cases, the representation for the NYCA and LIPA system is based on the 2020 NYISO RNA 70x30 scenario for Year 2030 peak ("Summer Peak 70x30 Case"), shoulder ("Shoulder 70x30 Case"), and light load condition ("Light Load 70x30 Case") with additional renewable resources. The 70x30 scenario models a portfolio of renewable resources that can produce enough electricity energy to meet the State's 70/30 goal. The type, size, and location of these resources were developed from the NYISO 2019 Congestion Assessment and Resource Integration Study (CARIS). The NYISO provided cases include 1,176 MW nameplate of behind the meter solar, 77 MW nameplate of utility-scale photovoltaic (UPV), and 1,778 MW nameplate of Off-Shore wind (OSW) interconnected to the LIPA system.

A summary of the OSW resources assumed by the NYISO for the LIPA system is shown in Figure 51below.

Figure 51: NYISO 70x30 Zone K Off-Shore Wind Resource Summary

Resource	Substation	Nameplate (MW)
Off-Shore wind	East Hampton 69kV	130
	Holbrook 138kV	880
	Ruland Road 138kV	384
	Brookhaven 138kV	384
Total		1,778

c) *LIPA 70x30 Scenario cases*

For LIPA's analysis, adjustments were made to the NYISO 70x30 cases to have approximately 3,000 MW nameplate of OSW interconnected to the LIPA system. LIPA, in coordination with CECONY, modified the NYISO provided cases to (1) increase OSW from 6,000 MW to 9,000 MW, maintaining the distribution between Zones J and K based on approximate load ratio share, per the NYISO's assumptions; and (2) modify Points of Interconnection (POI) of OSW renewable resources based upon projects in the NYISO interconnection queue and LIPA's knowledge of the relative cost of reinforcing its transmission system at various locations. These assumed POIs were selected for study purposes to illustrate the types of reinforcements needed to accommodate OSW, though different POIs might also be accommodated with similar reinforcements. As mentioned above, this adjustment results in approximately 3,000 MW nameplate of OSW interconnected to the LIPA system. While the CLCPA requires 9,000 MW of OSW by 2035, the Filing Parties determined it was reasonable to model 9,000 MW in 2030 in order to capture the full impact of the state goal in the Utility Study. For reference, a summary of the OSW resource assumed for LIPA system is shown in Figure 52 below. In addition, NYISO's 70x30 OSW and Solar resources dispatch schedule has been adopted for these cases and has been shown in Figure 53 below:

Figure 52: LIPA 70x30 Zone K Off-Shore wind Resource Summary

Resource	Substation	Nameplate (MW)
Off-Shore Wind	East Hampton 69kV	136
	Holbrook 138kV	880
	Ruland Road 138kV	700
	Ruland Road 138kV	700
	East Garden City 345kV	700
Total		3,116

Figure 53: NYISO 70x30 Base Case Resource Dispatch Schedule

Case	Off-Shore wind (% of Pmax)	Solar (% of Pmax)
Summer Peak 70x30 Case	20	45
Light Load 70x30 Case	45	0
Shoulder 70x30 Case	45	40

d) LIPA 70x30 Scenario sensitivity cases

In addition to the LIPA 70x30 Scenario cases, a set of sensitivity cases were created with several base case modifications for the LIPA system based on the LIPA 70x30 Scenario base cases. Starting from the LIPA 70x30 Scenario base cases described above, the OSW plants injected to Zone K have been dispatched at 100% nameplate output in the cases to stress the LIPA transmission system with higher power transfers across the system. Figure 54 illustrates the OSW and Solar resource dispatch for the LIPA 70x30 Scenario sensitivity cases.

Figure 54: LIPA 70x30 Sensitivity Base Case Resource Dispatch Schedule

Case	Off-Shore wind (% of Pmax)	Solar (% of Pmax)
Summer Peak 70x30 Case	100	45
Light Load 70x30 Case	100	0

For the LIPA system, the same behind the meter (BTM) solar output percentage from NYISO 70x30 scenario cases has been utilized in this analysis.[120] The BTM solar output for each case has been directly deducted from the system load as a load modifier consistent with NYISO's base cases. In addition, LIPA adopted the same generation unavailability assumption provided by

[120] LIPA's solar output percentage at peak load may vary from NYISO's assumption.

NYISO in the 70x30 scenario including those affected by DEC NOx regulation within the LIPA system.

2. *Steady State Analysis Approach*

System expansion and the incorporation of new facilities must follow the PSEG Long Island Transmission Planning Criteria for the LIPA System and applicable interconnection requirements. In addition, all facilities must be designed to conform with and adhere to all applicable North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and New York State Reliability Council (NYSRC) Reliability Rules.

For the purposes of evaluating the LIPA transmission system to understand where capacity "headroom" exists on the existing system as well as identifying existing constraints or bottlenecks that limit energy deliverability, a thermal transfer limits analysis was performed to maximize transfers over LIPA's internal transmission interfaces. The Siemens PTI PSS/E and PowerGem TARA programs were used to redispatch and shift generation across Long Island to maximize the transfer over LIPA interfaces in order to identify potential transmission constraints and bottlenecks for energy delivery in the three regions bounded by LIPA's internal interfaces: West of Newbridge, East of Holbrook, and Central. This analysis was performed to also identify any potential headroom available in these regions for resource interconnection.

To propose potential projects that would increase the capacity on the LIPA transmission system to allow for interconnection of new renewable generation resources, a detailed thermal analysis (considering N-0, N-1, N-1-1) was performed to assess the LIPA system impacts for delivering specified renewable energy injections included in the LIPA 70x30 Scenario base cases. In addition, LIPA's system is a semi-isolated system with limited off-island interconnections. With current LIPA system build-out, energy delivery and power transfers will rely on the local transmission and sub-transmission system (138kV below) which will be limited in its ability (*i.e.,* relatively congested) to support the significant amount (*i.e.,* on the order of hundreds MW) of resource injection into the system, such as from a large OSW plant with its nameplate output. As a result, a sensitivity analysis was performed with LIPA 70x30-scenario sensitivity base cases.

The entire analysis monitored LIPA Bulk Electric System facilities ("BES"), as well as underlying sub-transmission circuits, consistent with the PSEG Long Island Transmission Planning Criteria.

N-0 and N-1 design contingencies consistent with PSEG Long Island Transmission Planning Criteria were considered in the analysis, such as:

1. No Contingency (P0)
2. Loss of Single Transmission Lines
3. Loss of Transformers
4. Loss of a single generator
5. Loss of a switched shunt device

6. Loss of a bus section
7. Failure of a circuit breaker to operate (bus tie, non-bus tie)
8. Double circuit - Two circuits lines on the same transmission pole/tower
9. For N-1-1 reliability analysis, curtailment of OSW was not considered.

ii) Discussion of Existing Capacity "Headroom" within LIPA System

For the purposes of evaluating the LIPA transmission system to understand where capacity "headroom" exists on the existing system, a thermal transfer limits analysis was performed to maximize transfers over LIPA's internal transmission interfaces. This analysis was performed considering all available existing resources within the LIPA system.

For the purposes of this study, "headroom" is defined as the additional resource that can be injected into a region beyond the existing resource capability without a thermal violation on the LIPA system driven by the transfer of power. It is calculated by taking the sum of the interface transfer capability plus the region load and subtracting the existing resource capability in the analyzed region. For some thermal transfers, a negative value was calculated which indicates the tested area has existing power transfer constraints and does not have energy deliverability "headroom". Instead of documenting a negative value, a value of zero has been presented for clarity. Intertie capacity is not included in the value for the existing resource capability for the analyzed region.

Based on this methodology, for applicable contingencies consistent with PSEG Long Island Transmission Planning Criteria, none of the regions in LIPA's existing transmission system - with the exception of East of Holbrook transfer region under peak load condition have transmission headroom for additional generation injection beyond the existing resource capability. Power transfer capability was found to be most limiting on the LIPA transmission system in the East to West direction, especially during light load conditions. Figure 55 below specifically quantifies the "headroom" for the LIPA system for East to West power transfers.

Figure 55: LIPA Headroom Limits

Transfer Regions	Direction of Transfer	N-1 Peak "Headroom" (MW)	N-1 Light Load "Headroom" (MW)
Central & East of Holbrook to West of Newbridge	East to West	0	0
East of Holbrook to Central & West of Newbridge	East to West	200	0

Consideration of other variables such as re-dispatching of existing generation resources or inter-ties and, system load level (*i.e.,* peak load versus light load) will provide some additional degree of "headroom" on the existing system with minimal transmission upgrades.

Additionally, the transmission constraints on Long Island are dependent on the location of any additional resource injection combined with deliverability constraints across interfaces consistent with NYISO Deliverability Criteria. Other internal studies that were conducted as part of the OSW analysis demonstrated that some level of additional resources can be integrated within the Central region and in the Holbrook region without triggering significant transmission investments.

iii) Bottlenecks or Constraints that Limit Energy Deliverability within LIPA System

Based on the transfer study that has been performed, resource delivery in the regions is most constrained for the LIPA system under light load conditions. Bottlenecks on the transmission backbone are observed on 138kV circuits in Western Nassau County and Western Suffolk County during delivery of power east to west. In addition, it is possible that local constraints, including but not limited to transmission, transmission ROW or substation interconnection physical feasibility, will exist at resource interconnection points across the LIPA system. While this study does not specifically capture those local bottlenecks or constraints, it will be necessary to consider system upgrades at or around those interconnection points in order to facilitate the interconnection of additional resources.

With LIPA 70x30 Scenario base case assumptions with the specific resource output schedule described in Table II-3, there are no observed thermal violations. In addition, no thermal violations have been observed for the LIPA 70x30 Scenario sensitivity peak case. However, transmission bottlenecks/constraints have been identified with LIPA 70x30 Scenario sensitivity light load case. Due to the large amount of OSW injection into the existing LIPA transmission system, multiple transmission and local sub-transmission thermal violations have been observed under the light load condition:

- Identified constraints on Central corridor for both Normal and post-contingency conditions.
- Observed overloads on the transmission and sub-transmission paths between East Garden City to Glenwood to Shore Road for both Normal and post-contingency conditions.
- Exceedances of existing LIPA export limitations with high export value to maintain the energy balance between load demand and generation output in the LIPA system

It should be noted that the violations reported above under the light load condition could be alleviated with energy curtailments. Whether energy curtailment is a desired solution from a planning perspective will depend on the relative cost of upgrades versus the value of curtailed renewable energy, which would be unavailable to meet the CLCPA goals.

Moreover, in order to meet the CLCPA goal of 9,000 MW OSW by 2035, the OSW will likely need to connect to New York City and/or Long Island. LIPA is coordinating its study in this proceeding with the CECONY to identify optimal POIs for injection of OSW into the two service territories, considering local transmission constraints. Given the expected size and scale of an OSW project connecting to the LIPA system, it is recommended consideration be given to interconnecting OSW directly to the LIPA 138kV system or converting to a new 345kV system to interconnect OSW resources.

iv) Potential Projects that would Address Bottlenecks or Constraints that limit Energy Deliverability within LIPA System

Based on its analysis as part of the May 14 Order, and on related OSW studies coordinated with CECONY, LIPA has developed a comprehensive list of projects intended to help support the State's climate policy goals and CLCPA mandates.

In coordination with the DPS Staff, the Working Group has defined two "phases" of projects based on the current state of readiness: Phase 1 projects and Phase 2 projects.

These have been generally defined as follows:

Phase 1:

- Considered priority local transmission/ distribution upgrades due to safety, reliability, and compliance requirements that also have CLCPA benefits (*e.g.,* preventing/eliminating bottlenecks).
- Reliability, Safety, and Compliance projects that potentially could be accelerated because of the CLCPA benefits without the need for a Benefit Cost Analysis ("BCA") as the projects would be completed anyway due to its safety/reliability drivers.
- Projects that may be recovered through the utility's current rate plan, but some of these projects may require supplemental approvals.

Phase 2:

- Projects not currently in the Utilities' capital plans.
- Projects / solutions that are generally more complex and conceptual in nature, and which are driven primarily by CLCPA benefits that would be unlocked.
- Projects whereby the scope of work, the needs case being driven primarily by CLCPA, and broad regional benefits suggest that it is likely that cost sharing across utilities may be required.

Multiple transmission projects have been considered and categorized according to the broad "Phase 1" and "Phase 2" project definitions for the LIPA system.

1. *"Phase 1" projects*

The "Phase 1" projects which have been included are based on following considerations:

- Projects included in the LIPA 5-year budget plan.
- Projects documented within the 2019 PSEG Long Island Local Transmission Plan.
- Projects that will address local reliability constraints.
- Projects that will potentially address transmission bottlenecks or constraints by increasing the energy deliverability along certain transmission paths or substations and/or helping to decrease dependence on fossil generation needs for the LIPA system.
- Projects that will support Distributed Energy Resource (DER) additions on the local distribution system.

Figure 56: LIPA "Phase 1" Transmission projects Summary

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost	Estimated Project Benefit (MW)
138 kV Riverhead to Canal New Circuit	K	Riverhead	Canal	Install a new 138 kV circuit from the Riverhead substation to the Canal substation.	6/1/2021	$83M	260
Wildwood to Riverhead 69 kV to 138 kV Conversion	K	Wildwood	Riverhead	Convert the existing Wildwood to Riverhead circuit from 69 kV to 138 kV.	6/1/2021	$10M	160
Western Nassau Transmission Project	K	East Garden City	Valley Stream	Install a new 138 kV circuit from the East Garden City substation to the Valley Stream substation.	12/31/2020	$162M	70
Rockaway Beach 34.5 kV new circuits	K	Far Rockaway	Arverne	Install a new 34.5 kV circuit from the Far Rockaway substation to the Arverne substation.	6/1/2022	$31M	10
	K	Rockaway Beach	Arverne	Install a new 34.5 kV circuit from the Rockaway Beach substation to the Arverne substation.	6/1/2022	$37M	
69 kV Ruland Road to Plainview New Circuit	K	Ruland	Plainview	Install a new 69 kV circuit from the	6/1/2022	$41M	40

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost	Estimated Project Benefit (MW)
				Ruland Rd. substation to the Plainview substation.			
69 kV Pilgrim Bus Reconfiguration	K	Pilgrim	-	Reconfigure connections to 69kV Buses at Pilgrim substation.	12/1/2023	$1M	20
69kV Canal to Deerfield Double Circuit Reconfiguration	K	Canal	Deerfield	Reconfigure Canal to Southampton to Deerfield overhead circuits.	6/1/2024	$2M	5
69kV Elwood to Pulaski circuit upgrade	K	Elwood	Pulaski	Reconductor Elwood to Pulaski 69kV overhead circuit	6/1/2025	$35M	50
					Total:	$402M	

All the projects included on the "Phase 1" list will facilitate the integration of renewable resources such as solar, OSW, energy storage on both transmission and distribution levels to support the CLCPA initiatives. The three BES projects all have a near term in-service date within the next two years that will increase system reliability and support CLCPA initiatives for increasing the energy deliverability across the LIPA BES.

The In-Service Dates and estimated costs for "Phase 1" projects are based on the best available information at this time and are subject to change. In addition, the "Phase 1" project list may be impacted by system changes, and subject to change due to lump load addition in a specific area, potential fossil generation retirement, and specific amount of renewable energy resource connected to a specific area in the LIPA system.

2. *"Phase 2" projects*

The "Phase 2" projects are identified for their ability to increase the transfer capability to address both On-Peak energy deliverability and Off-Peak system bottlenecks on the LIPA transmission and underlying sub-transmission systems. These projects increase the thermal transfer capability of limiting circuit paths or create additional parallel paths to bottlenecked circuits, which have been identified in the 70x30 Scenario sensitivity analysis.

Figure 57: LIPA "Phase 2" Transmission projects Summary

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost	Estimated Project Benefit (MW)
LIPA central corridor 138kV to 345kV Conversion	K	East Garden City	Newbridge Road	Convert the existing East Garden City to Newbridge Road circuit No.4 from 138kV to 345kV	2025-2035 TBD[121]	$221M	1,100
	K	Newbridge Road	Ruland Road	Convert the existing Newbridge Road to Ruland Road circuit No.3 from 138kV to 345kV			
	K	East Garden City; Newbridge Road; Ruland Road	-	Substation expansions and constructions associated with the 345kV conversion.			
New circuit Shore Rd-Ruland Rd 345kV	K	Shore Road	Ruland Road	Install a PAR controlled new 345 kV circuit from the Shore Road substation to the Ruland Road substation.		$647M	
	K	Shore Road; Ruland Road; Syosset	-	Substation expansions and reconfigurations associated with the new 345kV circuit.			
Series Reactors on 138kV Newbridge Rd to Ruland Rd circuits	K	Newbridge Road	Ruland Road	Install two 2-Ohm Series Reactor on Newbridge Road to Ruland Road circuit No.1 and No.2.		$7M	
345kV inter-tie from LIPA East Garden City/Shore Road	K	Zone K East Garden City or Shore Road substation	Zone I or Zone J	Install a PAR controlled new 345kV inter-tie between LIPA and Con-Ed system		TBD	500
New Synchronous Condenser Installation(s)	K	Zone K	-	Install new Synchronous	2025-2035 TBD	$200M	-

[121] The proposed OSW related project In-Service dates will be staged to precede OSW Commercial Operating dates.

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost	Estimated Project Benefit (MW)
				condenser(s) in LIPA system			
Upgrades on several existing sub-transmission 69kV circuits	K	Holbrook	Nesconset	Upgrades on several existing sub-transmission 69kV circuits.	2024	$68M	50
		Newbridge Rd	Bellmore		2024	$100M	40
		MacArthur	Bayport		2025	$27M	90
		Indian Head	Deposit		2025	$11M	50
					Total:	$1,281M+[122]	

LIPA central corridor 138kV to 345kV Conversion –

(1) The preliminary plan for this project is going to convert portions of the existing 138kV path from East Garden City to Newbridge Road and Newbridge Road to Ruland Road to 345kV operations. This project is part of the LIPA 345kV expansion plan that will address the constraints that have been identified above.

New circuit Shore Rd-Ruland Rd 345kV –

(2) This project is the other part of LIPA 345kV expansion plan that would install a new PAR controlled 345kV circuit between Ruland Road and Shore Road 345kV substation. As a preliminary plan, additional substation expansions and reconfiguration at Shore Road, Syosset, and Ruland would be required. With both 345kV projects in-service, the constraints/bottlenecks identified on the LIPA Newbridge Interface from East to West direction will be resolved by introducing two new 345kV transmission paths across the constrained Interface. These two paths would facilitate approximately

[122] The total cost does not include the new inter-tie between LIPA and Con Ed system. Additional coordination between LIPA and Con Ed will be required.

3,000 MW OSW injection on the LIPA system and will provide flexibility on the LIPA BES to mitigate energy delivery constraints.

Series Reactors on 138kV Newbridge Rd to Ruland Rd circuits –

(3) This project is a 138kV project to support the LIPA 345kV expansion project. The scope of this project includes installing two series reactors on the existing Ruland Road to Newbridge Road 138kV circuit No.1 and No.2 at Ruland Road 138kV substation. These two 138kV circuits will experience minor thermal limitations once LIPA 345kV expansion projects are in service. With increasing impedance on both circuits, the power flow will be redirected and will alleviate the thermal constraints on the LIPA 138kV system.

345kV inter-tie from LIPA East Garden City/Shore Road –

(4) This preliminary plan will install at least one bulk transmission PAR controlled inter-tie from LIPA's East Garden City substation and/or Shore Road substation to the CECONY system to increase the export capability of the LIPA-CECONY interface, which connects NYISO Zone K to Zones I and J. The need for a new inter-tie is driven by the LIPA export limitation under light load condition. With a large amount of renewable resource such as OSW injected to the LIPA system, the LIPA load demand under light load condition will not be sufficient to meet the renewable energy output. It also should be noted that with limited off-island interconnections to the rest of New York State, total renewable resource injection into the LIPA system will be further limited under light load conditions. In this case, bottlenecked export capability on the LIPA system will require an upgrade / transmission expansion in order to deliver the renewable energy to rest of the New York State.

New Synchronous Condenser Installation(s) –

(5) A potentially major issue on the transmission system with the significant increase of inverter-based resources (IBR) and concurrent retirement of conventional fossil power plants is the weakness of the system and the potential for adverse IBR behavior due to this weakness, as well as voltage instability. This Report does not attempt to quantify this risk. It is very likely that new synchronous resources will be required (or alternatively, existing resources not being retired and run uneconomically) to strengthen the system such that these new IBR as well as the overall power system can operate in a stable manner. Therefore, we believe that it is reasonable to include a proxy project for at least one synchronous condenser installation on the LIPA system.

Upgrades on several existing sub-transmission 69kV circuits –

(6) Several 69kV upgrades have been identified to un-bottle and relieve power transfer constraints that inhibit energy delivery through the LIPA sub-transmission system. These include:

- Upgrades on the existing sub-transmission 69kV circuit between Holbrook and Nesconset substations.
- Upgrades on the existing sub-transmission 69kV circuit between Newbridge and Bellmore substations
- Upgrades on the existing sub-transmission 69kV circuit between Bayport and MacArthur substations.
- Upgrades on the existing sub-transmission 69kV circuit between Indian Head and Deposit substations.

All four sub-transmission projects documented above would facilitate renewable resource additions within the LIPA Central and East of Holbrook areas to increase the power transfer capability and energy deliverability in the area. It should be noted these projects may potentially be identified under the NYISO Interconnection Process / NYISO Deliverability Assessment for potential developer's Capacity Resource Interconnection Service (CRIS) rights based on future renewable resource injections. In addition, there are multiple sub-transmission constraints in the Western Nassau area identified from the sensitivity study based on LIPA 70x30 Scenario sensitivity light load cases. The need for local upgrades would be dependent on the 345kV expansion introduced above that will potentially resolve both bulk and LIPA sub-transmission constraints.

The "Phase 2" projects identified above are conceptual and currently not in the LIPA's capital plans. Additional analysis will be needed to optimize the solution. The LIPA 345kV transmission upgrades and PAR controlled inter-tie from LIPA to CECONY have been identified by LIPA and PSEG Long Island as transmission needs driven by the interconnection of OSW to LIPA's system regardless of the specific locations at which future OSW projects may be connected. The sub-transmission upgrades will also provide the additional capacity on the local transmission system to facilitate the renewable injection in the LIPA system to support CLCPA initiatives.

It is important to note that expansion of the LIPA transmission backbone to 345kV operation as well as new inter-ties to CECONY will need to be implemented with underground cable. These cables will add a very large amount of charging capacitance, which can create low-order harmonic resonance issues that create issues with respect to overvoltages, transformer energization, etc. . This Report does not attempt to quantify this risk. Additional system upgrades and their associated costs, which may be required to address these complex issues, are not captured here.

The “Phase 2” projects are mainly driven by the OSW injection in the LIPA system. The In-Service Dates and estimated costs for "Phase 2" projects are subject to change and will be better defined once additional information such as NYSERDA OSW solicitation results is available. The project list will likely be revised, and subject to change based on the location and size of OSW injections along with the additional renewable resource projects (such as Solar and Battery Storage) being built in the LIPA system.

The estimated project benefits (incremental benefits, in terms of MW) highlighted in the Phase 1 and Phase 2 tables are considered best case values, approximated by using a power flow based transfer analysis approach considering PSEG Long Island Transmission Planning criteria, or by the expected incremental thermal rating increase. The LIPA Summer Peak 70x30 Scenario Case was used for this analysis. Quantifying estimated project benefits in terms of MW can be done using various approaches and is therefore representative. Collective benefits achieved by grouping select projects together may yield higher overall benefits. The approach taken considered the unique aspects of each project, considering the specific benefits provided for unbottling and/or relieving constraints.

v) Potential Projects that would Increase Capacity on the Local Transmission and Distribution System to allow for Interconnection of New Renewable Generation Resources within LIPA System

Potential projects mentioned in Subsection iv (above) will serve to increase the transfer capability within the LIPA transmission system to allow for interconnection of new renewable generation resources within LIPA system, and to increase LIPA export capability in order to facilitate the Off Shore wind resources potential up to approximately 3,000 MW. In addition to the need to increase the energy deliverability in the western part of the LIPA system and increase overall export capability in support of OSW injections, there will also be a requirement for transmission upgrades to enhance the ability to move power from eastern Long Island to western Long Island. Such a requirement might also be accompanied by the need for lower-voltage upgrades that would be dependent on the location of OSW injections.

There are slightly varying assumptions regarding LIPA’s level of participation in helping the state achieve its solar and battery energy storage targets and goals under the CLCPA. The NYISO CARIS study assumed 1,176 MW nameplate of behind the meter solar and 480 MW of battery energy storage for the LIPA system. LIPA notes that these values exceed LIPA’s load-ratio share of these types of resources.

LIPA has not yet identified specific Transmission “Phase 2” projects associated with CLCPA driven solar mandates based on the specific Zone K Solar distribution and output percentage at peak load and light load, from NYISO 70x30 assumptions adopted in this study. LIPA believes that transmission upgrades are likely to become apparent as those areas see further definition and development. When such upgrades become apparent, LIPA will present those projects at the appropriate time and via the appropriate forum.

In addition, energy storage will play a crucial role in meeting New York's ambitious clean energy goals. In 2018, Governor Cuomo announced a nation-leading goal of 1,500 MW of energy storage by 2025. Later that year, the Commission issued a landmark energy storage order establishing a goal of 3,000 MW of energy storage by 2030, and deployment mechanisms to achieve both the 2025 and 2030 energy storage targets. Based on the proportion of peak load in Long Island compared to the entire State, approximately 187 MW should be installed on Long Island by 2025 and 375MW by 2030.

Although LIPA has not yet identified specific transmission "Phase 2" projects associated with energy storage goals, LIPA intends to meet its share of the goal through existing energy storage contracts, energy storage projects through Utility 2.0 filing, behind the meter storage initiatives and through PSEG Long Island Energy Storage RFP process. Transmission upgrade needs may emerge as the above energy storage initiatives advanced.

With the ongoing energy storage RFP process, LIPA envisions that additional transmission reliability analyses to assess system performance with the implementation of energy storage, considering synergies with the transmission upgrades, will be required to develop an optimized plan to support CLCPA initiatives.

vi) Possibility of fossil generation retirements and the impacts and potential availability of those interconnection points

Under the Amended and Restated Power Supply Agreement ("PSA") between LIPA and National Grid, LIPA purchases capacity and energy from National Grid from a fleet of steam and combustion turbine generating units aggregating approximately 3,700 MW. Within this fleet are eight steam generating units located at three sites totaling approximately 2,350 MW. Those three sites are the Northport, Port Jefferson, and Barrett power stations. National Grid also owns and operates 41 combustion turbine generating units at ten sites totaling approximately 1,350 MW. These ten sites are inclusive of the three steam generating stations.

The need for conventional fossil generating resources is declining due to the increasing penetration of rooftop solar, distributed resources, and energy efficiency, as well as the implementation of CLCPA mandates (100% carbon-free energy by 2040). Absent any retirements, LIPA has a growing surplus of generating capacity. Earlier this year, LIPA announced that studies are underway (expected completion in Q4 2020) that will identify up to 400 MW of desired steam unit retirements as early as the end of 2022, and additional retirements after 2024. Potential transmission reinforcements that may be needed to mitigate transmission security/reliability issues due to fossil generation retirement scenarios may be represented among the Phase 2 projects described above. Others will be identified as part of future studies. Additionally, two peaking units will be retired at West Babylon and Glenwood Landing in 2020 and 2021, respectively without the need for transmission reinforcements. Additional peaking unit retirements are under study, including at Glenwood Landing.

Regarding the existing generating units located at Northport, Port Jefferson and Barrett, while retirements of any of these units may create availability of interconnection points for new renewable energy resources or battery energy storage facilities, such substations may not eliminate the need for transmission upgrades if the operating profile of the new resources is different than that of the existing plants. All three of these sites also have physical / property constraints, as well as transmission exit constraints.

As discussed previously, the NYISO as provided 70x30 Scenario cases had multiple generators, including those affected by DEC NOx regulation within the LIPA system, unavailable for dispatch. These generators included select existing fossil steam plants as well select existing combustion turbine generating units. For some of the combustion turbine generating units, the generator owner has submitted DEC NOx compliance plans.

While potential fossil generation retirement scenarios under consideration will likely create additional "headroom" on certain portions of the LIPA transmission system, these retirement scenarios are not expected to have a significant impact on the Phase 1 Transmission or Phase 2 Transmission projects summarized above. A majority of the Phase 2 projects would be considered "no-regrets" type projects which generally support CLCPA targets related to the integration of OSW. As mentioned previously in this Report, resource delivery across the LIPA interfaces and total renewable resource injection into the LIPA system are most limited/constrained under light load conditions. Under such conditions, many of the generating units on Long Island would not likely be dispatched.

In summary, LIPA and PSEG Long Island are currently evaluating potential PSA steam / combustion turbine / peaking unit retirement scenarios, and retirement studies are in progress. The list of Phase 2 projects is subject to change, and additional Phase 2 projects might be identified considering, for example, the reliability impacts of such retirement scenarios. Finally, at the present time it is difficult to make any definitive conclusion regarding whether retirements of any of these generation units will create availability of interconnection points for new renewable energy resources or battery energy storage facilities. Further, availability of transmission interconnection points upon unit retirement is governed by NYISO tariffs and subject to FERC's open access policies. Any material change at an interconnection point (*i.e.,* retirement of a fossil facility replaced by a renewable energy resource) must conform with and adhere to the latest applicable NERC, NPCC, and NYSRC Reliability Rules, as well as applicable PSEG Long Island Transmission Planning and Interconnection criteria.

vii) Conclusion/Next Steps

Consistent with the May 14 Order, this LIPA report presents the results of its transmission security assessment identifying potential local system upgrades that will facilitate meeting CLCPA goals.

The "Phase 1" projects (*i.e.*, multi-value projects) identified above are included in the LIPA 5-year budget plan. These projects address local reliability issues as well as impediments to renewable energy utilization ("bottlenecks") by increasing the energy deliverability along certain transmission paths or substations and/or helping to decrease dependence on fossil generation needs for the LIPA system, supporting DER additions and thus have synergies with achieving the CLCPA's intended benefits.

The "Phase 2" projects shown above are identified for their ability to increase the power transfer capability to address both On-Peak energy deliverability and Off-Peak system bottlenecks on the LIPA transmission and underlying sub-transmission systems. LIPA recommends the Commission consider "Phase 2" transmission projects identified above as necessary or appropriate upgrades to the Long Island electrical network in order to timely achieve the renewable energy goals established by New York State legislative policies. LIPA suggests that the Commission consider evaluating whether these projects qualify as local transmission projects that are eligible for statewide cost allocation under the Accelerated Renewable Energy Growth and Community Benefit Act.

The estimated project benefits (incremental benefits, in terms of MW) highlighted in the Phase 1 and Phase 2 tables are considered best case values. Quantifying estimated project benefits in terms of MW can be done using various approaches and is therefore representative. Collective benefits achieved by grouping select projects together may yield higher overall benefits. The approach taken considered the unique aspects of each project, considering the specific benefits provided for unbottling and/or relieving constraints.

The significant increase of inverter-based resources (IBR) and concurrent retirement of conventional fossil power plants has the potential to create various issues for the power system, above and beyond thermal and voltage issues which were the focus of this analysis. This Report does not attempt to quantify these other reliability risks; future system studies will be required. Additional system upgrades and their associated costs, which may be required to address these complex issues, are not captured here.

As part of the State's ongoing effort to incorporate 9,000MW of OSW by 2035 to meet CLCPA state goals, LIPA is coordinating its studies in this proceeding with CECONY to determine an optimal plan for injection of OSW for delivery into the New York State Transmission System. Based on these coordinated studies, LIPA's "Phase 2" projects will be refined and optimized, as necessary.

B. Distribution

LIPA provides electric service to approximately 1.1 million customers in Nassau and Suffolk Counties and on the Rockaway Peninsula in Queens. LIPA's service territory covers about 1,230 square miles, encompassing nearly 90 percent of Long Island's total land area. The area closer to Queens County in New York City is more urbanized and the area to the eastern portion is rural. Three small independent municipal electric systems - Freeport, Rockville Centre, and Greenport - are located within the LIPA service territory.

The distribution system comprises 13 kV and 4 kV facilities and a combination of overhead and underground equipment. There are 152 distribution substations throughout the Service Area that step the voltage down from transmission to distribution levels. LIPA's distribution substations have a transformation capability of approximately 8,300 MVA. The LIPA distribution system is divided into the five geographic areas as described below.

1) Queens-Nassau area: includes the Rockaway Beach area, Far Rockaway region, Hempstead Township, and the City of Long Beach

2) Central Nassau area: includes North Hempstead and Oyster Bay Townships.

3) Western Suffolk area: includes Babylon, Islip, Huntington, and Smithtown Townships that are located east of NYS Highway Route 110.

4) Central Suffolk area: Predominately the Brookhaven Township, and includes the Fire Island region of Long Island.

5) Eastern Suffolk area: includes Riverhead, Southold, Southampton, and East Hampton regions that are located east of William Floyd Parkway to the Montauk region.

i) Discussion of LIPA Study Assumptions and Description of Local Design Criteria

For the 70x30 Scenario cases, the representation for the New York Control Area ("NYCA") and LIPA system is based on the 2020 NYISO Reliability Needs Assessment ("RNA") 70x30 scenario for Year 2030 peak ("Summer Peak 70x30 Case"), shoulder ("Shoulder 70x30 Case"), and light load conditions ("Light Load 70x30 Case") with additional renewable resources. The 70x30 scenario models a portfolio of renewable resources that can produce enough electric energy to meet the State's 70/30 goal. The type, size, and location of these resources were developed from the NYISO 2019 Congestion Assessment and Resource Integration Study ("CARIS"). The NYISO provided cases include 1,176 MW nameplate of behind the meter solar, 77 MW nameplate of utility-scale solar, and 1,778 MW nameplate of Off-Shore wind ("OSW") interconnected to the LIPA system. It is relevant to note that LIPA's allocated share and/or actual penetration of these types of resources may be different than these assumptions.

ii) Discussion of Available Capacity "Headroom" and Associated Constraints

The available headroom capacities are dependent on individual substation transformer and feeder characteristics combined with the total Distributed Energy Resources (DER) penetration on that feeder/substation. It also varies depending on size and location of Distributed Energy Resource (DER) under study. Actual headroom capacity at individual substations and feeders are calculated on a case by case basis as part of studies conducted per LIPA's Small Generator Interconnection Process.

The ability of the LIPA distribution system to accommodate DER is constrained by system performance, protection, operational, and ultimately thermal, issue. Additionally, there are physical constraints where there is no room for additional interconnection at the existing substations. A certain amount of DER can be integrated without significant adverse impacts or the need for mitigation measures. After DER penetration on individual feeders or distribution systems reach situationally specific thresholds, impacts become significant and require mitigation that drives the costs of DER integration. As penetration increases further, the incremental cost of impact mitigation tends to become progressively greater until the thermal limits of the distribution are reached. Beyond this level, the incremental integration costs become quite large and impacts the integration of Distributed Energy Resources. The following describes some of the primary constraints to DER integration:

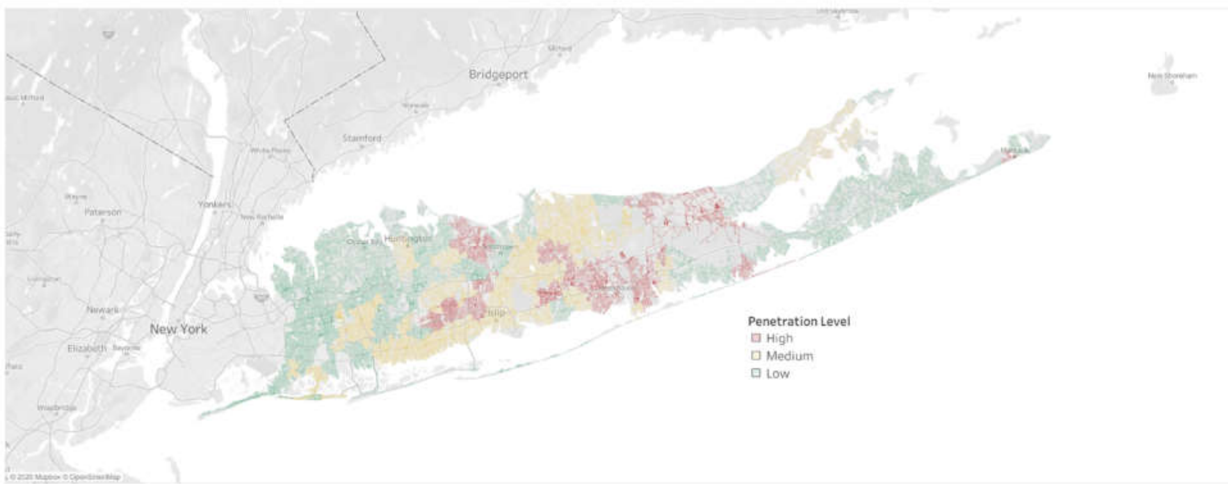
iii) Physical Constraints

The majority of distribution substations are relatively small in parcel size and are fully developed and cannot be expanded to accommodate DER injections. The substation expansion is typically needed when solar and battery DER with large injections connect to dedicated distribution feeders.

Developers are requesting to install DER injection predominately in the Eastern Suffolk part of Long Island. One reason is that Eastern Suffolk has more available land to accommodate DER installations. In this area, there is less load demand and fewer substations where DER can interconnect as compared to the rest of Long Island. This results in a limited DER injection capability in Eastern Suffolk County.

LIPA has a significant number of substations that are space constrained making the installation of new equipment that is required to accept injections of solar and battery power challenging. Figure 58 provides the penetration patterns of existing and projected DER from the queue.

Figure 58: Penetration of DG in the LIPA Service Territory



iv) System Performance Constraints

System performance constraints are primarily related to voltage levels caused by DER injection that would impact other utility customers as well as utility equipment, if not mitigated by protective equipment. DER injections tend to cause voltage rise and can result in voltages in excess of allowable limits at higher levels of local, feeder, or distribution system DER penetration. The injection can also interfere with the performance of existing utility voltage regulation controls and equipment, such as on-load tap changers and switched capacitor banks. One consequence of this interference is that some customers can be subjected to voltages less than acceptable minimum levels. Voltage variation caused by intermittent DER output (e.g., solar PV) can cause customer disturbance, excessive operation of utility voltage regulation equipment and increased potential for failure. Abrupt simultaneous loss of DER output, such as what might occur from a voltage disturbance (e.g., fault on another feeder or on the transmission system) can cause severe under voltage conditions, and abrupt return to service of DER following an outage can result in overvoltages.

v) Protection Constraints

Fault current contributions from DER can interfere with the ability of utility feeder protective relays to detect faults and can also cause undesired loss of service on a feeder due to incorrect protection operation for a fault on a different circuit. The DER fault current combined with fault current sourced by the LIPA system can also exceed the capabilities of LIPA equipment to sustain.

DER output can also cause potentially damaging transient overvoltages due to inadequate system grounding or abrupt separation of the distribution feeder from the utility substation. When DER output on a distribution system reaches approximately 80% of the load on that system, severe and damaging overvoltages can be created on the transmission system feeding that distribution system's substation when a ground fault occurs on the transmission line. DER system design, such as installing grounding transformers, provide mitigation of some of these issues but require that the DER developer add extra equipment to their projects when DER penetration levels are high.

DER can potentially maintain energization of a LIPA feeder that has become separated from the remainder of the utility system (islanding). Although DER are required to detect and eliminate islanding within two seconds, there are gaps in this performance. Because sustained DER islands requires a balance between DER output and concurrent system load in the island. At higher penetration levels, this balance occurs with greater frequency, thus exposing greater risk of islanding.

vi) Operational Constraints

The LIPA distribution systems are configured for flexible reconfiguration to restore service following outages of portions of circuits. Operational decisions made for such restoration are based on the observed load level, which can be greatly affected by DER output. The DER output masks the magnitude of the actual load and loss of the DER can result in a sudden large increase in net load that may exceed circuit capability when in the reconfigured state. This issue can be mitigated by continuous monitoring of DER output by a DER Management System (DERMS) and integration with the Distribution Management System that guides operational decisions.

vii) Thermal Limitations

The limitation to DER headroom is the thermal capacity of the system to withstand maximum reverse flow from the distribution system to the transmission system. The constraining element is typically the substation transformer, and replacement of the transformer with a larger capacity, addition of an additional transformer, or construction of a new substation require substantial capital expenditure that is almost always more than can be sustained by an individual DER project.

viii) Potential Projects that would Address Bottlenecks or Constraints within LIPA Distribution System

Based on an analysis as part of the Commission's May 14th Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, LIPA has developed a comprehensive list of projects intended to help support the State's climate policy goals and CLCPA mandates. In coordination with DPS Staff, the Working Group has defined two "phases" of projects based on current state of readiness: Phase 1 projects and Phase 2 projects.

These have been generally defined as follows:

1. *Phase 1:*
   - Considered priority local transmission/ distribution upgrades due to safety, reliability, compliance requirements in addition to the projects' CLCPA benefits (e.g., preventing/eliminating bottlenecks).
   - Reliability, Safety, and Compliance projects would be accelerated because of the CLCPA benefits without the need for a BCA as the projects would be completed anyway due to its safety/reliability drivers.
   - Projects that may be recovered through the utility's current rate plan, but some of these projects may require supplemental approvals.
2. *Phase 2:*
   - Projects not currently in the utilities' capital plans.
   - Projects / solutions that are generally more complex and conceptual in nature, and which are driven primarily by CLCPA benefits that would be unlocked.
   - Projects whereby the scope of work, the needs case being driven primarily by CLCPA, and broad regional benefits suggest that it is likely that cost sharing across utilities may be required.

Multiple distribution projects have been considered and categorized according to the broad "Phase 1" and "Phase 2" project definitions for the LIPA system.

3. *"Phase 1" projects*

The "Phase 1" projects which have been included are based on following considerations:

- Projects that are in the LIPA 5-year Capital Budget Plan.
- Substation transformer and switchgear installations projects which add breakers where DER can connect.

- Substation upgrade projects which increase headroom capacity
- 4kV to 13 kV feeder conversion projects which increase the feeder capacity and allow DER interconnections.
- Projects that will support DER additions on the local distribution system.

Figure 59: LIPA "Phase 1" Distribution Projects Summary

Project Name	Zone	Substation	Project Description	Proposed I/S Date	OOM Cost ($M)	Estimated Project Benefit (MW)
Rockaway Beach Convert all 4kV feeders to 13kV	K	Rockaway Beach	Convert three 4kV feeders to 13kV	Dec-21	$11.3	20
Flowerfield Replace 6.25 MVA bank with 69/13kV 33 MVA banks, switchgear & C&R	K	Flowerfield	Replace 6.25 MVA bank with 69/13kV 33 MVA banks, switchgear and C&R	Dec-20	$11.4	23
Upgrade 14 MVA transformers to 33 MVA transformers	K	Far Rockaway	Upgrade 14 MVA transformers to 33 MVA transformers	Jun-21	$9.3	23
Install new 138/13 kV transformer and switchgear	K	Roslyn	Install new 138/13 kV transformer and switchgear	Jun-21	$21.9	28
Install new 138/69 kV transformer and switchgear	K	Ronkonkoma	Install new 138/69 kV transformer and switchgear	Jun-21	$19.7	28
Install new transformer and switchgear	K	Rockaway Beach	Install new transformer and switchgear	Jun-21	$11.3	24
Construct new 69/13kV substation	K	Lindbergh	Construct new 69/13kV substation	Dec-20	$54.5	56
Construct New Substation 69/13kv bank and 2 feeders	K	Round Swamp	New Substation 69/13kv bank and 2 feeders	Jun-21	$30.2	56
Install new transformer and switchgear	K	Brightwaters	Install new transformer and switchgear	Jun-22	$20.4	28
North Bellmore Install 33 MVA Bank, Swgr, Feeders & C&R	K	North Bellmore	Install 33 MVA Bank, Swgr, Feeders & C&R	Jun-23	$21.9	28
Expand 69/13kV substation & distribution circuits	K	New South Road	Expand 69/13kV substation & distribution circuits	Jun-22	$21.2	28
Upgrade existing distribution transformers	K	Peconic	Replace 1-14 & 2-6.25 MVA Banks with 2- 33 MVA Banks	Jun-23	$7.0	34
Install new 3rd bank and switchgear	K	Bridgehampton	Install new 3rd bank and switchgear	Jun-22	$11.1	28
Construct new 69/13kV substation	K	Brooklyn Ave.	Construct new 69/13kV substation	Jun-23	$32.6	56

Project Name	Zone	Substation	Project Description	Proposed I/S Date	OOM Cost ($M)	Estimated Project Benefit (MW)
Upgrade substation from 23 kV to 33 kV	K	Hero	Upgrade substation from 23 kV to 33 kV	Dec-23	$0.7	3
Upgrade substation from 23 kV to 33 kV	K	Culloden Point	Upgrade substation from 23 kV to 33 kV	Dec-22	$6.2	9
Upgrade substation from 23 kV to 33 kV	K	Amagansett	Upgrade substation from 23 kV to 33 kV	Jun-22	$15.7	12
New Navy Road substation	K	Navy Road	Replace Montauk substation with Navy Road	Oct-23	$31.7	18
Upgrade substation from 23 kV to 33 kV	K	Hither Hills	Upgrade substation from 23 kV to 33 kV	May-24	$13.0	18
				Total	$351.1	

The In-Service Dates and estimated costs for "Phase 1" projects are based on the best available information at this time and are subject to change. The “Phase 1” project list may be impacted by system changes, and subject to change due to lump load additions in a specific area, among other factors. The estimated project benefit reflects the additional MW capability added by that specific project and is not a direct correlation of additional distribution energy resources that can be added at the substation without any additional cost.

4. *Phase 2 projects*

The “Phase 2” projects are identified for their ability to increase the DER injection capability on the LIPA distribution system by addressing various constraints discussed above. Because the locations of DER injections significantly determine the specific projects, the following figure provides a representation of the types of projects that may be needed, and specific project locations may change based on the location of DER injection. The estimated MW benefit reflects the MW benefit related to the specific project and is not additive across all project categories. The actual MW benefit for the entire Phase 2 projects will be lower than the individual sum of these projects and dependent on specific substation location and the constraints associated with that substation. The project benefit for each category strictly provides the MW benefit associated with solving that specific constraint and does not reflect headroom created at those substations. The actual headroom created at a substation is the MW benefit gained by addressing all relevant constraints at a substation.

The following Phase 2 projects would increase capacity on the distribution system and allow for interconnection of new renewable generation resources. These projects align with the DPS request to support the CLCPA initiative.

a) New Substations or Transformer Upgrade Projects

Based on the land use pattern of existing DER penetration, it is anticipated that DER penetration will be concentrated in select geographic areas triggering the need to either upgrade the existing substation transformers or install new substations. Substation transformers and switchgear installations will add breakers where DER can connect.

b) Additional Breaker Cubicles for DER Feeders

Some larger commercial DER facilities will require additional equipment to interconnect the DERs directly to LIPA substations. These DER facilities will require dedicated feeders to connect to substation switchgear and their associated circuit breakers. LIPA would likely need to increase capacity by installing additional distribution breaker cubicles at certain substations (if possible) in order to permit higher DER injections at distribution substations or replacing existing switchgear with five-feeder cubicles. This would also address some of the physical constraints on the LIPA distribution system.

The “Phase 2” Breaker Cubicle projects which have been included are based on following assumptions:

- Install one additional breaker cubicle at twelve substations to allow new DER interconnections.
- Replace one ½ lineup of distribution switchgear at nine substations to allow new DER interconnections.

c) Protection Projects

In some locations, the installation of DER will require additional substation protection equipment to provide ground fault protection and voltage control. Substations with limited transmission ties may need to install transmission side ground-fault overvoltage protection (3VO) requiring the installation of relays and potential transformers to mitigate the overvoltages. In addition, the installation of the DER may require replacement of the distribution transformer load tap changer (LTC) controls in order to recognize reverse power into the transmission system. Individual feeders require the installation of capacitors and regulators to address the voltage constraints resulting from the high penetration of DERs.

The “Phase 2” Protection projects which have been included are based on following assumptions:

- Install 3V0 relays and potential transformers (PTs) on 135 transmission busses to provide grounding protection.
- Install 48 line regulators and/or capacitors on DER feeders to maintain to provide reactive compensation for DER inverters and associated voltage control.

Figure 60: LIPA "Phase 2" Distribution Projects Summary

Project Name	Zone	Project Description	Proposed I/S Date	OOM Cost ($M)	Estimated Project Benefit (MW)
Yaphank Install 33 MVA Bank, Swgr, Feeders & C&R	K	Install 33 MVA Bank, Swgr, Feeders & C&R	Jun-25	$12.0	28
Wildwood Replace 14 MVA Bank with 33 MVA Bank & Switchgear	K	Replace 14 MVA Bank with 33 MVA Bank & Switchgear	Jun-25	$6.1	16
Babylon Install 33 MVA Bank, Swgr, Feeders & C&R	K	Install 33 MVA Bank, Swgr, Feeders & C&R	Jun-26	$20.2	28
New Doctors Path Substation	K	Install 2-33 MVA Bank, Swgr & Transmission	2029	$22.7	28
Additional Breakers Cubicles for DER Feeders	K	Install 1 additional breaker cubicle at 12 substations	2021-2030	$7.3	108
Replacement of ½ lineup of distribution switchgears	K	Replacement of one ½ lineup of distribution switchgear at 9 substations	2021-2030	$40.0	81
Grounding Protection for Transmission Busses	K	Install 3V0 relays and PTs on 135 transmission busses	2021-2030	$47.2	600[123]
Voltage Regulation for DER Feeders	K	Install 48 line regulators and/or capacitors on DER feeders	2021-2030	$11.7	48
			Total	$167.2	

ix) Potential new or emerging solutions that can accompany or complement traditional upgrades

PSEG Long Island submits its Utility 2.0 Long Range Plan (Utility 2.0 Plan) annually for review by the Long Island Power Authority ("LIPA") and the New York State Department of Public Service ("DPS"). This submittal is in accordance with Public Authorities Law Section 1020-f (ee)

123 The MW value is estimated across 135 transmission buses and can be realized only if the other constraints are addressed.

and the Amended and Restated Operations Services Agreement dated December 31, 2013. The proposed 2020 Utility 2.0 Plan recommends projects to adapt to changing needs of customers, advancing technology, and the policy direction and goals developed within the Reforming the Energy Vision (REV) process in New York, and in alignment with the CLCPA. Following is an overview of some the projects from the 2020 Utility 2.0 that would further the CLCPA goals:

x) Hosting Capacity Maps

PSEG Long Island is presently developing a Hosting Capacity Map that indicates the approximate available DER MW injection for each distribution feeder and at the substation. The hosting capacity maps will provide interconnection customer with information on the amount of DER that can be accommodated on the feeder. In 2020, PSEG Long Island will launch Stage 2 hosting capacity maps, which will provide the minimum and maximum hosting capacity that can be accommodated on the feeder. In 2021, Stage 3 hosting capacity maps will be released and will provide granular information on the amount of DER that can be accommodated at a particular node on the feeder.

xi) Distributed Energy Resource Management System (DERMS)

To support the State Goal of meeting 70x30, it is critical to implement technology, which provides operational platform for distribution to allow distribution operators to better manage DERs under different system conditions. To enable safe integration of DERs on LIPA system, PSEG Long Island is proposing to launch the DERMS (Distributed Energy Resource Management System) platform for 2021.

PSEG Long Island requested funding in 2020 Utility 2.0 filing to deploy an operational platform to allow distribution operators to effectively manage DERs under different system conditions. DERMS is an operational platform that enables the integration, measurement, monitoring, and control of DERs. This system will provide operators with the visibility of real time status and output of DERs under various system conditions. It will also provide operators enough information to ensure reliable operations of the system with higher penetration of Distributed Energy Resources. With the greater amounts of distributed generation on Long Island system, this capability is inevitable to understand the DER contributions at feeder level so that operational actions can account for load masking effects under contingency scenarios. Implementation of this platform is essential to promote higher DER penetration by providing visibility to the potential thermal constraints on the distribution system. This platform serves as the building block to utilize the monitoring and control capabilities and optimizes DER integration onto the grid.

For the future, other capabilities such as market-related functions associated with the DERs will need to be considered once the market rules associated with the DERs are established.

xii) Smart Inverter Capability

With the increase in the penetration of solar as envisioned under CLCPA, there is a need to ensure that the renewables are integrated in the most safe and reliable manner onto the distribution grid. To enhance the reliability of the system with increase in penetration of DER, PSEG Long Island will be conducting a pilot project with Smart Inverters in 2022 under its Utility 2.0 program. Under this project, PSEG Long Island will explore the capabilities, controls and functions of the smart inverters and assess the feasibility of implementing smart inverters across Long Island. The goal will be to utilize the pilot project to learn the capabilities of smart inverter technology and to develop roadmap to implement this technology in the safest and efficiency manner. In addition, smart inverter capability to address DER-caused voltage issues depends on reactive support from the grid. In order to leverage smart inverter capability, voltage support projects such as capacitor banks will be needed.

1. Energy Storage

Every capital project on Long Island is evaluated for non-wire alternative solutions. PSEG Long Island deployed two storage systems of total capacity of 10 MW/80 MWh in South Fork in 2018 which is the fastest growing region in Long Island with ~2% annual load growth. To increase operational flexibility on the grid and to defer the need for costly grid infrastructure investments, PSEG Long Island is evaluating on a continuous basis the need for deployment of energy storage systems on the distribution grid. With the advancement and lower cost of energy storage technology, energy storage solutions are being considered as alternatives to traditional capital projects.

xiii) Conclusion/Next Steps

A review of the LIPA electric distribution system was performed to determine the actions necessary to meet the NYS CLCPA directives and the Commission's May 14, 2020 Order. This review outlined the major constraints that limit the integration of Distributed Energy Resources. The "Phase 1" projects identified above address local reliability issues and promote the integration of DERs, and thus have synergies with providing CLCPA benefits. LIPA recommends that the Commission consider "Phase 2" distribution projects identified above as a representation of potential upgrades to the Long Island distribution network in order to meet the renewable energy goals established by New York State legislative policies. As the penetration of distributed energy resources increases on LIPA system, it is necessary to upgrade existing technology platforms and communication infrastructure. Identification of these types of projects require additional considerations and hence not included as part of this Report.

The Phase 2 projects identified in the report support additional integration of DERs and adequate cost sharing or cost recovery mechanism needs to be considered should these projects move forward. LIPA suggests that the Commission consider evaluating whether these projects could qualify as local distribution projects that would be eligible for cost allocation or cost recovery under the AREGCB Act.[124]

[124] Transmission Planning Proceeding, May Order, pp. 8-9.

V. NATIONAL GRID

A. Transmission

National Grid's service territory covers a large geographic area of New York including portions of NYISO West, Genesee, Central, North, Mohawk Valley, and Capital zones and serves approximately 1.6 million electric customers. National Grid's transmission system is a heavily networked system and is comprised of transmission lines and substations operating at 69kV, 115kV, 230kV, and 345kV with approximately 6,500 circuit miles of 69kV, 115kV, 230kV, and 345kV lines. These facilities are extensively interconnected with facilities owned by other transmission owners in New York, surrounding states, and Canada. Further, the Company's system includes more than 200 transmission substations, over 3,200 circuit miles of sub-transmission lines, over 500 distribution substations, more than 711 large power transformers, approximately 44,000 circuit miles of primary distribution line supplying over 410,000 line transformers, with over 1.2 million distribution poles and many more assets.

Transmission facilities operating above 200kV are considered to be part of New York's bulk transmission system defined by the May Order, which is outside the scope of this study. The New York transmission facilities operating below 200kV are considered to be part of each Transmission Owner's local system and are therefore included in the scope of this study.

i) Discussion of National Grid Study Assumptions and Description of Local Design Criteria

Meeting the State's CLCPA goals requires a significant amount of renewable generation, energy storage, energy efficiency measures, demand response, and electric transportation, all of which will impact both the transmission and distribution (T&D) systems. The focus of this portion of this Report is on the transmission system.

1. National Grid Study Assumptions

This Utility Study is based upon the database established and used by the NYISO for the 2020 Reliability Needs Assessment (RNA) 70x30 CLCPA Scenario. The participants of the Technical Working Group subgroup made efforts to collaborate on high level study assumptions and methodologies; however, each utility has tailored the cases and their analysis to meet their individual needs based on system characteristics, utility planning criteria, etc.

The NYISO provided six (6) base cases that were developed as part of its 2020 RNA for use by the Technical Working Group subgroup. The cases include all transmission owner firm plans as described in the NYISO 2020 gold book. After reviewing these cases, the Technical Working Group selected three (3) cases as the starting point for the 70x30 scenario studies: (i) Day Peak Load of 30,000 MW; (ii) Shoulder Load of 21,500 MW; and (iii) Light Load of 12,500 MW. The load is modeled based on the 2020 Gold Book forecast for 2030. The renewable Resources Mix (based on nameplate MW) included in the database includes: (i) 6,098 MW of Off-

Shore Wind ("OSW"); (ii) 8,773 MW of Land Based Wind ("LBW"); and (iii) 15,150 MW of utility based photovoltaic ("UPV"). Figure 61 below provides a breakdown of the distribution of renewable resources connecting to National Grid's system; because of the networked nature of the upstate transmission system, however, the resources connecting outside of the National Grid service territory are also material to the results of this study.

Figure 61: Renewable Resource Assumptions

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

The maximum available nameplate of LBW and UPV was originally determined by the NYISO in the 2019 Congestion Assessment and Resource Integration Study (CARIS) 70x30 scenario and is also being used by the NYISO in the 2020 RNA 70x30 scenario. In CARIS, NYISO modeled the additional resources needed to meet the 70x30 goals at voltages 115 kV or higher regardless of where they may actually be located on the local system. National Grid did not adjust the interconnection point of any generation when assessing the bottlenecks that may develop and limit generation dispatch.

Starting from the 70x30 scenario peak load, shoulder load, and light load cases created by the NYISO, National Grid built 44 sensitivity cases examining different renewable dispatch conditions. These dispatch scenarios were communicated with neighboring utilities for their consideration and use in their study work. While developing the case dispatches, overloads and voltages outside of the acceptable range on the 345kV and 230kV systems were not reviewed and existing transfer limits were not respected, as these were considered out of scope for this assessment of the local system performance.

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

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

Once the above assumptions were made in each case, LBW and UPV generation was dispatched to various levels. In the National Grid testing, LBW, primarily located in western, central and northern NY, was varied between 0 percent of nameplate up to 75 percent of nameplate and UPV, located in most areas from A to G, was dispatched between 0 percent of nameplate up to 70 percent of nameplate. No cases with wind or solar resources dispatched to 100 percent of nameplate were studied. In each scenario, all LBW or UPV was dispatched to the same percentage of nameplate, regardless of the location of the resource.

Some cases developed by National Grid include a mix of LBW and UPV. For example, one shoulder case modeled LBW at 30 percent of nameplate and UPV at 27 percent of nameplate. In addition to the cases, the NYISO also provided the zonal data of hourly load, LBW output, OSW output, and the UPV output from its CARIS study. This data from the NYISO was used to validate that the dispatches selected by National Grid were observed in the CARIS 70x30 scenario analysis. For example, LBW greater than or equal to 30 percent of nameplate concurrent with UPV output greater than or equal to 27 percent occurred in the CARIS 70x30 scenario for 802 hours. Another example of the many cases created was LBW at 15 percent of nameplate and UPV at 52 percent of nameplate, with the dispatch of these renewables at or above this level occurring in the CARIS 70x30 scenario for 457 hours. All dispatches reviewed by National Grid occurred in the NYISO CARIS 70x30 scenario for 100 hours or more.

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

In addition to the cases described above. The NYISO initially provided a set of cases representing Business as Usual (BAU). These scenario cases represent the conditions where only resources that meet the NYISO inclusion rules were modeled in the study. Screening of these cases by National Grid found no notable conclusions and further analysis with these cases was abandoned to focus study efforts on the 70x30 scenario cases.

2. Local Design Criteria

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

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

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

ii) Possibility of Fossil Generation Retirements and the Impacts and Potential Availability of Those Interconnection Points

The National Grid study work included an evaluation of peak, shoulder and light load cases that modeled all fossil generation out of service concurrently with all existing and planned LBW and UPV out of service. In these cases, the only generation in service in zones A through F was hydro and nuclear. Analysis of these cases showed no N-1 steady state thermal overloads or voltages outside of limits. This analysis supports the conclusion that for normal system operation, the existing fossil generation fleet would not be needed for N-1 reliability or system security reasons. This test also confirms that all overloads found in this study are a direct result of the interconnection of solar and wind generation resources.

Prior to any generator retiring, additional testing would be required to confirm that the retirement does not create any steady state N-1-1 issues and would not result in a system instability. Any planned generator retirement would also need to be examined to confirm that no system upgrades or settings changes would be required to address system protection issues.

Following the retirement of a generator, the interconnection point may be available for use by a new generator. However, the new generator would have to go through the NYISO interconnection process, and the interconnection station would have to meet all National Grid interconnection requirements.

iii) Discussion of Existing Capacity "Headroom" within National Grid's System

National Grid's 115kV system operates as a continuous network from Buffalo across National Grid and Avangrid service territories to points north of Poughkeepsie and is also operated in parallel with the higher voltage and lower voltage networked systems. This makes the concept of headroom difficult to apply to individual pockets of the system. The capacity headroom analysis determined the total amount of renewable generation in MWs that can be injected into the existing system without exceeding system limits. The methodology developed is relatively complex due to the load and dispatch scenarios that were not considered, which can significantly affect the results. This is especially true of the assumed location of new renewable resource on a networked system.

To provide some indication of available capacity, National Grid performed a test where unlimited generation was added to the main 115kV switching stations in a given pocket. The cases were initialized assuming that no existing wind, solar or fossil generation was in service and that the fictitious generation at the main switching stations has zero output. An optimized dispatch was then developed that would keep all transmission elements in the pocket within acceptable loading for any N-0 or N-1 condition. This headroom calculation is the theoretical maximum generation that could be located within the pocket. For some pockets, generation may have been increased at only one switching station. In other pockets, the optimal dispatch spread the generation out across many switching stations. A real generator interconnection project located away from one of these optimal generation points would reduce the maximum area headroom at more than a one for one rate.

The maximum or optimal amount of generation within the pocket when an overload is found is listed as the headroom for that pocket. This test is only valid for the conditions in the cases used and for the assumed generator interconnections directly to the area switching stations. The test also does not account for generation in upstream pockets, which could result in lower downstream capability. Analysis does not distinguish between the type of generation, only estimates the capability for simultaneous output from generation within the local 115kV network.

Figure 62: Existing Headroom on National Grid System

Area	Peak Load	Shoulder Load	Light Load
Southwest	810	740	540
Genesee	900	780	630
East of Syracuse	1800	1850	1620

Area	Peak Load	Shoulder Load	Light Load
Watertown/Oswego/Porter	1010	1030	1080
Porter/Inghams/Rotterdam	550	460	430
Capital/Northeast	660	690	730
South of Albany	810	730	710

iv) Discussion of Bottlenecks or Constraints that Limit Energy Deliverability within National Grid's System

Using the dispatched cases and testing methodology, National Grid has completed an assessment of its local transmission system to identify system constraints, or "bottlenecks," that limit renewable energy deliverability under normal and N-1 contingency conditions. This testing has concluded that bottlenecks exist in seven major renewable generation pockets within the National Grid system. To eliminate all identified constraints in these pockets, National Grid would need to resolve 924 circuit miles of conductor overloads.

All observed overloads could be fully corrected by curtailing renewable generation. However, addressing transmission limitations through generation curtailments may require the suboptimal installation of additional renewable generation to overcome the energy curtailed and meet 70X30. An estimate of the amount of generation in each pocket that would have to be curtailed, or relocated to where it would be fully deliverable, to address transmission overloads is given in Figure 63. However, given the constraints encountered in many parts of the system, identifying an area where this generation could relocate without being curtailed is unlikely.

Figure 63: Summary of System Concerns in Generation Pockets

Constrained Area	Miles of Overloaded Conductor	Highest Area Circuit Loading (% of Rating)	Highest Base Case Generation Curtailment	Estimated Equivalent Replacement Generation Capacity
Southwest	101 miles	205%	330MW	440MW
Genesee	17 miles	156%	110MW	140MW
East of Syracuse	0 miles	157%	90MW	270MW
Watertown/Oswego/Porter	380 miles	368%	870MW	1,160MW
Porter/Inghams/Rotterdam	267 miles	448%	660MW	950MW
Capital/Northeast	13 miles	159%	2,590MW	7,190MW
Albany South	146 miles	252%	660MW	950MW
Total	924 miles			

Area descriptions:

1. Southwest - south of Buffalo to the New York-Pennsylvania border
2. Genesee - east of Buffalo to Rochester

3. Watertown/Oswego/Porter - bound by Moses and Willis stations in the north, Oswego in the southwest and Porter in the southeast
4. East of Syracuse - south and east of Syracuse from Cortland to Oneida
5. Porter/Inghams/Rotterdam - bound by Porter to the west and Rotterdam to the east
6. Capital/Northeast – bound by Rotterdam to the west and New Scotland to the south
7. Albany South - the area from New Scotland south to Pleasant Valley and from Greenbush south to Pleasant Valley

1. Potential Projects that would Address Bottlenecks or Constraints that Limit Energy Deliverability within National Grid's System

Potential projects that would address bottlenecks or constraints as well as the potential projects that would increase capacity on the local system to allow for interconnection of new renewables are discussed in the following section.

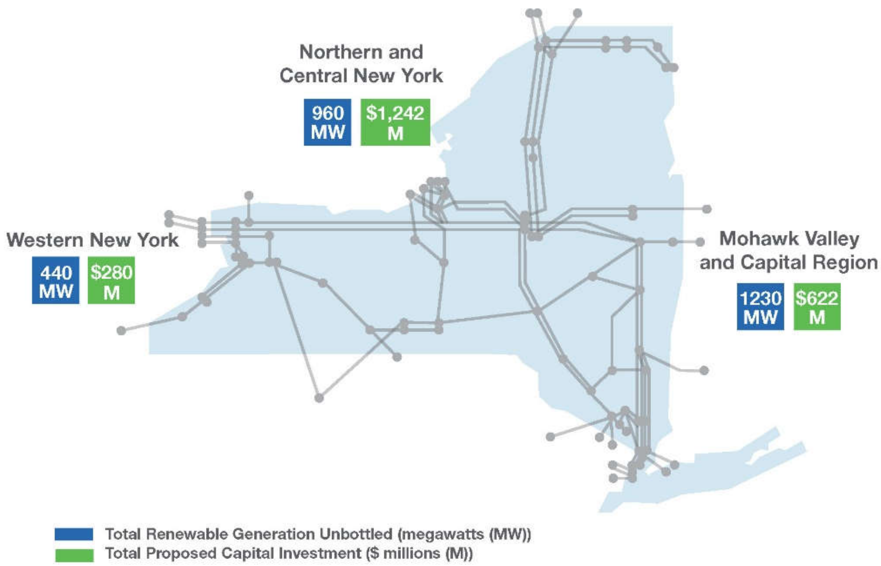
2. Potential Projects that would Increase Capacity on the Local Transmission and Distribution System to Allow for Interconnection of New Renewable Generation Resources within National Grid's System

Based on the study identified constraints limiting renewable energy integration in each area of the National Grid system, projects were developed. For each area, recommend transmission solutions are separated into Phase 1 and Phase 2. An estimate of the amount of generation unbottled in the most constrained case tested as part of this study is included for the Phase 1 projects as well as the combination of the Phase 1 and Phase 2 projects. The MW of additional generation capability reported represents the increase in deliverability of the area generation. In some areas the recommended projects would provide increased headroom above that required for the area generation included in the study cases. All Phase 2 Projects are consolidated and summarized in Figure 65: . The Phase 2 projects are conceptual and additional analysis will be needed to optimize those solutions.

Although a few alternatives were considered in each area, one option is recommended as the most cost effective and efficient solution to the area needs after consideration of Multi Value Transmission drivers. Most of the cost estimates in this study are considered to be Order of Magnitude level based on a limited desktop engineering analysis with an accuracy of +200/-50%. The proposed in-service dates are also estimates that will require additional refinement through detailed engineering and scope development.

National Grid requests the Commission approve all Phase 1 projects described below, and illustrated in Figure 64. National Grid believes these projects are immediately actionable and will provide significant benefits towards unbottling the renewable resources needed to meet CLCPA objectives. In addition, National Grid requests the Commission approve the cost recovery framework described in Section V of this Report for the costs associated with Phase 1 projects not currently in National Grid's existing capital investment plan or included in its most recent rate filing.

Figure 64: National Grid's Total Regional Transmission Investments, and Associated Renewable Benefits



a) Southwest Pocket: Phase 1

The Phase 1 projects in this area are estimated to reduce the need for generation curtailment by 310MW. The combination of the Phase 1 and Phase 2 projects are estimated to reduce the need for generation curtailment by 440MW.

Figure 65: List of Phase 1 Projects in the Southwest Pocket

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date
Dunkirk – Falconer 115kV Line Upgrades	A	Dunkirk	Falconer	115kV Upgrade: sections of Dunkirk-Falconer	2027
Moons Series Reactors	A	Moons	Moons	Retire and relocate series reactors near end of life	2024 *In rate case
Homer Hill – Bennett 115kV Terminal Upgrades	A/C	Homer Hill	Bennett	Address all limiting 115kV terminal equipment at various stations between Homer Hill and Bennett	2023
Batavia – Golah 115kV Line Upgrade	B	Batavia	Golah	115kV Upgrade: sections of Batavia – Golah	2026
				Total Cost	$262M

b) East of Syracuse: Phase 1

The Phase 1 projects in this area are estimated to reduce the need for generation curtailment by 90MW.

Figure 66: Phase 1 Projects in the East of Syracuse Pocket

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date
Clarks Corners – Oneida 115kV Terminal Upgrades	C	Clarks Corners	Oneida	Address all limiting 115kV terminal equipment at various stations between Clarks Corners and Oneida	2023
				Total Cost	$5M

c) Watertown/Oswego/Porter: Phase 1

The phase 1 projects in this area are estimated to reduce the need for generation curtailment by 300MW. The combination of the Phase 1 and Phase 2 projects are estimated to reduce the need for generation curtailment by 870MW.

Figure 67: Phase 1 Projects in the Watertown/Oswego/Porter Pocket

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date
Colton – Boonville 115kV Terminal Upgrades	E	Colton	Boonville	Address all limiting 115kV terminal equipment at various stations between Colton and Boonville	2022 *In rate case
Lighthouse Hill – Clay 115kV Clearance Limits	C/E	Lighthouse Hill	Clay	Address all clearance limits on the Lighthouse-Clay 115kV line	2023
Coffeen – Black River 115kV Terminal Upgrades	E	Coffeen	Black River	Address all limiting 115kV terminal equipment on lines connected to Coffeen	2023
Malone 115kV PAR	D	Malone	Malone	Add a 115kV Phase Angle Regulator to the Willis – Malone circuit	2026 *In rate case
				Total Cost	$18M

d) Porter/Inghams/Rotterdam: Phase 1

The Phase 1 projects in this area are estimated to reduce the need for generation curtailment by 150MW. The combination of the Phase 1 and Phase 2 projects are estimated to reduce the need for generation curtailment by 660MW.

Figure 68: Phase 1 Projects in the Porter/Inghams/Rotterdam Pocket

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date

Rotterdam 69kV Line and Station Upgrades	F	Rotterdam	Rotterdam	69kV Upgrade at Rotterdam and sections of 69kV circuits connected to Rotterdam	2027 *In rate case
Inghams – Rotterdam 115kV Line Upgrades	F	Inghams	Rotterdam	115kV Upgrade: Inghams-Rotterdam circuits	2026-2030
				Total Cost	$433M

e) Capital Region: Phase 1

The Phase 1 projects in this area are driven by much higher flows into the Rotterdam area across the local and bulk system and are not related to a specific generator or group of generators. Due to the generation being further away from the constraint, the projects are estimated to reduce the need for generation curtailment by 2590MW. No Phase 2 projects were identified as being needed in this area.

Figure 69: Phase 1 Projects in the Capital Pocket

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date
Rotterdam – Wolf/State Campus 115kV Line Upgrades	F	Rotterdam	Wolf Rd / State Campus	115kV Upgrade: sections of Rotterdam-Wolf, Rotterdam-State Campus	2027
				Total Cost	$46M

f) Albany South: Phase 1

The Phase 1 projects in this area are estimated to reduce the need for generation curtailment by 280MW. The combination of the Phase 1 and Phase 2 projects are estimated to reduce the need for generation curtailment by 570MW.

Figure 70: Phase 1 Projects in the Albany South Pocket

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date
Churchtown– Pleasant Valley 115kV Upgrades	F/G	Churchtown	Pleasant Valley	115kV Upgrade: sections of Churchtown- Pleasant Valley	2025
				Total Cost	$9M

g) National Grid Company-Wide: Phase 2

All proposed Phase 2 projects for National Grid are summarized below, the benefits of the projects in each region are summarized with the Phase 1 projects above.

Figure 71: National Grid Phase 2 Projects

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date
Lockport – Mortimer 115kV Smart Valve System	B	Lockport	Mortimer	115kV Upgrade: Add Smart Valve system to Lockport-Mortimer Lines	2027
Black River – Lighthouse Hill 115kV Line Upgrade	C/E	Black River	Lighthouse Hill	115kV upgrade: sections of Black River to Lighthouse Hill	2025
Taylorville – Boonville 115kV Line Upgrade	E	Taylorville	Boonville	115kV upgrade: sections of Taylorville to Boonville	2027
Coffeen – Black River 115kV Line Upgrade	E	Coffeen	Black River	115kV upgrade: sections of Coffeen to Black River	2027
Lighthouse Hill – Clay 115kV Line Upgrade	C/E	Lighthouse Hill	Clay	115kV upgrade: sections of Lighthouse Hill to Clay	2029
Coffeen – Lyme 115kV Line Upgrade	E	Coffeen	Lyme	115kV Upgrade: sections of Coffeen to Lyme	2030
Black River – Taylorville 115kV Line Upgrade	E	Black River	Taylorville	115kV upgrade: sections of Black River to Taylorville	2031
South Oswego – Lighthouse Hill 115kV Line Upgrade	C	South Oswego	Lighthouse Hill	115kV upgrade: sections of South Oswego to Lighthouse Hill	2033
Boonville – Porter 115kV Line Upgrade	E	Boonville	Porter	115kV upgrade: sections of Boonville to Porter	2035
Meco Station Upgrade	F	Meco	Meco	Upgrade Meco	2026
Albany 115kV PAR	F	TBD	TBD	Add a 115kV Phase Angle Regulator South of Albany	2027
Marshville Station Upgrade	F	Marshville	Marshville	Upgrade Marshville	2028
Leeds Station Upgrade	F	Leeds	Leeds	Upgrade Leeds	2028
				Total Cost	$1,371M

v) Conclusion

Based on current and future renewable generation developer interest, a significant amount of renewable generation necessary to meet CLCPA objectives is expected to be interconnected to the local transmission system in National Grid's service territory. National Grid has performed extensive system analysis and has determined that the Company's transmission system creates bottlenecks or constraints in many of the areas that renewable generator developers have shown interest. All observed overloads could be fully corrected by curtailing renewable generation production. Addressing transmission limitations through energy production curtailments would require the suboptimal installation of additional renewable generation capacity to overcome the energy production curtailed and meet 70X30. However, given the large number of constraints encountered in many parts of the system, identifying an area where this generation could relocate without being curtailed is unlikely. The Phase 1 and Phase 2 projects that have been identified by National Grid are needed to address these local system limits and avoid curtailments. National Grid also selected these projects because they would not only support renewable energy deliverability but many of them provide additional benefits to customers (i.e. Multi-Value Transmission). Without these projects, the amount of resulting energy curtailments will require additional generation capacity to be built in order to meet the CLCPA's 70X30 target.

B. Distribution

i) Introduction

This portion of the report provides a high-level overview of National Grid's detailed analysis and results of the worst case scenario impacts on its 5 kV – 46 KV distribution system ("grid") in achieving the State's CLCPA goals up to, and including, the year 2030. Although several CLCPA targets exceed this time frame, such as achieving 100% clean electrical energy by 2040, analysis of such impacts on the distribution system are beyond the scope of this Report. National Grid's current Distribution Planning Criteria was applied in these studies.

The analysis primarily captured DER technologies that are expected to have the most negative impacts on National Grid's distribution system and require system upgrades to resolve. In this regard, solar PV has been, and is expected to continue to be, the most significant driver of grid upgrades.

To examine the key elements of the study identified in the May Order, including identification of bottlenecks, traditional capital projects that can alleviate bottlenecks, and new projects to alleviate all remaining bottlenecks, the Company developed detailed forecasts that capture a range of potential scenarios. In particular, National Grid identified the following four forecast scenarios[125] to frame the study:

1. 2019 gross loads with existing generation and energy storage, plus interconnection queue for generation and storage projects that have made 25% CIAC interconnection cost payment made as of June 1, 2020.
2. 2019 gross loads with existing generation and energy storage, plus 100% of total generation and storage in the interconnection queue as of June 1, 2020.
3. NYISO 70x30 peak load case[126] with 69% dispatch of behind the meter (BTM) solar PV.[127]
4. 2030 CLCPA bottom-up feeder level forecast.[128]

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125 None of the forecast scenarios capture heat pumps as the forecasts for that technology is not currently available. Also note only limited storage (below the CLCPA targets) and zero demand response is modeled as the study aimed to identify the violations that could then potentially be solved by these technologies/programs.

126 See Figure 61, above

127 BTM is defined as any DER that is not seen/bidding into the markets i.e. treated as net load by the NYISO

128 Highly granular forecast as described in detail in the Company's 2020 DSIP Update Report that was adjusted to meet achieve National Grid's expected portion of the 2030 CLCPA goals.

ii) Overview of Results

1. Existing Headroom

The May Order directed that utilities determine where capacity "headroom" exists on today's grid. To that end, National Grid conducted an analysis of all four forecast scenarios and identified the locations where the forecast scenario power flows are less than the current grid asset hosting capacity[129] available. The results show that for the worst case scenario (Scenario 2), the grid has limited existing headroom available and highlights a key challenge where most of the interconnection queue looks to connect to the grid in constrained locations, such as rural areas with available land but weak grid infrastructure. On the other hand, Scenario 4 revealed sufficient headroom exists that could potentially accommodate the Company's solar PV CLCPA 2030 goals. It is important to note, however, under Scenario 4, the allocation method of solar PV projects only locates solar PV to those geographic areas where there is enough available hosting capacity. Therefore, the Company does not believe Scenario 4 accurately reflects where solar PV is looking to interconnect over the duration of the forecast.[130] However, the Company has and continues to promote solar PV specifically, in areas where the grid has sufficient hosting capacity headroom via the Company's publicly available hosting capacity map website.[131]

2. Bottlenecks

The second question in the May Order is to identify existing constraints or bottlenecks that limit energy deliverability. To answer this question, the Company identified the assets and associated locations that show violations (i.e., power flows above the asset hosting capacity) for all four forecast scenarios. The results revealed that Scenario 2 had the greatest number of asset violations, with Scenarios 1 and 3 producing some violations that in general overlapped with violations identified in Scenario 2. Scenario 4 revealed no violations. The list of projects in the tables below highlight the locations of the grid where such bottlenecks exist.

3. Capital Expenditure Synergies

The third question in the May Order directs utilities to identify synergies with traditional capital expenditure projects driven by aging infrastructure, reliability, resilience, market efficiency, and operational flexibility that simultaneously alleviate some bottlenecks identified (*i.e.*, increase hosting capacity). This concept aligns with the Multi-Value Distribution concept as part of the on-going New York Standardized Interconnection Requirements ("NYSIR") cost sharing proposal being discussed at the Interconnection Policy Working Group ("IPWG"). To answer this question, the Company reviewed its current five year Capital Investment Plan

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129 The term hosting capacity is considered in the broadest term (i.e., ability to host both generation and load).

130 The Company is currently making revisions to its bottom up forecast methodology to address this issue

131 https://ngrid.portal.esri.com/SystemDataPortal/NY/index.html

("CIP")[132] and identified existing projects that solve reliability, capacity, and asset condition issues but also provide increased hosting capacity primarily to resolve Scenario 1 and 2 violations. The analysis identified several projects as shown in Figure 72, below[133] and are labeled as Phase 1 projects.[134] National Grid's study revealed limited overlap between planned capital projects and the CLCPA driven violations identified, as a large portion of the Company's planned capital projects are to replace or build new assets in the Company's towns and cities that suffer from asset condition challenges, such as, the City of Buffalo and contrasts with the more rural areas where solar PV is typically looking to interconnect.

4. New Incremental Projects

The fourth question identified for the study in the May Order is to identify potential new projects that would increase hosting capacity on the grid to resolve all remaining bottlenecks not resolved via projects in the capital plan. These projects are referred to as Phase 2[135] projects as shown in the Figure 73 below. The results identified a significant number of projects that would be required to meet CLCPA goals, mostly driven by Scenario 2. It is important to note that the solutions and estimates are based on traditional, wire-based solutions. Non-Wire Alternatives (e.g., controllable and dispatchable DER)[136] may be able to solve some of the violations identified. It is also important to note resources, including procurement, design, engineering, right-of-way, installation and operations staff, required to implement Phase 2 projects will be significant and are not factored into this analysis and the proposed projects listed.

5. New or Emerging Solutions

The fifth question is to determine potential new or emerging solutions that can accompany or complement traditional upgrades. This includes identifying opportunities to propose new innovative solutions to create additional hosting capacity in areas with bottlenecks. National Grid has a number of new or emerging projects already in flight (Phase 1) and recently proposed in its most recent rate filing that will support the CLCPA goals either directly or indirectly. National Grid's Distributed System Implementation Plan provides significant details of how these new or emerging solutions support CLCPA goals. Examples include energy storage projects, NWAs, Volt/VAR Optimization (VVO) and Conservation through Voltage Reduction (CVR), and Advanced Distribution Management System (ADMS), as well as the Clean Innovation

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132 2020 Electric Transmission and Distribution Capital Investment Plan, filed March 31, 2020 in Case 17-E-0238.

133 Several projects are currently proposed in the Company's 2020 July 31st rate filing.

134 Located on circuits that create impediments to renewable energy utilization (bottlenecks), provide multi-value benefit such as to asset condition or reliability in addition to the projects' CLCPA benefits and are projects already listed in the Company's latest version of the CIP,

135 These projects are not currently in the Utilities' capital plans, solutions are generally more complex than phase 1 projects, are driven primarily by CLCPA benefits that would be unlocked, require commission approval to proceed, for example, the JU Cost Sharing proposal and are subject to changing market conditions

136 The Company would look to apply the current NWA criteria to identify potential NWA RFP opportunities.

and Distributed Energy Resource Management System (DERMS) Investigation projects proposed in the Company's 2020 rate case. None of these new or emerging solutions were factored into the detailed analysis due to the complexity in modeling and simulating their impacts. National Grid has not identified any new or emerging Phase 2 solutions at this time, but continues to actively participate in R&D related groups and forums such as NYSERDA projects, EPRI, and CEATI programs to help inform future potential new or emerging solutions for the longer term.

6. Prioritization

In addition to the questions discussed above, the May Order also requests the list of proposed projects be ranked and prioritized. As such the Phase 1 and Phase 2 lists are provided as the answer to this question, where it is recommended Phase 1 projects are the higher priority than Phase 2 due to the multi-value nature provided by these projects as described previously.

iii) Results

1. Phase 1

Figure 72: Phase 1 Projects[137]

Project Name	Violation Type	Zone	Terminal A	Terminal B	Project Description	Est. Proposed I/S Date	OOM Estimate	Incremental Hosting Capacity [138]
Stoner Sub	Substation	F-4	Stoner	N/A	Upgrade 25MVA transformer bank with 40MVA bank to address asset condition and hosting capacity concerns	2019-2021	$2.5M	15 MW
Hoosick Sub	Substation	F-4	Hoosick	N/A	Upgrade 12.5MVA transformer bank with 25MVA bank as part of rebuild for IEC 61850 standard	2020-2024	$11M	12.5 MW
Altamont Sub	Substation	F-4	Altamont	N/A	Upgrade 22.4MVA to 40MVA bank to address asset condition and hosting capacity concerns	2025-2030	$10M	17.6 MW
Cllinton Sub	Substation	E-3	Clinton	N/A	Upgrade 10.5 MVA bank to address asset condition and hosting capacity concerns, size TBD	2025-2030	$10M	TBD
3V0 and LTC upgrades Phase 1	Substation	multi ple	various	N/A	51 Pending customer and company funded 3V0/LTC upgrades	2020-2025	$32.5M	224 MW
Buffalo Station 32 Rebuild	SubT	A-1	Stat 32	N/A	Removal of all the existing equipment and the installation of four (4) new 23/4.33kV 3.75/4.687 MVA transformers	2020-2024	$7.6M	4 MW
Buffalo Station 38 Rebuild	SubT	A-1	Stat 38	N/A	Removal of all the existing equipment and the installation of four (4) new 23/4.33kV 3.75/4.687 MVA transformers	2020-2024	$9.7M	4 MW
Buffalo Station 139	SubT	A-1	Stat 139	N/A	Replace Transformers. This project will replace the existing 3.75/4.687MVA transformer with a 7.5/9.375MVA transformer.	2024-2027	$2.9M	4.7 MW
Golah Sub TB1	SubT	B-29	Golah	N/A	Upgrade 63kV to 34.5 kV transformer from 10MVA to 25 MVA	2020-2024	$4.5M	15 MW
Golah Sub TB3	SubT	B-29	Golah	N/A	Upgrade 63kV to 34.5 kV transformer from 10MVA to 25 MVA	2020-2024	$4.5M	15 MW
Perkins South West to DG	SubT	TBD	Perkins	DG	Reconductor 2.1 miles 34.5 kV conductor to 336.4	2020-2025	$1.4M	2 MW
Avon to Golah	SubT	B-29	Avon	Golah	10 MW/ 20 MWh battery project at 34.5 kV	2022	$8M	2 MW
Newark to Maplewood Refurb	SubT	F-4	Maple	NRLT	Install a new 34.5 kV cable	2020	$0.7M	3 MW
Raquette Lake	SubT	E-3	Raquette	N/A	Replace the existing (3)-333KVA 46:4.8kV substation transformer with 46/4.8 kV 2.5 MVA pad-mounted transformers	2020-2021	$0.9 M	1.5 MW
Fairdale	SubT	C-2	Fairdale	N/A	Replace 2.5 MVA transformer with new 5 MW transformer	2020-2021	$0.9 M	2.5 MW
Gilbert Mills	SubT	C-2	Gilbert Mills	N/A	Upgrade of transformer bank one (1) from 9.375MVA to a 15/20/25MVA transformer and includes the installation of EMS at the station.	2023-2026	$3M	15.625 MW
West Adams	SubT	E-3	W Adams	N/A	New second transformer bank at West Adams substation	2023-2026	$3.5M	1MW

137 Several projects are also captured in the National Grid rate case as filed on July 31st, 2020.

138 Hosting capacity increases are not typically incremental and should not be added together

Project Name	Violation Type	Zone	Terminal A	Terminal B	Project Description	Est. Proposed I/S Date	OOM Estimate	Incremental Hosting Capacity [138]
Sorrell Hill	SubT	C-2	Sorrell Hill	N/A	Install second 115/13.2kV 15/20/25MVA transformer at Sorrell Hill.	2023-2027	$5M	1MW
Feeder 1562	Distribution	TBD	TBD	TBD	Rebuild portions of Catt. F1562	2020-2025	$1.5M	17MW
Feeder 32451	Distribution	TBD	TBD	TBD	Minor Storm Hardening – 32451	2020-2025	$17M	12MW
Feeders 7765, 7656, 23251, 20653, 7656, 7656, 20653, 7656	Distribution	TBD	TBD	TBD	Middleport F7765 Tie w/Shelby 7656 F23251 Create Ties with 20653&7656 F7656 to relieve F20653 for Cust MSH Upgrade Limited Tie to F7656	2020-2025	$25M	8MW
Feeder 98352	Distribution	TBD	TBD	TBD	State HWY 58 Relocation 98352	2020-2025	$1.7M	8MW
Feeder 37061	Distribution	TBD	TBD	TBD	NR-Hammond 37061-T.I. Transformers	2020-2025	$10.6M	7MW
Feeder 93852	Distribution	TBD	TBD	TBD	Ogdensburg 93852 HWY 37 - Rebuild	2020-2025	$2M	6MW
Feeder 97654	Distribution	TBD	TBD	TBD	97654 Skinnerville Road - Rebuild	2020-2025	$2.1M	6MW
Feeders 7958, 15351, 6161	Distribution	TBD	TBD	TBD	Create Fdr Tie F7958-F15351&F6161	2020-2025	$2.6M	4MW
Feeders 7958, 15351, 6161	Distribution	TBD	TBD	TBD	Create Fdr Tie F7958-F15351&F6161	2020-2025	$4.1M	3MW
Feeders 0456, 0457	Distribution	TBD	TBD	TBD	F0456/0457 Build feeder tie	2020-2025	$12.5M	3MW
Feeder 66954	Distribution	TBD	TBD	TBD	MV-Lehigh 66954 Reconductoring	2020-2025	$1.9M	3MW
Feeder 25456	Distribution	TBD	TBD	TBD	NY14 Fairdale 64 tie with 25456	2020-2025	$3.8M	2MW
Feeder 2861	Distribution	TBD	TBD	TBD	Rebuild portion of E. Otto F2861	2020-2025	$1.2M	2MW
Feeder 26552	Distribution	TBD	TBD	TBD	Burdeck 26552 - Burnett St Conversion Burdeck 26552 - Westcott / Curry Rd	2020-2025	$1.1M	2MW
Feeders 15351, 15352, 15151, 15351, 15151, 15351, 7958, 15351, 6161	Distribution	TBD	TBD	TBD	Create Full Tie F15351 to F15352 Make Ready Fdr Tie F15151-15351 MSH Create Fdr Tie F15151-15351 Create Fdr Tie F7958-F15351&F6161	2020-2025	$9M	1MW
Feeders 89552, 89552, 89552	Distribution	TBD	TBD	TBD	89552 Crooks Road - Rebuild 89552 Dyke Road - Rebuild French Road Relocation 89552	2020-2025	$15.3M	1MW
Feeder 22651	Distribution	TBD	TBD	TBD	Knapp Rd 22651 Feeder Tie	2020-2025	$5.3M	1MW
Feeder 98455	Distribution	TBD	TBD	TBD	Dekalb 98455 Town Line rd - Rebuild	2020-2025	$1.5M	1MW
Feeder 3354, 10451	Distribution	TBD	TBD	TBD	MSH-WOlean 3354 tie 10451 Chipmunk	2020-2025	$2.6M	1MW

Project Name	Violation Type	Zone	Terminal A	Terminal B	Project Description	Est. Proposed I/S Date	OOM Estimate	Incremental Hosting Capacity [138]
New/Emerging Technologies Phase 1	Various	multiple	various	various	Grid Modernization investments filed in rate case and IT rents	2021-2024	$520M	Requires complex analysis[139]

2. Phase 2

Figure 73: Phase 2 Projects

Project Name	Violation Type	Zone	Terminal A	Terminal B	Project Description	Est. Proposed I/S Date	OOM Estimate	Incremental Hosting Capacity [140]
>10 MW in Queue	Substation	multiple	various	N/A	12 stations in National Grid territory currently with over 10MW of DG in queue above the nameplate rating of the bank include 44 South Park, Berry Rd, Brockport, Cattaraugus, East Pulaski, East Watertown, Hudson, Lawrence Ave, Lisbon E. S., North Carthage, Salisbury ES, and W Hamlin.	2025-2030	36M to $180 M depending on scope of upgrades	15 MW to 330 MW depending on the scope for each upgrade
>Nameplate<10MW in queue	Substation	multiple	various	N/A	47 station transformers across all 3 regions where DG in queue is greater than rating but under 10MW: 171 Burt, 51 Elk St, 76 Shawnee, 89 Ransomville, Ashley, Batavia Station, Bennett Rd, Boyntonville, Bremen, Bridgeport, Brunswick, Butts Rd, Delphi, E. Batavia Station, East Otto, Ft. Covington, Hammond, Hudson Falls, Knapp Rd, Langford, Lyme E.S., Moira, Morristown, N. Eden, New Haven, Nicholville, Niles, North Governeur, Ogdensburg, Peterboro, Phoenix, Port Henry, Port Leyden, Randall Rd, Rock City Falls, Schodack, Sharon, Shelby, Sherman WRCC, South Wellsville, St Johnsonville, Starr Rd, Stittville, Thousand Islands, W Albion, Whitehall, and York Ctr	2025-2030	$141 M to $705 M depending on scope of upgrades	59 MW to 1292 MW depending on the scope for each upgrade
3V0 and LTC upgrades Phase 2	Substation	multiple	various	N/A	Additional 3V0/LTC upgrades	2025-2030	$63.5 M	498 MW
Sub Transmission Thermal Violations Phase 2	SubT	multiple	various	various	23 bank upgrades, 29 build new ties, 3 new stations, 16 reconductor,	2025-2030	$211 M	124 MW

139 Does not include foundational investments such as feeder sensors, substation SCADA, AMI etc.

140 Hosting capacity increases are not typically incremental and should not be added together.

Project Name	Violation Type	Zone	Terminal A	Terminal B	Project Description	Est. Proposed I/S Date	OOM Estimate	Incremental Hosting Capacity [140]
Sub Transmission Voltage Violations Phase 2	SubT	multiple	various	various	Regulator and capacitor bank installations	2025-2030	$26.7 M	Requires complex analysis
Distribution Phase 2	Distribution	multiple	various	various	119 feeder violations with no solution already in CIP	2025-2030	$106 M	456 MW
New/Emerging Technologies Phase 2	Various	multiple	various	various	Additional Grid Modernization investments	2025-2030	TBD	TBD

iv) Key Assumptions

Several key assumptions were made to conduct the study as listed below:

1. *Global:*

- All costs are capex only
- No consideration of CLCPA targets beyond 2030
- In alignment with the local transmission study, did not account for NYSERDA reports
- Studies did not explicitly model Grid Modernization investments other than for Distribution Feeder analysis
- No modeling of time-of-use (TOU)/time-variable pricing (TVP) impacts on load via advanced metering infrastructure (AMI)
- No inclusion of DR or standalone energy storage i.e. does not meet associated CLCPA goals but are considered as solutions rather than problems generating technologies/programs
- No beneficial electrification is heat modeled

2. *Scenario 1*

- 1317 MW of solar plus some storage combined less than 5 MW individually

3. *Scenario 2*

- 3036 MW of solar plus some storage combined less than 5 MW individually

4. *Scenario 3*

- Only 1 scenario (peak load and high solar) studied based on worst case TPAM sensitivities
- 1925 MW of behind the meter[141] solar, other DER is netted with load

[141] NYISO defines behind the meter solar as projects that are not bidding into the NYISO wholesale market.

5. Scenario 4

- 440 MW Connected solar PV
- 446 MW of incremental Rooftop solar PV
- 547 MW of incremental Non-Roof Top Solar PV
- 641 MW of incremental Solar & some storage
- 1014 MW of incremental EV
- 566 MW of incremental EE
- Solar PV is spread based on available hosting capacity

6. Distribution Feeder Analysis:

- Minimum load is not factored into analysis due to the conservative approach taken in this analysis
- Phase 2 solutions do not consider include feeder conductor upgrades but are based on linearized $/kW hosting capacity costs accounting for recloser settings changes, bi-directional voltage regulators, fixed to switched capacitor banks, smart inverters and energy storage
- Average Max-Min hosting capacity values with some weighting was applied and not the more recent nodal hosting capacity analysis
- Combination of four variables drive the violations identified including thermal, voltage, protection, and short circuit
- Available hosting capacity limits are based on 2020 hosting capacity result values
- Released incremental hosting capacity is based on size of violation and not actual MVA of solution
- CIP projects are assumed to completely solve the hosting capacity violation

7. Substation Transformers & 3V0 + LTC Analysis:

- Minimum load is not factored into analysis due to the conservative approach taken in this analysis
- Accounts for new proposed transformers that would be built with 3V0 and LTC as part of the Company's standard design
- Does not include DTT upgrades
- Does not account for any dual banks where only one combined 3V0 scheme would be deployed

8. Sub-Transmission Analysis:

- Day time minimum load modeled for scenario 1 & 2
- Modeled NYISO Sub-Transmission connected generation and queue generation from the September 2020 NYISO queue
- Sub-Transmission loads scaled to match NYISO scenario 3 case
- Peak and minimum load cases applied for scenario 4

- Investments do not include solutions to several extreme low voltages identified due to complexity of the contingencies and the associated solutions that require more time to evaluate
- Released incremental hosting capacity is based on size of violation and not actual MVA of solution for Phase 2 projects only

9. New /Emerging Technologies:

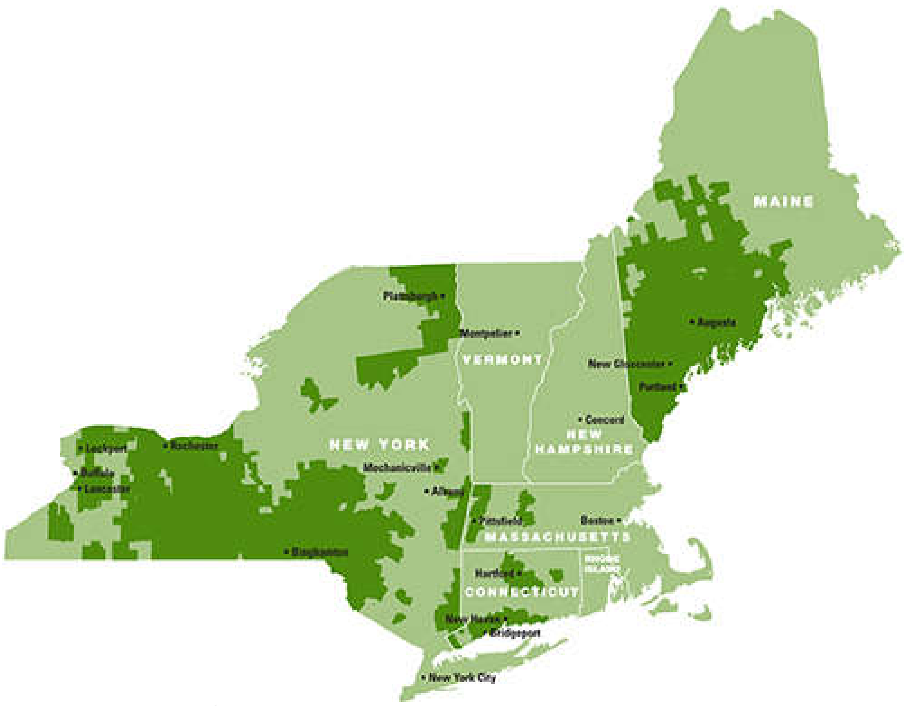
- Other than distribution feeder upgrades that capture smart inverters and energy storage in the analysis, no other new/emerging technologies were factored in the analysis and as such could offset some of the traditional wire-based upgrades proposed.
- In accordance with National Grid's planning criteria, NWAs would be considered to solve violations.

VI. NYSEG AND RG&E

A. Transmission

AVANGRID has assets and operations in several U.S. states and has two primary lines of business including its Networks and Renewables companies. The AVANGRID Networks business is shown in Figure 74 below and includes eight electric and natural gas utilities, serving 3.2 million customers in New York (i.e. NYSEG and RG&E) and New England. The AVANGRID Renewables business owns and operates 7.1 gigawatts of electricity capacity, primarily through wind power, with a presence in 22 states across the United States.

Figure 74: AVANGRID Networks (Electric + Gas) Service Territories

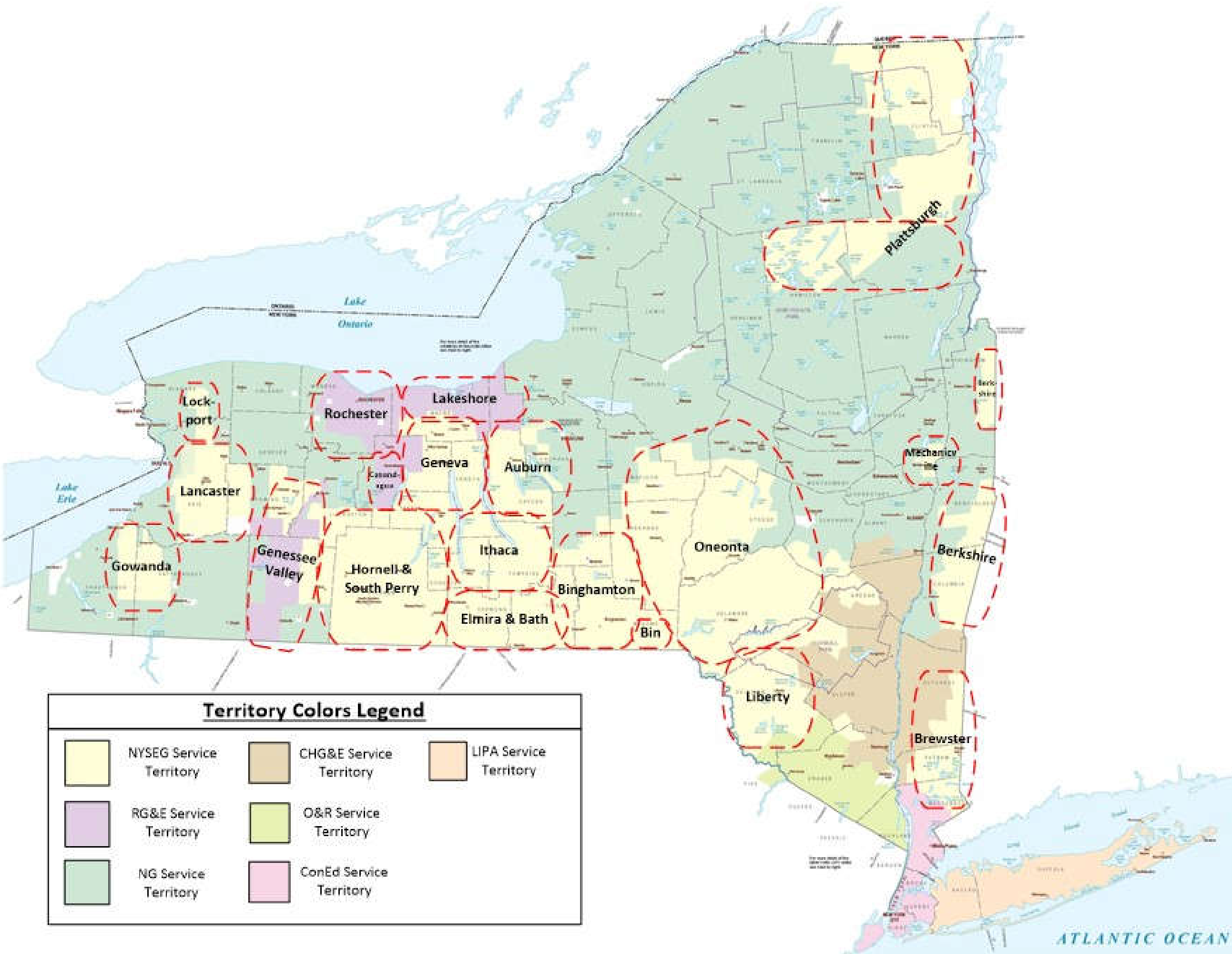


In New York, NYSEG serves approximately 900,000 electricity customers. RG&E serves approximately 380,000 customers, primarily within the city of Rochester and the adjacent municipalities.

The NYSEG and RG&E's transmission systems are predominantly networked and operate at a range of voltage levels including 345, 230, 115, 46, 34.5, and some 11.5 kilovolts (kV) facilities. However, according to the scope in the Commission Order, this study will focus more on "Local" system which include transmission facilities with the operating voltage less than 200 kV. AVANGRID's transmission facilities operating above 200kV are considered to be part of NY's "Bulk transmission system" which will be analyzed by other studies. In addition, AVANGRID makes a further distinction on its Local transmission system and refers to facilities operating below 100kV, and also serving as interconnections between load serving and or switching substations, as Sub-Transmission facilities.

Figure 75 show the service territories of the NYSEG and RGE operating companies and the sub-areas that were referenced in this study. Furthermore, in this Report, "AVANGRID" represents AVANGRID's electric service territories in New York (i.e. NYSEG and RGE).

Figure 75: AVANGRID NYSEG and RG&E Territory



i) Discussion of AVANGRID Study Assumptions, Methodologies, and Description of Local Design Criteria

The NY Utility T&D Technical Subgroup, referred to as the "working group" throughout this document, agreed that each utility would be permitted to make appropriate changes to the NYISO provided cases to create system conditions judged to be most suitable to their local systems. In addition, each utility developed and applied its own unique methodology for estimating the existing available headroom (available capacity in MW's) and existing bottlenecks (limiting elements or facilities) for the Utility Study. For AVANGRID, a number of modifications were made to the starting base cases and methodologies. These changes are broken down into five categories as described in more detail in this section:

1. *Study Scenarios*

Consistent with the scope of work jointly developed by the working group, the results in this Report are driven from two basic scenarios including "Business as Usual" and "70/30" which are described in more detail below:

Business as Usual (BAU): This scenario represents the conditions where only resources that meet the New York Independent System Operator (NYISO) "inclusion rules" were modeled in the study. These are resources and facilities that have shown significant developmental progress. Consequently, only a limited number of renewable resources have met these criteria and thus have been included in this scenario. As such, their limited combined output was recognized to be less than the renewable resource requirements needed to meet the full CLCPA goals. Two base cases, 2030 peak and 2025 off-peak, were studied to determine the existing capacity headroom on the local system. These study cases did not include any future planned AVANGRID transmission or substation projects where the projected in-service dates are beyond 5 years. The excluded projects may be considered for advancement later if determined to be beneficial to accommodate the renewable goals.

70/30: This scenario models a portfolio of renewable resources that can produce enough energy to meet the State's 70/30 goal. The type, size, and location of these resources were developed from the NYISO 2019 Congestion Assessment and Resource Integration Study (CARIS). The NYISO provided six (6) base cases with these resources that were developed as part of its 2020 Reliability Needs Assessment (RNA) for use by the working group. After reviewing these cases the working group selected three (3) representative cases as the starting point for the 70/30 scenario studies. These are cases 1, 3, and 6 that represent Peak, Light, and Shoulder load conditions with varying renewable dispatches and a summary of these cases is shown in the figure below. Additionally, the NYISO provided zonal hourly resource output data including for Land-Based Wind (LBW), Off-Shore Wind (OSW), and Utility-Scale Photovoltaic (UPV) as used in its CARIS study. This information is referred to as the "hourly profiles".

Figure 76: Starting Points 70/30 Scenario Base Cases

NYISO RNA Case #	Case Load	Net Load including BTM[142] solar reductions (MW)	LBW Output (% of Pmax)	OSW Output (% of Pmax)	UPV Output (% of Pmax)
1	Day Peak Load	30,000	10%	20%	45%
3	Light Load	12,500	15%	45%	0%
6	Shoulder Load	21,500	15%	45%	40%

2. *Base Case Development*

A summary of major modifications that were made to the starting NYISO base cases to facilitate the scope of this study is described below:

Planned Transmission Upgrades ("Firm"): The initial base cases included all NYISO designated "firm" projects. However, AVANGRID has elected to remove those outside the five (5) year horizon (year 2025) since they have less certainly.

DER: Existing DER is usually modeled as a reduction in forecasted load in study models. Where appropriate, AVANGRID modeled explicitly large resources using information from the "SIR Inventory Information" (or distribution DER queue). The outputs of these resources were considered fixed and therefore not adjusted during any study scenarios unless otherwise stated.

Electrical Location of Renewable Resource: The 2019 NYISO CARIS study modeled the additional resources needed to meet the 70/30 goals at voltages 115 kV or higher (Bulk Electric System – BES) regardless of their specific point of interconnection on the local system. AVANGRID made efforts to use available locational data to more accurately model the electrical location of the CARIS resources and then subsequently model them at the nearest appropriate sub-transmission stations (e.g. 34.5kV system).

Fossil Generation Identifications: As specified in the Commission order, to identify options and impacts of past and future fossil generation retirements, the study identified the locations of the remaining active and the recently retired fossil generation in AVANGRID's New York service areas. It also estimated the potential future use capacity of these locations such that they may be re-used for new renewable interconnections. Public information regarding retired fossil units in the past 7 years is shown in the figure below.

[142] BTM = Behind-The-Meter resources

Figure 77: Fossil Retirements – Possible Interconnection Options

Generator	Zone	Status	Unit Type[143]	Fuel Type[144]	Approximate Summer Capability (MW)
Somerset*	A	Retired	ST	BIT	676.4
Monroe Livingston	B	Retired	IC	MTE	2.4
Cayuga I & II	C	Retired	ST	BIT	309
Steuben County LF	C	Retired	IC	MTE	3.2
Auburn - State St.	C	Retired	GT	NG	5.8
Binghamton Cogen	C	Retired	CoGen	-	43.8

* Note: The Somerset unit was modeled off-line throughout this analysis since it is connected to the Bulk System and therefore considered outside this scope of this study.

Resource Addition and Dispatches: Figure 78, below provides a breakdown of additional renewable resources to meet the 70/30 goals based on information provided in the 2019 NYISO CARIS study. This CARIS study allocated approximately 6.8 GW of total capacity within AVANGRID's footprint. In addition to what is shown in the figure below, approximately 7,500 MW of behind-the-meter PV resources was accounted for in the study as a reduction in load and not modeled as discrete generators. The renewables in Figure 78 were modeled in the base cases as generation resources. In addition, Figure 78 shows a comparison of AVANGRID's proportion of New York load and projected renewable capacity.

[143] ST = Steam Turbine, IC = Internal Combustion, GT = Gas Turbine, CoGen = Cogeneration

[144] BIT = Bituminous Coal, MTE = Methane (Bio Gas), NG =Natural Gas

Figure 78: Zonal Load and Renewable Capacity Allocation

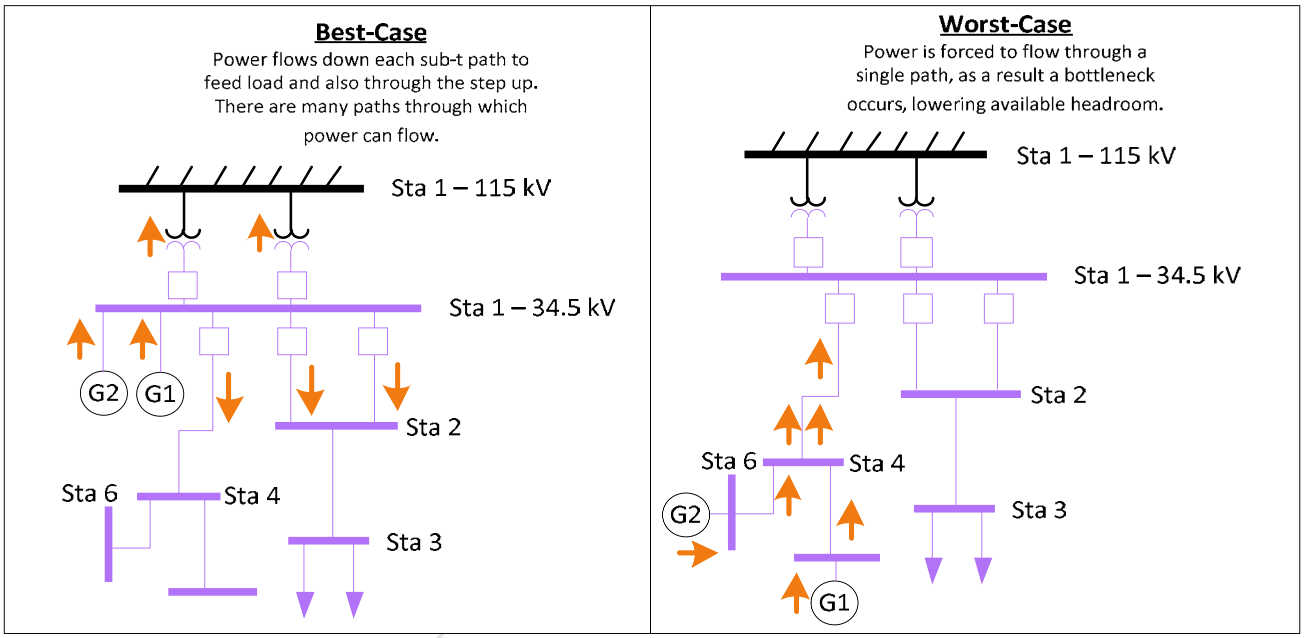
NYISO Zone	New York Renewable Capacity (2019 CARIS)			NY/AVANGRID Renewable Allocation			NY/AVANGRID Load Share		
	OSW (MW)	LBW (MW)	UPV (MW)	NY Total (MW)	AG Total (MW)	% AG	NY Total (MW)	AG Total (MW)	% AG
A		2,286	4,432	6,718	2,288	34%	2,290	572	25%
B		314	505	819	387	47%	1,780	1,467	82%
C		2,411	2,765	5,176	3,131	60%	2,411	1,196	50%
D		1,762		1,762	0	0%	675	55	8%
E		2,000	1,747	3,747	818	22%	928	280	30%
F			3,592	3,592	244	7%	1,839	101	6%
G			2,032	2,032	0	0%	1,639	16	1%
H							599	340	57%
I							1,382	0	0%
J	4,320			4,320	0	0%	11,362	0	0%
K	1,778		77	1,855	0	0%	4,245	0	0%
Totals	6,098	8,773	15,150	30,021	6,868	**23%**	29,150	4,028	**14%**

In order to study the impacts from high renewable output, the output from LBW and UPV resources in upstate area were increased and non-renewable resources were decreased until a bulk constraint was reached. The AVANGRID local system was then analyzed to determine local bottlenecks and constraints that will limit renewable energy from reaching the bulk system. In addition, in order to ensure these renewable output figures are realistic, these dispatches for LBW and UPV resources were compared against the hourly profiles from the 2019 NYISO CARIS study to make sure they are reasonable. This dispatching approach was developed in coordination with AVANGRID's neighboring utilities and included the following three renewable dispatch considerations beyond the starting base cases (i.e. Moderate LBW + Moderate UPV, High LBW, High UPV).

3. Capacity Headroom Analysis

The capacity headroom analysis determines the amount of additional renewable generation in MWs that can be injected into the existing system without exceeding system limit(s). It should be noted that since there is no consistent definition or methodology available for the calculation of "headroom", AVANGRID developed and utilized an approach that it considers sufficiently accurate to meet the objective of the Utility study. Since the amount of headroom can vary by many factors, especially the assumptions of the Point of Interconnection (proxy location(s) selected[145]), and number of proxy location(s) selected, AVANGRID provided the values of the existing capacity in a MW range rather than a specific value. In general, the closer the proxy location(s) are to the BES system, the more likely the resource can (1) serve local load as well as (2) export excess energy; whereas resources farthest from the BES will most likely be limited by smaller distribution and sub-transmission lines before reaching the BES. Figure 79 shows how the estimated capacity headroom can vary based on the proxy location(s) selected.

Figure 79: Example: Sub-Transmission Injection Points



The methodology to estimate existing capacity headroom includes a number of analytic steps summarized at a high level as follows:

1. Addition of new renewable resources at varying locations (POI).
2. Dispatch new resources upwards until a new system limit(s) is reached (e.g. thermal overload).
3. The existing capacity headroom is estimated to be equal to the total increased output in MWs prior to reaching the new system limit(s).
4. Repeat the process under different placement or injection point scenarios if exact locations are not defined.

In addition, it was found that system topology, flow patterns, type of resources, and the directions from the Commission order also impact the headroom analysis. These contributing

[145] Due to the size of the system. there are large number of potential Point of Interconnection (POI) in the system. Avangrid determined the Headroom based on a selected set of POIs. These include the locations that should yield the highest (best-Case) and lowest headroom (Worst-Case) in each study scenario.

factors are summarized below. These contributors could impact both the sub-transmission system and the BES facilities as the results from the study will be provided in Section (ii).

Sub-Transmission (non-BES) Load Pockets: It was important to begin the analysis by defining load pockets based on the system topology particularly at voltages level below 115 kV. These "Load Pockets" are defined as areas that predominantly serve local loads without significantly affecting the regional Bulk System's reliability or power transfers. Accordingly, the study defined a Load Pocket as portion of a sub-transmission network surrounded by step-up transformer(s) interconnecting the sub-transmission system to the BES. The existing capacity headroom on the sub-transmission system are summarized by AVANGRID divisions.

DER Resources: For locations where AVANGRID determined substantial DERs have been interconnected or there are significant DER interconnection requests in the local distribution list queue (DPS SIR Inventory List), the headroom was computed. For this Headroom analysis, all DER interconnections of 1 MW or larger in AVANGRID's service territory were treated as a set of generation injection points. The results are discussed in Section (ii).

Local NYISO Renewable Queue (already in Generation Queue): This analysis also incorporated known local proposed transmission-connected renewable resources (voltage level at the POI less than 200 kV) based on the NYISO's interconnection queue. The results are discussed in Section (ii).

Existing and Retired Fossil Fuel Locations: The headroom methodology was also used to understand how much renewable resources can be interconnected at the POI of already retired fossil units as well as existing fossil units' locations. This analysis includes an assessment of fossil generation retirements along with the potential to repurpose these interconnection points for new renewable generation in an effort to limit renewable interconnection costs. The results are discussed in Section (vi).

4. *Bottleneck Analysis Methodology*

This analysis determined where there were constraints or "bottlenecks" (i.e. Needs) on the existing system under simulated high renewable dispatches that would limit renewable energy deliverability under normal and contingency conditions. Each identified bottleneck or constraint was then analyzed to determine the main drivers contributing to the limitation.

5. *Analysis Criteria*

This study utilized criteria based on a subset of AVANGRID's Local Planning Criteria as deemed relevant to the intent of this study. Generally, this study included N-0 and N-1 analysis. AVANGRID analysis assumed that BES renewables (UPV and LBW) can be curtailed in-between contingencies to eliminate overloads, if needed. Therefore, detailed N-1-1 analysis as required by NERC, NPCC, and NYSRC AVANGRID local criteria were not considered. Also, most of the emphasis of the assessment was on thermal needs and any voltage, short circuit, and stability needs will be addressed in the individual generator interconnection study. However, if the analysis determined that a voltage problem (i.e. voltage collapse) could significantly limit renewable energy delivery, the identified needs are addressed as part of the solution development in Section (iv).

ii) Discussion of Existing Capacity "Headroom" within AVANGRID 's System

As discussed in Section (i)), the existing capacity headroom was determined for the sub-transmission system (non-BES) which includes areas of active renewable interest on the local system (DER) as well as the BES systems. In general, the higher the headroom in a given location the more renewables that will be able to connect in that area without requiring significant system upgrades due to thermal constraints. The existing capacity headroom results were presented by NYSEG & RGE divisions and the geographic locations of these divisions are shown in Figure 75 for reference.

The figure below summarizes the existing capacity headroom determined on the sub-transmission system that has strong interactions with the DERs. In addition, an overview of the average existing headroom on the sub-transmission network per injection point in AVANGRID service area is shown in Figure 82.

Figure 80: Headroom for "Non-BES" System

Division	Headroom Range* (MW)		Approx. # of Injection Points**
	Low	High	
Auburn	59	163	4
Berkshire & Mechanicville	129	431	10
Binghamton	179	715	13
Brewster	70	408	6
Elmira & Bath	138	557	9
Genesee Valley	34	77	3
Geneva	146	514	9
Gowanda	17	28	1
Hornell & South Perry	16	978	11
Ithaca	163	428	13
Lakeshore	5	29	4
Lancaster	149	827	14
Liberty	101	255	8
Lockport	46	76	2
Oneonta	62	523	14
Plattsburgh	137	307	14
Rochester & Canandaigua	576	2078	44

Notes:
*The headroom range is provided to show variation in results due to number of injection points, location of injection points and the load level.
** The number of injection points show the maximum number of locations studied for each division which includes known interconnection points and methodology to selecting additional points; the existing capacity headroom is likely to fall between the provided ranges if the number of injection points are met.

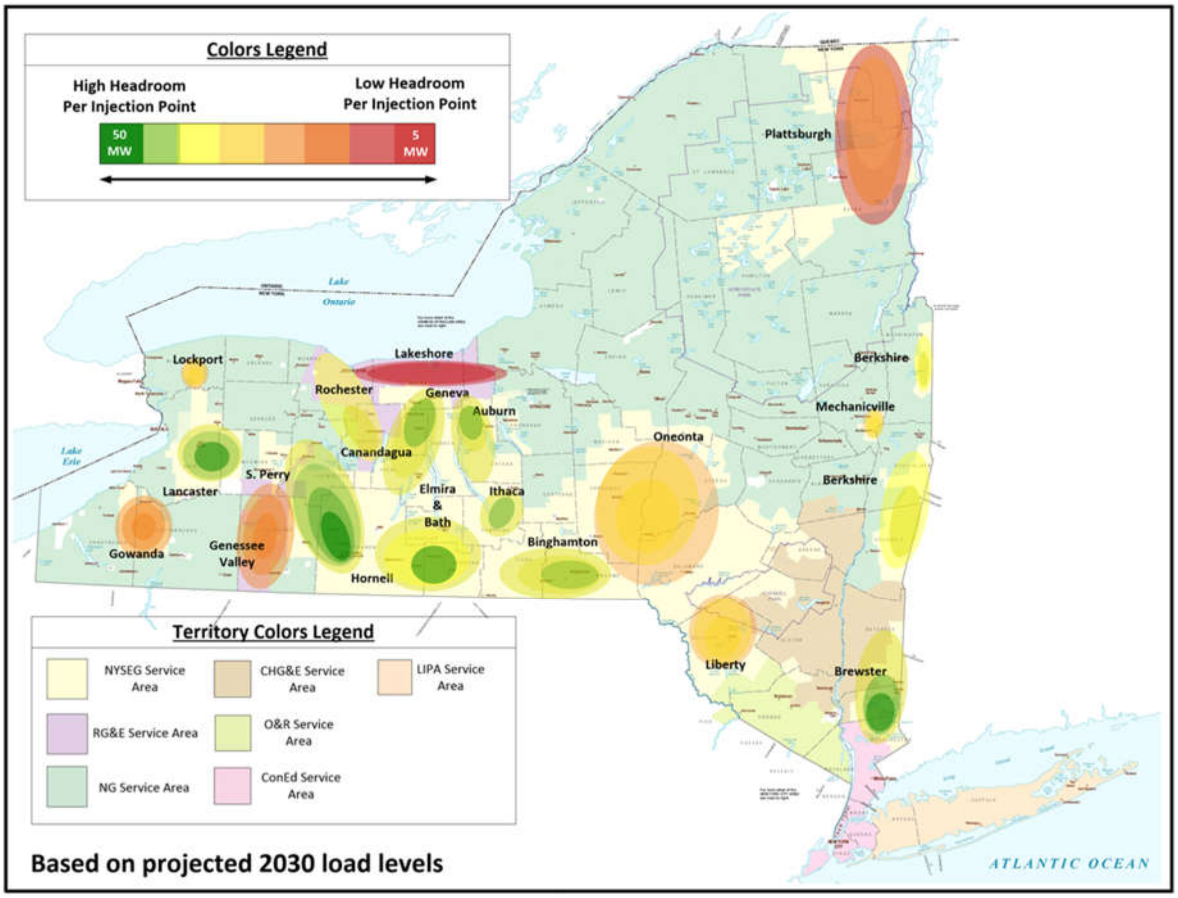
The figure below summarizes the existing capacity headroom on the local BES system that are primarily impacted by Local NYISO Renewable Queue locations.

Figure 81: Headroom for "BES" System (less than 200 kV points)

Division	Headroom Range [1] (MW)		Approx. # of Injection Points[2]
	Low	High	
Auburn	63	66	2
Berkshire & Mechanicville	263	268	1
Binghamton	159	217	4
Brewster	65	78	1
Elmira & Bath	0	41	1
Genesee Valley	8	20	1
Geneva	266	271	3
Gowanda[3]	N/A	N/A	N/A
Hornell & South Perry	263	448	4
Ithaca	178	194	1
Lakeshore[3]	N/A	N/A	N/A
Lancaster	541	560	4
Liberty[3]	N/A	N/A	N/A
Lockport[3]	N/A	N/A	N/A
Oneonta[3]	N/A	N/A	N/A
Plattsburgh	41	42	4
Rochester & Canandaigua	287	289	4

Notes:
1) The headroom range is provided to show variation in results due load level only (the number of injection points and the location of injection points were defined using NYISO Interconnection queue).
2) Number of injection points less than 200 kV in the NYISO Queue at the time of the study.
3) Divisions without known NYISO renewable queue points at the time of the study.

Figure 82: Approximated Sub-Transmission Headroom Per Injection Point in NYSEG/RGE Divisions



iii) Discussion of Bottlenecks or Constraints that Limit Energy Deliverability within AVANGRID's System

This study identified the "bottlenecks" or constraints (i.e. Needs) limiting renewable energy integration across AVANGRID service territory. These bottlenecks include issues found on both the BES and Sub-Transmission facilities. The common driver for these bottlenecks is the output from the assumed renewable resource simulations to meet NY's goals.

Details about each bottleneck are also summarized in the figure below including the location, type, constraint driver and its severity. The violation type refers to whether this is a normal (or pre-contingency, N-0) or post-contingency (N-1) violation. The Main Driver column provides a high-level indicator of which key factor is causing the congestion issue. The last column, Severity (%), provides the degree of the severity for each bottleneck. For N-0 or normal conditions the overload is presented in terms of the elements Normal MVA rating while for N-1 conditions it is appropriately based on the LTE MVA rating.

Figure 83: AVANGRID Local System - Summary of Needs (Bottlenecks)

NYISO Zone	Division	Terminal A	Terminal B	Violation Type	Main Driver	Severity (%)
A	Lockport (LK)	Robinson Rd 230	Robinson Rd 115	N-1	Forecasted UPV	>140
A	Lockport	Robinson Rd 115	Hinman 115	N-1	Forecasted UPV	>200
A	Lockport	Hinman 34.5	Vine 34.5	N-1	Forecasted UPV	>140
A	Lancaster (LN)	Stolle 345	Stolle 115	N-1	Forecasted UPV	>110
A	Lancaster	Stolle 115	Stolle 34.5	N-1	Forecasted UPV	>120
A	Lancaster	Stolle 115	Gardenville 115	N-0, N-1	Forecasted UPV	>140
A	Lancaster	Stolle 115	Erie 115	N-1	Forecasted UPV	>140
A	Lancaster	Pavement 34.5	Cemetery Rd 34.5	N-1	Forecasted UPV	>120
A	Lancaster	Alpine 34.5	Cobble Hill 34.5	N-1	DER	>140
B	Rochester (ROC)	S082 115	Highbanks 115	N-0, N-1	Forecasted LBW	>140
B	Genesee Valley (GV)	Highbanks 115	South Perry 115	N-0, N-1	Forecasted LBW	>140
B	Genesee Valley	Highbanks 115	Highbanks 115	N-0, N-1	DER	>200
B	Genesee Valley	Highbanks 115	Highbanks 115	N-0, N-1	DER	>170
B	Genesee Valley	Highbanks 115	S8373 34.5	N-0, N-1	DER	>170
C	South Perry (SP)	South Perry 115	Meyer 115	N-1	Forecasted LBW and UPV	>200
C	Hornell (HO)	Bennett 115	Palimiter 115 (to NG Homer)	N-0, N-1	Forecasted LBW and UPV	>110
C	Hornell	Bennett 115	Howard/Spencer Hill 115	N-0, N-1	Forecasted LBW and UPV	>200
C	Hornell	Bath 115	Howard/Spencer Hill 115	N-0, N-1	Forecasted LBW and UPV	>200
C	Hornell	Bennett 115	Moraine 115	N-0, N-1	Forecasted LBW and UPV	>200
C	Hornell	Meyer 115	Moraine 115	N-0, N-1	Forecasted LBW and UPV	>200
C	Hornell	Meyer 115	Eelpot 115	N-0, N-1	Forecasted LBW and UPV	>200
C	Hornell	Flat St 115	Eelpot 115	N-0, N-1	Forecasted LBW and UPV	>200
C	Hornell	Flat St 115	Greenidge 115	N-0, N-1	Forecasted LBW and UPV	>200
C	Hornell	Avoca 230	Stoney Ridge 230	N-1	Forecasted LBW and UPV	>100
C	Hornell	Bennett 34.5	Marsh Hill 34.5	N-1	DER	>140
C	Hornell	Troupsburg 34.5	Marsh Hill 34.5	N-1	DER	>110
C	Elmira/Bath (EB)	Bath 115	Montour Falls 115	N-0, N-1	Forecasted LBW	>110
C	Elmira/Bath	Montour Falls 115	Hillside 115	N-1	Forecasted LBW	>120
C	Elmira/Bath	Hickling 115	West Erie 115	N-1	Forecasted LBW	>120
C	Elmira/Bath	Canada Tap	Polly-O 34.5	N-1	Flow through	>120
C	Geneva (GN)	Flat St 115	Greenidge 115	N-0, N-1	Forecasted LBW	>140

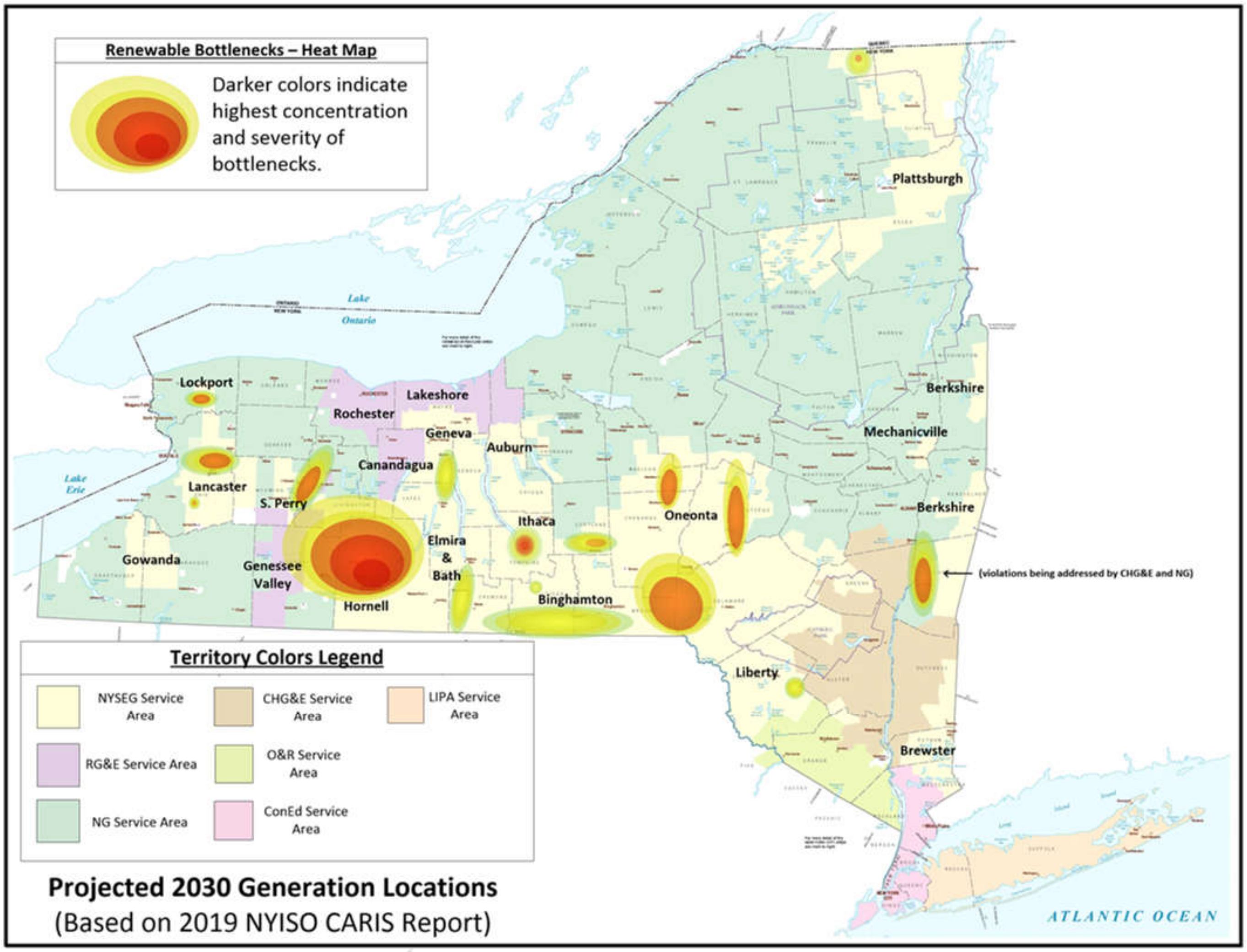
NYISO Zone	Division	Terminal A	Terminal B	Violation Type	Main Driver	Severity (%)
C	Geneva	Border City 115	Hyatt Rd (to NG Elbridge) 115	N-0, N-1	Forecasted UPV	>120
C	Geneva	Border City 115	Guardian 115	N-1	Forecasted UPV	>110
C	Geneva	Border City 115	Farmington115	N-1	Forecasted UPV	>110
C	Geneva	Border City 115	Border City 34.5	N-1	Forecasted UPV	>110
C	Geneva	Border City 115	Border City 34.5	N-1	Forecasted UPV	>110
C	Geneva	Border City 34.5	Oak Corners 34.5	N-1	Forecasted UPV	>170
C	Binghamton (BG)	Oakdale 230/115		N-1	Flow through	>100
C	Binghamton	Hillside 115	South Owego 115	N-1	Flow through	>140
C	Binghamton	Goudey 115 / Oakdale 115	South Owego 115	N-1	Flow through	>120
C	Binghamton	Willet 115	Willet 34.5	N-1	DER + Forecasted UPV	>140
C	Ithaca (IT)	Etna		N-1	Flow through	Voltage Collapse
C	Ithaca	Coddington		N-1	Flow through	Voltage Collapse
C	Ithaca	Etna 115	Willet 115	N-1	Flow through	>170
C	Ithaca	Montour Falls 115	Coddington 115	N-1	Flow through	>140
C	Ithaca	Candor 115	Candor 34.5	N-0, N-1	DER	>120
C	Auburn	Hyatt Rd 34.5	State St 34.5	N-1	Forecasted UPV	>120
C	Auburn	Hyatt Rd 34.5	Seneca Falls 34.5	N-1	Forecasted UPV	>140
D	Plattsburg (PL)	Chateaugay 115	Chateaugay 34.5	N-0, N-1	Forecasted UPV	>200
E	Oneonta (ON)	Jennison		N-1	Flow through	Voltage Collapse
E	Oneonta	East Norwich		N-1	Flow through	Voltage Collapse
E	Oneonta	Colliers		N-1	Flow through	Voltage Collapse
E	Oneonta	East Norwich 115	Jennison 115	N-0, N-1	Forecasted LBW	>170
E	Oneonta	Fraser 115	Jennison 115	N-0, N-1	Forecasted LBW	>200
E	Oneonta	Oakdale 115	Jennison 115	N-0, N-1	Forecasted LBW	>140
E	Oneonta	Stilesville 115	Jennison 115	N-0, N-1	Forecasted LBW	>170
E	Oneonta	Richfield Springs 115	East Springfield 115	N-0, N-1	Forecasted UPV	>120
E	Oneonta	Richfield Springs 115	Colliers 115	N-0, N-1	Forecasted UPV	>120
E	Oneonta	East Norwich 115	Brothertown Rd 115	N-1	Forecasted LBW	Voltage Collapse
E	Oneonta	East Norwich 115	Willet 115	N-1	Forecasted LBW	>170
E/G	Liberty (LI)	West Woodbourne 115	West Woodbourne 69	N-0, N-1	Flow through	>110

Below are some key observations from the study results shown in the figure below:

1. The output from local renewable resources (DER and Utility-Scale) and flow through are two key drivers causing congestion. Consequently, when designing the upgrades, potential impacts from renewable development in the neighboring areas must also be considered.
2. A number of local transmission facilities in AVANGRID's service area have strong interactions with the bulk system. For this reason, it is important that a comprehensive approach considering a larger area is sometimes appropriate rather than narrowly focusing only on areas in the immediate vicinity of the bottleneck. An example would be the Hornell and Ithaca area bottlenecks which also have strong interactions with the 230 kV corridor; in this case a comprehensive solution approach was used.
3. The study results show multiple facilities can experience severe overloads, particularly under contingency conditions. In some cases, these overloads would even exceed the facility's STE ratings meaning that pre-contingency actions such as curtailment would be necessary to prevent such a severe condition.

Figure 84 shows a summary heat map of the renewable bottlenecks across the AVANGRID service territory under this study's projected renewable generation levels. These are also the general locations where mitigating solutions are needed to avoid renewable generation curtailment that could impact the states renewable goals.

Figure 84: Bottleneck Heat Map - AVANGRID Service Areas



iv) Discussion of Potential Projects that would Address Bottlenecks or Constraints that limit Energy Deliverability within AVANGRID 's System

This section describes the upgrades (or solutions) that have been developed to address the bottlenecks (or needs) identified and summarized in section (iii). For each bottleneck, AVANGRID evaluated multiple alternatives to alleviate the congestion and then selected one as the likely "preferred alternative" in consideration of the order of magnitude estimate accuracy available on some projects along with other factors including the state's desire to implement storage and other new technologies.

Following are some of the key factors considered when evaluating alternatives:

1. Synergies: There are a number of existing projects in AVANGRID's long term plan that are driven by either reliability (e.g. Bulk Electric System studies) or asset condition (e.g.

deterioration, obsolescence, etc.) needs that are also beneficial to renewable resource integration goals either in their current form or with some incremental modifications. In many cases this study found that existing proposed projects alone can provide significant renewable integration benefits, but these can be even further enhanced with incremental upgrades. These multi-value projects that address a range of conventional reliability and asset condition needs while also serving to enable renewable resources are often the lowest overall cost when compared to addressing each need and benefit individually. This study makes a general distinction between the project types using the terms Phase 1 and Phase 1+ to indicate synergies with existing or existing expanded projects respectively while Phase 2 projects are those that only serves to provide a CLCPA benefit. Following is a summary of the definitions and identifiers used in this study:

- Phase 1 (X): Existing projects already in AVANGRID's capital plan (driven from Reliability or Asset Condition based needs).
- Phase 1+ (Y): Incremental upgrades to existing planned projects in order to achieve an enhanced renewable resource integration benefit.
- Phase 2 (Z): New upgrades that serve only to provide renewable resource integration benefits (i.e. does not address conventional Reliability or Asset condition needs).

2. Cost: In general, the lowest cost alternative addressing all needs (e.g. reliability, asset condition, CLCPA, etc.) is preferred, however, consideration is also given to the states goals to enable increased levels of storage solutions onto the system. It should be noted that the cost estimates in this study should generally be considered to be at an Order of Magnitude accuracy level since some are based on limited desktop engineering analysis without the benefit of site specific assessments. As such, there may be situations where the estimate accuracy ranges of competing alternatives overlap making a future estimate refinement likely necessary to confirm the low cost alternative.

3. Project In-Service Date: This study provides the estimated in-service dates (ISD) for each project as an indication of how fast each of the projects could be executed once authorized. It should be noted that these ISD's assume the projects can proceed without delay and begin in early 2021. In addition, the schedule also makes the important assumption that Article VII and other permitting processes do not take any longer than one year from the filing date.

4. Renewable Benefit ($/MW): A preliminary indicator of the value of each project is to compare the ratio of the project cost to the system MW capacity benefit provided in terms of a $/MW ratio with lower values indicating more favorable projects. The capacity (MW) benefit is measured by comparing the maximum output of renewable resources the system can accommodate, before and after the upgrade is constructed. This is accomplished by first determining the amount of renewable capacity in the existing system (pre-project) by increasing the renewable resource outputs in the vicinity

of the upgrades. The maximum capacity is determined when the first transmission limit is reached. Next the proposed project is added, and the prior steps are repeated. The difference between the two numbers is the renewable benefit or MW capacity gained with the proposed upgrade.

5. Consideration of New and Emerging Technologies: While there are no clear definitions as to what is considered a new technology, AVANGRID considered the potential utilization of Storage, flow control technologies, and dynamic line ratings as potential solutions to mitigate some bottlenecks. AVANGRID received guidance from the Utility T&D Advance Technology Subgroup and subject matter experts in determining which technologies could be classified as "new and emerging technologies" and also which could be practically implemented. In this study, AVANGRID considered the following three groups of technologies as candidates based on their effectiveness to mitigate the overload and their technological maturity.

    - Energy Storage (ES): In general, storage technology was considered to address bottlenecks requiring significant transmission capacity increases largely to accommodate the intermittent nature of the renewable resources (i.e. overloads that occur a couple of hours per day).
    - Power Flow Control Devices: Power flow control devices can be beneficial by providing a means of controlling and diverting power flows away from constrained areas toward areas with more available capacity.
    - Dynamic Line Ratings (DLR): DLRs may be considered in cases where overloads are marginal and primarily driven by wind resources in an area. This technology provides a means of adjusting facilities ratings based on real time ambient conditions, however, since there was insufficient available information to demonstrate this technologies maturity and practical effectiveness it was not recommended to address any bottlenecks in this study.

Figure 85 summarizes the solution alternatives considered in this study to mitigate all identified bottlenecks. Figure 85 describes a summary of the project attributes including the Project Type (or Phase), Order of Magnitude cost (OOM cost in $M), ISD, Estimated Project Benefit (MW), and an estimate of the Benefit ($M/MW) achieved. In addition, a Preferred solution was selected although it is currently classified as "likely" since it is based on order of magnitude level estimate comparisons which may require further refinements prior to a final determination. Also, considerations beyond cost may influence the final decision for reasons including a desire to pilot new technologies and or non-wire alternatives (e.g. storage, etc.). It should be noted that there are some cases where a reduced project scope could be implemented at a lower cost to reduce the congestion, although it would not completely eliminate it.

Figure 85: Solution Summary Table

Name	Project Type (Execution Phase)		Descriptions	ISD	OOM Cost ($M)	Estimated Project Benefit (MW)	Benefit ($M/MW)	Preferred (Likely)
Lockport Area Phase 1 Upgrades	X1	Phase 1	Rebuild Robinson Rd substation and install a new transformer and reroute several lines in this area	2025	34	400	0.09	X
	X2	Phase 1	Retire part of Hinman substation and reroute existing lines to a nearby substation	2025	--	--	--	--
	Y1	Phase1+	Reconductor 115 kV line	2025	10	130	0.08	X
	Y2	Phase1+	Substation upgrades	2025	--	--	--	--
Lancaster Area Phase 1 Upgrades	X1 Y1	Phase1+	Rebuild and upgrade Stolle Rd substation Install a new transformer	2026	53	675	0.08	X
	X1 Y2	Phase1+	Rebuild and upgrade Stolle Rd substation Install additional transformer and reconfigure substation	2025	--	--	--	--
	X1 Y3	Phase1+	Rebuild and upgrade Stolle Rd substation Reconductor 115 kV lines	2025	--	--	--	--
Lancaster Area Phase 2 Upgrades	Z1	Phase 2	Install up to 10 MW, 6-Hour of Energy Storage	2027	--	10	--	X
	Z2	Phase 2	Install a new transformer and upgrade substation	2025	--	--	--	--
	Z3	Phase 2	Reconductor 34.5 kV line	2024	--	--	--	--
South Perry Area Phase 1 Upgrades	X1	Phase 1	Reconductor the line from Meyer to South Perry substations	2027	49	260	0.19	X
Genesee Valley Area Phase 2 Upgrades	Z1	Phase 2	Build a new 115 kV station, bring in a new source, and add a new transformer at multiple substations. Add Power Flow Control Device - Static Series Synchronous Compensator	2025	--	75	--	X
	Z2	Phase 2	Reconductor multiple 34.5 kV lines and replace transformers in area	2026	--	--	--	--
Hornell Area Phase 2 Upgrades	Z1	Phase 2	Install up to 10 MW, 6-Hour of Energy Storage	2027	--	10	--	X
	Z2	Phase 2	Reconductor 34.5 kV line	2023	--	--	--	--
	Z3	Phase 2	Build a new 34.5 kV line and install a new transformer	2025	--	--	--	--

Name	Project Type (Execution Phase)		Descriptions	ISD	OOM Cost ($M)	Estimated Project Benefit (MW)	Benefit ($M/MW)	Preferred (Likely)
Hornell, Elmira & Bath Phase 2 Reinforcement	X1	Phase 1	Build a new 230/115/34.5 kV station (Wagner Hill) in the vicinity area of Bath substation, reroute existing transmission lines to connect to this new substation	2025	35	70	0.50	X
	Z1	Phase 2	Install 2 additional transformers, add 2 Power Flow Control Devices. Reconductor 115 kV line and build new lines. Install a Power Flow Control Device, and upgrade terminal equipment at several substations	2027	--	500	--	X
	Z2	Phase 2	Reconductor several 115 kV lines	2027	--	--	--	--
	Z3	Phase 2	Expand multiple substations and build multiple lines	2031	--	--	--	--
Elmira & Bath Area Phase 2 Upgrades	Z1	Phase 2	Reconductor portion of a 34.5 kV line	2023	--	8	--	X
Geneva Area Phase 1 Upgrades	X1	Phase 1	Rebuild Border City 115 kV and add capacitor banks at this and Haley Rd substations	2026	76	20	3.80	X
	Y1	Phase1+	Install 115 kV PAR	2025	--	--	--	--
	Y2	Phase1+	Install 115 kV Power Flow Control Device - Static Series Synchronous Compensator	2022	4	8	0.50	X
	Y3	Phase1+	Reroute 115 kV line, upgrade 115 kV terminal equipment	2025	--	--	--	--
Geneva Area Phase 2 Upgrades	Z1	Phase 2	Build new 115 kV line	2025	--	155	--	X
	Z2	Phase 2	Install up to 40 MW, 6-Hour Energy Storage	2027	--	--	--	--
Binghamton Area Phase 1 Reinforcement	X1a	Phase 1	Rebuild Oakdale substation, install a 3-winding transformer and retire Westover 115 kV substation	2025	226	400	0.57	X
	X1b	Phase 1	Reroute 115 kV lines in the area of Etna, Willet, and Clarks Corners substations	2026	60	125	0.48	X

Name	Project Type (Execution Phase)		Descriptions	ISD	OOM Cost ($M)	Estimated Project Benefit (MW)	Benefit ($M/MW)	Preferred (Likely)
	X1c / Y1	Phase1+	Reconductor the line between South Owego and Hillside substations / Reconductor 115 kV line	2027	245	230	1.07	X
Binghamton Area Phase 2 Upgrades	Z1	Phase 2	Install a new transformer	2025	--	35	--	X
	Z2	Phase 2	Rebuild 34.5 kV substation and reconfigure sub-transmission network	2025	--	--	--	--
	Z3	Phase 2	Install up to 25 MW, 6-Hour of Energy Storage	2027	--	--	--	--
Ithaca Area Phase 1 Reinforcement	X1	Phase 1	Rebuild Etna substation, upgrade Coddington substation and install capacitors	2026	97	140	0.69	X
	Y1	Phase1+	Reconductor 115 kV line	2025	42	123	0.34	X
Ithaca Area Phase 2 Upgrades	Z1	Phase 2	Install up to 10 MW, 6-Hour Energy Storage	2027	--	10	--	X
	Z2	Phase 2	Install a new transformer	2025	--	--	--	--
	Z3	Phase 2	Replace a transformer	2025	--	--	--	--
Plattsburg Area Phase 2 Upgrades	Z1	Phase 2	Add two new transformers	2025	--	--	--	--
	Z2	Phase 2	Replace existing transformer and install a new transformer	2025	---	90	--	X
Oneonta Area Phase 1 Reinforcement	X1	Phase 1	Rebuild and expand East Norwich substation; Rebuild and expand Jennison substation and bring line in and out; Rebuild and expand Colliers 115 kV; Build a new substation called New Morris substation and build line to Collier, Jennison, and Fraser substations	2028	569	160	3.56	X
	Y1	Phase1+	Reconductor 115 kV line, upgrade terminal equipment at multiple 115 kV substations. Install 115 kV Power Flow Control Device - Static Series Synchronous Compensator technology	2027	60	300	0.20	X
	Y2	Phase1+	Reconductor 115 kV lines, upgrade terminal equipment at multiple substations	2027	--	--	--	--
Oneonta Area Phase 2 Upgrades	Z1	Phase 2	Install up to 40 MW, 6-Hour Energy Storage	2027	--	40	--	X
Liberty Area Phase 2 Upgrades	Z1	Phase 2	Install up to 10 MW, 6-Hour Energy Storage	2027	--	10	--	X
	Z2	Phase 2	Install a new transformer	2025	--	--	--	--

Following are some general observations and findings that can be observed from the solution summary the figure above:

1. Synergies: A number of existing projects in AVANGRID's existing capital plan are selected as Preferred projects since they are found to provide substantial CLCPA benefits in either their original form or with some incremental modification. These projects are listed as either Phase 1 or Phase 1+ projects respectively.
2. Cost: In most cases, the lowest cost alternative was selected as the preferred solution. However, in some cases, other factors such as cost estimate accuracy ranges and the desire to implement advanced technologies are considered (e.g. Storage, etc.).
3. Energy Storage: Energy storage was considered and recommended as preferred at several locations based on the preliminary analysis and order of magnitude cost estimates.
4. Power Flow Control Devices: This technology was proposed at several locations including three (3) different technologies (Series Reactors, Phase Angle Regulators, and Static Series Synchronous Compensator devices). Series Reactors were found to have the lowest cost but also provide the least amount of real time operational flexibility as they are static or fixed flow control devices. PAR's tended to be the most expensive but also provided maximum flexibility in responding to varying system power flow conditions. Static Series Synchronous Compensator devices are a newer technology that may offer a balanced solution between cost and flexibility although there is limited industry experience with these and they are not widely available across multiple vendors. Although this study made preliminary recommendations in some cases, further study will be necessary to make a final determination.
5. Renewable Benefit ($/MW): This study found that many existing projects (Phase 1 and Phase 1+) had the highest renewable integration benefit values with the lowest cost per MW of headroom gained. These existing projects also provide the benefit of addressing many other reliability and asset condition needs across the system.

v) Discussion of Potential Projects that would Increase Capacity on the Local Transmission to allow for Interconnection of New Renewable Generation Resources within AVANGRID 's System

As shown in Section (iv), the development of Phase 1, Phase 1+, and Phase 2 projects would create increased headroom in AVANGRID's footprint to allow for new renewable resources to interconnect. This local transmission study identified a number of upgrades that create up to 4 GW of increased capacity on the system. A summary of these projects and the approximated increased capacity benefit from these projects are shown in Figure 85.

vi) Identify the possibility of fossil generation retirements and the impacts and potential availability of those interconnection points

There are several fossil generators in AVANGRID service territory, which are shown in Figure 86. The existing capacity headroom at these locations was computed and the results are shown in Figure 86.

Figure 86: Local Headroom - Potential Fossil Retirement Locations

Division	Headroom Range (MW)		Approximate Location
	Low	High	
Auburn	157	368	State St, Wright Ave
Binghamton	52	52	Binghamton Cogen
Elmira & Bath	43	45	Steuben LF
Genesee Valley	138	148	Not provided*
Geneva	292	327	Not provided
Hornell & South Perry	18	76	Not provided*
Ithaca	0	190	Cayuga
Lockport	294	333	Not provided*
Plattsburgh	230	247	Not provided*

* Note: locations of existing fossil units that have not yet retired.

vii) AVANGRID Local Utility Study Conclusion

This study found that the implementation of AVANGRID's proposed transmission system upgrade projects as described in this Report can enable 6.8GW of renewable resources onto the NYSEG and RGE Local transmission systems. Many of these Projects not only serve to unlock renewable resources, but they also provide substantial system benefits in terms of improved customer reliability and modernization of portions of the New York electric grid. A summary of the order of magnitude costs and schedule are provided in the figure below.

Figure 87: Summary of Order of Magnitude Costs and Schedule by Project Type

Project Type (Execution Phase)	In-Service Years	OOM Cost ($M)
Phase 1	2025-2028	1,146
Phase 1+	2022-2027	414
Phase 2	2023-2027	780
	Total	2,340

To the extent that any Phase 1 or other (as applicable) projects are not currently contemplated in utility rate plans, the Commission should permit the utilities to submit a petition for Commission approval of timely cost recovery of the carrying costs through a transmission surcharge (or other applicable pass through clauses). The surcharge would be designed to allow the utility to recover its CLCPA projects' carrying costs, including depreciation, until its next rate case, at which time the investment would be reflected in base rates.

B. Distribution

AVANGRID, Inc. (AVANGRID) respectfully submits the "Utility Study" report of its New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RG&E) operating companies in accordance with the New York Public Service Commission's Order dated May 14, 2020. The Order directed each New York electric utility to identify appropriate distribution and local transmission upgrades to achieve the State's climate goals as set out in NY's Climate Leadership and Community Protection Act ("CLCPA"). There are seven (7) sections in this Report. This Report describes two types of projects at the distribution-level of AVANGRID's system (NYSEG, RG&E):

1. Existing capital projects with objectives of deliverability, resilience, security and modernization that also create headroom for customer DG interconnection and contribute to CLCPA goals for 2030. These are considered Phase 1 projects that will deliver headroom in the period 2020 to 2025.
2. New proposed projects with objectives to create headroom for customer DG interconnection in the network areas where there is greatest interconnection interest and lack of existing system capacity. These are considered Phase 2 projects that are not in the current Capital Expenditure Plan, so the timing of their delivery is not yet secured.

The total DG interconnection headroom created in aggregate as a result of existing capital projects is 166 MW. No amendments to these existing CapEx projects are recommended as these projects do not overlap between existing load-related, resilience, asset replacement and customer focused projects and the identified DG interconnection hot-spots.

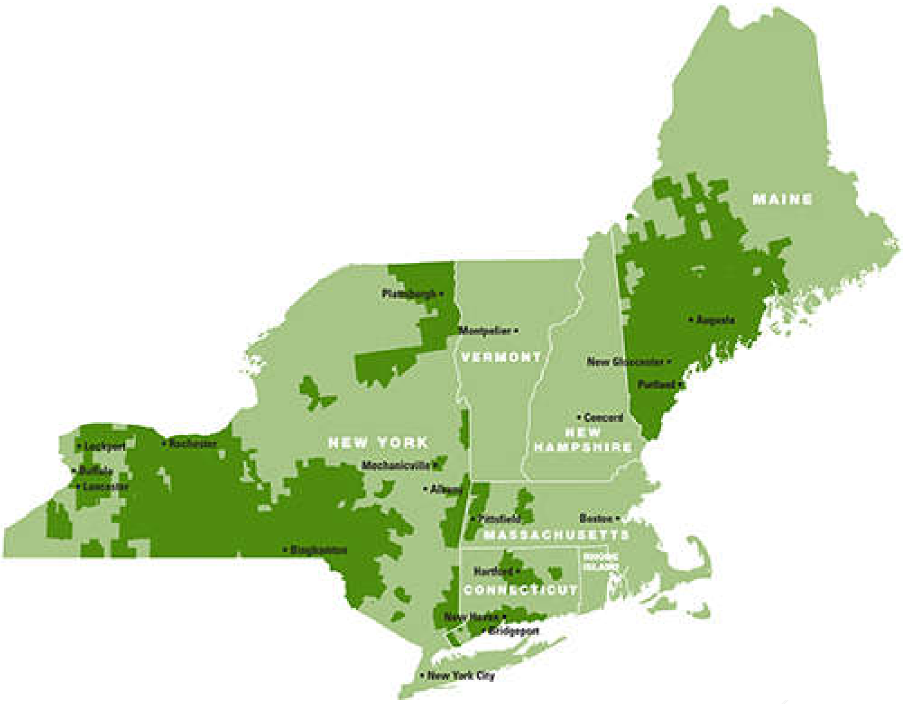
AVANGRID has proposed five specific DG interconnection headroom creating Phase 2 projects at Limestone, Keeseville, Guildford, Woods Corners and Kanona Substations. The total aggregated DG interconnection headroom created as a result of these new projects is estimated to be 88 MW.

AVANGRID has considered the application of Flexible Interconnection Capacity Solution (FICS) for DG and Non-Wires Alternatives (NWA) as targeted solutions across both RG&E and NYSEG network territories. These solutions are evaluated alongside conventional 'wires' options as a means to create cost-effective local distribution DG headroom.

i) Description of AVANGRID and its Service Area (including NYSEG and RGE)

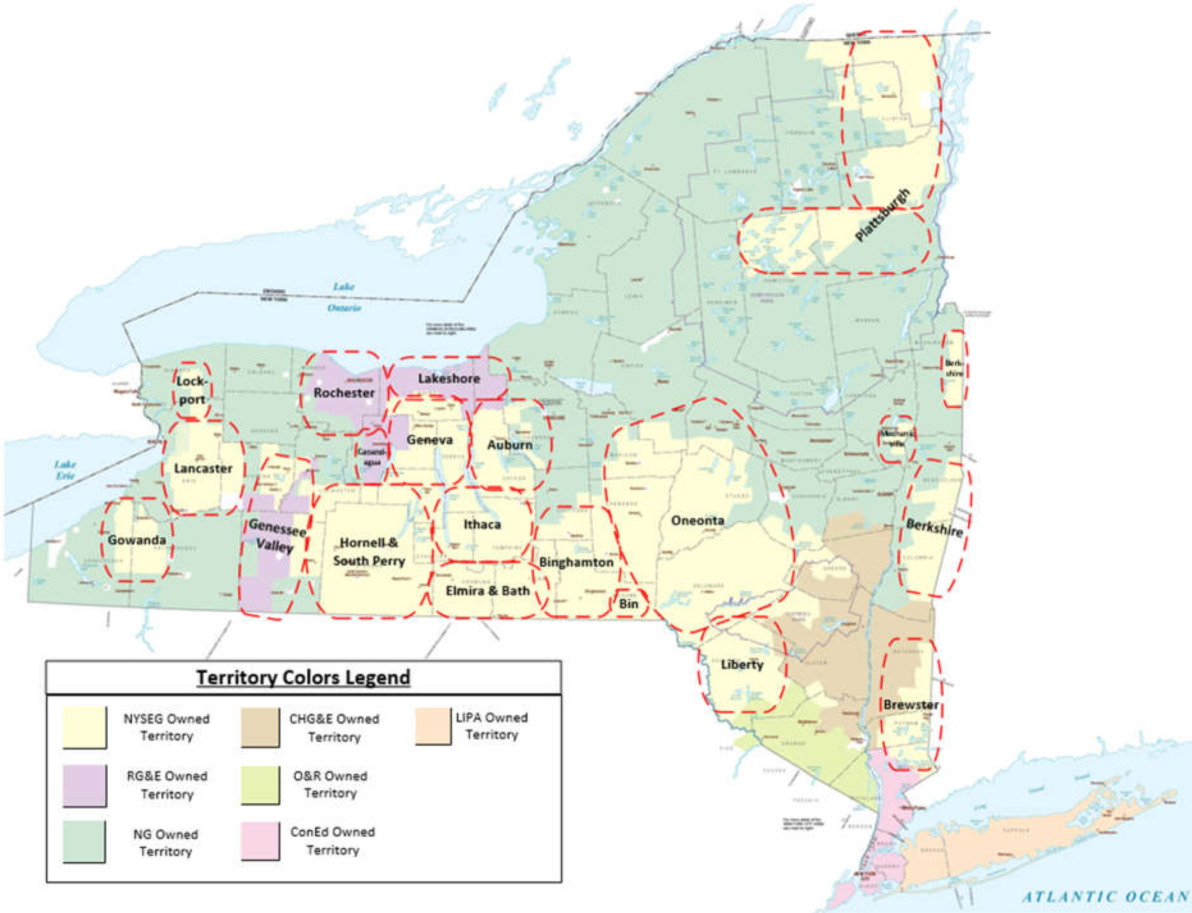
AVANGRID has assets and operations in several U.S. states and has two primary lines of business including its Networks and Renewables companies. The AVANGRID Networks business is shown in Figure 88 below and includes eight electric and natural gas utilities, serving 3.2 million customers in New York (i.e. NYSEG & RGE) and New England. The AVANGRID Renewables business owns and operates 7.1 gigawatts of electricity capacity, primarily through wind power, with a presence in 22 states across the United States.

Figure 88: AVANGRID Networks (Electric + Gas) Service Territories



In New York, NYSEG serves approximately 900,000 electricity customers within 13 operational divisions. RG&E serves approximately 380,000 customers, primarily within the city of Rochester and the adjacent municipalities. The NYSEG and RG&E's transmission systems are predominantly networked and operate at a range of voltage levels including 345, 230, 115, 46, 34.5, and some 11.5 kilovolts (kV) facilities. The NYSEG and RGE distribution systems which supply localized customer loads are predominantly radial in nature and operate at voltage levels between 2.4 – 34.5 kV. Figure 89 shows the service territories of the NYSEG and RGE operating companies, respectively and the appropriate sub-divisions in AVANGRID New York. In this Report, AVANGRID represents AVANGRID's electric service territories in New York (i.e. NYSEG and RGE).

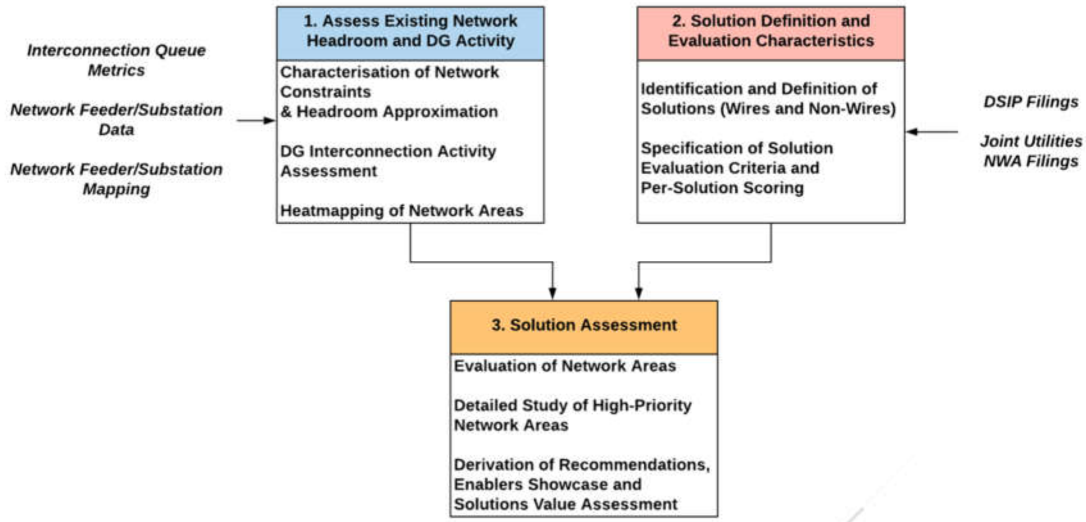
Figure 89: AVANGRID service territory



ii) Discussion of AVANGRID Study Assumptions, Methodologies, and Description of Local Design Criteria

The methodology developed and carried out for analyzing the RG&E and NYSEG distribution networks is well-aligned with the requirements set forth by the Commission Order as well as existing AVANGRID system planning, system operations, and investment planning processes. The study methodology is illustrated in Figure 90.

Figure 90: AVANGRID Distribution Study Methodology



The study methodology is divided into three tracks:

Track 1 ('Assess Existing Network Bottleneck/Headroom and DG Activity') built a full system-wide model of distribution circuits and substations with capacity, loading, DG connected, DG interconnection queue and headroom screens. Additional data collation, cleansing and enhancement has created data and models that will underpin subsequent development of AVANGRID's network to fulfil the New York State (NYS) clean energy goals.

Track 2 ('Solution Definition and Evaluation Characteristics') created definitions of a full AVANGRID suite of interconnection headroom solutions (traditional wires, non-wires and smart-innovative solutions), screens of the DSIP and Capital Expenditure Plan, and means of evaluation of potential solutions for headroom problems. These solutions are at various stages of maturity from established wires solutions to emerging, innovative solutions (including commercial and customer participation) but will all likely play important roles in developing AVANGRID's network to support clean energy deployment.

Track 3 ('Solution Assessment') created more detailed headroom and solution assessment models, detailed models for evaluation of solutions in high priority network areas and proceeded to develop project recommendations in the identified headroom hot-spots.

iii) Evaluation of Existing Headroom, Constraints, Bottlenecks for DG Interconnection

This section details the results of the DG interconnection headroom assessment based on AVANGRID's current distribution network – these include: (1) existing system headroom for DG interconnection, (2) identification of key constraints / bottlenecks of system that limit headroom for DG interconnection, and (3) identification of network areas with insufficient headroom to support DG interconnection currently in the application queue.

The study has taken a system-wide view of NYSEG and RG&E distribution service territories, including all substations and circuits, along with DG interconnection activities in assessing existing headroom. The following activities were undertaken as part of this analysis:

Data Collection – A multitude of data sets were collected and compiled across several AVANGRID departments including Distribution Planning, Transmission Planning, Transmission Services, Projects, Operations, Smart Grid, and NWA groups. The data necessary for conducting the analysis included distribution system information (circuit / substation information, equipment ratings / limits, topologies), load demand, DG interconnection (connected DG, queued applications, interconnection criteria), system reliability, hosting capacity (outputs of EPRI DRIVE tool), cost information (capex, opex), and typical system planning and operational practices. All data and information were combined into the "Universal Dataset."

Distribution System-wide Headroom Model - The models created from the universal dataset include 1697 circuits, 726 substations, and 975 DG interconnection applications with an aggregate capacity of 1500 MW. The model supports CLCPA/Commission study and other purposes.

Evaluation of Existing DG Headroom (System-Wide) – There are a number of planning screens applied to DG sites when studied for interconnection. These screens reflect asset capacity/ampacity limitations, system protection requirements and the need to maintain operation within secure limits such as voltage thresholds. Given the need for high-level modelling to allow study at system-wide scale, the headroom analysis has focused on the most limiting constraint types, where targeted investment can provide significant uplift in DG headroom.

DG Headroom is approximated for each circuit and substation subject to various system constraints. System constraint analysis is performed in line with NYSIR guidelines of AVANGRID and the Joint Utilities (JU). The total effective DG interconnection capacity is calculated based on the most severe system constraint which has the lowest MVA capacity value. The system constraints considered in the study included:

1. Circuit Thermal Headroom
2. Circuit Voltage Rise Headroom
3. Substation Thermal Headroom

Headroom is calculated for each screen considering the cases of connected DG and connected plus queued DG. The queued DG is the pipeline of interconnection applications that are in process.

Identify Existing Bottlenecks / Constraints – The study identified areas of limited DG interconnection capacity based on the underlying system constraints, labelling these as DG interconnection "hot spots". First, the areas with high DG interconnection activity and interest by developers were identified. Next, based on hosting capacity approximation (performed previously), the distribution study screened individual circuits and substations where capacity shortfall was identified for DG interconnection. This identified the network locations where capacity bottlenecks are most acutely preventing DG interconnection. Figure 91 shows the levels of DG interconnection activity and approximated hosting capacity at aggregated level across each AVANGRID division.[146] Whilst in all areas there is sufficient hosting capacity at an aggregate level, i.e. totaled across all circuits and substations, there are specific locations where a shortfall in hosting capacity creates bottlenecks that will limit interconnection for the Queued DG.

Figure 91: DG Interconnection, Hosting Capacity and Capacity Shortfalls.

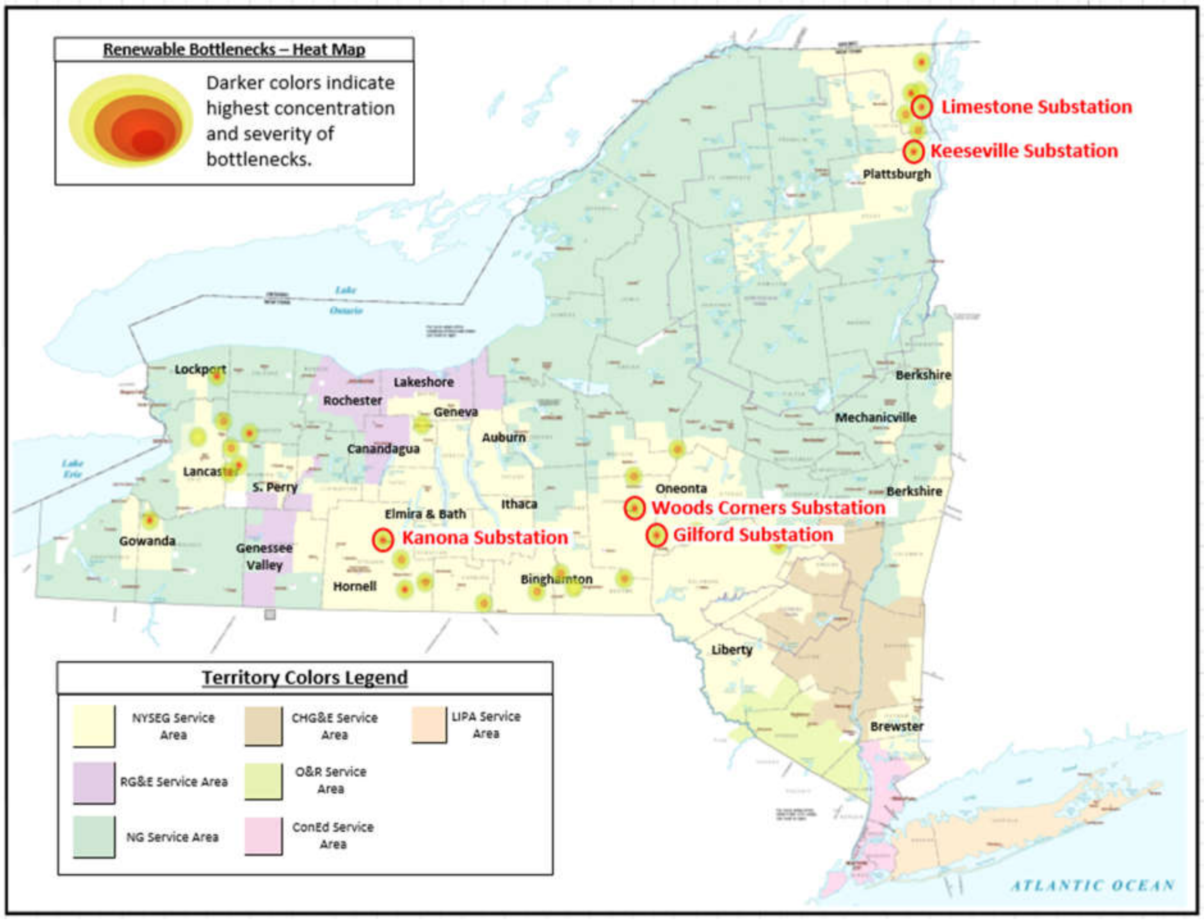
Division	Connected DG (MW)	Queued DG (MW)	Hosting Capacity (MW)	Substation Areas with Hosting Capacity Shortfall
Auburn	15.1	62.0	69.4	6
Binghamton	18.0	131.5	186.2	14
Brewster	15.4	18.0	118.5	3
Canandaigua	11.3	12.2	70.0	3
Elmira	17.9	90.7	92.2	10
Genesee	14.9	118.8	37.1	6
Geneva	27.5	26.6	38.9	6
Hornell	7.2	65.4	39.3	5
Ithaca	10.9	44.3	108.0	6
Lakeshore	8.3	15.6	43.1	3
Lancaster	25.7	35.2	309.6	7
Liberty	14.8	30.5	97.8	8
Lockport	2.4	12.2	27.6	1
Mechanicville	13.6	27.9	33.8	3
Oneonta	18.7	33.6	171.9	11
Plattsburgh	12.9	69.4	72.0	9
Rochester	91.9	69.1	467.5	13
Total	326.6	962.9	2,132.6	114

[146] Circuit / substation areas with no interconnection activity was excluded from the analysis.

1. *Distribution Headroom Analysis in Hot-Spot Areas*

Based on analysis of circuit and substation system constraints and DG interconnection activity, a series of “Hot Spots” substations were identified – see Figure 92.

Figure 92: Distribution Substation Hot Spots



From the list of hotspot substations that are projected to experience DG headroom problems, the top five substation areas – **Keeseville, Kanona, Woods Corners, Guildford, and Limestone** – were analyzed and built into new project proposals (detailed in Section 6). These substations reflect areas where the combination of high levels of DG interconnection interest and the existence of capacity bottlenecks would offer high-impact projects to release DG headroom.

2. *Distribution and Transmission Study Alignment*

The DG interconnection hot-spots have been aligned with the Transmission Study to ensure that proposed solutions for transmission constraints and bottlenecks are assessed for additional benefit on the distribution system. Bottlenecks were identified for transmission/distribution interfaces at 34.5 kV and 69 kV voltage levels; stepping down from higher sub-transmission voltages. Substation transformers and circuits at these voltage levels could limit the deliverability of distribution (<69 kV) DG interconnections. Several proposed sub-transmission projects will alleviate distribution system DG interconnection headroom issues. These projects include 34.5kV substation transformer upgrades, transformer additions, and 34.5 kV circuit re-conductoring / upgrades / additions.

In addition to the five Phase 2 projects, Willet and Candor network areas were also studied in detail due to high levels of DG interconnection activity, with 98 MW of connected and queued DG. The headroom issues are resolved by proposed transmission projects.

The distribution Phase 1 and Phase 2 projects that create DG interconnection headroom are not expected to have a negative impact on the transmission system since they enable the interconnection of DG capacity similar to the levels already present in the interconnection queue. These levels of DG interconnection capacity have already been assessed in the transmission study, so the effect of the distribution projects should not have a material impact on the existing and new headroom in the transmission network.

iv) Synergies with Capital Expenditure Projects

This section reviews the existing AVANGRID Capital Expenditure (CapEx) plan, identifies relevant DG headroom projects and assesses their headroom contribution.

The CapEx Plan consists of Transmission and Distribution investment projects that are driven by multiple factors such as security of supply (grid resilience), load growth, and condition-related asset renewal. A review of the Capital Plan has identified the investment projects that will have a direct benefit for the DG headroom of the distribution network – see list of project in the figure below. Whilst the primary impetus for these projects is not necessarily increasing the hosting capacity of the distribution network, it is noted that each project does provide overall benefit for generation interconnection in capacity terms.

The total aggregated DG interconnection headroom created as a result of existing distribution capital projects is 166 MW. No amendments to current CapEx plan projects are proposed as there are strong rationales for the load serving deliverability, resilience, security and asset condition/health in in the current projects. With the exception of one substation area (Hilldale), there is appears to be little DG interconnection activity at these project areas. As some substations / circuits are upgraded to higher voltage levels (e.g. 4.8 kV to 12 kV), DG interconnection interest may increase as a result[147]. At present, no modifications are

[147] Higher voltage levels may signal to DG developers that more interconnection capacity is available. However, it is just one of several factors. DG interconnection interest is driven by a variety of factors such as ease of interconnection (e.g. hosting capacity map indication), land availability / price, energy yield (e.g. solar irradiance), etc.

recommended as there exists adequate headroom to accommodate the level of DG interconnection interest at these project locations.

Figure 93: Capital Plan (Phase 1) Projects that Increase DG Headroom

Company	Project Name	Project Description	Primary Voltage	Secondary Voltage	Existing Headroom	New Headroom	Net Increase in Headroom
NYSEG	Hilldale Substation[148]	Transformer Upgrade / Replacement	34.5 kV	12.5 kV	7.4 MW	33.1 MW	25.7 MW
RG&E	Station 43	34.5kV Transformers Upgrade; 12kV Circuit Upgrade	34.5 kV	34.5 kV	11.3 MW	35.5 MW	24.2 MW
RG&E	Station 46	34.5kV Transformers Upgrade; 12kV Circuit Upgrade	34.5 kV	4.16 kV	11.9 MW	35.6 MW	23.7 MW
RG&E	Station 49	115/34.5kV Transformers Upgrade	34.5 kV	4.16 kV	20.3 MW	60.5 MW	40.2 MW
RG&E	Station 117	13.2kV Circuit Upgrade	34.5 kV	4.16 kV	4.7 MW	17.6 MW	12.9 MW
NYSEG	Amenia Substation	12kV Circuit Upgrade	46 kV	4.8 kV	5.0 MW	28.6 MW	23.7 MW
NYSEG	Dingle Ridge Substation	Transformer Upgrade / Replacement	46 kV	4.8 kV	8.8 MW	17.7 MW	8.9 MW
NYSEG	Sloan Substation	12kV Circuit Upgrade; Additional 12kV circuits; 34.5kV Transformer Upgrade	34.5 kV	4.8 kV	8.4 MW	35.0 MW	26.6 MW

Existing Substation Headroom: The remaining headroom for new generation interconnection at present, accounting for the capacity of generation currently connected to the network.
New Substation Headroom: The estimated headroom for new generation interconnection, accounting for existing generation sites, following the planned investment projects.
Net Increase in Headroom: The increase in headroom for new generation interconnection, accounting for existing generation sites, following the planned investment projects.

v) Discussion of Potential Projects that would Increase Capacity on the Distribution System to allow for Interconnection of New Renewable Generation Resources within AVANGRID's System (Phase 2 Projects)

This section presents the process to short-list options that are considered as viable alternative to the headroom hot-spots.

An exercise of scanning, scoping and defining potential project options identified a list of 25 potential headroom creating and interconnection barrier options. These are organized below under the classifications of traditional 'wires' options, customer and third-party provided

[148] An NWA solicitation is anticipated for early 2021 that could defer or replace the need for this project.

services of 'non-wires alternative' options, and new and emerging technologies based on 'smart innovative' options:

1. Wires Options:
    a) Complete 12kV Substation & Circuit Upgrade and Conversion
    b) Substation Transformer bank addition
    c) Substation Transformer up-rating
    d) Cables / Wires N-1 upgrades
    e) Cables / Wires upgrade / re-conductoring
    f) Switching / Topology change (static)
    g) Voltage Regulation Upgrades: LTC / Regulation upgrades / Capacitor banks
2. Non-Wires Alternative (NWA) Options
    a) Load relief and grid support from Non-Wires Alternatives (typically energy storage or demand flexibility)
    b) Demand Response (DR)
    c) EV Smart / Managed Charging
    d) Customer Energy Efficiency (not an applicable option)
    e) ToU & Other Pricing (not an applicable option)
    f) Market Services
3. Smart Innovative Options
    a) Flexible Interconnection Capacity Solution (FICS) for DG
    b) Auto-switching for N-1 Contingency
    c) FLISR (not an applicable option)
    d) DTT upgrades (not an applicable option)
    e) Smart Inverter Controls
    f) Volt-Var Optimization (VVO)

This full options list was evaluated using a multi-criteria evaluation process, inputs for AVANGRID subject matter experts across various departments, and assessment of the network headroom challenges identified in modelling. An example of the screening process is illustrated in Figure 94.

Figure 94: Example of multi-criteria screening of DG headroom options

Solution	Solution Category	Criterion & Weighting					Weighted Score	Ranking - All	Ranking - NWA & Smart Innovative	Ranking - NWA	Ranking - Smart Innovative
		Headroom / Energy Release	Technology Readiness	Costs	Lead Time	Technology Enabling Systems					
		2	2	3	1	1					
12kV voltage upgrade & meshing	Wires Solutions	5	5	1	3	5	31	11			
Transformer bank addition	Wires Solutions	3	5	2	3	5	30	12			
Transformer up-rating	Wires Solutions	4	5	2	3	5	32	9			
Cables / Wires N-1 upgrades	Wires Solutions	4	5	2	4	5	33	4			
Cables / Wires upgrade / re-conductoring	Wires Solutions	4	5	2	4	5	33	4			
Switching / Topology change (static)	Wires Solutions	2	5	5	4	5	38	2			
Voltage Solutions: LTC / Regulation upgrades / Capacitor banks	Wires Solutions	1	5	4	4	5	33	4			
Load relief and grid support from BESS/BESS+PV,	Non Wires Solutions	3	5	1	2	3	24	16	9	6	
Demand Response (DR)	Non Wires Solutions	1	5	3	3	2	26	15	8	5	
EV Smart / Managed Charging	Non Wires Solutions	1	3	5	3	3	29	13	6	3	
Customer Energy Efficiency	Non Wires Solutions	1	5	3	1	5	27	14	7	4	
ToU & Other Pricing	Non Wires Solutions	1	5	5	1	5	33	4	3	1	
Market Services	Non Wires Solutions	1	5	5	3	2	32	9	5	2	
FICS	Smart Innovative Solutions	3	5	5	3	3	37	3	2		2
Auto-switching for N-1 Contingency	Smart Innovative Solutions	5	5	5	4	2	41	1	1		1
FLISR	Smart Innovative Solutions	1	5	2	2	2	22	17	10		4
DTT upgrades	Smart Innovative Solutions	1	5	5	3	3	33	4	3		3
Smart Inverter Controls	Smart Innovative Solutions	1	4	2	2	4	22	17	10		4
Volt-Var Optimization (VVO)	Smart Innovative Solutions	2	4	2	2	2	22	17	10		4

The potential options were subsequently organized into the options that are viable in different timeframes in relation to the current headroom shortfalls in specific network locations, possible deployment in the 2030 planning horizon, and less mature options for resolving headroom problems:

1. Options ready for deployment for DG interconnection and headroom problems now or in the short-to-medium term:
    a) Complete 12kV Substation & Circuit Upgrade and Conversion
    b) Substation Transformer up-rating
    c) Cables / Wires upgrade / re-conductoring
    d) Switching / Topology change (static)
    e) Voltage Regulation Upgrades: LTC / Regulation upgrades / Capacitor banks
    f) Flexible Interconnection Capacity Solution (FICS) for DG
2. Options ready for deployment the medium-to-longer term
    a) Non-Wires Alternative (NWA), specifically Battery Energy Storage
    b) Auto-switching for N-1 Contingency
    c) EV Smart / Managed Charging
    d) Smart Inverter Controls
    e) Volt-Var Optimization (VVO)

The remaining options were not considered as viable candidates to provide headroom in the near-to-medium term.

1) *Identification of Least Cost Traditional Upgrade Projects to Increase Headroom*

The distribution study has assessed the full set of conventional network options as upgrades to increase hosting capacity and create headroom in interconnection hot-spots. Least cost upgrade options were identified that could generally increase DG headroom by alleviating existing circuit and substation bottlenecks / constraints. These options included:

- Substation Transformer upgrade
- Substation Transformer Bank Addition
- Substation 12 kV Circuit Uprating and Meshing

These options are described in the subsections that follow.

<u>Substation Transformer Upgrade</u>

Description: Replace existing substation supply transformer with higher rated transformers. This will potentially require associated HV side cable, lines and switchgear associated with each transformer.

DG Headroom Impact: This option can address both demand and DG thermal headroom. Transformer voltage regulation can be considered to assist with improved voltage headroom if required. For transformer supplies to lower voltage substations the option to move to 12kV on the LV side should be considered. Note that fault level issues need to be considered on moving to a larger circuit rating.

<u>Substation Transformer Bank Addition</u>

Description: Where a transformer is added to a substation with a single existing transformer supply, this would be treated as adding redundant supply capacity i.e. moving from N-0 to N-1. The increase in thermal headroom would be limited to the long-term emergency rating of the transformers for demand. This could be operated in parallel with existing transformer/transformers where LV side fault ratings permit or run with a split LV busbar (open bus-section breaker added with circuits allocated to on or other busbar section) or as a hot standby where there is more than one existing transformer providing N-1 redundancy and where fault levels do not permit parallel operation of the additional transformer.

DG Headroom Impact: For generator export the full new transformer capacity could be used assuming generation export is reduced on entering an N-1 condition (DG inter-trip, or DERMS). Where a third hot standby transformer supply circuit is added, this could increase demand and DG headroom by the transformer MVA rating (all assumed to have the same MVA rating).

<u>Complete 12kV Substation & Circuit Upgrade and Conversion</u>

Description: This option replaces lower voltage distribution circuits and transformers (e.g. 4kV) with 12kV. This will include the replacement of existing cables and overhead wires with equivalents having a higher ampacity / thermal rating to increase overall circuit headroom. This option may also include uprating from single-phase to three-phase circuits.

DG Headroom Impact: This option can be applied at any voltage level and can directly increase thermal headroom for generation and demand assuming no other constraining factors.

2) Identification of Potential New or Emerging Options

In addition to the traditional wires options highlighted above, the distribution study has considered a broad set of non-wires alternative options (following the definition and assessment process agreed with the Joint Utilities) and smart innovative options that feature in AVANGRID's grid modernization and NY REV Demo programs, as detailed in the 2020 Distributed System Implementation Plan (DSIP). Enabling technologies are also a central component in the Grid Modernization investments set out in AVANGRID's Capital Expenditure Plan and DSIP.

The smart innovative and non-wires options considered viable for the purposes of DG interconnection headroom are:

1. Flexible Interconnection Capacity Solution (FICS) for DG
2. Non-Wires Alternative (NWA): Battery Energy Storage

These options are described in subsections below.

The RG&E and NYSEG DSIP (July 2020) describes the priorities for developments to enable the companies to deliver Distributed System Platform (DSP) capabilities to serve customers and NYS clean energy goals. Of particular importance to the goals of headroom for DG interconnection are the following DSIP programs, projects and priorities:

1. *Grid Automation* program to enable *Measurement, Monitoring and Control (MM&C)* of power flows in the networks to accommodate large numbers and combined capacity of clean energy assets (generation, storage and beneficial electrification loads)
2. This study makes use of improved network data integrity and accuracy (targeted in the DSIP) for the purposes of assessing interconnection headroom and conventional and new options to enhance that headroom. The system-wide headroom model constructed and utilized in this study will be valuable for assessing further headroom creating network investments as future needs arise.
3. *Advanced DMS (D-SCADA, VVO, FLISR and DERMS)* control system implementation to optimize the grid and interconnected DER to achieve better customer and clean energy goals.

There are several other areas described in the DSIP that support future headroom and clean energy goals. Many of these are evident in the long-list of non-wires and smart-innovative options listed above.

Flexible Interconnection Capacity Solution (FICS) for DG

AVANGRID's Flexible Interconnection Capacity Solution (FICS) is a smart, innovative technology option aimed at resolving grid interconnection, headroom and capacity problems for DG. FICS is a new grid management paradigm that employs grid sensing and controls technology that departs from traditional utility system planning. FICS utilizes real-time data to maintain grid reliability and safety relative to DG operation. Typically, it is quicker and cheaper for customers to obtain interconnection with a FICS option than to wait and meet the expense of grid equipment.

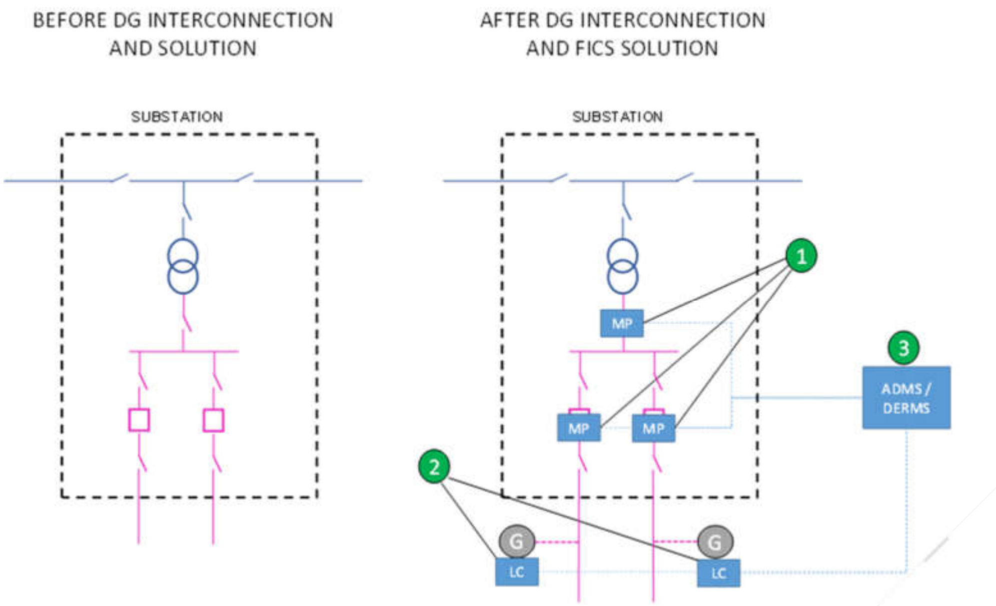
1. FICS monitors and manages network conditions

A range of interconnection problems can be resolved through monitoring grid and DG conditions in real-time (e.g. power flow, direction, voltage, DG export) and comparing this with known equipment and system limits including thermal capacity of lines/cables/transformers, voltage limits, voltage step limits, reverse power flow limits of regulators, harmonics limits from inverter connected DG. Measurement equipment continuously monitor selected parts of the system and as grid and DG conditions approach those limits, control instructions are sent to DG units and network assets to take incremental actions to restore the network to a safe operating state within the limits. This real-time control of DG can allow network interconnection in bottleneck areas without the need for conventional 'wires' expense and delay.

2. FICS requires Monitoring, Measurement & Control Equipment

The example FICS project illustrated in Figure 95 shows Measurement Points (MP) where the network measurements are taken. Measurements are also taken at the Generating (G) units through the Local Controllers (LC). Measurements are gathered in the DER Management System (DERMS) at an AVANGRID control center. The DERMS also receives data from the Advanced Distribution Management System (ADMS) at the AVANGRID control center and computes the required changes in DG operation to maintain safe and secure network operation. This is communicated back to the LCs to implement the new operating point if required. The LCs also contain local intelligence to take safe action should any part of the control and communication system fail.

Figure 95: Example FICS Project with Equipment and Communications Links



The example FICS deployment in Figure 95 shows MPs at constraints on two circuits into the substation and one further constraint at the transformer. Two generators are shown with LCs, one on each of the constrained circuits. Conditions might dictate that one or both generators would be instructed to a lower export setpoint if the transformer approached its operating limits. The generators would only be subject to curtailment for their respective circuit constraints.

FICS leverages AVANGRID's REVDemo project which is now being rolled out in AVANGRID services territories. FICS also leverages investments in Monitoring, Measurement and Control (MM&C) as part of AVANGRID's Distributed System Implementation Plan (DSIP). Through these programs, it is possible to meet CLCPA goals through creation of more interconnection headroom, while providing AVANGRID customers with the option of quicker and cheaper interconnection.

3. DG Export Curtailment

To maintain the network within its safe operating limits, DG is instructed to reduce export to the system when grid conditions dictate. Curtailment is requested only at the moment in time when the network approaches its operating limits and is removed as soon as those conditions relax. The FICS technology that AVANGRID is deploying is highly location specific in the application of DG export reduction and calculates and recalculates any curtailment on a second-by-second basis to reduce the impact on DG developers.

Curtailment of DG export tends to occur at times when local load demand is low (so more DG export will require to flow upwards into the grid) and when other DG output is high (so more DG power compete for the same network capacity). Advanced analytical methods can provide an accurate estimate of expected curtailment for DG of specific technology, operating in a specific network location and with a range of operating conditions for the DG unit itself and for neighboring DG and load customers.

Experience of similar FICS deployments over the last decade shows that DG interconnection in a headroom constrained network area can be doubled at the expense of 5-10% DG curtailment.

4. Interconnection process and FICS costs

An interconnection process that provides customers with the FICS option alongside a conventional interconnection will provide information on the equipment required, the costs and the cost allocation between customer and AVANGRID.

Implementing a FICS project involves:

- Measurement Points (MP) installed on each circuit, node with a headroom constraint.
- Extending MM&C monitoring, communications, data infrastructure to new 'FICS Zone' if required.
- Extension of DERMS (Vestal) infrastructure to incorporate new 'FICS Zone'.
- FICS Local Controllers (LC) installed at each FICS DG customer site.

Non-Wires Alternatives (NWA): Battery Energy Storage

AVANGRID already has a Commission and JU standard process for procuring load relief services from customers and third parties. These are known as Non-Wires Alternatives (NWA), as they are alternative approaches to resolving network constraints or problems.

A similar approach to procuring generation export constraint relief services can be deployed to enable customers and third parties to provide network capacity and headroom options. Many of the processes already in operation for load relief non-wires options can be adapted for the planning, procurement, implementation and operation of an export NWA.

The option requirements could involve the connection of suitably sized (power rating and energy storage capacity) energy storage either behind-the-meter (BTM) at customer premises or front-of-the-meter (FTM) connected to the network or located at a substation. These could be single flexible demand (turn up) or energy storage assets or aggregated units, distributed within the distribution network.

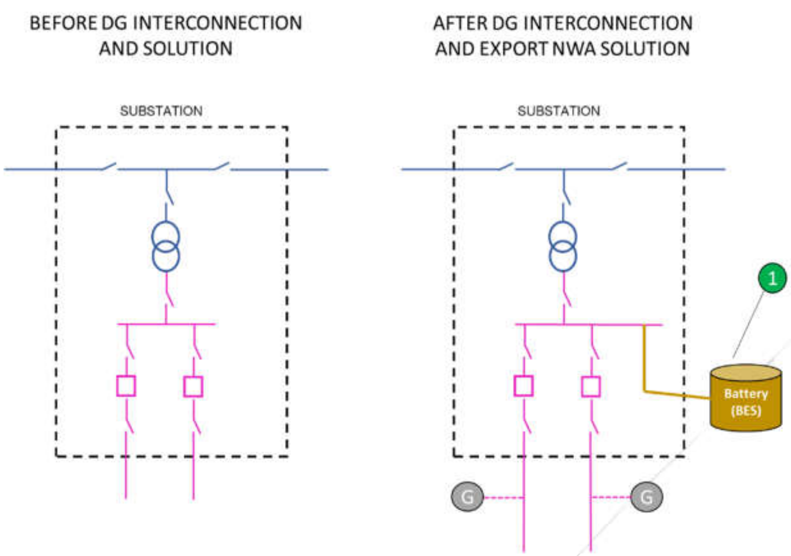
An ADMS, DERMS or other dispatch system is required to issue schedule and control signals to provide headroom and export relief at the appropriate times. BTM NWA based options require suitable contractual arrangements and, possibly for wider network options, some form of market trading or schedule optimization platform for provision of other system and market services.

The option can be used to reduce demand or generation loading on constrained circuits at peak usage times to create thermal headroom. The option can be used to improve voltage regulation, reduce harmonics, peak load reduction for demand and generation and improve supply security and resiliency.

An NWA solicitation would be required to finalize costs and determine final technology specifications from qualified bidders. A solicitation should take place for every application when the order of magnitude estimate is competitive with other solution options.

Figure 96 below provides an example illustration of the NWA battery energy storage solution.

Figure 96: Example of Non-Wires Alternative (Battery Energy Storage) Project



vi) Discussion of Potential Projects that would Increase Capacity on the Distribution System to allow for Interconnection of New Renewable Generation Resources within AVANGRID's System (Phase 2 Projects)

The study has identified a series of additional projects that will deliver additional DG interconnection headroom in network areas where there is high levels of generator interconnection activity and existing system constraints / bottlenecks. These distribution hot-spots areas were identified as specific network substations and circuits where grid capacity constraints, or bottlenecks, will block further interconnection DG developments. The study has focused on the areas where substation-level capacity issues will block additional generation interconnection across the entire area served by the substation. Locational-specific circuit-level issues (e.g. conductor thermal overload, overvoltage) could exist that would require additional solutions / upgrades to be implemented but this is outside the scope of the study.

The five proposed new Phase 2 projects – Limestone, Keeseville, Guildford, Woods Corners and Kanona Substations – are estimated to create a total increase in aggregated DG interconnection headroom of 88 MW. These projects represent the most cost-effective set of projects that leverage existing capital expenditure plans, that exploit conventional options as well as non-wires options and smart-innovative options with a strong data-centric evidence base using the methodologies set out above.

A summary of projects #1-#5 and their assessed options is presented in Figure 97 and Figure 98.

Note on Cost Estimate: In general, the lowest cost alternative addressing all needs (e.g. reliability, asset condition, CLCPA, etc.) is preferred, however, consideration is also given to the states goals to enable more storage solutions onto the system also. In addition, the cost estimates in this study are considered as Order of Magnitude (OOM) level based on a limited desktop engineering analysis. As such, there may be situations where the estimate accuracy ranges of competing alternatives overlap making a future estimate refinement necessary to verify which alternative is in fact the lowest cost. These estimate refinements, if necessary, will likely require substantially more detailed site specific engineering detail considerations as compared to the OOM estimates available for many of the projects evaluated in this study.

Figure 97: Analysis of System Need and Alternative Solutions Proposed

Project	Primary Voltage	Secondary Voltage	Connected + Queued DG	Transformer Capacity	Substation Peak Load	Existing Substation Headroom	New Substation Headroom with Alternative Solutions			
							12kV upgrade (MW)	Transformer Replacement / Addition	FICS (MW)	NWA Energy Storage
Limestone	46 kV	12.5 kV	11.8 MW	10.5 MVA	6.7 MW	8.8 MW	n/a	17.7 MW	11.4	11.7 MW
Keeseville	46 kV	4.8 kV	2.8 MW	2.5 MVA	1.5 MW	2.1 MW	28.2	n/a	3.0	2.8 MW
Guildford	46 kV	4.8 kV	4.6 MW	2.5 MVA	1.7 MW	2.1 MW	28.2	n/a	3.0	4.5 MW
Woods Corner	46 kV	8.32 kV	10.0 MW	8.4 MVA	4.6 MW	7.0 MW	28.7	n/a	9.0	10.0 MW
Kanona	34.5 kV	12.5 kV	16.0 MW	10.5 MVA	4.8 MW	6.6 MW	n/a	15.5 MW	8.6	14.0 MW

Connected + Queued DG: The total volume of DG either connected to the network or in the interconnection queue awaiting connection, at that substation.
Transformer Capacity: the MVA continuous rating of the substation transformer(s).
Substation Peak Load: The MW 5-year average peak load at the substation transformer(s).
Existing Substation Headroom: The remaining headroom for new generation interconnection at present, accounting for the capacity of generation currently connected to the substation and in the interconnection queue.
New Substation Headroom [12kV upgrade option/transformer replacement option/FICS/NWA Energy Storage option]: The estimated headroom for new generation interconnection, accounting for existing generation sites, following the planned investment projects of 12kV Upgrade/Transformer Replacement/FICS deployment

Figure 98: Export Constraint NWA Requirement

Project	Primary Voltage	Secondary Voltage	Connected + Queued DG	Transformer Capacity	Substation Peak Load	Power Requirement for Energy Storage	Duration Requirement for Energy Storage
Limestone	46 kV	12.5 kV	11.8 MW	10.5 MVA	6.7 MW	1.5 MW	6-Hour
Keeseville	46 kV	4.8 kV	2.8 MW	2.5 MVA	1.5 MW	0.5 MW	4-Hour
Guildford	46 kV	4.8 kV	4.6 MW	2.5 MVA	1.7 MW	2.1 MW	8-Hour
Woods Corner	46 kV	8.32 kV	10.0 MW	8.4 MVA	4.6 MW	2.1 MW	6-Hour
Kanona	34.5 kV	12.5 kV	16.0 MW	10.5 MVA	4.8 MW	6.5 MW	8-Hour

Primary/Secondary Voltage: The Primary (HV) and Secondary (LV) voltage levels at the substation.
Connected + Queued DG: The total volume of DG either connected to the network or in the interconnection queue awaiting connection, at that substation.
Transformer Capacity: the MVA continuous rating of the substation transformer(s).
Substation Peak Load: The MW 5-year average peak load at the substation transformer(s).
Power Requirement for NWA: The MW rating of service provision required from Non-Wires Alternatives required to accommodate the queued DG and avoid headroom constraint.
Duration Requirement for Energy Storage: The hour duration rating of service provision required from Non-Wires Alternatives required to accommodate the queued DG and avoid headroom constraint.

1) Project #1: Limestone Substation

Figure 99: Project Overview

Utility Area	NYSEG
Utility Division	Plattsburgh
Project Name	Limestone Substation
Primary Voltage	46 kV
Secondary Voltage	12.5 kV
Transformer Rating	10.5 MVA
Substation Peak Load	6.7 MW
Connected DG	0.1 MW
Queued DG	11.7 MW
Description of System Need	Substation transformer observed capacity constraint with an additional 2.9 MW of substation capacity required to accommodate Queued DG. There is sufficient DG headroom on 12.5kV circuits.
Existing Headroom	8.8 MW
Estimated Headroom Increase with Recommended Solution	5.5 MW (Solution #2 + Solution #3)
Estimated Cost for Recommended Solution	-- (Solution #2 + Solution #3)
Proposed In-Service Date	2023

Figure 100: Evaluation of Options for Increasing DG Headroom

Solution	Description	Capacity Gained (MW)	Order of Magnitude Cost ($)	Headroom Increase ($/MW)
# 1	Transformer Upgrade - Replace existing 10.5MVA (46/12.5kV) transformer with a new 22.4MVA (46/12.5kV) transformer;	8.9 MW	--	--
#2	Flexible Interconnection Capacity Solution (FICS) for DG [149] - FICS Measurement Points (MP) for real-time monitoring of power flow through the substation transformer; - FICS Local Controller (LC) for each controlled FICS DG site; - FICS central ADMS/DERMS control system and integration of MPs and LCs to ADMS/DERMS.	2.6 MW	--	--
#3	Battery Energy Storage Solution - Procurement of non-wires solution (e.g. battery energy storage) at substation. Estimated minimum storage requirement of 1.5MW Rating and 6-hour storage capacity.	2.9 MW	--	--

Preferred Solution Alternative: Combination of Solution #2 (Flexible Interconnection Capacity Solution for DG) and Solution #3 (Battery Energy Storage Solution). FICS and BESS can deploy incrementally and are complimentary as FICS is based on dialing down DG output while BESS absorbs excess DG output. Based on order of interconnection, FICS is first deployed to accommodate new DG without need for any substantial upgrades or new deployments. Once FICS capacity becomes limited (i.e. due to high curtailment), BESS is then deployed to address any additional power outflows from additional DG. The deployment of both solutions yields an approximate combined 5.5 MW DG headroom, with a unit cost of $1.3M per MW.

[149] Solution #2: Based on relatively high levels of substation load, FICS can address the headroom issues and accommodated generation up to installed capacity 11.5 MVA. An approximation of headroom uplift indicates that it will offer similar levels of headroom to the transformer upgrade option. In the case of FICS, headroom uplift is defined as the MVA volume of generation that can connect before export curtailment levels become excessive, i.e. ensuring curtailment is below 10% of annual production.

2) Project #2: Keeseville Substation

Figure 101: Project Overview

Utility Area	NYSEG
Utility Division	Plattsburgh
Project Name	Keeseville Substation
Primary Voltage	46 kV
Secondary Voltage	4.8 kV
Transformer Rating	2.5 MVA
Substation Peak Load	1.5 MW
Connected DG	0.0 MW
Queued DG	2.8 MW
Description of System Need	Substation transformer observes capacity constraint with additional 0.7 MW substation capacity required to accommodate Queued DG. There is sufficient DG headroom on the 4.8kV circuits.
Existing Headroom	2.1 MW
Estimated Headroom Increase with Recommended Solution	26.1 MW (Solution #1)
Estimated Cost for Recommended Solution	-- (Solution #1)
Proposed In-Service Date	2025

Figure 102: Evaluation of Options for Increasing DG Headroom:

Solution	Description	Capacity Gained (MW)	Order of Magnitude Cost ($)	Headroom Increase ($/MW)
# 1	Complete 12kV Substation & Circuit Upgrade and Conversion[150] 12kV upgrade to the substation and associated circuits will address capacity headroom challenges, fully accommodating queued DG. There is 28.2 MW substation capacity (above queued DG) once this reinforcement is delivered. - Replace existing 2.5MVA (46/4.8 kV) transformer in substation bank #2 with 37.3MVA (46/12.5kV) transformer; - Upgrade 4.8kV Circuit to 12.5kV; - Replace downstream secondary transformations from 4.8kV to 12.5kV.	26.1 MW	--	--
#2	Flexible Interconnection Capacity Solution (FICS) for DG[151] - FICS Measurement Points (MP) for real-time monitoring of power flow through the substation transformer; - FICS Local Controller (LC) for each controlled FICS DG site; - FICS central ADMS/DERMS control system and integration of MPs and LCs to ADMS/DERMS.	0.9 MW	--	--
#3	Battery Energy Storage Solution - Procurement of non-wires solution (e.g. battery energy storage) at substation. Estimated minimum storage requirement of 0.5 MW, 4-hour storage capacity.	0.7 MW	--	--

Preferred Solution Alternative: Solution #1 – Complete 12kV Substation & Circuit Upgrade and Conversion. This delivers significant levels of capacity to the substation on a cost-effective basis, both improving substation and circuit headroom for future DG interconnection.

[150] Solution #1: 12kV upgrade to the substation and associated circuits will address capacity headroom challenges, fully accommodating queued DG. There is 14.3MVA substation capacity (above queued DG) once this reinforcement is delivered

[151] Solution #2: FICS can deliver sufficient headroom increase to accommodate Queued DG and this could present a temporary solution to accelerate connection of DG ahead of the 12kV Mesh reinforcement.

3) *Project #3: Guilford Substation*

Figure 103: Project Overview:

Utility Area	NYSEG
Utility Division	Oneonta
Project Name	Guilford Substation
Primary Voltage	46 kV
Secondary Voltage	4.8 kV
Transformer Rating	2.5 MVA
Substation Peak Load	1.7 MW
Connected DG	0.1 MW
Queued DG	4.5 MW
Description of System Need	Substation transformer observes capacity constraint with additional 2.4 MW capacity required to accommodate Queued DG. There is insufficient headroom on 4.8kV circuits.
Existing Headroom	2.1 MW
Estimated Headroom Increase with Recommended Solution	26.1 MW (Solution #1)
Estimated Cost for Recommended Solution	-- (Solution #1)
Proposed In-Service Date	2025

Figure 104: Evaluation of Options for Increasing DG Headroom

Solution	Description	Capacity Gained (MW)	Order of Magnitude Cost ($)	Headroom Increase ($/MW)
# 1	Complete 12kV Substation & Circuit Upgrade and Conversion[152] 12kV upgrade to the substation and associated circuits will address capacity headroom challenges, fully accommodating queued DG. There is 28.1MVA substation capacity (above queued DG) once this reinforcement is delivered. - Replace existing 2.5MVA (46/4.8 kV) transformer in substation with 37.3MVA (46/4.8kV) transformer; - Upgrade 4.8kV Circuit to 12.5kV conductor; - Replace secondary transformations from 4.8kV to 12.5kV.	26.1 MW	--	--

Preferred Solution Alternative: Solution #1 – Complete 12kV Substation & Circuit Upgrade and Conversion. Other solution alternatives were considered but did not result in sufficient headroom to accommodate queued DG. The preferred solution delivers significant levels of capacity to the substation, both improving substation and circuit headroom for future DG interconnection.

[152] There is 12.5MVA of additional substation capacity available for DG beyond the queued customers, however the 12kV circuits may limit development to the lower level of 5.2MVA.

4) Project #4: Wood Corners Substation

Figure 105: Project Overview

Utility Area	NYSEG
Utility Division	Oneonta
Project Name	Woods Corners Substation
Primary Voltage	46 kV
Secondary Voltage	8.32 kV
Transformer Rating	8.4 MVA
Substation Peak Load	4.6 MW
Connected DG	0.0 MW
Queued DG	10.0 MW
Description of System Need	Substation transformer observes capacity constraint with additional 3 MW capacity required to accommodate Queued DG. There is also insufficient aggregate hosting capacity on the 8.32kV circuits.
Existing Headroom	7.0 MW
Estimated Headroom Increase with Recommended Solution	21.7 MW (Solution #1)
Estimated Cost for Recommended Solution	-- (Solution #1)
Proposed In-Service Date	2025

Figure 106: Evaluation of Options for Increasing DG Headroom

Solution	Description	Capacity Gained (MW)	Order of Magnitude Cost ($)	Headroom Increase ($/MW)
# 1	Complete 12kV Substation & Circuit Upgrade and Conversion[153] 12kV upgrade to the substation and associated circuits will address capacity headroom challenges, fully accommodating queued DG. There is 18.7MVA substation capacity (above queued DG) once this reinforcement is delivered. - Replace existing 2.5MVA (46/8.32 kV) transformer in substation with 37.3MVA (46/12.5kV) transformer; - Upgrade 4.8kV Circuit to 12.5kV conductor; - Replace downstream secondary transformations from 4.8kV to 12.5kV.	21.7 MW	--	--
#2	Flexible Interconnection Capacity Solution (FICS) for DG[154] - FICS Measurement Points (MP) for real-time monitoring of power flow through the substation transformer; - FICS Local Controller (LC) for each controlled FICS DG site; - FICS central ADMS/DERMS control system and integration of MPs and LCs to ADMS/DERMS.	2.0 MW	--	--

[153] Solution #1: 12kV upgrade to substation and associated circuits addresses the capacity issues at substation and circuits. Following this solution there is 18.7MVA of additional substation capacity available for generation beyond the queued sites.

[154] Solution #2: FICS can deliver sufficient headroom increase to accommodate up to 9MW of DG – this could present a temporary solution to accelerate connection of DG ahead of the 12kV Mesh reinforcement.

Preferred Solution Alternative: Solution #1 – Complete 12kV Substation & Circuit Upgrade and Conversion. Solution #2 does not provide enough DG headroom increase to accommodate current DG queued applications.

5) Project #5: Kanona Substation

Figure 107: Project Overview

Utility Area	NYSEG
Utility Division	Elmira
Project Name	Kanona Substation
Primary Voltage	34.5 kV
Secondary Voltage	12.5 kV
Transformer Rating	10.5 MVA
Substation Peak Load	4.8 MW
Connected DG	2.0 MW
Queued DG	14.0 MW
Description of System Need	Substation transformer observed capacity constraint with an additional 7.4 MW of capacity required to accommodate Queued DG. There is insufficient headroom on 12.5kV circuits.
Existing Headroom	6.6 MW
Estimated Headroom Increase with Recommended Solution	8.9 MW (Solution #1)
Estimated Cost for Recommended Solution	-- (Solution #1)
Proposed In-Service Date	2025

Figure 108: Evaluation of Options for Increasing DG Headroom

Solution	Description	Capacity Gained (MW)	Order of Magnitude Cost ($)	Headroom Increase ($/MW)
# 1	Transformer Upgrade - Replace existing 10.5MVA (46/12.5kV) transformer with a new 22.4MVA (46/12.5kV) transformer; *Additional upgrades required on 12.5kV circuits to increase headroom.	8.9 MW	--	--
#2	Flexible Interconnection Capacity Solution (FICS) for DG[155] - FICS Measurement Points (MP) for real-time monitoring of power flow through the substation transformer; - FICS Local Controller (LC) for each controlled FICS DG site; - FICS central ADMS/DERMS control system and integration of MPs and LCs to ADMS/DERMS.	2.1 MW	--	--

[155] Solution #2: Given the high levels of constraint, FICS is unable to address the capacity headroom issues at the substation. It may however address some of the circuit-level issues to accommodate a smaller proportion of the DG queue ahead of reinforcement. FICS would address the circuit-level headroom issues, providing an additional 1MVA of capacity beyond the queued & connected DG.

Preferred Solution Alternative: Solution #1 – Transformer Upgrade. Solution #2 delivers insufficient capacity to accommodate the existing DG application queue.

vii) AVANGRID Distribution Study Conclusion

This study found that targeted upgrades to the AVANGRID distribution system can provide system capabilities to support the state's CLCPA goals. The study also found that many previously planned upgrades, as designed, provide additional significant benefits to meeting these CLCPA goals.

This study found that the implementation of AVANGRID's proposed distribution system upgrade projects can enable additional renewable resources onto the NYSEG and RGE Local transmission systems. Many of these Projects not only serve to unlock renewable resources, but they also provide substantial system benefits in terms of improved customer reliability and modernization of portions of the New York electric grid. A summary of the order of magnitude costs and schedule are provided in the figure below.

Figure 109: Summary of Order of Magnitude Costs and Schedule by Project Type

Project Type (Execution Phase)	In-Service Years	OOM Cost ($M)
Phase 1	2021-2027	229
Phase 2	2023-2025	125
	Total	354

Figure 110 below, provides a summary of the project alternatives and their associated capacity improvements that were evaluated as part of this study.

Figure 110: Summary of Distribution Phase 1 and Phase 2 Projects

Division	Bottleneck Descriptions		Project Descriptions							
	Violation	Main Drivers	Name	Type	Descriptions	ISD	Order of Magnitude Cost ($)	Capacity Gained (MW)	Headroom Increase ($/MW)	Preferred Solution
Liberty	Substation Transformer	Capacity	Hilldale Substation[156]	Phase 1 (Existing Project)	Transformer Upgrade / Replacement	2024	$32M	25.7 MW	$1.2M / MW	X
Rochester	Substation Transformer; Conductors	Asset Condition, Reliability & Resiliency	Station 43	Phase 1 (Existing Project)	34.5kV Transformers Upgrade; 12kV Circuit Upgrade	2026	$47M	24.2 MW	$1.9M / MW	X
Rochester	Substation Transformer; Conductors	Asset Condition, Reliability & Resiliency	Station 46	Phase 1 (Existing Project)	34.5kV Transformers Upgrade; 12kV Circuit Upgrade	2025	$49M	23.7 MW	$2.1M / MW	X
Rochester	Substation Transformer	Asset Condition, Reliability & Resiliency	Station 49	Phase 1 (Existing Project)	115/34.5kV Transformers Upgrade	2021	$19M	20.1 MW	$0.9M / MW	X
Rochester	Substation Transformer; Conductors	Asset Condition, Reliability & Resiliency	Station 117	Phase 1 (Existing Project)	13.2kV Mesh Upgrade	2026	$25M	12.9 MW	$1.9M / MW	X
Brewster	Substation Transformer; Conductors	Capacity	Amenia Substation	Phase 1 (Existing Project)	12kV Circuit Upgrade	2021	$13M	23.7 MW	$0.5M / MW	X
Brewster	Substation Transformer	Capacity	Dingle Ridge Substation	Phase 1 (Existing Project)	Transformer Upgrade / Replacement	2021	$16M	8.9 MW	$1.8M / MW	X

[156] An NWA solicitation is anticipated for early 2021 that could defer or replace the need for this project.

Division	Bottleneck Descriptions		Project Descriptions							
	Violation	Main Drivers	Name	Type	Descriptions	ISD	Order of Magnitude Cost ($)	Capacity Gained (MW)	Headroom Increase ($/MW)	Preferred Solution
Lancaster	Substation Transformer; Conductors	Capacity	Sloan Substation	Phase 1 (Existing Project)	12kV Circuit Upgrade; Additional 12kV circuits; 34.5kV Transformer Upgrade	2027	$28M	26.6 MW	$1.3M / MW	X
Elmira	Substation Transformer	DG Interconnection	Kanona Substation	Phase 2 (New Project) – Alt 1	Transformer Upgrade	2025	--	8.9 MW	--	X
				Phase 2 (New Project) – Alt 1	Flexible Interconnection Capacity Solution (FICS) for DG	2023	--	2.1 MW	--	
Plattsburgh	Substation Transformer	DG Interconnection	Limestone Substation	Phase 2 (New Project) – Alt 1	Transformer Upgrade	2025	--	8.9 MW	--	
				Phase 2 (New Project) – Alt 2	Flexible Interconnection Capacity Solution (FICS) for DG	2023	--	2.6 MW	--	X
				Phase 2 (New Project) – Alt 3	Battery Energy Storage Solution	2023	--	2.9 MW	--	X
	Substation Transformer	DG Interconnection	Keeseville Substation	Phase 2 (New Project) – Alt 1	Complete 12kV Substation & Circuit Upgrade and Conversion	2025	--	26.1 MW	--	X
				Phase 2 (New Project) – Alt 2	Flexible Interconnection Capacity Solution (FICS) for DG	2023	--	0.9 MW	--	
				Phase 2 (New Project) – Alt 3	Battery Energy Storage Solution	2023	--	0.7 MW	--	

Division	Bottleneck Descriptions		Project Descriptions							
	Violation	Main Drivers	Name	Type	Descriptions	ISD	Order of Magnitude Cost ($)	Capacity Gained (MW)	Headroom Increase ($/MW)	Preferred Solution
Oneonta	Substation Transformer	DG Interconnection	Guildford Substation	Phase 2 (New Project) – Alt 1	Complete 12kV Substation & Circuit Upgrade and Conversion	2025	--	26.1 MW	--	X
Oneonta	Substation Transformer	DG Interconnection	Woods Corners Substation	Phase 2 (New Project) – Alt 1	Complete 12kV Substation & Circuit Upgrade and Conversion	2025	--	21.7 MW	--	X
Oneonta	Substation Transformer	DG Interconnection	Woods Corners Substation	Phase 2 (New Project) – Alt 2	Flexible Interconnection Capacity Solution (FICS) for DG	2023	--	2.0 MW	--	

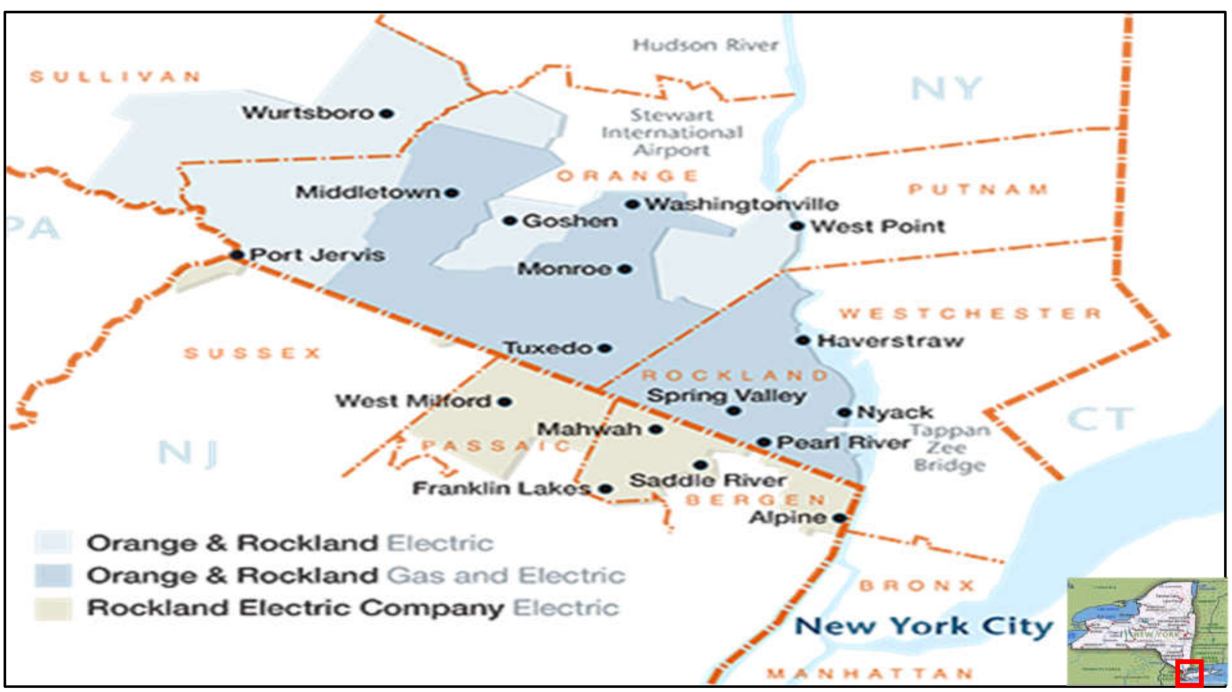
VII. ORANGE & ROCKLAND UTILITIES

A. Transmission

i) Description of O&R and its Service Territory

O&R's study area is the portion of the New York Control Area located in Zone G in the Lower Hudson Valley Area. O&R's electric service territory is comprised of Rockland County, portions of Orange County, and portions of Sullivan County. O&R's service territory is further divided into three (3) divisions, *i.e.*, Eastern, Central and Western. O&R's transmission system includes facilities operated at voltages between 34.5 kV and 345 kV (O&R also operates 34.5 kV distribution facilities). O&R interconnects with the State bulk power system through seven (7) bulk power 345/138 kV transformer interfaces (*i.e.*, West Haverstraw Bank 194, Bowline Bank 455, Ramapo Bank 1300 & 2300, Sugarloaf Bank 1112, Middletown Tap Bank 114 and South Mahwah Bank 258). Although O&R owns no generation, several power plants connected to the bulk power system are located within its service territory (*i.e*. Bowline, CPV Valley). Furthermore, approximately 70 MW of small hydro electric and gas turbines exist within the O&R service territory and are connected to the O&R's 69 kV and 34.5 kV transmission systems. Figure 111 below shows the O&R service territory.

Figure 111: O&R Service Territory



ii) Discussion of O&R's Study Assumptions and Description of Local Design Criteria

1. Study Cases

O&R used the following cases in this study:

1. 2020 O&R summer case;
2. NYISO's 2030 Reliability Needs Assessment ("RNA") case, also referred to as the "business-as-usual" summer case; and
3. "Enhanced" summer case with transmission renewable projects added to this case (see discussion in Section IV).

Study cases 2 & 3 above modeled the independent distribution station peak load with consideration of (1) the 8760- load profile, (2) load curve of the Distribution Photo-voltaic ("PV"), and (3) evening peak load.

2. Transmission Planning Design Criteria

The O&R transmission system shall be designed to serve load when the system is in normal configuration (N-0), as well as during single contingency events (N-1). Under normal configuration, no transmission facility shall exceed its normal thermal ratings and no thermal violations shall be observed in all divisions. During N-1 conditions, O&R transmission system shall be designed to sustain single contingency events such as an outage of a single transmission circuit, transformer or a bus section without loss of load. During any of the above contingencies, no facility will be loaded above its normal rating. When the normal rating is exceeded during a single contingency event, T&S Engineering shall propose system reinforcements and/or improvements to mitigate the violation(s). Both N-0 and N-1 criteria were based on *NERC Standard TPL-001-4 Table 1 Category P0 - No contingency condition and Category P1 – Single Contingency condition,* respectively. All bus voltages for both conditions shall be within 0.95 to 1.05 per unit of their nominal voltage.

Based on these criteria, O&R has included in its 2021-2030 capital budget several transmission projects aimed at mitigating the various thermal as well as voltage violations in its system, summarized in Figure 112 below. Note that several 2020 capital projects are included in the table; these projects are expected to be completed before year-end.

Figure 112: 2021-2030 Transmission Capital Projects

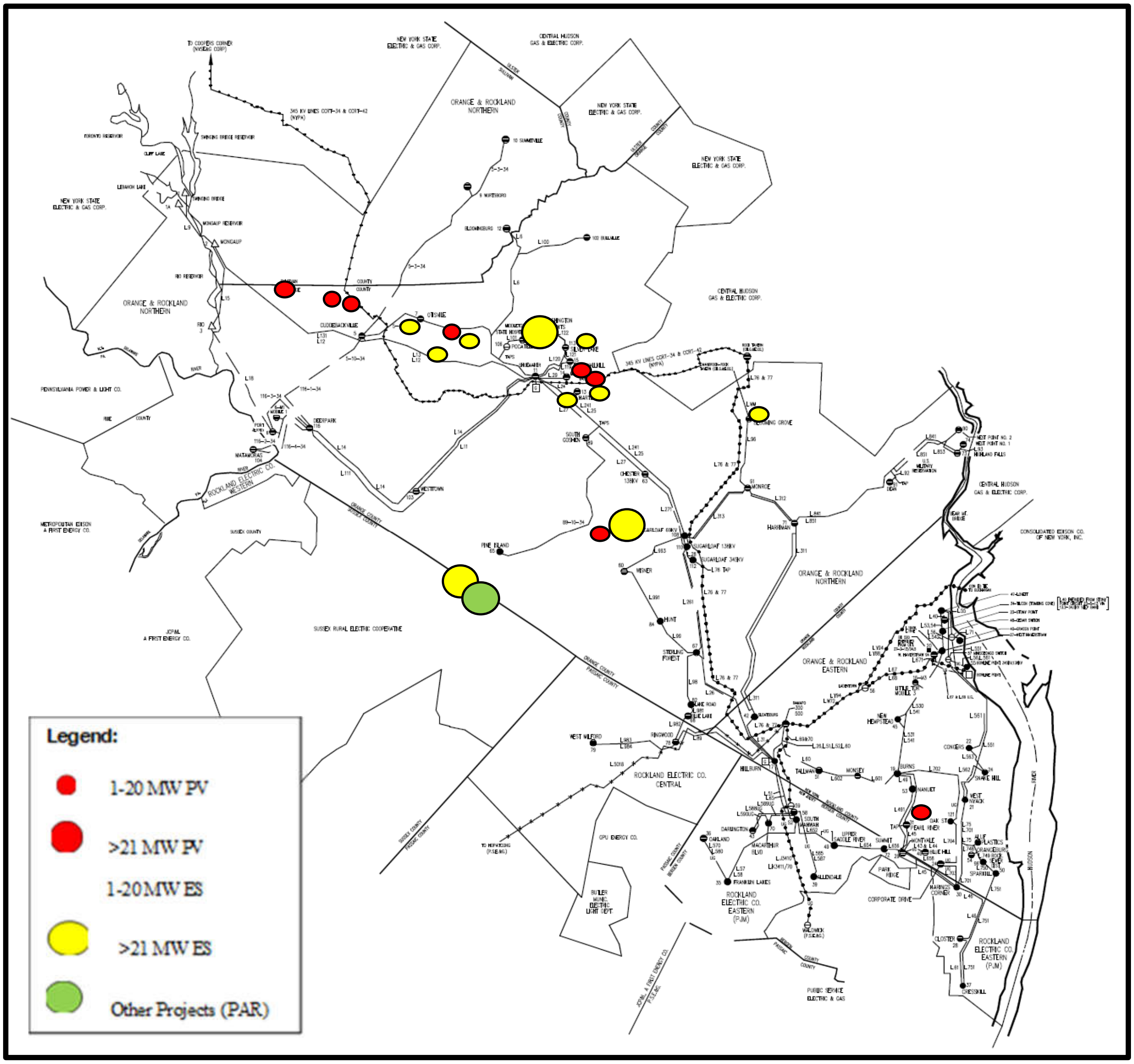
Project Name/Description	Division	In-Service Year	Remarks
Sloatsburg Switch Upgrade	Eastern	2020	Year-end completion date
Line 47/Harings Corner Terminal/Closter Station Re-configuration	Eastern	2020	Year-end completion date
Line 111 Extension into Port Jervis (Port Jervis 69kV)	Western	2021	
Port Jervis Sub 69kV UG Intrastation Tie (Port Jervis 69kV)	Western	2021	
Line 51 Upgrade	Eastern	2023	
Lovett 345 kV Station	Eastern	2023	
West Point 69kV (Upgrade of Transmission Lines 841, 851, and 853 to 69kV Design and Construction)	Central	2025	
Line 705/West Nyack 2nd Auto-bank	Eastern	2027	
New Shoemaker 34.5kV, 69 & 138Yards	Western	2028	High level project scope
Line 120 Extension to Silver Lake to Washington Heights	Western	2029	High level project scope
West Nyack 138kV Yard	Eastern	2030	High level project scope
Harings Corner 138kV Yard	Eastern	2030	High level project scope
Western Division 34.5 kV Sub-transmission upgrade	Western	2030	High level project scope

3. NYISO Transmission Interconnection Queue

O&R is currently tracking the NYISO Interconnection Queue with the proposed renewable generation projects, including PV, Energy Storage ("ES") and other projects. Figure 113 shows the proposed location of all renewable generation projects (as of August 31, 2020). Note that majority of the proposed projects are in the Central and Western Divisions of the O&R service territory.

O&R's Central and Western Divisions contain current and former farmlands and open spaces that offer opportunities for developers to site their PV and ES projects. Based on this, O&R has developed a flexible investment approach that prioritizes the removal of older transmission facilities while installing system improvements that will provide capacity for normal load growth and accommodate current and future renewable generation projects.

Figure 113: PV, ES and Other Projects (Proposed Location)



iii) Discussion of a possibility of fossil generation retirements and the impacts and potential availability of those interconnection points

O&R owns no generation. However, several large power plants connected to the bulk power system are located within the O&R service territory (*i.e.*, Bowline, CPV Valley). The retirement of these plants will not cause reliability violations in O&R's local transmission system. However, the NYISO is responsible for the reliability studies to determine the impact of these retirements in the bulk power system. Furthermore, approximately 70 MW of small hydro electric and gas turbines exist within the O&R service territory and is connected to O&R's 69 kV and 34.5 kV transmission systems. Because of their relatively small sizes and locations, the retirement of these generators also will not impact O&R's local transmission system.

iv) Discussion of Existing Capacity "Headroom" within O&R's Transmission System

O&R determined the existing headroom capacity in 2020 and compared it with the 2030 "enhanced" summer case. The 2030 "enhanced" summer case included the proposed transmission renewable projects in the NYISO interconnection queue, as well as the 2021-2030 capital transmission projects listed in Figure 113 above. The summary of results and findings is set forth in Figure 114 below. The black numbers indicate the headroom available for that particular equipment. The negative (-) red numbers indicate that the headroom for that particular equipment has exceeded its normal rating.

Figure 114: Capacity Headroom

ELEMENT NAME	TERMINAL STATIONS	AVAILABLE HEADROOM (MW Based on Normal Rating)		RELATED RENEWABLE PROJECTS
		2020 O&R Summer Case	2030 70 x 30 "Enhanced" Summer Case – Added Projects	
Line 4	Shoemaker – Pocatello	2	3	
Line 6	Shoemaker – Pocatello – Decker Switch – Bloomingburg – Wurtsboro	2	6	
Line 100	Decker Switch – Bullville	5	15	
Line 12	Shoemaker -Mongaup	31	-14	PV, ES
Line 13	Shoemaker-Cuddebackville	31	-12	PV, ES
Line 18	Rio-Port Jervis	12	7	
Line 24	Shoemaker- Hartley-Sugarloaf	33	-7	PV
Line 25	Shoemaker-South Goshen-Sugarloaf	33	-35	PV
Lines 26	Ramapo-Sterling Forest	139	-73	AC TRANSMISSION, PV
Line 98	Lake Road-Sterling Forest	12	-18	PV
Line 261	Sterling Forest-Sugarloaf	66	-18	AC TRANSMISSION, PV
Line 312	Harriman-Monroe	18	1	PV
Line 131A	Mongaup- Cuddebackville	31	-13	PV, ES
Line 131B	Mongaup-Cuddeackville	31	-14	PV, ES
5-3-34.5 kV	Cuddebackville – Bullville	-20	-12	Solution: Line 120 Extension (2031)

The study results indicate that available headroom on O&R's transmission system will decrease in 2030 due to the addition of PV and ES projects in the NYISO queue. If left unaddressed, renewable generation connected to these lines would be curtailed under peak load conditions. Even with the addition of other O&R transmission projects through 2030, the headroom deficiency on some transmission lines will remain. As discussed further below, O&R has identified multi-value transmission projects that can help increase the available headroom on the system, thereby unbottling generation on these lines.

v) Discussion of Bottlenecks or Constraints that Limit Energy Deliverability within O&R System

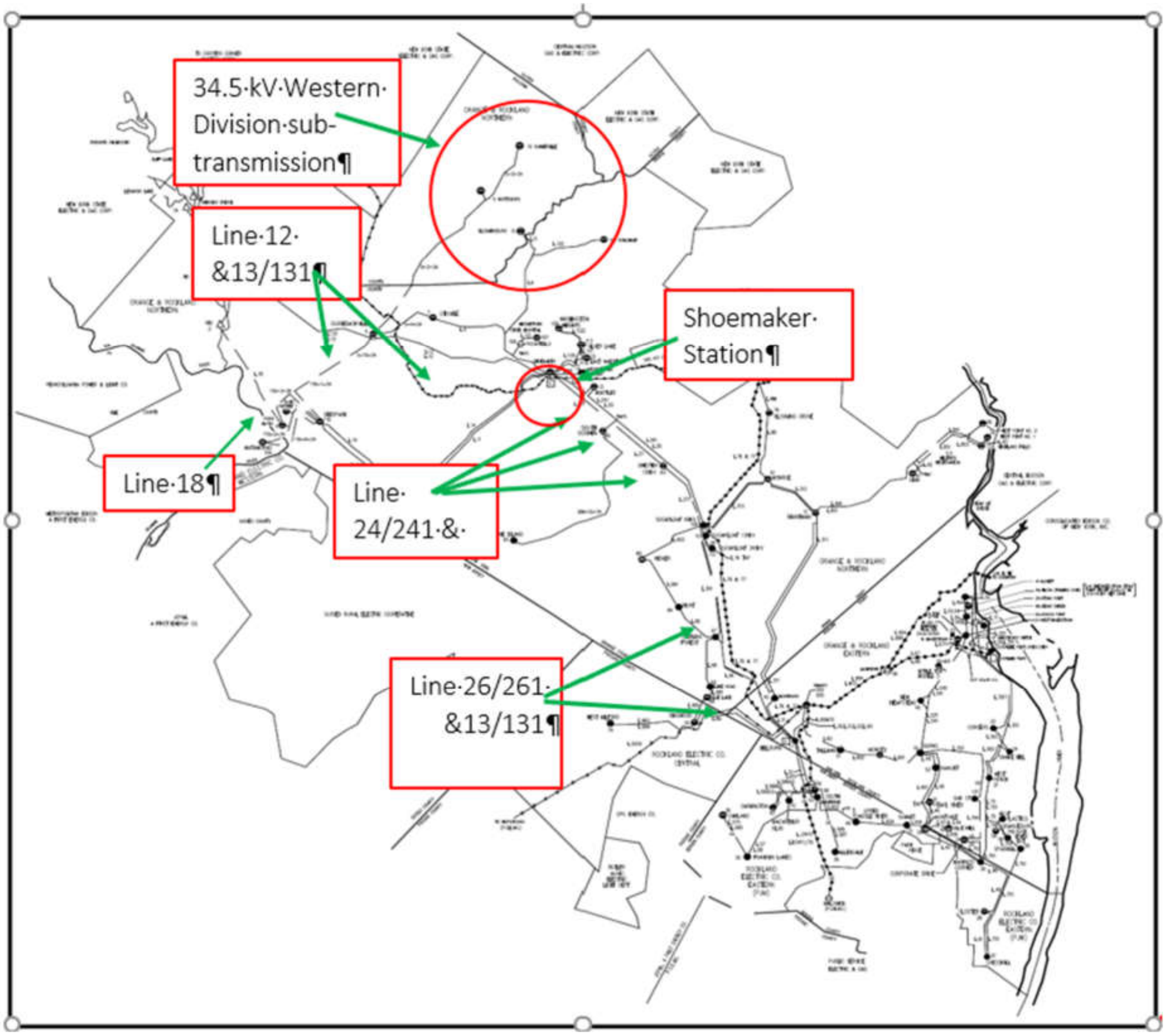
The headroom analysis in Section IV above identifies several lines in the O&R Western Division that develop ratings capacity constraints for future growth of system expansion for potential renewable interconnection.

vi) Discussion of Potential Projects that would Address Bottlenecks or Constraints that limit Energy Deliverability within O&R's System

O&R is well positioned to develop and implement multi-value projects that will enable utility-scale distributed energy resources and storage interconnections, unbottle capacity limited facilities, and facilitate the upgrade of aging and obsolete infrastructure. O&R is informed by the NYISO queue on targeted development areas that align very well with "no regrets" investment containing all the attributes described above. As noted previously, O&R's Central and Western Division contain farmlands and open spaces that offer opportunities for developers to site their PV and ES projects which will assist in meeting CLCPA's targets. O&R has developed a flexible investment approach that prioritizes the removal of older facilities while installing systems that will provide capacity for normal load growth and accommodate renewable projects. This approach will facilitate the achievement of the CLCPA's goals.

O&R believes that the upgrades of the Central and Western Division transmission system qualify for multi-value no regrets investments and will continue to review the best timing for project execution moving forward (see Figure 115). Constraints related to project timing include scheduling constraints to perform obsolescence projects that are difficult to schedule when consideration of higher impact reliability jobs take priority.

Figure 115: Location of Proposed Phase 1-CLCPA Transmission Projects



O&R also must consider other constraints for the challenging process of upgrading existing facilities while maintaining continuity of service.

The projects listed below, with the exception of the upgrade of the 34.5 kV Western Division sub-transmission system and Shoemaker 138kV and 69kV Station Upgrade, are not currently part of O&R's 10-year plan but have been identified by O&R as potential future projects that will replace aging infrastructures, support load growth and allow the integration of renewables. As noted above, O&R's flexible investment approach focuses on multi-value Phase 1 transmission projects, which are set forth in Figure 116 below. O&R did not identify any Phase 2 transmission projects in its study.

Figure 116: O&R Phase 1 CLCPA Transmission Projects

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	OOM ($M)	NET MW BENEFIT
TL Lines 12 & 13/131*	G	Shoemaker	Cuddebackville, Mongaup	Upgrade of 69kV Transmission Lines 12 & 13/131	2027		109
Shoemaker 34.5, 69 and 13kV Station Upgrade*	G	Shoemaker	Shoemaker	Upgrade of Shoemaker Station	2028		-
Western Division 34.5 kV System	G	Shoemaker	Pocatello – Decker Switch- Bloomingburg -– Wurtsboro	Upgrade of 34.5 kV Western Division sub-transmission system	2029		50
TL Line 18 to 69kV	G	Rio	Port Jervis	Upgrade of 34.5kV Line 18 to 69kV	2030		99
TL Lines 24/241 & 25	G	Shoemaker	South Goshen, Hartley Road, Sugarloaf	Upgrade of 69kV Transmission Lines 24/241 & 25	2033		98
TL Lines 26 and 261	G	Sugarloaf	Sterling Forest, Ramapo	Upgrade of 138kV Transmission Lines 26 and 261	2036		144
					Total:	$417	500 MW

* These projects have spending in the upcoming proposed ORU rate case for 2022 through 2024.

1. Upgrade of 69kV Transmission Lines 12 & 13/131

Line 12 (Shoemaker-Mongaup) and Line 13/131 (Shoemaker-Cuddebackville-Mongaup) are parallel 69 kV transmission lines built in 1927. The foundations of the lattice towers that support these facilities are direct embedded grillages which are prone to deterioration over time. In addition, Figure 116 above shows that headroom on lines 12, 13, 131A, and 131B will decrease to -12-14 MW by 2030 due to the addition of PV and ES resources anticipated, based on the NYISO queue, as well as load growth in the area. To increase headroom, O&R would replace these lines, eliminating the existing 4/0 copper conductor, and constructing the new facilities with 795 MCM ACSR or larger conductor. The capacity increase in Line 12 & Line 13/131 will significantly improve their available headroom to unbottle current renewable projects, as well as future generation projects in the area that are planning to interconnect to these lines.

2. Upgrade of Shoemaker 34.5, 69 and 138kV Substations

The original 69kV Shoemaker Substation went into service in the early 1930's and has been in continuous service serving the Western Division. Currently the 69kV yard serves the local distribution system, as well as a switching station connecting to 14 other substations. During the 1950's, as the load continued to grow, O&R constructed a 34.5kV yard to serve the Western Division. In the 1970's, to reinforce the system further, O&R constructed a 138kV yard which currently supplies the 69 and 34.5kV yards. As shown in Figure 114above, Line 4 and Line 6 terminate at these substations and have limited available headroom by 2030. By upgrading the substation, particularly the 34.5 kV yard, it would be possible to terminate larger conductors thereby increasing the capability on these lines. This project calls for the construction of new 138 and 69kV stations adjacent to the existing stations. The preliminary design will consist of two new air insulated stations. The 138kV yard will have two 138/69 kV, 196MVA autotransformers and two 138/13.2kV, 50 MVA distribution transformers supplying a switchgear line up. In addition, there will be 138/34.5kV, 50MVA autotransformer to supply a new 34.5kV switchgear. The 138 and 69kV yards will have new control buildings. O&R will construct the new stations on property presently owned by O&R.

3. Upgrade of 34.5 kV Western Division sub-transmission system

The 34.5 kV Western Division sub-transmission system is a group of 34.5 kV lines that originate from Shoemaker Station and feed several distribution stations. This group of lines is comprised of Line 4 (Shoemaker – Pocatello), Line 6 (Shoemaker – Pocatello – Decker Switch – Bloomingburg – Wurtsboro) and Line 100 (Decker Switch – Bullville). These lines were built circa 1924 and are supported primarily by wood poles with some lattice towers. Many of the wood poles are original to the line and some of the foundations of the lattice towers that support these facilities have direct embedded grillages which are prone to deterioration over time. Moreover, O&R's study found that system headroom on line 6 will be used up by 2030 due to the addition of renewables and load growth. O&R would rebuild these lines using 795 MCM ACSR or larger conductor. The capacity increase of Line 4, Line 6 and Line 100 will significantly improve their available headroom to allow the interconnection of future generation projects in the area.

4. Upgrade of 34.5kV Line 18 to 69kV

Line 18 is a 34.5 kV transmission line built in 1928 and runs from Rio Station to Port Jervis Station. Line 18 is supported by wood poles and lattice steel towers. Many of the wood poles are original to the line and the foundations of the lattice towers that support these facilities are direct embedded grillages which are prone to deterioration over time. In addition, as shown in Figure 114, Line 18 has only 7 MW of headroom by 2030. To further increase headroom for the future addition of renewables and to meet load growth in the area, O&R would remove the existing 2/0 copper conductors and structures, replacing them with a 69kV line with 795 MCM ACSR or larger conductor. The capacity increase in Line 18 will significantly improve its available headroom to allow the interconnection of future generation projects in the area.

5. Upgrade of 69kV Transmission Lines 24/241 & 25

Line 24/241 (Shoemaker- Hartley-Sugarloaf) and Line 25 (Shoemaker-South Goshen-Sugarloaf) are parallel 69kV transmission lines built in 1929. The foundations of the lattice towers that support these facilities are direct embedded grillages which are prone to deterioration over time. As shown in Figure 114, Lines 24, and 25 have negative headroom of -7 and -35 MW by 2030, respectively, due to the assumed additions of PV and ES, along with load growth. To increase headroom, O&R would replace these lines, eliminating the existing 336 MCM ACSR conductor, and constructing the new facilities with 795 MCM ACSR or larger conductor. The capacity increase of Line 24/241 & Line 25 will significantly improve their available headroom to unbottle current renewable projects, as well as future generation projects in the area that are planning to interconnect to these lines.

6. Upgrade of 138kV Transmission Lines 26 and 261

Lines 26 (Ramapo-Sterling Forest) and 261 (Sterling Forest-Sugarloaf) are 138kV transmission lines built in 1929. The foundations of the lattice towers that support these facilities are direct embedded grillages which are prone to deterioration over time. As shown in Figure 114, lines 26 and 261 have negative headroom of -73 and -18 MW by 2030, respectively, due to the assumed additions of PV and ES, along with load growth. To increase headroom, O&R would replace these lines, eliminating the existing 336.4 MCM ACSR conductor, and constructing the new facilities with 795 MCM ACSR or larger conductor. The capacity increase of Lines 26 and 261 will significantly improve their available headroom to allow the interconnection of future generation projects in the area.

vii) Potential Projects that would Increase Capacity on the Local Transmission and Distribution System to allow for Interconnection of New Renewable Generation Resources within O&R's System

In addition to Phase 1 proposed transmission projects identified in Section VI, O&R's Phase 1 proposed distribution projects will be discussed in the Distribution report.

viii) Summary of Transmission Projects

This study allowed O&R to develop and plan for multi-value projects that will enable utility-scale distributed energy resources and storage interconnections, unbottle capacity limited facilities, and facilitate the upgrade of aging and obsolete infrastructure. O&R used the NYISO's transmission renewable projects queue to align its "no regrets" investment. Therefore, O&R recommends the following O&R transmission projects to support the CLCPA:

1. Upgrade of 69kV Transmission Lines 12 & 13/131;
2. Upgrade of Shoemaker 34.5, 69 and 138kV substation;
3. Upgrade of 34.5 kV Western Division sub-transmission system;
4. Upgrade of 34.5kV Line 18 to 69kV; and
5. Upgrade of 138kV Transmission Lines 26 and 261.

B. Distribution

i) Introduction

To achieve the clean energy goals outlined in the CLCPA, significant local transmission and distribution investment will be required to eliminate system constraints that inhibit the interconnection of DER, increase transmission and distribution hosting capacity, and provide the necessary headroom to support the anticipated load due to beneficial electrification.

Each year, O&R invests significant capital resources in well-prioritized traditional infrastructure improvements designed to improve system reliability, address aging or obsolescent equipment, and provide for the future capacity needs of the communities we serve. As per the May 14 Order, O&R considered the following:

- Determine where existing "headroom" exists on the system;
- Identify existing constraints/bottlenecks that limit energy deliverability;
- Identify synergies with the traditional capital investment plan to identify multi-value projects;
- Identify new/emerging technologies that can accompany or completement traditional upgrades;
- Identify least cost upgrade projects to increase the capacity of the existing system;
- Identify new projects which would increase capacity and allow for interconnection of new renewable generation sources; and
- Identify the possibility of fossil generation retirements.

To determine where existing headroom exists, O&R conducted a planning analysis at the substation level using the 2030 base (business as usual) summer peak forecast.[157] To identify any gaps between the base forecast and the 70x30 CLCPA goals, O&R compared modifier assumptions in the base forecast to the CLCPA projections in O&R's Long-Range Plan ("LRP"). As a result, O&R used a higher EV adoption rate for this analysis (see Figure 117). To determine available 'headroom' by substation, O&R conducted a planning analysis to determine the maximum load each station can support while still meeting the Distribution Design Standards for loss of bank.

[157] Based on 2019 Summer Peak Forecast.

Figure 117:. 2030 Base Case versus CLCPA Modifier Assumptions

Load Modifier	2030 Base Forecast Assumption	2030 CLCPA Assumption	Comment
EV	68MW	214MW	~146MW additional EV considered
Space Heating	None	None	System remains summer peaking in 2030. Additional sensitivity analysis performed for later years 2030+.
PV	76MW (coincident), 321MW (nameplate)	Same	PV forecast includes adoption assumptions for small projects (<50kW) plus 100 percent of DER queue
EE	154MW (includes 10MW DR and 7MW of Organic EE)	Same	EE Reduction assumptions same for base versus CLCPA forecast.
Storage	81MW (83MW Nameplate)	Same	Storage assumptions same for base case versus CLCPA forecast
DG/CHP	29MW	Same	DG/CHP assumptions same for base case versus CLCPA forecast

In addition to the CLCPA 70x30 case, O&R performed additional sensitivity analysis in O&R's LRP to determine the impact of the 2040 and 2050 CLCPA goals. While O&R identified no additional projects at this time, assumptions regarding adoption rates, technologies, and policy may drive the need for future capital projects to support winter peaking loads beyond 2030.

As seen in

Figure 118, O&R identified fourteen NY substations with potential “headroom” issues by 2030, due to either base load growth or higher EV adoption rates. O&R then compared these results to the current ten-year capital investment plan to determine synergies with existing projects and/or programs. As shown in Figure 119, constrained areas align well with existing budgeted projects.

Figure 118:. 2030 Summer Peak Substation Base Forecast with Incremental CLCPA EV Load

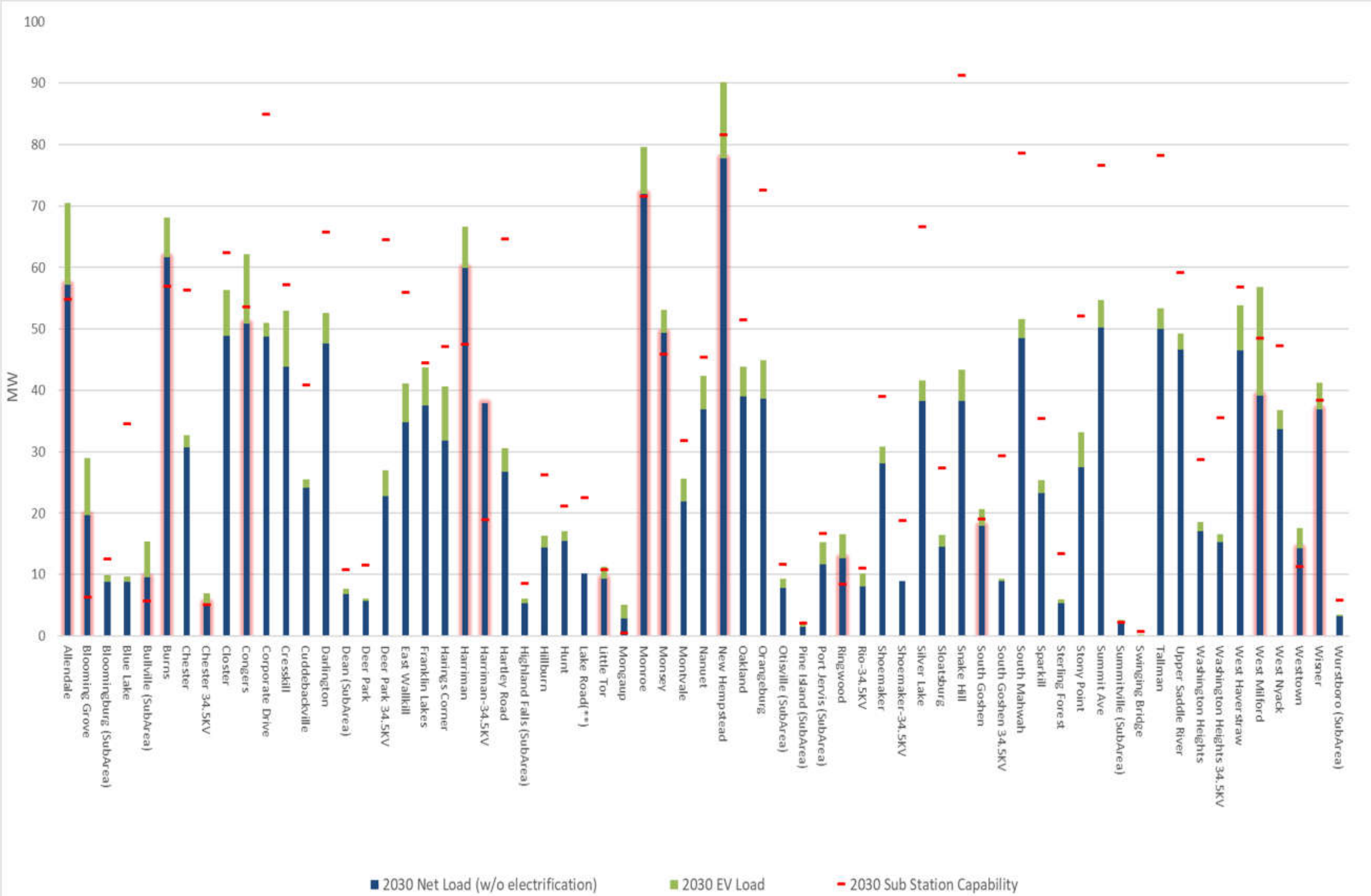


Figure 119: NY Distribution Substations with Potential 2030 Capacity Constraints

Substation	Solution	Budget Year
Blooming Grove	New Blooming Grove Substation	2023
Bullville	Bullville Substation Upgrade	2027
Burns	Burns 3rd Bank/Upgrade remaining two banks & switchgear	2026/2028
Chester 34.5kV	New South Goshen Station will provide relief to S Goshen 34.5kV which will increase backup to Chester 34.5kV	2032
Congers	Little Tor Substation/Congers Bank & Switchgear Upgrades	2023/2030
Harriman	Woodbury Substation/Harriman Upgrade	2025/unbudgeted
Harriman 34.5kV	Line 841/851 Upgrade	Currently in Study Phase
Little Tor Mobile	Little Tor Substation	2023
Mongaup	Mongaup Upgrade	unbudgeted
Monroe	Woodbury Substation	2025
Monsey	Monsey NWA	In progress
New Hempstead	Little Tor Substation/Burns 3rd Bank	2023/
South Goshen	New South Goshen Substation	2032
Westtown	Westtown 2nd Bank	2029
Wisner	W. Warwick NWA/W. Warwick Substation	In progress/2028

Consistent with the May 14 Order, O&R also considered constrained areas or areas with known bottlenecks. Due to the high penetration of distribution sided resources in O&R's Western Division, the Westtown and Bullville Substations are at/near maximum hosting capacity based on the full interconnection queue. O&R recommends the upgrade of these stations as Phase 1 projects. These upgrades will eliminate bank/circuit thermal capacity constraints and allow increased interconnection of DERs in these areas. Bullville is also limited by the existing 34.5kV sub-transmission system that supplies the station. Upgrade of these lines (see Western 34.5kV upgrades in the transmission portion of this document) is also required to reach the full hosting capacity of the substation.

The May 14 Order also directs the Utilities to identify new technologies that can accompany/complement traditional upgrades. This approach was taken with several of the Phase 1 recommended projects. The Bullville, Blooming Grove, and Woodbury substation projects will be traditional investments designed with an area reserved for on-site energy storage. O&R envisions that this 'hybrid' approach can leverage battery technology to capture excess local generation, reduce peak loading on equipment, and improve load factor. This additional storage capability is critical to achieving CLCPA targets for storage and balancing the bi-directional flow of energy. In addition, the proposed Woodbury Battery project will use a mobile battery technology to reduce local circuit peak to support new area load growth until the new Woodbury substation is constructed. See Phase 1 project descriptions for additional detail on these projects.

In addition, O&R has been modernizing its electric delivery system for over 15 years by investing in key systems and technologies directly in line with its Distributed System Implementation Plan ("DSIP"). This includes 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"). O&R views these systems and technologies as critical to improving the safety, reliability, and operation of the distribution system as well as foundational investments in the transition to Distributed System Platform ("DSP") provider. O&R views implementation of these technologies as critical to support the CLCPA and Reforming the Energy Vision ("REV") goals (see Figure 120). Additional detail on the Companies programs can be found in the 2020 DSIP filing.

Figure 120:. Grid Modernization and DSP Investment

Program/Project	2021	2022	2023	2024	2025	Commentary/Work Plan
MOAB Upgrade Program	$1.2M	$1.2M	$1.2M	$1.2M	$1.2M	Replace manual field switches with DSCADA controlled motor operated switches
DA Smart Grid Expansion Projects NY	$4.5M	$8.3M	$8.3M	$8.3M	$8.0M	Deploy Smart Grid Automation (Reclosers/MOABS)
NYSERDA PON 4074	$0.8M	$1.1M	$0.2M	-	-	Westtown Automation
ADMS	$4.5M	$6.8M	$4.7M	-	-	ADMS system
ADMS – Phase 2 (DERMS)	-	-	$3.9M	$1.5M	$1.5M	DERMS
Grid Mod 4G-5G	$1.5M	$1.2M	$1.2M	$1.2M	$1.2M	Communication
DA RTU Replacement	$0.08M	$0.6M	$0.8M	$1.2M	$1.6M	DSCADA RTU Upgrades
Total	$12.6M	$19.2M	$20.3M	$13.4M	$13.5M	

O&R also continues its foundational Clean Energy initiatives detailed in its 2020 DSIP Plan that includes Grid Modernization projects, non-wires alternatives, EV make ready programs and Bulk Storage solicitations. The five (5) year spending plan is shown in Figure 121.

Figure 121: CLCPA Initiatives

Program/Project	2021	2022	2023	2024	2025	Commentary/Work Plan
Non-Wires Alternative Solutions	$5.4M	$44.1M	$40.7M	$4.6M	$4.7M	Pomona Monsey West Warwick Hillburn Mountain Lodge Park Sparkill
EV Make Ready Infrastructure Program	$5.2M	$5.2M	$5.2M	$4.2M	$4.2M	Make Ready Incentives Future Proofing Fleet Assessment Service Implementation Costs
Bulk Storage Solicitation	$1M	$1M	$14M	-	-	
Total	$11.6M	$50.3M	$59.9M	$8.8M	$8.9M	

ii) Non-Wires Alternatives ("NWA")

O&R envisions NWA to be an integral part of deploying DERs to achieve CLCPA goals. Currently New York State is ranked #1 for NWA in the country. O&R will continue to execute NWA projects to further the State's goals of deploying DERs and integrating it with their overall system planning and system operations.

O&R continues to pursue NWA projects where non-traditional technology can be used to address system constraints and defer traditional capital investment. Over the next five years, O&R is investing approximately $99.5 million in six NWA solutions (see Figure 121). Additional detail regarding each of these proposed NWA projects can be found in the 2020 DSIP filing.

iii) EV Make Ready Infrastructure Program

Over the next five years O&R is planning to spend approximately $24 million on the electric vehicle ("EV") make-ready investments (see Figure 121). Additional details can be found in O&R's EV Make Ready Implementation Plan. The Make Ready Infrastructure will support the State's goal to deploy 850,000 EVs by 2025.

iv) Bulk Storage Solicitation

The Commission mandated that O&R procure 10MW of storage as part of a Bulk Solicitation initiative. O&R's first round solicitation did not yield any winning vendors. O&R has conducted multiple rounds of review with vendors, Commission and NYSERDA to understand how to amend its RFP to meet the market needs. O&R is on track to issue a new RFP for the Bulk Storage Solicitation in Q2, 2021. This $16 million investment in ES will advance the CLCPA's goals for energy storage.

v) Phase 1 Distribution Projects

Based on the multi-value approach O&R has taken with the study, all the recommended distribution projects in this Report are being considered Phase 1 (projects included in O&R's capital plan). To address the CLCPA's goals, many of the designs have been modified to facilitate DER interconnection, increase hosting capacity and support future beneficial electrification. Where appropriate, new substations are being designed with provisions for future on-site ES to advance the CLCPA's goals and balance the bi-directional flow of energy. This ES will be used to capture local excess generation, reduce station peak load and improve load factor. No new Phase 2 projects were identified, and retirement of fossil fuel generation does not apply to O&R.

As stated in the Transmission study section of this Report, O&R's Central and Western Divisions contain farmlands and open spaces that offer opportunities for developers to site their PV and ES projects which will assist in meeting the CLCPA's targets. O&R has developed a flexible investment approach that prioritizes the removal of older facilities while installing systems that will provide capacity for normal load growth and accommodate renewable projects. Figure 122 details O&R's Phase 1 project portfolio.

Figure 122: O&R Phase 1 CLCPA Distribution Projects

Project Name	Related CLCPA Transmission Project	Project Description	Proposed I/S Date	OOM ($M)	Net MW Benefit
Bullville Substation*	Western Division 34.5 kV System	Upgrade existing 25MVA single bank substation with provisions for modular utility owned storage.	2027		33
Bloomingburg Substation	Western Division 34.5 kV System	Upgrade existing 20MVA single bank substation	2030		38
Wurtsboro Substation	Western Division 34.5 kV System	Upgrade existing 5MVA single bank substation and convert 4.8kV area	2029		30
Rio Substation	Line 18	Upgrade existing 18MVA single bank substation	2030		21
Shoemaker Substation	Shoemaker Campus Upgrade	Construct new 138kV transmission yard and upgrade existing 35MVA single bank substation	2028		41
Blooming Grove Substation*	NA	Upgrade existing 25MVA single bank substation with provisions for modular utility owned storage.	2023		51
Woodbury Substation*	NA	New Substation to support load growth, reliability, and hosting capacity in the Harriman Area (Monroe, Blooming Grove, Woodbury, Harriman).	2025		76
Woodbury Batteries*	NA	Utility owned batteries to support area growth that could potentially have mobile capability to interconnect into future substations.	2023		-

Project Name	Related CLCPA Transmission Project	Project Description	Proposed I/S Date	OOM ($M)	Net MW Benefit
Westtown Second Bank/UG Exits	NA	Improve reliability for loss of Bank 1103 and increase hosting capacity in this area (bank limitation reached).	2029		18
			Total	156	308

* These projects have spending in the upcoming proposed ORU rate case for 2022 through 2024.

1. *Bullville Substation*

The Bullville Substation is a single-bank station on the edge of the service territory with one 25MVA, 34.5/13.2kV transformer serving three 13.2kV distribution circuits. The 34.5kV feed to the station is radial from Line 100 with manual backup from a long 34.5kV distribution circuit. The ability for this station to serve load and host DER is currently limited by the 34.5kV sub-transmission system.

Once the 34.5kV transmission system is upgraded (see Western Division 34.5kV CLCPA transmission project), the constraint will become the single 25MVA transformer. To address station reliability, age and obsolescence issues, and minimum approach distance ("MAD") concerns, the station is budgeted to be upgraded to a two-bank station in 2027.

The new station will have two larger 35MVA banks with additional circuits to support reliability and improve DER hosting capacity. Additional space at the substation site will be reserved for future on-site ES. This ES will be sized to store excess generation during the day which can be discharged in the evening to reduce station peak and improve station load factor.

Estimated Substation DER Hosting Capacity Increase: 33MW

2. *Bloomingburg Substation*

The Bloomingburg Substation is a single bank station with one 20MVA, 34.5/13.2kV transformer serving two 13.2kV distribution circuits. The ability for this station to serve load and host DER is currently limited by the station bank/circuit capacity. The 34.5kV feed to the station is radial from a long 34.5kV circuit that also serves area load directly. Transmission backup is automatic from another long radial 34.5kV circuit that serves two substations and distributed load. Once the 34.5kV transmission system is upgraded (see Western Division 34.5kV CLCPA transmission project), the station will be supplied from the new reliable transmission loop. To address station reliability, age and obsolescence issues, and MAD concerns, the station is budgeted to be upgraded to a two-bank station in 2030. The new station will have two larger 35MVA banks with additional circuits to support area reliability and improve DER hosting capacity.

Estimated Substation DER Hosting Capacity Increase: 38MW

3. Wurtsboro Substation

The Wurtsboro Substation is a single bank station with one 5MVA, 34.5/4.8kV transformer serving two 4.8kV distribution circuits. The ability for this station to serve load and host DER is severely limited by the 4.8kV area operating voltage, small bank size, and circuit capacity. The 34.5kV feed to the station is radial from a long 34.5kV circuit that also serves one additional substation and other area load directly. Transmission backup is automatic from another long radial 34.5kV circuit that serves one substation and other distributed load. Once the 34.5kV transmission system is upgraded (see Western Division 34.5kV CLCPA transmission project), the station will be supplied from the new reliable transmission loop. To address station reliability, age and obsolescence issues, and MAD concerns, the station is budgeted to be upgraded in 2029. The new station will have provisions for two banks. One 35MVA transformer will be installed initially, with the ability to install a second when needed to support area load/DER hosting capacity. Other area projects are currently planned to begin the conversion of the area from 4.8kV to 13.2kV to improve reliability, hosting capacity, and prepare for the future station upgrade.

Estimated Substation DER Hosting Capacity Increase: 30MW

4. Rio Substation

The Rio Substation is a single-bank station on the edge of the service territory with one 18MVA, 69/34.5kV transformer (Bank 53) serving one 34.5kV distribution circuit. For loss of Bank 53, 34.5kV Line 18 can provide 100 percent bank backup. In 2010, to improve circuit reliability, O&R installed two 5 MVA, 34.5/13.2kV transformers outside the Rio substation and part of the Rio load area was converted to 13.2kV. Each transformer supplied one 13.2kV circuit allowing the load area to be split and distribution automation to be installed. This significantly improved area reliability and prepared for the future upgrade of the Rio Substation. Although Bank 53 has a higher rating, the 5MVA banks limit the ability of the station to serve load and host DER. With the proposed upgrade of Line 18 (see Upgrade of 34.5kV Line 18 to 69kV CLCPA Transmission Project), Rio will no longer have backup for loss of Bank 53. To meet Design Standards, during the upgrade of Line 18 the station will be upgraded to a two- bank design. The new station will have two larger 20MVA banks with additional circuits to support reliability and improve DER hosting capacity. At that time, the 5MVA transformers will be removed significantly increasing area hosting capacity.

Estimated Substation DER Hosting Capacity Increase: 21MW

5. Shoemaker Substation

The Shoemaker Substation is an energy hub located in the Western Division of O&R’s service territory. The existing campus includes transmission yards operating at 138kV, 69kV, and 34.5kV. The 69kV yard is the most critical transmission station in the Western Division. Nearly all of the Western Division Substations are supplied either directly or indirectly from the 69kV yard.

In addition, the area is experiencing high interest from developers to interconnect BESS/PV projects at both the distribution and transmission level.

Due to age (civil conditions), equipment obsolescence, and to improve both transmission and distribution reliability, the Shoemaker campus is scheduled to be rebuilt in 2028 (see Shoemaker Station Upgrade CLCPA Transmission Project). The upgraded station will also function as an area 'clean energy hub' by redistributing excess green energy from area stations with lower load to locations of higher demand.

As part of the upgrade, the existing 35MVA, 69/13.2kV transformer will be replaced with two 50MVA, 138/13.2kV transformers with five additional circuit positions to support area reliability and improve DER hosting capacity.

Estimated Substation DER Hosting Capacity Increase: 41MW (distribution only)

6. *Blooming Grove Substation*

The existing 69kV Blooming Grove Substation is a single bank substation with one 25MVA, 69/13.2kV transformer serving four 13.2kV distribution circuits. The northern portion of the load area served by Blooming Grove borders Central Hudson's service territory. This limits distribution tie capability to the two circuit ties to the south (along Routes 94 and 208). Due to the limited switchable backup, the station does not meet the distribution design standard for loss of bank.

In late 2018, O&R issued an NWA request for proposals to solve for the loss of Bank 276. While O&R received several proposals, a thorough third-party and internal review determined that none were technically viable and/or in the spirit of New York State's REV initiative as they relied heavily on fossil fuel generation. As a result, the traditional solution was re-prioritized in the budget and is currently scheduled for completion in 2023.

To address station reliability, age and obsolescence issues, and MAD concerns, the station is budgeted to be upgraded to a two-bank station in 2023. The new station will have two larger 50MVA banks with additional circuits to support reliability and improve DER hosting capacity. Additional space at the substation site will be reserved for future on-site energy storage. This storage will be sized to store excess generation during the day which can be discharged in the evening to reduce station peak and improve station load factor.

Estimated Substation DER Hosting Capacity Increase: 51MW

7. *Woodbury Substation*

A new area substation is required by June 2026 to meet the projected demand in the rapidly growing municipalities of the Village/Town of Monroe, Woodbury, Palm Tree, and Harriman. O&R has evaluated several area parcels and is working to secure a site. The overall project scope includes the construction of the new Woodbury Substation, the underground transmission extension of existing 69kV Transmission Line 312 to feed the new substation, and the associated new substation distribution circuit exits.

The new station will be constructed with two 50MVA, 69/13.2kV transformer banks with provisions to install a third future transformer. The switchgear will be designed with 15 circuit positions to support area load growth, reliability, and improve DER hosting capacity. At this time, natural gas service may not be available to several of the proposed subdivisions. To support the potential for additional electric load due to electric heating, the station is being designed with larger transformers, additional circuit positions, and the ability to expand the station.

An area at the substation site will be reserved for future on-site ES to reduce station peak demand and improve station load factor as local DER penetration increases.

Estimated Substation DER Hosting Capacity Increase: 76MW

8. Woodbury Batteries

A new area substation (see Woodbury Substation project) is required by June 2026 to meet the projected demand in the rapidly growing municipalities of the Village/Town of Monroe, Woodbury, Palm Tree, and Harriman. Until the substation project is completed, approximately 3MW/12MWH mobile batteries are needed at two locations to meet the peak load in this area. This load relief will prevent thermal issues on existing equipment and allow O&R to meet projected load demand until completion of the proposed Woodbury Substation in 2026. At that time, the batteries will no longer be required at that location and can be re-used at other locations or stored for future use.

Estimated Substation DER Hosting Capacity Increase: N/A

9. Westtown Second Bank/UG Exits

The Westtown Substation is a single-bank station with one 35MVA, 69/13.2kV transformer serving four 13.2kV distribution circuits. Although the 2019 WN peak load on the station was only 12.4 MVA, the bank is currently closed to new large DER interconnections to prevent thermal violations of the bank. While the station currently passes the Design Standard for loss of bank, it has limited outside ties which make the station difficult to offload for emergency or scheduled work. Due to the high penetration of DER in the area, additional distribution switching is usually required to disconnect large generators before transferring load between circuits/stations.

To improve area reliability and re-open the station to new DER interconnections, a second 35MVA transformer should be installed with four additional circuit positions. O&R will install new underground exits as part of the project to reduce circuit exposure and unbottle DER hosting capacity on constrained circuits. The existing station is already constructed to accept a second bank. Additional work is needed to modify or replace the existing switchgear and install new underground exits.

Estimated Substation DER Hosting Capacity Increase: 18MW

vi) Conclusion

Orange and Rockland has provided details for proposed Transmission and Distribution Phase 1 type projects that can be seen as multi-value with no regrets. The projects will enable renewable generation interconnection as well as remedy the condition of aging assets. While the vast majority of the projects are in the current ten (10) year budget plan, O&R has included incremental Transmission investment in the next proposed rate case for our January 2021 filing (first rate year 2022). This includes the Line 12/13/131 upgrade project, which is the first of several 69kV projects scheduled for upgrade.

The remaining CLCPA Phase 1 Distribution projects are in alignment with O&R's base budget plan with no acceleration proposed in the upcoming rate case.

Part 3: Advanced Technologies Working Group

I. INTRODUCTION

The goal of the Advanced Technologies Working Group (ATWG) is to develop plans for the Utility Transmission and Distribution Investment Working Group to further the goals of the Climate Leadership and Community Protection Act (CLCPA) by considering roles and opportunities for grid investments in advanced technologies that apply to the Utilities, transmission owners, and operators. The working group focuses on developing research and development plans for new and/or underutilized technologies and innovations necessary to meet and advance New York's clean energy goals. The context for the ATWG's initial focus are:

I. The transmission system, especially the sub-transmission system (138/115 kV) and below.
II. The 70% renewable energy by 2030 targets.

II. OBJECTIVE

To address these goals, the working group is developing plans to study, evaluate, pilot, demonstrate, and deploy new and/or underutilized technologies and innovations that are able to increase electric power throughput, increase electric grid flexibility, increase renewable energy hosting capacities, increase the electric power system efficiencies and reduce overall system costs. Among the questions being considered are the following:

- Are there existing technologies that can improve the efficiency of the grid that are being underutilized?
- Are there research and development opportunities for new or emerging technologies?
- How should we organize the State's research and development effort?
- How do we coordinate work with other State, National, and International research and development stakeholders (EPRI, Universities, National Labs, DOE, ARPAe, etc.)?
- How do we coordinate this work with the other technical analysis and policy working group teams?
- How will the Utilities integrate new technologies into planning and operations?

III. PRIORITIZED ISSUES

The group has prioritized several issues as being key to achieving CLCPA goals. These include the need to:

- Alleviate transmission system bottlenecks to allow for better deliverability of renewable energy throughout the State,
- Unbottle constrained resources to allow more hydro and/or wind imports and the ability to reduce system congestion,
- Optimize utilization of existing transmission capacity and right of ways, and
- Increase circuit load factor through dynamic ratings.

To address transmission system bottlenecks, the group has developed a list of potential technology solutions that could include:

- Utilizing energy storage for transmission and distribution services,
- Investigating low-frequency AC transmission systems,
- Utilizing high voltage DC grids,
- Utilizing and coordinating deployment of flexible AC transmission system components,
- Utilizing dynamic and ambient adjusted transmission line and cable rating systems,
- Utilizing dynamic, closed-loop voltage and reactive power controls,
- Improving operator situational awareness,
- Utilizing wide-area monitoring systems,
- Developing new decision support tools,
- Developing new advanced energy management automation,
- Developing new advanced contingency analysis tools,
- Utilizing dynamic power flow controllers, and
- Developing new renewable energy siting tools.

To address the optimized utilization of existing transmission capacity and rights of way, the group has developed a list of potential technology solutions that could include:

- Transformer, cable and transmission line monitoring systems,
- Advanced sensor placement tools,
- Advanced transmission and sub-transmission voltage regulation systems,
- Dynamic line and equipment rating systems,
- Energy storage for grid services,
- Advanced high-temperature-low-sag conductors and new composite conductors,
- New compact tower designs,
- Power flow controllers,
- Global information system utilization,
- Sulfur hexafluoride monitoring and alternative systems,
- Modular solid-state transformers and other advanced grid control devices, and
- Improved ability of transmission lines to redirect flow to underutilized lines.

IV. POTENTIAL TECHNOLOGY SOLUTIONS

The working group engaged the Electric Power Research Institute (EPRI) to develop potential technology solution summaries for the highest prioritized technology categories which included an overview of their technologies, key application considerations, their commercial readiness level, vendor landscape, and field/lab testing experience. The developed summary information, use cases, and/or case studies for these solutions categories included: dynamic line ratings and improved transmission utilization; power flow control devices and distributed or centralized flexible AC transmission systems (FACTS); energy storage for transmission and distribution services; improved operator situational awareness; transformer monitoring; advanced high-temperature, low sag conductors; compact tower designs; and sulfur hexafluoride or alternative fluid monitoring systems. Below is a brief overview of each of the potential technology solution summaries.

A. Dynamic line ratings and improved transmission utilization:

There are several factors, including line clearance, thermal rating limits, contingency conditions, that contribute to the overall rating of a transmission line. While other solutions exist for increasing capacity, many efficient solutions have been exhausted or are not feasible. For example, re-tensioning a line can be used to mitigate clearance concerns. However, the conductor, tower, and foundations must all be capable of supporting increased mechanical load for this to be a viable option. Increasing tension can also lead to vibration issues which are detrimental to conductor health if mitigation methods are not deployed. Real time or dynamic rating technologies seek to leverage the time-varying changes in the environment. Utilities using static ratings have more capacity available most of the time due to the conservative nature of the rating method. A static rating is simplest for design and operations as it never changes. The rating today is the same as the rating tomorrow. The odds of the true capacity of the line being lower than a static rating defines the rating risk. Ratings risk tolerance varies by utility and can vary within a utility transmission system. Case studies and available literature show that most utilities would have additional capacity available between 80% and 99% of the time. The amount of extra capacity depends on the real time weather conditions and is examined in the technology summary.

B. Power flow control devices – distributed and centralized FACTS:

Power flow control devices, in addition to traditional transmission technologies, provide a suite of alternatives to direct the flow of power more efficiently on the grid, improving flexibility and enabling the grid to be more responsive and resilient. Traditional technology solutions to control power flow—such as phase-shifting transformers (PSTs)—have been used extensively for reducing loop flows or to maintain scheduled power flow on certain paths. They have also been used in some cases to reduce overloads by diverting power flow from heavily loaded lines to other lines with spare capacity, increasing the utilization of existing transmission assets and consequently reducing the need for certain transmission upgrades. In recent years, new power flow control technologies have been developed. Relative to the more traditional power flow technologies such as PSTs, flexible AC transmission systems (FACTS), and high voltage direct current (HVDC) technologies, the new PFC devices are simpler, more compact, and scalable. Some of these new PFCs have great potential but still are at an intermediate stage of development, while others are already commercially available, such as the distributed series compensator technology, developed and commercialized by vendors.

C. Energy storage for T&D services:

Energy storage is increasingly being considered for many transmission and distribution (T&D) grid applications to potentially enhance system reliability, support grid flexibility, defer capital projects, and ease the integration of variable renewable generation. Central to the State's policies and mandates is the need to enhance power system flexibility to effectively manage renewable energy deployment and the associated increase in variability. As power systems begin to integrate higher penetrations of variable, renewable, inverter-based generation in place of conventional fossil-fuel fired synchronous generation, grid-scale energy storage could become an increasingly important device that can help maintain the load-generation balance of the system and provide the flexibility needed on the T&D system. Pumped hydro storage (PHS) and compressed air energy storage (CAES) are long-established bulk energy storage technologies. Utility-scale lithium ion battery storage has expanded dramatically, as decreasing lithium ion battery costs make this an increasingly cost-effective solution to meet T&D non-wire, reliability, and ancillary service needs. Redox flow batteries, sodium sulfur batteries, thermal energy storage (both latent and sensible heat), and adiabatic compressed air energy storage are all in various stages of demonstration. This information provides a concise overview of a wide variety of existing and emerging energy storage technologies being considered for T&D systems. It describes the main technical characteristics, application considerations, readiness of the technology, and vendor landscape. It also discusses implementation and performance of different energy storage technologies. In this Report, energy storage systems greater than 10 MW and four or more hours of duration, are considered as bulk and transmission and sub-transmission-connected energy storage.

D. Improved operator situational awareness:

Recent changes and trends in electrical energy—both on the generation side, with increasing levels of electricity generation from renewable energy sources such as wind and solar, and on the energy consumption side, with new and more efficient consumption technologies—are changing use patterns and dynamical characteristics of the entire infrastructure. Traditional situational awareness tools available to system operators in the energy management system (EMS) will not be adequate due to a stochastic environment with faster dynamics resulting from these changes. Developing advanced analytical tools to perform system security analysis and based on that provide integrated decision support solutions using cognitive systems engineering to the system operators will be necessary. This section discusses some of the advanced situational awareness tools in various stages of technology readiness being developed to meet the future needs. Some of the tools discussed are those using synchrophasor technology, dynamic security analysis, advanced short-term forecasting tools for much granular real and reactive power load as well as solar and wind generation, and much faster simulation and analytical tools. In addition, a comprehensive monitoring system would ensure the operators that all the advanced situational awareness tools are functioning as planned.

E. Transformer monitoring:

Large substation transformers that interconnect different voltage levels of the grid are major capital assets that are essential to the reliable delivery of economic power. Transformers can also perform a critical role in supporting utility efforts to increase power flows through existing transmission corridors to optimize grid utilization. Given the importance of transformers in a power system—and their high cost and long lead time for replacement—managing transformer fleets to maintain high levels of health and performance presents ongoing challenges for utilities striving to employ their assets to the fullest extent possible while maintaining system reliability and controlling costs. The challenges are compounded by transformer demographics. A high percentage of installed transformers are approaching or have exceeded their 40-year design lives. Replacing large numbers of these aging assets is neither practical nor financially feasible, so utilities seek to get as much performance and remaining life as possible from their transformer fleets. System abnormalities, loading, switching, and ambient conditions normally contribute to transformer accelerated aging and sudden failure. Therefore, central to transformer management is effective monitoring to gain a comprehensive view of transformer health, which can help utilities assess equipment condition, diagnose incipient degradation, anticipate problems, prevent failures and extend transformer life. Provided results are properly interpreted, monitoring offers intelligence to support repair/refurbish/ replace decisions that maximize performance and minimize costs. In short, monitoring can help utilities ensure that transformers stay healthy and perform critical functions such as supporting sustained additional loads, and not be the weak links in the power delivery chain.

F. Advanced high-temperature, low sag (HTLS) conductors:

More than 80% of bare stranded overhead conductors used in transmission lines consist of a combination of 1350-H19 (nearly pure aluminum, 1350, drawn to the highest temper possible—H19) wires, stranded in one or more helical layers around a core consisting of one or more steel strands. The steel strands are coated by one of several different methods to resist corrosion. By varying the size of the steel core while keeping the cross-sectional area of aluminum constant, the composite tensile strength of aluminum cable steel reinforced (ACSR) conductors can be varied over a range of 3 to 1. The mechanical and electrical properties of ACSR (and all aluminum conductors, such as AAC, AAAC, and ACAR) are quite stable with time, as long as the temperature of the aluminum strands remains less than 100°C. Above 100°C, the work-hardened aluminum strands lose tensile strength with time at an increasing rate with temperature. The steel core strands, however, are unaffected by operation at temperatures up to at least 300°C (although conventional "hot-dip" galvanizing may be damaged by prolonged exposure to temperatures above 200°C). The sag-temperature behavior of ACSR is also dependent on the size of the steel core. At moderate to low conductor temperatures, the thermal elongation rate of ACSR is between that of steel (11.5 micro strain per °C) and that of aluminum (23 micro strain per °C). For example, with Drake ACSR, the thermal elongation is 18.9 micro strain per °C up to a temperature about 70°C but decreases to the thermal elongation rate of the steel core alone (11.5 micro strain per °C) at higher temperatures. High temperature low sag (HTLS) conductors are able to operate continuously at temperatures above 100°C (the HT part) without any reduction in breaking strength. In addition, they exhibit thermal elongation rates that are less than ACSR (the LS part). This characteristic allows the HTLS conductor to sag less than a conventional ACSR conductor at any temperature, especially elevated temperatures.

G. Compact tower designs:

Increasing transmission transfer capacity within existing right of ways is a potentially efficient and economic approach to solving thermal constraints. A compact transmission line may, be defined as a line where the lateral dimensions of the line - tower height, tower width, and minimum right-of-way width - are reduced relative to older existing lines of the same voltage class. There are numerous compact tower designs for horizontal, vertical, and phase compaction that can be considered to increase transfer capacity. The technology summary examines each of the line compaction designs and explores the associated advantages and disadvantages.

H. SF6 monitoring/ SF6 alternatives:

Electric utilities are facing increasing regulatory pressure and technical challenges related to the management of sulfur hexafluoride (SF6), which is widely used as an arc-quenching medium and as electrical insulation in gas-insulated substations (GIS) and gas-insulated lines (GIL). SF6 is a powerful greenhouse gas and at times can produce toxic decomposition products under certain fault conditions. Several countries outside of the United States and some U.S. states have implemented or are considering regulations to limit SF6 emissions above certain thresholds. In addition, alternatives to SF6 have emerged. The twin challenges of increasing regulatory scrutiny and the existence of potential SF6 replacements put the industry on the brink of significant technological disruption in this area. The issues associated with SF6 management and emerging SF6 alternatives are of concern especially for utilities seeking to build new substations and lines to alleviate transmission bottlenecks, reduce congestion and allow delivery of power from renewable sources from remote or distant locations. Gas-insulated substations and lines offer many benefits including compact size, modularity, physical security and protection from pollution and harsh environments. Their compactness and modularity make them especially suitable when new substations are needed in areas where land space is limited and/or expensive, or in communities that desire visually unobtrusive power infrastructure. The industry thus has two high-priority needs regarding GIS/GIL and SF6: effective monitoring and diagnostic technologies to support SF6 management, and answers to significant questions about the dielectric performance, safe and effective handling, operation, maintenance, and disposal of SF6 alternatives. Also needed is a clear understanding of the tradeoffs and expectations utilities may experience when using the new technologies.

V. CONSIDERATIONS

A. Forum / Venue / Evaluation Plan

As part of this section, the working group is providing some high-level recommendations for better planning the investment in and implementation of new technologies and innovations for the New York state electricity grid. The following three items are of great value in the evaluation and coordinated implementation process:

i) Operation of a joint utility R&D advisory working group:

As transmission and distribution grids are evolving, it is becoming increasingly evident that the grid operates in an integrated manner. In an environment like NY, where a highly interconnected electricity grid is owned by several transmission owners, proper coordination among all these stakeholders is needed to optimize the grid operation and performance. This also applies to the deployment of advanced technologies, especially the ones that are utilized for improving the power system operation and control. Many of these technologies only provide their true value and maximum potential if deployed strategically in a coordinated way. For New York to be able to more effectively utilize and adopt new technologies, it is, therefore, of high importance to maintain proper coordination among all relevant stakeholders on this topic. This will allow new ideas to be thoroughly discussed and evaluated from a holistic perspective, identifying the best use cases for them, which can provide maximum value to the grid overall. It will also allow for pilot or demonstration projects as well as the coordinated optimal deployment when a technology reaches a potential implementation stage.

A second significant benefit of an ongoing advisory working group is the continuous exchange of information between transmission owners and other stakeholders in a more comprehensive and formalized way. This will lead to sharing experiences with specific technologies or products, therefore avoiding duplication of effort leading to similar learnings or mistakes. Coordination would also avoid duplication of research resources and funds. When it comes to new technologies and ideas, it is important and valuable to have some initial joint R&D efforts until a technology is brought to a fairly mature level and could then be adopted up by entities who are more interested in it or get the most value out of it for actual implementation and deployment. Such an advisory group could coordinate such initial research and development stages.

Consequently, this collaborative process will result in improved prioritization of R&D work, better focus on technologies that provide value to the overall grid, and therefore, overall a more streamlined and optimized decision and investment making process in NY's roadmap for adopting and utilizing new technologies for successfully achieving its CLCPA goals.

ii) Creation of a research and development venue:

In many cases, appropriate evaluation of new technologies cannot be performed only by literature surveys, shared experiences, or developer/vendor information. Specific grid details or requirements might make it difficult or inaccurate to extrapolate performance and benefits based on experience from others. In such cases, further specific studies or demonstrations are needed to appropriately evaluate a technology and obtain more confidence in it. Given that actual field demonstrations are often complex and risky, realistic studies, tests, and demonstrations taking place in a controlled laboratory environment provide a very good alternative to experiment with and further develop new technologies. This approach has been successfully used in many other places worldwide, such as in Europe (e.g. https://www.hvdccentre.com/) Asia (e.g. https://www.kepri.re.kr:20808/newEng/index, http://eng.csg.cn/Press_release/News_2019/201909/t20190916_303623.html), and Canada (e.g. http://www.hydroquebec.com/innovation/en/institut-recherche.html, http://energymanitoba.com/partners-members/manitoba-hvdc-research-centre/). Such a laboratory environment should have several key features and provide key capabilities that would allow stakeholders to properly experiment, study, test, and evaluate new ideas and technologies in an accurate and realistic way and also allow them to gain experience working with them and operating them prior to field deployments. Some crucial capabilities include, at a high-level:

- The venue should provide a collaborative environment where utility personnel can work with various other stakeholders as well as technology providers.
- The venue should have research, development, and testing capabilities spanning a wide area of technologies that relate to the electricity grid operation at all levels (transmission, sub transmission, distribution).
- The venue should provide a large variety of analytical and physical tools that would allow people to run studies and experiment with software or hardware equipment and new apparatus or techniques.
- The venue should provide a variety of modeling and simulation tools and capabilities that would facilitate studies and experimentation. Such tools should be using actual grid models and data that can mimic the reality as much as possible. In order for such an environment to be useful and successful, such models should be kept up to date and provide a high-fidelity representation of the grid at various levels and domains to support a variety of different studies.
- The venue should have the capabilities, policies, and processes in place to appropriately secure confidential data and ensure proper utilization of such data accordioning to utility and governmental policies and guidelines.

- The venue should have enough space and other capabilities to accommodate demonstration and testing of larger-scale hardware equipment. Such a lab should go beyond performing traditional model based studies and should be able to provide capabilities to test software and equipment in set ups as close as possible to real field conditions, providing capabilities for new system configuration, preliminary commissioning testing prior to moving to the field commissioning, as well as training for personnel on the actual equipment in a safe lab-based training environment. The venue should be able to support such equipment configuration, commissioning, and training needs for new technologies.
- The venue should be able to serve as a "one-stop shopping" location, where new technology developers and vendors can reach out to the entire group of NY electricity grid stakeholders and present their ideas for a more collaborative and coordinated discussion and evaluation.

Development of such an environment would allow NY stakeholders to work more closely together and seek collaborative solutions to common issues, avoiding duplication of investment and effort, in particular at earlier R&D stages. It would also provide NY utilities a controlled environment that they can experiment and test (or even to some extent develop and expand) new technologies without having to solely rely on vendor or other third-party information and experience. Such an environment could also be leveraged by manufacturers or renewable energy developers for some of their more detailed and advanced studies, potentially resulting in reduced project development costs.

iii) Coordinated technology evaluation plans:

Based on the above two items, a coordinated pilot implementation plan can be devised for a potentially useful new technology. The plan would approximately follow the high-level process presented below:

- A new idea or a new technology is proposed as a solution for addressing one or more specific issues on the NY grid resulting for CLCPA goals.
- The idea is presented and discussed in the joint utility advisory working group.
- Utilities discuss any knowledge or experience that they may have with this technology and potentially seek input and information from vendors or other entities or utilities outside NY.
- If the idea is deemed of interest and value by some of the NY utilities and is seen as having good potential for benefiting the NY grid, a study or a lab testing and demonstration project is defined to further evaluate the technology in a more systematic way and its applicability and benefit for the NY grid.
- Based on the lab evaluation, if the idea is determined as viable for moving forward, a preliminary plan for pilot implementation(s) is created and a cost/benefit analysis is

performed. Lab testing can be used to assist, facilitate, and de-risk the specific pilot implementation.

- Based on the pilot outcomes, the idea/technology is picked up by the entity or entities that are more appropriate for implementation and large-scale deployments, either based on the fact/estimation that they get the most value of this technology, or based on the fact/estimation that implementation in their system(s) would provide the most benefit for the grid. At this stage, deployment of this technology becomes a regular utility project that follows all the existing or updated implementation policies and procedures.

B. Benefit and Cost Analysis

The group has gathered information for the cost and benefit analysis of potential technology solutions; and provided some recommendations.

A BCA of any Research & Development (R&D) project should consider both quantitative and qualitative factors to make a base case for the investment. It should also compare similar projects to determine the potential benefits, risks, and likelihood of success. A BCA should be conducted before allocating funds to any project. A thorough analysis of a project should identify all potential benefits and the probability of achieving goals, compared with the all-in associated costs. The outcome of the analysis should help decision makers determine if the project is feasible and if it should proceed, or if the funds are better spent elsewhere. If a project is to go ahead, the benefits should be compared to the costs to meet the intended goals. A thorough BCA should identify the purpose and goals behind the project, gather business and project requirements, identify all of the resources to be used, determine the metrics to measure success, and consider other potential options.

The Utilities have developed a BCA Analysis Handbook that provides a framework based on the February 26, 2015 Order Adopting Regulatory Policy Framework and Implementation Plan. The BCA determination recognizes that the Reforming the Energy Vision (REV) is a long term, far reaching initiative that will eventually touch most parts of the Utilities' infrastructure and business practices. The BCA framework recognizes that a quantified analysis on the wide-ranging set of potential benefits in a REV approach against hypothetical future cost scenarios under both REV and conventional approaches would be artificial and counterproductive. Such an effort would distract from the far more important task of carefully phasing the implementation of REV so that actual expenditures are considered in light of potential benefits recognizing that in this multi-phased implementation process, benefits and costs will be considered with increasing specificity. The Utilities have prepared a BCA Handbook to provide a foundational methodology along with valuation assumptions to support a variety of utility programs and projects. The BCA Handbook was issued with the expectation that it will be revised and refined over time and as informed by new opportunities that REV provides, experience gained from programs and project deployment, and experience gained from transmission and distribution grid system enhancements. The Handbook typically covers the following four categories of utility expenditures, as required per the BCA Order: investments in distributed system platform (DSP) capabilities; procurement of distributed energy resources (DER) through competitive selection; procurement of DER through tariffs; and energy efficiency programs. The Handbook was prepared consistent with the BCA Order list of principles of the BCA Framework. These principles stated that the BCA Handbook should establish the BCA Framework, be based on transparent assumptions and methodologies, list all benefits and costs including those that are localized and more granular, avoid combining or conflating different benefits and costs, assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures), address the full lifetime of the investment while reflecting sensitivities on key assumptions, and compare benefits and costs to traditional alternatives instead of valuing them in isolation. Given these principles and framework guidance, the purpose of the BCA Handbook is to provide the methodology for calculating benefits and costs of their programs, projects and investments using the input assumptions as provided within and/or referenced to external sources.

The Transmission Policy Working Group has developed recommended changes by including CLCPA benefits in the scope of the Transmission Planning criteria. This effort will allow the development of transmission upgrades that may not be justifiable under the current transmission criteria which focus more on system reliability. This approach can be applied to the full range of potential local transmission and distribution projects that have the potential to unlock CLCPA benefits. The methodology is focused on additional CLCPA-related metrics, and uses a simple, easily repeatable methodology that would include a combination of metrics enhancements and understanding of project contributions to CLCPA. These objectives would include a BCA to establish relative cost-effectiveness, net benefits to capture the scale of benefit achieved, and incremental cost of additional hosting capacity to evaluate distribution projects. Key preliminary recommendations being considered are for the Commission to accept the proposed local transmission-related BCA guidelines for CLCPA projects to allow a transmission owner to efficiently prioritize its CLCPA-related investments.

The Department of Energy (DOE) developed guidance for evaluators who conduct impact assessments to determine the economic benefits and costs, energy benefits, environmental benefits, and other impacts of the Office of Energy Efficiency and Renewable Energy's (EERE) R&D projects. The impact assessments covered in their guide are intended to address the following questions of interest to managers of DOE, Congress, the general public, and other stakeholders: to what extent has the project produced energy and economic benefits relative to the next best alternative; to what extent has the project achieved environmental benefits, and enhanced societal benefits; to what extent has the project cultivated a knowledgebase in the research community that has impacted innovations in today's markets; would today's commercialized technologies likely have happened at the same time, and with the same scope and scale, without the project efforts; and was the public investment worth it? In addition to energy and economic impacts, the approach should quantify emissions reduction, environmental and other health benefits, health cost avoidance, energy policy benefits, and knowledge creation and diffusion. It addresses attribution of benefits through the use of the counterfactual model which seeks to compare outcomes with what would likely have happened in the absence of the R&D project. The method presented in this guide builds on the R&D impact assessment approach used by the National Institute of Standards and Technology (NIST) and improves on the approach employed by the National Research Council (NRC).

A study completed by several European agencies that explored the BCA of R&D projects found that the use of BCA to evaluate these types of projects have often been hindered by the intangible nature and the uncertainty associated to the achievement of R&D results. The core of their BCA is an evaluation of the project socio-economic benefits and costs. The net effect on society is computed by a quantitative performance indicator (the net present value, or the internal rate of return, or a benefit/cost ratio). In line with the general BCA fundamentals, a BCA model of these type of projects should make use of: shadow prices to capture social costs and benefits beyond the market or other observable values; a counterfactual scenario to ensure that all costs and benefits are estimated in incremental terms relative to a 'without project' world; discounting to convert any past and future value in their present equivalent; and a consistent framework to identify social benefits by looking at the different categories of agents (producers, consumers, tax payers, rate payers). The project evaluations are dividing social benefits in two broad classes. The first is benefits accruing to different categories of direct and indirect users of the infrastructure services, such as firms benefitting from technological spillovers, consumers benefitting from innovative services and products, and the general public. The second is the identification of use-beneficiaries that is project specific reflecting the social value of the discovery potential of the research project.

The goal of the working group is to coordinate and evaluate all BCA options for each R&D project pursued in this effort and continue to improve on these BCA methods as new and underutilized technologies are being evaluated in New York State.

C. Impediments / Mitigations

Figure 123 summarizes key issues that utilities consider as the factors that could delay or prevent the implementation of new technology solutions in the three highest-prioritized technology categories. Generally, while these technologies may have demonstrated their technical capabilities to facilitate the CLCPA, these issues could introduce some uncertainties or make it difficult to benchmark these new technologies against the conventional solutions.

Figure 123: Technology Solutions

Technology Solution	Impediment	Mitigation
Dynamic Line Ratings (DLR) and improved overhead and	Effectiveness: It is difficult to ensure the higher ratings can always be achieved when they are needed in the future. Particularly, if the ratings	Additional studies should be conducted to better determine the future benefits from DLR and the

underground cable transmission utilization	are depending upon critical factors such as the wind speed that has high variability. This could make it difficult to compare the benefits of DLR against the conventional solutions	extent that DLR could be effectively utilized in the local and bulk transmission system.
Power flow control devices – distributed and centralized	Coordination: Power flow control devices do not increase system capability but redirect power. Increasing the utilization of this technology may create planning operational complexity since it could impact wider areas.	A comprehensive study should be conducted to evaluate potential impacts from large-scale power flow control utilization and the systems needed to ensure that the operations of these devices will be well coordinated.
Energy storage for T&D services	Cost Estimate: Sufficient cost estimate for a storage project is needed to allow it to be compared against conventional solutions. Currently, it is difficult to come up with this level of estimate.	A guidance document and compilation of project experience should be developed to help facilitate cost estimation.
	Specifications: Detailed specifications of Storage require more information that may not be available at this point. For example, future congestion pattern is needed to develop the specifications of the Storage	Additional studies at a more granular level should be conducted to provide relevant information regarding future benefits.
	Benefit quantifications: The true benefits or use cases for Storage are still unclear. This can put Storage in disadvantage positions when benchmarking it with conventional solutions.	Similar to the above, additional studies should be conducted to understand benefits and impacts of the various use cases. A guideline to quantify the benefit could be useful as well.

VI. CONCLUSIONS / RECOMMENDATIONS

In summary, the group concludes the following:

- The group has prioritized several issues and potential technology solutions as being key to achieving CLCPA goals. These technology solutions are consistent with the transmission needs identified by the Technical Analysis working group.
- A survey of the group found that various members are already implementing either operationally or in R&D pilots some of the technology solutions identified and reviewed in this study. For those technology solutions already being implemented by some, there is opportunity for knowledge transfer among the members of the group. Through knowledge transfer, members can learn from each other so as, to be in better position to assess further adoption of the technology solutions. The figure below provides an overview of the implementation of these technology solutions among the group members.

Technology Solution	Avangrid	Central Hudson	Consolidated Edison	LIPA/PSEG LI	National Grid	Orange and Rockland	NYPA
Dynamic line ratings and improved transmission utilization	Ongoing Pilot (NYSERDA Future Grid Challenge)	Past R&D pilot with mixed results	Use on underground transmission lines	Limited use on underground transmission lines	Demonstrated in New England; currently deploying Line Vision technology in Upstate NY	Limited success with past installations, waiting for technology to mature	R&D pilots only with various technologies
Power flow control devices – distributed and centralized	Several PARs used in Rochester; proposed Smartwire technology as alternative for ongoing Utility Study	Pilot temporary Smartwires project on 115kV, proposed permanent project on 345kV (in NYISO gold book)	Use of PARs at transmission level	Limited use of PARs at transmission level	Demonstrated Smart Wires technology in New England	-	Planning for potential pilot
Energy storage for T&D services	NWA solicitation for any new transmission project; A few storage systems installed; Proposed several storage systems for ongoing Utility Study	In design battery storage project per PSC order	Limited installations of utility owned energy storage	Limited installations of BESS on distribution system with PPA. Potential developer owned BESS on both T&D system	Limited installations of utility owned energy storage	Actively working with developers as well as planning on installing battery storage along with the construction of new distribution substations	One pilot at transmission level but mainly as generation asset
Improved operator situational awareness	ongoing improvement on alarms	Various technologies in use, in investigation phase	Efforts have been on improving the managing of alarm information	-	proposed	Improving alarm information by getting discrete alarms	Mainly work phasor measurement units
Transformer monitoring	-Various types of monitoring in use throughout system	Various types of monitoring in use throughout system	Various types of monitoring currently in use throughout the system	Various types of monitoring currently in use throughout the system	Various types of monitoring in use throughout system	In operational use for predictive maintenance and asset management	In operational use for predictive maintenance and asset management
Advanced high-temperature, low sag (HTLS)	Proposed at one location for CapEx project; will be considered in the future	-	-	Use of ACSS on OH transmission lines	Demonstrated in New England	Use of ACSS on a number of transmission projects in past with success; only installed steel core conductors, with both conventional (round) and trapezoidal stranding	-
Compact tower designs	-	-	-	-	-	-	-

SF6 monitoring/SF6 alternatives	SF6 monitoring system are used in the current/planned facilities	69kV vacuum breaker installed in one location	SF6 monitoring in use to help identify leaks for repairs	Utilization of 69kV vacuum breakers currently under review	SF6 monitoring in use to help identify leaks for repairs, currently discussing low voltage vacuum breaker pilot	-	-

- It would be beneficial for the joint utilities to share R&D knowledge on a regular basis. This helps to increase awareness of state-of-the-art and emerging technologies among the joint utilities, thereby creating greater interest to assess the technologies and possibly leading to their use.
- In furthering the goals of the CLCPA, it would be more cost-effective for the joint utilities to work together than separately to test out and assess the use of new technologies. However, there are issues that need to be addressed before this can happen. Foremost among the issues is the need for funding, which NYSERDA can help cover most, if not, all the funding requirements. Another issue is the need for a governance structure to select, among many things, which joint R&D projects will be funded.
- The challenges of adopting advanced technologies include the following:
  - Advanced technologies typically include an inherent risk of not meeting expectations or even failure. Therefore, their results and effectiveness are not guaranteed until thoroughly tested and evaluated and until enough field operating experience is obtained.
  - Advanced technologies are not typically a substitute to more traditional solutions or system upgrades, but they can be used to supplement such solutions and ensure that additional value is extracted from such solutions in longer timeframes.
  - Advanced technologies may need close coordination between stakeholders in order to result in implementations that are effective and provide value. In many cases, unless deployed in a wider scale and in a coordinated way, benefits might not be demonstrated by a few individual pilot installations.
  - Advanced technology solutions might typically require upfront effort and funding for testing and pilot projects, which by themselves do not demonstrate benefits. These efforts are needed, however, in order to make the technology more mature, obtain operational experience, and move the technology to a stage that it can be reliably deployed and start demonstrating benefits. This implies that many new technologies might not have a valid "business case" as there are upfront sunk costs, and the benefits may have to be over longer-term to substantially surpass the upfront costs. In addition, many benefits may not be easily quantifiable and may need additional actions and assumptions to occur prior to being materialized.
  - Advanced technologies are not equally suited throughout the system and the State. The regional and local environment and existing transmission configurations will have to be considered as to where would be appropriate to incorporate the various advanced technologies.
- Any joint R&D projects should initially focus on these three technology solutions: dynamic line ratings, power flow control devices, and energy storage for T&D services, because although additional capacity would be needed on the transmission network, these technologies could enhance operator flexibility to ensure reliability and reduce

system congestion furthering the goals of CLCPA in integrating greater amounts of renewables.

- The above three chosen technology focus areas are not a direct replacement for additional system capacity. When system upgrades are needed to mitigate the challenges of the future, Transmission Operators are encouraged to utilize new technologies such as HTLS and innovative tower design in project design when such technologies are more cost effective than traditional ones.
- New York State has a wealth of R&D resources such as NYPA's small-scale Advanced Grid Innovation Laboratory for Energy (AGILe), academic institutions and a national laboratory that should be utilized to help the joint utilities to further the goals of the CLCPA prior to the development of new resources.
- The intangible nature and the uncertainty associated with the achievement of R&D results often hinder the BCA of R&D projects. More specifically the risk resides primarily with the anticipated benefits in the BCA calculation, because the benefits are dependent on the success of the R&D project. Therefore, the anticipated benefits in the BCA calculation should be risk adjusted based on the project's likelihood of success. This will help guide the selection of projects with greater likelihood of success while not precluding projects with potentially home run benefits.

Based on these conclusions, the group believes there is an opportunity to create a New York State focused R&D consortium to be comprised of, at minimum, the New York State investor owned utilities ("IOUs"), NYPA, LIPA, the NYISO and NYSERDA to expedite the assessment and adoption of state-of-the-art and advanced technologies that are already being used elsewhere in the U.S. or the world. This R&D consortium would also help each IOU to identify and assess which of the state-of-the-art technologies it should implement or expand their use, consistent with how best to further the goals of the CLCPA while also addressing the need to provide affordable, safe and reliable service to its customers.

Therefore, the Advanced Technologies working group recommends the following:

1. A New York R&D consortium should be created with the initial task to identify two to three R&D projects, preferably one project for each of the three technology solutions: dynamic line ratings, power flow control devices, and energy storage for T&D services. These initial projects should demonstrate the use and benefits of the selected technologies. The selected technologies should be state-of-the-art and commercially available.
2. The R&D consortium will initially include all the New York State IOUs, NYPA, LIPA, the NYISO and NYSERDA and may be expanded over time to include academic institutions in New York State as well as possibly Brookhaven National Laboratory on Long Island.
3. The projects proposed should be evaluated based on the potential benefits and costs of the project but should also be risk adjusted based on the project's likelihood of success.

4. Projects selected by the R&D consortium should be funded through NYSERDA, with the IOUs, NYPA and LIPA participating in the project having the opportunity to choose to support the project through co-funding or in-kind contribution on a project by project basis. Any IOU co-funding would be limited to the extent that the funding is within the IOU's Commission approved rate plan and that the advanced technologies being investigated by the R&D projects support their deployment in the IOU's capital plan. For TOs that are not co-funding the projects, they can support the projects through an advisory role, in-kind participation, or even choosing to host the demonstrations or piloting of the advanced technologies. The Commission should support incremental funds sought for these projects by NYSERDA and / or through IOU rate proceedings.
5. The R&D consortium will further investigate specific needs, capabilities, and plans for the establishment of a collaborative R&D and testing venue, first assessing existing resources in New York State, which could be utilized as part of the evaluation of currently new or future advanced technologies.

The Advanced Technologies working group anticipates it will take at least six months to: establish the R&D consortium with the necessary governance structure and legal agreements in place; establish the criteria for project selection; identify the candidate projects for evaluation and selection; and select two to three projects from the project candidate list and prepare the work scope for each selected project. R&D projects typically run one to two years once the work scope is finalized.

Respectfully submitted,

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Appendices

APPENDIX A: TRADITIONAL PLANNING CRITERIA

A foundational input for both the Net Benefits and Benefit/Cost Ratio is the quantity of MWh of unbottled renewables. There are multiple approaches for this type of calculation, and there is no one-size-fits-all approach that must be used. In some cases, different approaches may be applicable for different parts of a utility's transmission system. Each utility will determine the approach that is appropriate for the unique topology of its system, and will, if necessary, provide evidence to the Commission that the chosen methodology(ies) provides reliable results. Utilities are currently considering three methodologies.

A. Production Cost Modeling

Production cost modeling is a tool for simulating and studying the electric market in a defined area. Typical uses include day-ahead market simulation, long-term market impact studies, future year production cost, planning and market efficiency simulation, multi-day resource and ancillary services optimization, and congestion and outage analyses. For production cost modeling many available tools are available to utilize. For example, a Linear Programming-based Security Constrained Economic Dispatch (SCED) and/or Security Constrained Unit Commitment (SCUC) can be used to perform both short- and long-term market simulation.

Inputs for a production cost model include generator data (nameplate capacity, operating characteristics, fixed costs, cost curves, hourly profiles for renewables, etc.), demand data (hourly by zone), fuel prices, emissions rates and prices, transmission topology, monitored branches, contingencies, interface definitions, and outage schedules. One production cost modeling software package, PROBE-LT, reads in load flow models and CSV files of the input data and solves the dispatch iteratively. Each day in a long-term study period can be solved consecutively, carrying over the prior day's units' statuses. Common outputs include the overall production cost of running the system in the defined area, locational marginal pricing at a nodal level, generator dispatch, flows over monitored branches, and congestion impacts, all reportable with hourly granularity. These results provide an overview of market performance over the defined time of the study. By way of example, National Grid used PROBE-LT and production cost modeling for its Multi-Value Transmission projects included in its current rate case. In that case, production cost modeling served as a tool to evaluate the interactions and system impacts of load and renewable profiles overlaid over the course of a year. Production cost modeling should be one of the tools available to the Utilities as they seek to prioritize projects in support of the CLCPA mandates.

B. DFAX

This proposed approach estimates the quantity of MWh of unbottled renewables by comparing the amount of renewable energy curtailments (MWh) before and after the proposed upgrade over 1-year period (8760 hours). The difference in curtailed renewable energy between the two scenarios is the curtailment reduction benefit. This approach may be appropriate for addressing the characteristics of many bottlenecks in the service territories that are not load pockets, but rather are the facilities that also deliver renewable power through its service area and to the bulk power system. This approach also satisfies the need to allow the Utilities to perform initial benefit/cost analysis on a large number of CLCPA-related projects quickly and consistently for those areas where boundaries of load pockets are difficult to define.

By way of comparison to the other methodologies described in this filing, an approach that relies on Load Duration Curve works well for an area that consists of clearly defined load pockets, but would be very challenging to implement in areas where the boundaries of load pockets do not exist or very difficult to define for most of the bottlenecks. Conversely, the DFAX-based approach may be challenging to implement for constrained areas that depend on Phase Angle Regulated (PAR) ties. In addition, while Production Cost Modeling (PCM) is a powerful tool, it requires complex, expensive software, and specialized training. PCM results are highly dependent upon study assumptions, and results can give a false sense of precision when compared to other methods.

i) The proposed method

In this section, the term "bottleneck" refers to transmission facility that was identified as the limitation that prevents renewable resources from delivering energy to the load. In addition, the term "driver" represents any factor that could impact power flow on the bottleneck. For example, if a study determines that the thermal limit of transmission line A is not enough to accommodate the output from renewable resources X, Y, and Z, from this context, line A is the bottleneck and resources X, Y, and Z are the drivers. Below are the key concepts and components of the methodology.

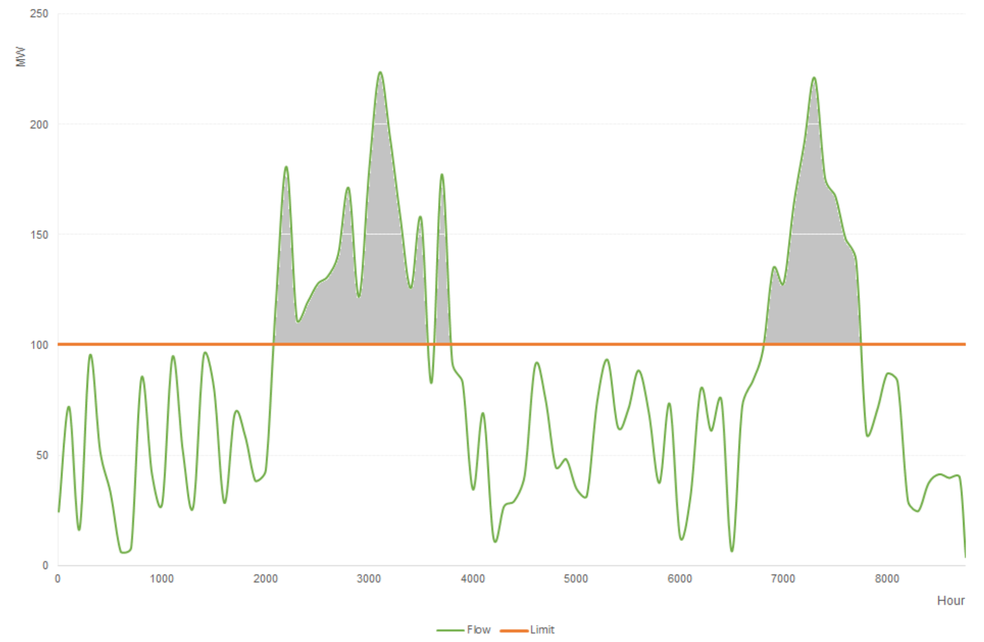
1) Data Requirements: Three main types of data are required for the calculation.
    a. Details of the bottlenecks and conditions they were identified. This information is obtained from other studies such as the work performed by the Utility T&D technical subgroup.
    b. Power flow base cases. These contain the initial system conditions and network topology that will be used to calculate DFAX.
    c. Hourly data (such as renewable output) from each driver over 1-year. For example, if the output from Land-Based Wind (LBW) is impacting the flow on a bottleneck, the expected hourly output (8760 data points) must be provided.
2) Distribution Factors (DFAX) or Shift Factor: These indexes are calculated and used to estimate the flow on the bottleneck for each hour. It indicates the proportion

of the changes at a driver that would appear on the bottleneck. For example, if the output from a LBW is impacting the flow on the bottleneck, DFAX can estimate the changes of power flow on the bottleneck for every 1 MW change from LBW output. This concept has been widely used in power industry and it is similar to the technique that has been used in commercial PCM packages such as GridView, and others.

3) DFAX Calculation: DFAX are calculated from Power Flow software and they are assumed to be constant if the network topology stays the same. First, potential drivers that could impact power flow on the bottlenecks are determined. Then, power flow on the bottlenecks after increasing the output from each driver by a certain amount (i.e. 10 MW) is compared with the power flow on the same facility at previous hour. DFAX is equal to the flow difference divided by the incremental output from the driver. A potential driver has DFAX very small or zero DFAX on the bottleneck may be considered to have negligible impacts.
    a. Example[158], assuming LBW X is a potential driver for the bottleneck (Line) A and power flow on this line at Hour 0 is 100 MW. DFAX can be calculated by increasing the output from LBW X by 10 MW then solve the power flow. If the new power flow on Line A = 105 MW, DFAX is 0.5 (or 50%).
4) Hourly (8760) power flow calculation: Power flow on a bottleneck at each hour is calculated by adjusting the amount of power flow on this facility from the previous hour with all the changes from all drivers that occur within an hour. For example, if load, LBW, and Utility Photovoltaic (UPV) are determined to impact the flow on Line A, power flow on Line A at each hour is the summation of:
    a. Power flow on this line from the previous hour (H0)
    b. Impact from load change within an hour (Load DFAX multiplied by load change)
    c. Impact from LBW change within an hour (LBW DFAX multiplied by LBW output change)
    d. Impact from UPV change within an hour (UPV DFAX multiplied by LBW output change)
    e. Power flow on Line A (H1) = a + b + c +d
5) Curtailed Renewable Energy Calculation: The amount of curtailed renewable energy (MWh) for each hour is determined by the amount of the flow that exceeds facility rating. For example, assuming the rating of the bottleneck is 100 MW and the power flow on the bottleneck is shown as green line in Figure 1, the curtailed renewable energy over a 1-year period is represented by the gray-shaded area in this figure.

[158] For demonstrating the concept only. The actual power flow program may employ different technique to perform the same task.

Figure 124: Hourly flow and curtailed energy



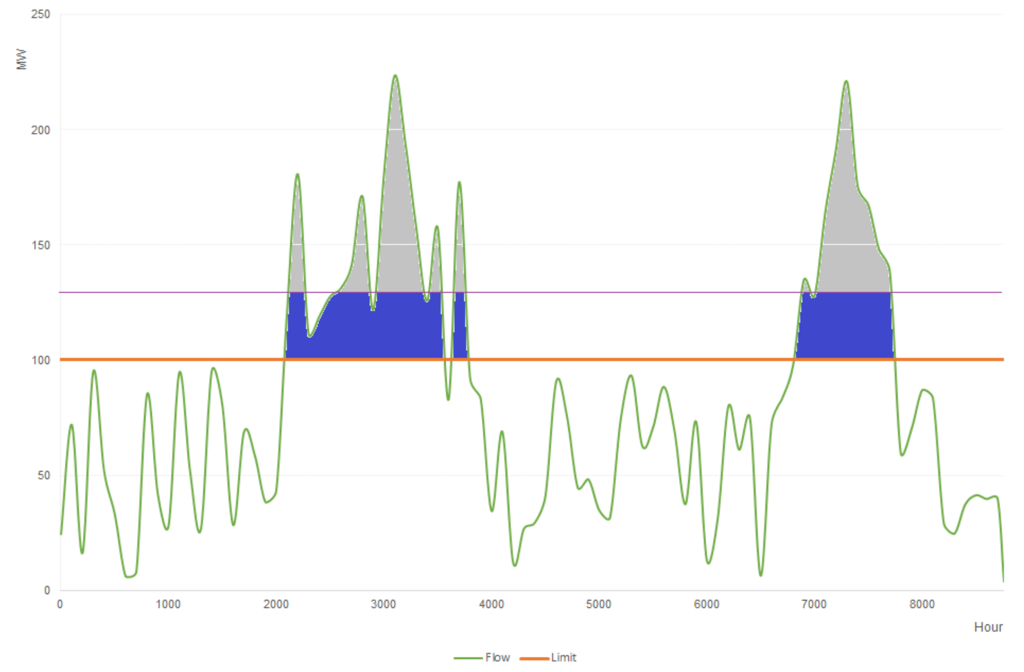
This curtailment value can also be easily calculated using spreadsheet approach. For example, as shown in table 1, the total amount of congestion energy over 6-hour period is 110 MWh.

Figure 125: Example of curtailment calculation

Hr	Flow (MW)	Limit (MW)	Curtailment (MWh)
1	90	100	0
2	80	100	0
3	120	100	20
4	95	100	0
5	170	100	70
6	120	100	20
…	…	…	…
…	…	..	…
…	…	..	…
Total		110	

Curtailment reduction calculation: With the upgrade, the curtailment reduction benefit is calculated by comparing the curtailed renewable energy before and after the upgrade. As shown in Figure 2, assuming the upgrade increases the rating of Line A to 130 MW (pink line), the area shown in blue represents congestion energy reduction by the upgrade. In some cases, an upgrade could result in different shape of power flow plot due to impedance changes. If needed, DFAX can be recalculated to estimate the new flow.

Figure 126: Hourly flow before and after the upgrade as well as curtailment reduction



Similar to the above, this benefit can also be calculated using spreadsheet.

Figure 127: Example of curtailment reduction calculation

Hr	Flow (MW)	Existing System		With Upgrade A			With Upgrade B		
		Limit (MW)	Curtailment (MWh)	Limit (MW)	Curtailment (MWh)	Curtailment Saving (MWh)	Limit (MW)	Curtailment (MWh)	Curtailment Saving (MWh)
1	240	200	40	250	0	40	350	0	40
2	260	200	60	250	10	50	350	0	60
3	270	200	70	250	20	50	350	0	70
4	270	200	70	250	20	50	350	0	70
5	200	200	0	250	0	0	350	0	0
6	200	200	0	250	0	0	350	0	0
7	160	200	0	250	0	0	350	0	0
8	160	200	0	250	0	0	350	0	0
9	220	200	20	250	0	20	350	0	20
10	270	200	70	250	20	50	350	0	70
…	…	…	…	…	…	…	…	…	…
…	…	…	…	…	…	…	…	…	…
Total (MWh)			330		70	260		0	330

From this example, for over a 10-hour period, up to 330 MWh of curtailed renewable energy can be observed over the existing system (no upgrade). With upgrade A, the rating of the bottleneck increases to 250 MW, the curtailed renewable energy drops to 70 MWh and the curtailment reduction benefit from this upgrade is 260 MWh. If a larger upgrade is built as shown as upgrade B, curtailments of renewables no longer exist in the system at the studied level of renewable energy development.

C. Load Duration Curve

i) Load Duration Curve Method to Calculate Unbottled Energy

Another method the utilities may use to identify the amount of energy unbottled by a project is to compare the load or generation hourly profile to the transfer capability into or out of the generation or load pocket. This method is best applied to stand alone or embedded load pockets (see diagrams below), which are common in New York City and other parts of the state. In other areas, particularly upstate, constrained areas may be hard to define due to external power transfers. For those types of pockets, one of the other methods proposed in this Report may be more appropriate. However, in the case of a standalone or embedded load pocket, this approach is a reasonable simplification of the dynamics of the load pocket and offers the benefits of ease of calculation and consideration of the full 8760 profile of the year.

Figure 128: Stand Alone Constrained Area

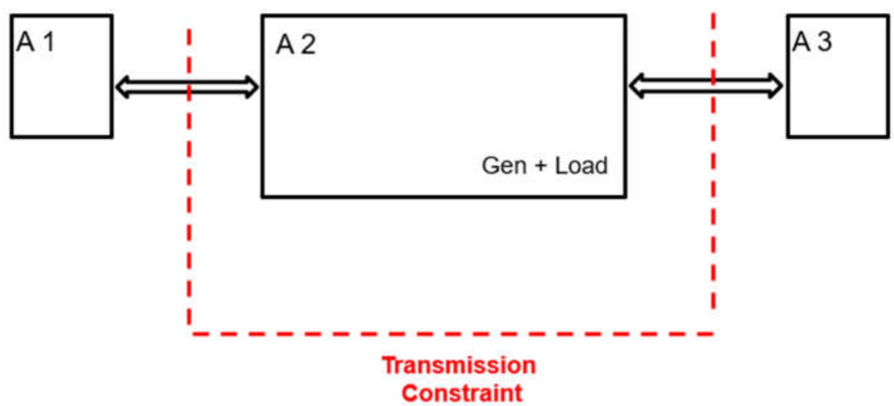


Figure 129: Embedded Constrained Area

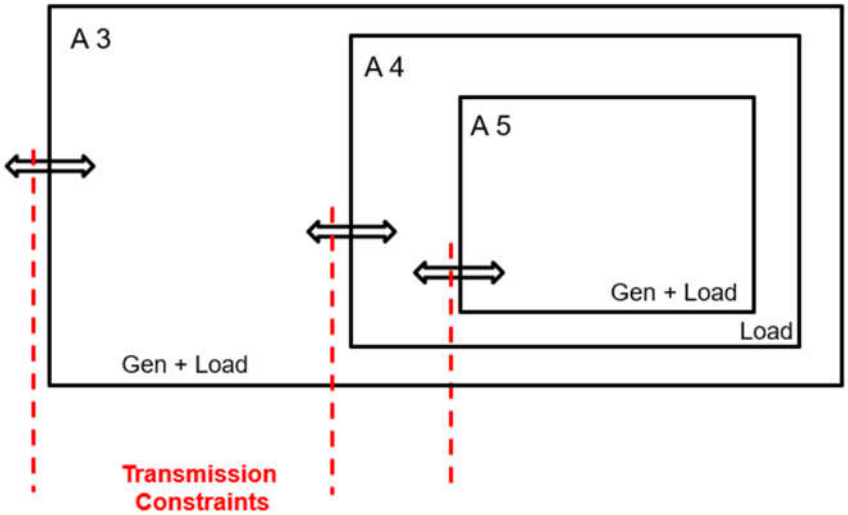
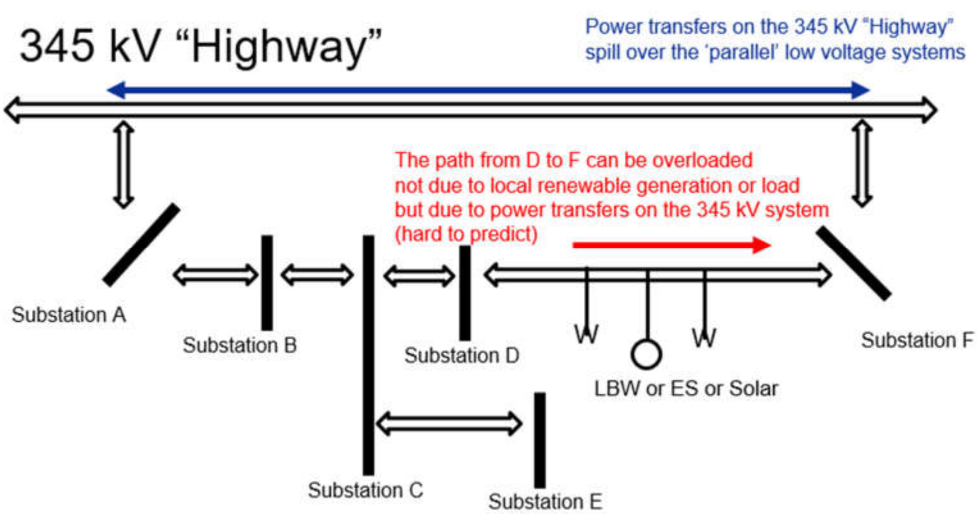


Figure 130: Constrained Area Impacted by External Transfers



ii) Methodology

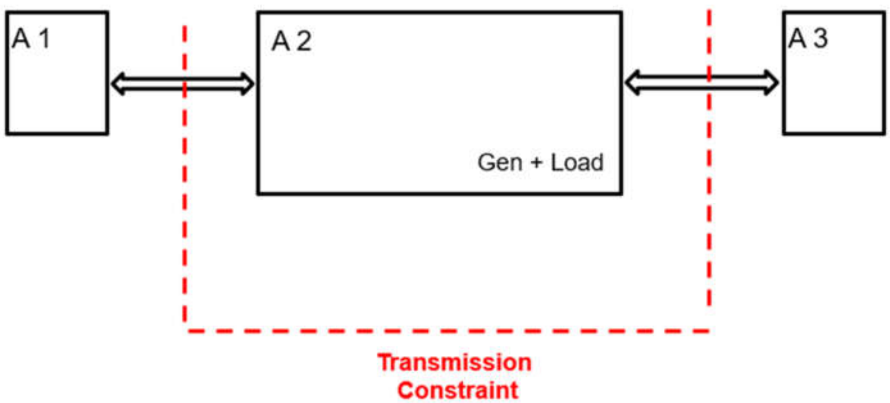
The steps below outline the approach for using the load duration curve approach to calculate the number of MWhs unbottled by a project. The approach may be applied to either generation or load pockets. The steps, described further below, include

- Step 1: Identify Constrained Area
- Step 2: Identify current Design Capability
- Step 3: Identify future Design Capability with project
- Step 4: Compile hourly load and generation profiles
- Step 5: Compare Design Capability to hourly profile

- **Step 6:** Calculate MWhs unbottled by project

Step 1: Identify Constrained Area

Identify a Constrained Area on the utility Transmission System. This may be either an already established (operationally) Constrained Area, or one that is identified through power flow analysis.



Step 2: Identify Design Capability

Identify how much power can be imported to (for a load pocket) or exported from (for a generation pocket) the Area, based on the design criteria for the Constrained Area. This should be done for both the summer and winter operating seasons, due to differences in feeder ratings, and include Renewable Resources.

Step 3: Identify future Design Capability with project

Using the same approach as under Step 2, identify the Design Capability to import or export power with the proposed project in place.

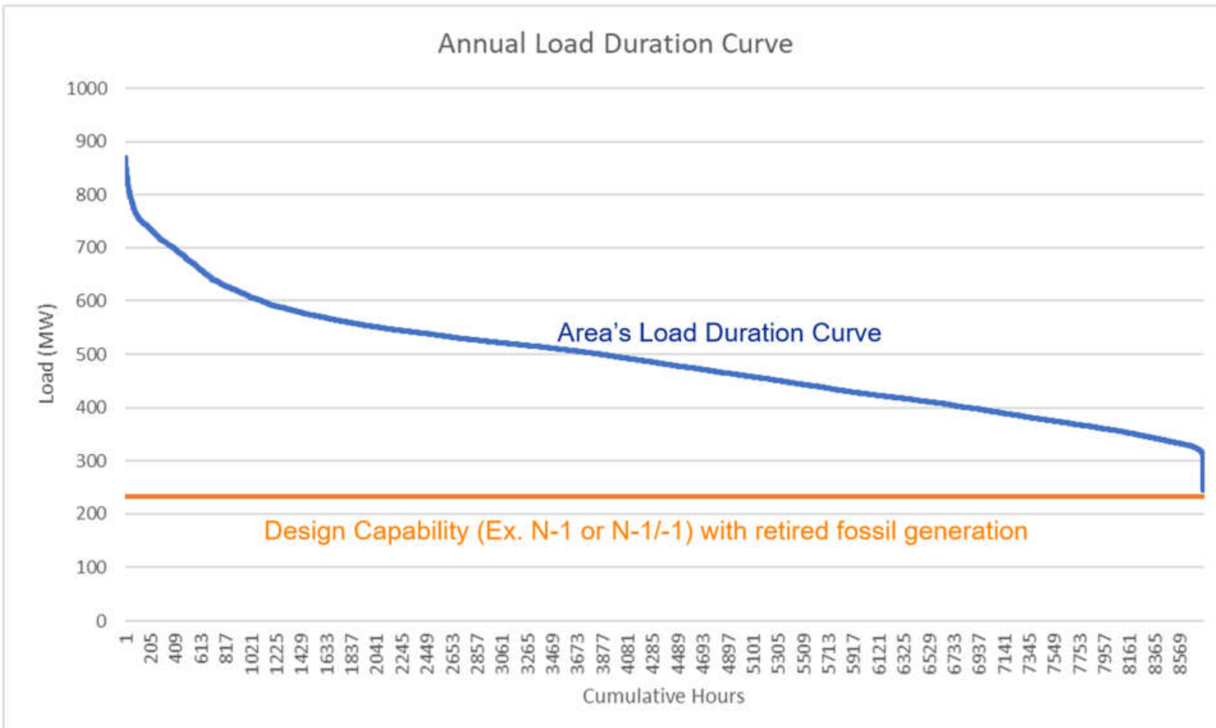
Step 4: Compile hourly load and generation profiles

Compile a historical load profile (8760 hours in a year) for the identified Constrained Area. This information is available from utilities' Plant Information (PI) data systems. For a generation pocket, the hourly generation profile for renewables within the pocket will also need to be calculated. This can be derived from NREL wind shape data or other sources.

Step 5: Compare Design Capability to hourly profile

Compare the Design Capability with and without the project to the hourly load profile, as illustrated in the charts below. Area above the Design Capability line represents the Constrained Area's bottled generation or load that cannot be fed due to a constraint.

Figure 131: Load pocket – without project



Note: load curve has been sorted from peak hour (left) to lowest load hour (right). Data is illustrative only.

Figure 132: Load pocket – with project

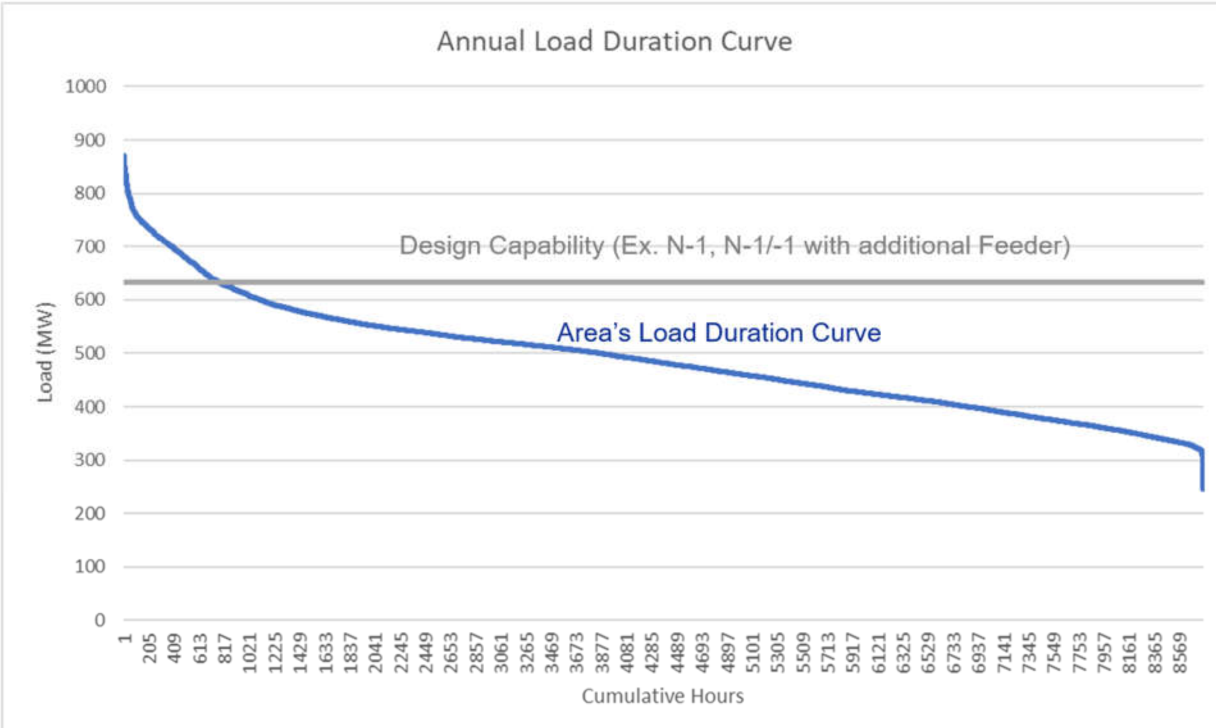


Figure 133: Generation pocket – without project

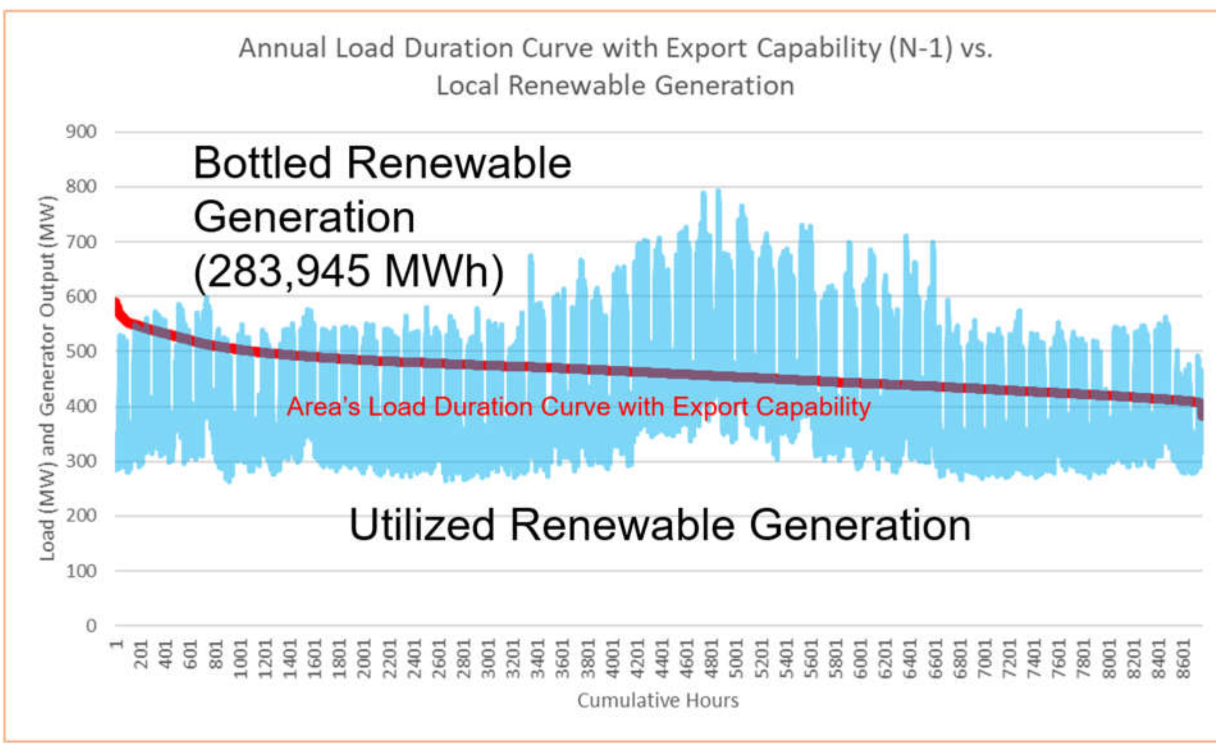
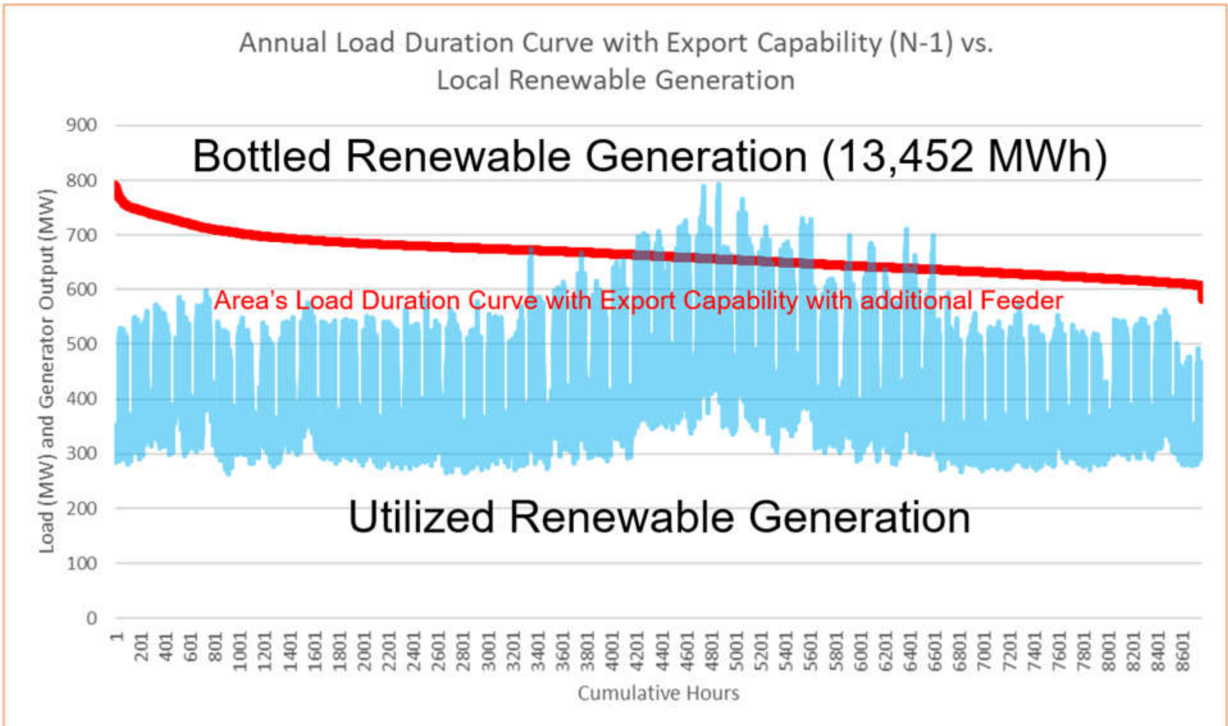


Figure 134: Generation pocket – with project



Step 6: Calculate MWhs unbottled by project

The area between the Design Capability post-project and Design Capability pre-project represents the number of MWhs unbottled by the project. This number would then be fed into the benefit cost analysis as the "MWh" (or "Inc MWh") factor in the equation.

APPENDIX B: BCA EXAMPLE CALCULATIONS

Assumptions

Project Cost (Millions$)	$ 50.0
Utility after-tax WACC: 6.811% (NYSEG rate used to calculate revenue requirement example)	
Discount Rate (Wtd. Avg. after-tax utility WACC	7.073%

Outputs

Benefit/Cost Ratio	1.38
Net Benefits (Millions$)	$25.5
PV Benefits (Millions$)	$92.5
PV Costs (Millions$)	$67.0

Conversion of ICAP Price to $/MWh

A	B	C	D = (A x B x 12 x 1000)/(C x 8760)
ICAP Price ($/kW-month)	ICAP Credit %	Capacity Factor	ICAP Price in $/MWh
$ 7.28	20%	30%	$ 6.65

A	B	C	D	E	F = (B+C+D)/(1-E)	G	H = F x G	I = ATRR	J = H - I
Year	LBMP ($/MWh)*	REC ($/MWh)*	ICAP ($/MWh)*	Curtailment %*	Curtailed Energy Value ($/MWh)	Unbottled MWh*	Benefit (Millions$)	Cost (Millions$)	Net Benefit (Millions$)
2021	$31.97	$20.00	$6.65	7.0%	$63.03	-	$0.0	$0.0	$0.0
2022	$34.04	$20.00	$6.65	7.0%	$65.26	-	$0.0	$0.0	$0.0
2023	$38.09	$20.00	$6.65	7.0%	$69.61	-	$0.0	$0.0	$0.0
2024	$40.11	$20.00	$6.65	7.0%	$71.78	-	$0.0	$0.0	$0.0
2025	$44.39	$20.00	$6.65	7.0%	$76.39	100,000	$7.6	$8.3	($0.6)
2026	$45.85	$20.00	$6.65	7.0%	$77.96	100,000	$7.8	$8.1	($0.3)
2027	$47.12	$20.00	$6.65	7.0%	$79.32	100,000	$7.9	$7.9	$0.0
2028	$49.16	$20.00	$6.65	7.0%	$81.52	100,000	$8.2	$7.8	$0.4
2029	$50.14	$20.00	$6.65	7.0%	$82.57	100,000	$8.3	$7.6	$0.7
2030	$51.15	$20.00	$6.65	7.0%	$83.65	100,000	$8.4	$7.4	$0.9
2031	$52.17	$20.00	$6.65	7.0%	$84.75	100,000	$8.5	$7.3	$1.2
2032	$53.21	$20.00	$6.65	7.0%	$85.87	100,000	$8.6	$7.2	$1.4
2033	$54.28	$20.00	$6.65	7.0%	$87.02	100,000	$8.7	$7.0	$1.7
2034	$55.36	$20.00	$6.65	7.0%	$88.19	100,000	$8.8	$6.9	$2.0
2035	$56.47	$20.00	$6.65	7.0%	$89.38	100,000	$8.9	$6.7	$2.2
2036	$57.60	$20.00	$6.65	7.0%	$90.59	100,000	$9.1	$6.6	$2.5
2037	$58.75	$20.00	$6.65	7.0%	$91.83	100,000	$9.2	$6.4	$2.7
2038	$59.93	$20.00	$6.65	7.0%	$93.09	100,000	$9.3	$6.3	$3.0
2039	$61.12	$20.00	$6.65	7.0%	$94.38	100,000	$9.4	$6.2	$3.3
2040	$62.35	$20.00	$6.65	7.0%	$95.70	100,000	$9.6	$6.0	$3.5
2041	$63.59	$20.00	$6.65	7.0%	$97.04	100,000	$9.7	$5.9	$3.8
2042	$64.87	$20.00	$6.65	7.0%	$98.40	100,000	$9.8	$5.9	$4.0
2043	$66.16	$20.00	$6.65	7.0%	$99.80	100,000	$10.0	$5.8	$4.2
2044	$67.49	$20.00	$6.65	7.0%	$101.22	100,000	$10.1	$5.7	$4.4
2045	$68.84	$20.00	$6.65	7.0%	$102.67	100,000	$10.3	$5.6	$4.6
2046	$70.21	$20.00	$6.65	7.0%	$104.15	100,000	$10.4	$5.6	$4.8
2047	$71.62	$20.00	$6.65	7.0%	$105.66	100,000	$10.6	$5.5	$5.1
2048	$73.05	$20.00	$6.65	7.0%	$107.20	100,000	$10.7	$5.4	$5.3
2049	$74.51	$20.00	$6.65	7.0%	$108.77	100,000	$10.9	$5.4	$5.5
2050	$76.00	$20.00	$6.65	7.0%	$110.38	100,000	$11.0	$5.3	$5.8
2051	$77.52	$20.00	$6.65	7.0%	$112.01	100,000	$11.2	$5.2	$6.0
2052	$79.07	$20.00	$6.65	7.0%	$113.68	100,000	$11.4	$5.1	$6.2
2053	$80.65	$20.00	$6.65	7.0%	$115.38	100,000	$11.5	$5.1	$6.5
2054	$82.27	$20.00	$6.65	7.0%	$117.11	100,000	$11.7	$5.0	$6.7
2055	$83.91	$20.00	$6.65	7.0%	$118.88	100,000	$11.9	$3.3	$8.6
2056	$85.59	$20.00	$6.65	7.0%	$120.69	100,000	$12.1	$3.4	$8.7
2057	$87.30	$20.00	$6.65	7.0%	$122.53	100,000	$12.3	$3.4	$8.8
2058	$89.05	$20.00	$6.65	7.0%	$124.40	100,000	$12.4	$3.4	$9.0
2059	$90.83	$20.00	$6.65	7.0%	$126.32	100,000	$12.6	$3.5	$9.2
2060	$92.64	$20.00	$6.65	7.0%	$128.27	100,000	$12.8	$3.5	$9.3
2061	$94.50	$20.00	$6.65	7.0%	$130.27	100,000	$13.0	$3.6	$9.5
2062	$96.39	$20.00	$6.65	7.0%	$132.30	100,000	$13.2	$3.6	$9.6
2063	$98.31	$20.00	$6.65	7.0%	$134.37	100,000	$13.4	$3.6	$9.8
2064	$100.28	$20.00	$6.65	7.0%	$136.48	100,000	$13.6	$3.7	$10.0

*Prices, curtailment percentage and unbottled energy are illustrative only, and prices are in nominal dollars.

Appendix D

(to Initial Report on New York Power Grid Study)

Offshore Wind Integration Study

Offshore Wind Integration Study: Final Report

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Acronyms and Abbreviations

A	Ampere
BMP	Best management practice
BOEM	Bureau of Ocean Energy Management
CAPEX	Capital expenditures
CHPE	Champlain Hudson Power Express
CLCPA	Climate Leadership and Community Protection Act
CMP	Coastal Management Program
ConEd	Consolidated Edison
DoD	Department of Defense
DOT	New York State Department of Transportation
DPS	New York State Department of Public Service
FHWA	Federal Highway Administration
GBS	Gravity based solutions
GIS	Geographic information systems
GW	Gigawatt
HB	Half bridge
HDD	Horizontal directional drilling
HVAC	High-voltage alternating current
HVDC	High-voltage direct current
KWH	Kilo-watt hour
LIPA	Long Island Power Authority
LTCOE	Levelized transmission cost of energy
LTE	Long-term emergency
LTP	Local transmission plan
M$	Millions
M/S	Meters per second
MVA	Megavolt ampere
MW	Megawatts
MWh	Megawatt hour
NEPA	National Environmental Policy Act
NLCD	National Land Cover Database
NMFS	NOAA National Marine Fisheries Service
NPV	Net present value
NREL	National Renewable Energy Lab
NRHP	National Register of Historic Places
NWI	National Wetlands Inventory
NYCRR	New York Codes, Rules and Regulations
NYISO	New York Independent System Operator’s
NYSERDA	New York State Energy Research and Development Authority
OPAREA	Operating Area
OPEX	Operational expenditures
OREC	Offshore Wind Renewable Energy Certificate

OSW	Offshore wind
PAR	Phase Angle Regulator
PCB	Polychlorinated biphenyl
PFA	Polyfluoroalkyl substance
POI	Point of interconnection
PPA	Power purchase agreement
REPEX	Replacement expenditure
ROW	Right of way
SHPO	State Historic Preservation Office
STE	Short-term emergency
T&E	Threatened and endangered
TLA	Transmission Load Areas
TO	Transmission Owner
TRL	Technology readiness level
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service
V	Volt
VSC	Voltage Source Converters
W	Watt
WACC	Weighted average cost of capital
WEA	Wind energy area
XPLE	Cross linked polyethylene

Executive Summary

In July 2019, Governor Andrew M. Cuomo signed the Climate Leadership and Community Protection Act (CLCPA), which adopted the most ambitious and comprehensive state climate and clean energy legislation in the country. The CLCPA requires New York State to achieve a zero-emission electricity system by 2040 and reduce greenhouse gas emissions 85% below 1990 levels by 2050. As part of this push to decarbonize the grid, the CLCPA codifies groundbreaking goals under the Green New Deal, including a mandate for at least 70% of New York's electricity to come from renewable energy sources, such as wind and solar, by 2030. This ramp-up of renewable energy is expected to include quadrupling New York's offshore wind (OSW) target to 9,000 megawatts (MW) by 2035, up from 2,400 MW by 2030.

The achievement of this goal is likely to require investments in New York's electricity system. In this context, the State Team (NYSERDA and DPS) engaged DNV GL, PowerGEM, and WSP to conduct analysis that supports the development of potential long-term OSW transmission solutions (the Study).

The main objectives of the Study were to identify better-performing onshore substations to interconnect 9 GW of OSW into New York City and Long Island in a reliable and cost-effective manner; evaluate the environmental and permitting challenges associated with bringing the OSW power to selected onshore substations; and evaluate plausible offshore transmission solutions for collecting and delivering the remaining 7,175 MW of OSW that is not procured yet.

Development of feasible OSW transmission strategies to collect and deliver up to 9 GW of wind energy from offshore locations to New York City and Long Island requires detailed consideration of various technical aspects and practical limitations, including but not limited to, technology availability, scalability, cost-effectiveness, grid reliability and compliance, energy market fundamentals, as well as environmental, physical, and geographical limitations associated with the offshore seabed, narrows, shorelines and landing points. To achieve the Study's main objectives while accounting for the previously mentioned technical aspects, a Study methodology was developed that included three main tasks, namely onshore grid assessment; offshore transmission assessments; and environmental constraint analysis. Given the intrinsic dependency and relations that exist among the technical aspects and practical limitations, these three tasks were performed partially in parallel and partially in sequence to more effectively inform and guide one another.

The first step of onshore grid assessment consisted of screening of the existing substations in zones J and K using reliability security analysis and production cost modeling. Subsequently, building on the results of substation screening, onshore grid assessment was performed for two alternative OSW injection splits between New York City and Long Island regions: ~6 GW of OSW allocated to New York City and ~3GW to Long Island and 5 GW of OSW allocated to New York City and ~4GW to Long Island. The reliability security and production cost analyses were conducted using a range of onshore grid operating conditions and demand forecasts. The use of energy storage facilities was also incorporated into various scenarios in the analysis. Overall, the analysis identified scenarios of 6 GW into New York City and 3 GW into Long Island that minimized onshore transmission system upgrades and involved very limited OSW curtailment. However, if more OSW capacity (~4GW) is injected into Long Island, there is expected to be an increased risk of OSW energy curtailment and onshore system upgrades are likely needed and may necessitate the addition of a new tie-line to export energy off of Long Island.

A transmission cable routing feasibility assessment was conducted to evaluate the environmental and permitting challenges of routing transmission cables from potential offshore lease areas to substations identified in the onshore grid assessment. Major potential constraints were identified for many of the illustrative route segments, but these challenges may be overcome with suitable planning and outreach efforts. Thus, the assessment supports a finding that the illustrative routings are feasible. Other key findings of the routing assessment include the following:

- The analyzed onshore routes could feasibly accommodate between two and six separately installed cable circuits.
- Six separate cables (or circuits) could feasibly be installed through New York Harbor to the analyzed substations.

As part of the offshore transmission assessment, uncertainties around the future development of OSW projects, including their locations and area sizes, were considered by developing five illustrative OSW build-out scenarios. These scenarios represent a possible range of geographically diverse future outcomes that could potentially occur. For each OSW build-out scenario, five offshore transmission connection concepts (Radial, split, shared substation, Meshed, and Backbone) were developed. The OSW connection concepts were established using the combination of 220 kV HVAC and ±320/525 High-voltage direct current (HVDC) technologies, subject to technical characteristics and physical limitations as documented in the report. Preliminary analysis of the assumed OSW build-out scenarios along with the OSW connection concepts were indicative of the following key observations:

- The relative benefits and cost comparisons of OSW connection concepts remained consistent in all assumed OSW build-out scenarios, which suggests a single representative OSW build-out scenario can be utilized for detailed analysis to determine the relative performance of the OSW connection concepts with minimal risk of compromising key findings.

- For OSW networked connection concepts (i.e., substation sharing, Mesh, or Backbone) to be economically justifiable, the networked connection concept should encompass at least three OSW projects with minimum aggregate rating of approximately 3 GW.

- Uncertainty related to the availability of wind energy areas (WEAs) makes it challenging to pivot from an OSW's Radial connection concept to other OSW networked connection concepts.

    - However, these challenges could be overcome by proper upfront preparation and investments (e.g., over-sizing cables, converters, and additional breaker positions).

    - In addition, among all OSW connection concepts studied, the Meshed connection concept was observed to be the most flexible considering WEA uncertainty.

    - Furthermore, moving from a Radial connection concept to substation sharing connection concept is expected to be relatively more challenging given WEA and OSW project location uncertainty.

- Close coordination with the Bureau of Ocean Energy Management (BOEM) to make more WEAs available will foster more competitive OSW procurements and facilitate the potential development of networked offshore transmission systems.

- With key findings in mind and considering Radial and split connection concepts were observed to have very similar performance in the preliminary assessment, the Radial, Meshed and Backbone connection concepts were shortlisted for the further detailed offshore analysis that included detailed levelized transmission cost of electricity (LTCOE) and availability assessments.

Detailed calculations were conducted for the shortlisted OSW connection concepts, including both the wet-side and dry-side (between the landing points and onshore grid substations) components. Furthermore, to provide a better comparison between the three shortlisted OSW connection concepts by considering the magnitude of OSW energy that they would deliver to the onshore grid, LTCOE was calculated to reflect the cost of transferring the OSW energy for each delivered MWh of OSW energy to the onshore grid.

Offshore Radial and Meshed connection concepts were observed to result in lower LTCOE compared to the Backbone connection concept. In addition, OSW Meshed connection concept resulted in a higher availability and operational benefits among the three shortlisted OSW connection concepts.

Provided draft Call Areas in the New York Bight become WEAs, 9 GW of OSW connected to New York's electricity system by 2035 is possible. Though more technical assessment should be completed to more robustly evaluate solutions, the Study finds there exists feasible options for offshore cable concepts and routing, cable landfall and onshore cable routing, and existing substations for the interconnection of 9 GW of OSW. For all options, smart systematic planning is key to cost-effective outcomes.

1 Background

In July 2019, Governor Andrew M. Cuomo signed the Climate Leadership and Community Protection Act (CLCPA), which adopted the most ambitious and comprehensive state climate and clean energy legislation in the country. The Act requires New York State to achieve a zero-emission electricity system by 2040 and reduce greenhouse gas emissions 85% below 1990 levels by 2050. As part of this push to decarbonize the grid, the CLCPA codifies groundbreaking goals under the Green New Deal, including a mandate for at least 70% of New York's electricity to come from renewable energy sources, such as wind and solar, by 2030. This ramp-up of renewable energy is expected to include quadrupling New York's offshore wind (OSW) target to 9,000 megawatts (MW) by 2035, up from 2,400 MW by 2030.The achievement of this goal is likely to require investments in New York's electricity system. In this context, the State Team engaged DNV GL, PowerGEM, and WSP to conduct technical analysis (the Study), as described in following sections of this report, to support the development of potential long-term OSW transmission strategies to achieve the OSW milestones The Study assessed various aspects of the electricity system in and around New York City (Zone J) and Long Island (Zone K) to determine reliable and low-cost solution(s) to accommodate the OSW target capacities in 2025, 2030, and 2035.

1.1 Study Goals

The Study aimed to address the following research questions:

1. **Question 1**: Where are good opportunities at onshore substations for adding 9 GW of OSW into New York City and Long Island in a reliable and low-cost manner?

2. **Question 2**: What are the environmental and permitting challenges associated with bringing OSW to existing onshore substations?

3. **Question 3**: Considering the 1,825 MW of OSW that have recently been procured,[1] what are plausible offshore transmission strategies for collecting and delivering the remaining 7,175 MW of OSW? How does an illustrative networked offshore transmission strategy compare to a Radial connection scenario?

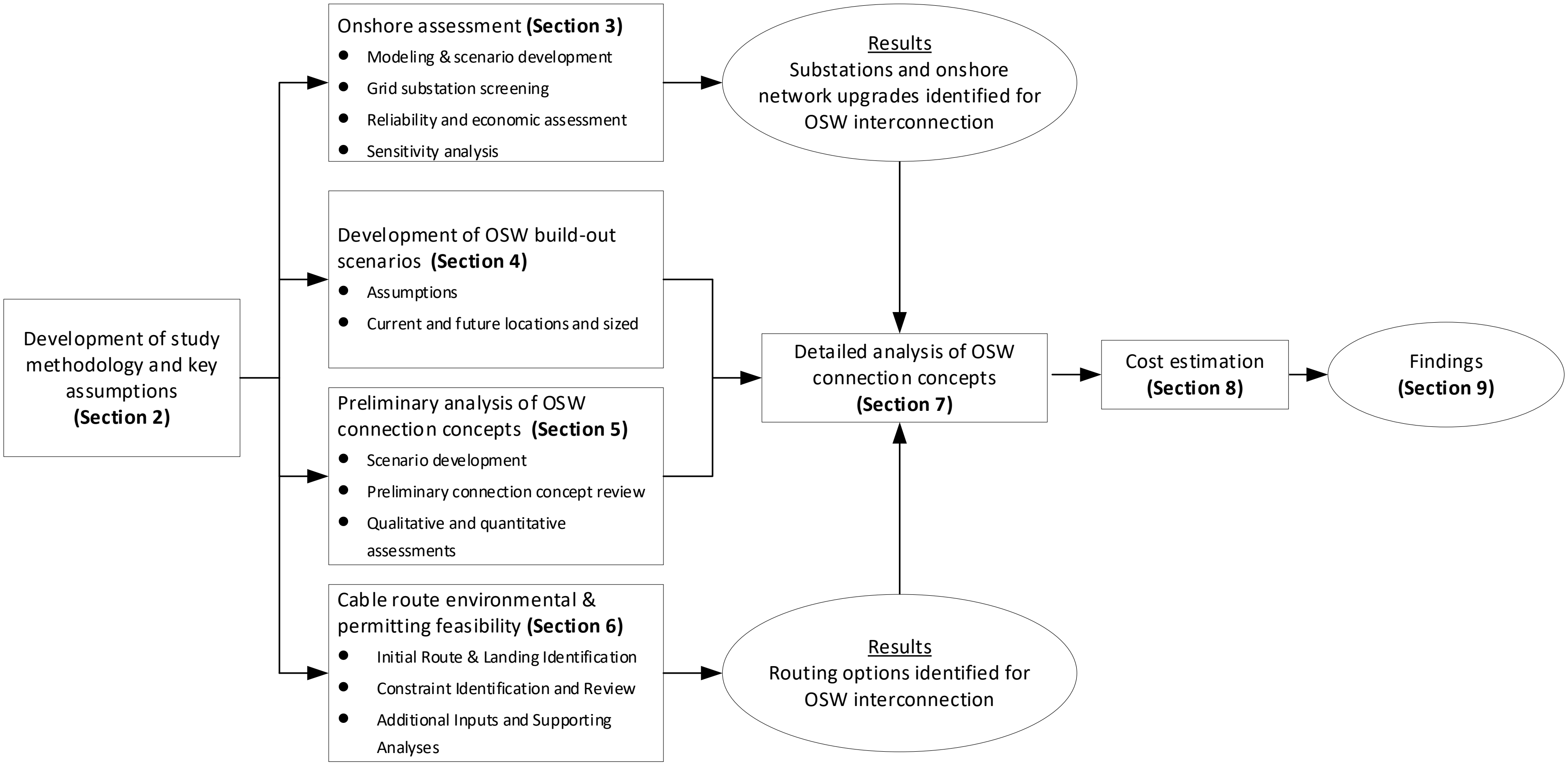
[1] For more detail, refer to https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/Focus-Areas/NY-Offshore-Wind-Projects

2 Study Methodology

Development of a feasible transmission strategy to collect and deliver up to 9 GW of wind energy from offshore locations to New York City and Long Island requires detailed consideration of various technical aspects and practical limitations including, but not limited to, technology availability, scalability, cost-effectiveness, grid reliability and compliance, energy market fundamentals, as well as environmental, physical and geographical limitations associated with the offshore seabed, narrows, shorelines and landing points. To that effect, a detailed methodology to answer the research questions noted in Section 1.1, and to achieve the State Team's overall goals related to OSW transmission system planning, was developed by DNV GL, PowerGEM, and WSP and approved by the State Team.

The Study methodology included three main tasks, namely: onshore grid assessment; offshore grid assessments; and environmental constraint analysis. Given the intrinsic dependency and relations that exist among the technical aspects and practical limitations of these three tasks, each were performed partially in parallel and partially in sequence to more effectively inform and guide one another. Figure 2-1 illustrates an overview of the Study methodology and notes where each task is described in this report.

Figure 2-1. Overview of the Study Methodology and Tasks Mapped to Sections of the Report



A more detailed summary of each task's methodology and scope is provided in the following Sections (2.1, 2.2, and 2.3). Further details, such as key limitations, opportunities, and applicable assumptions, are discussed in subsequent Sections 3 through 8, each dedicated to a specific Study task, which present analysis results and observations.

In support of the Accelerated Renewable Energy Growth and Community Benefit Act, that drove the need for this analysis, DNV GL and the rest of the consulting team worked with Department of Public Service and NYSERDA staff in consultation with the New York Power Authority, the Long Island Power Authority, the state's grid operator and utilities, to conduct this study.

2.1 Onshore Assessment

The Study onshore assessment consisted of the following tasks:

- Substation screening
- Development and analysis of OSW connection scenarios

2.1.1 Onshore Substation Screening

In this task, all substations within zones J and K were evaluated as feasible OSW connection points. Based on combination of reliability assessment and market analysis, as well as system topology, transfer analysis results and engineering judgment, a set of 20 substations were selected as candidate OSW connection points. These substations should not be construed as optimal OSW connection points; rather, the purpose of substation screening was to establish an initial manageable set of possible connection points, so that analytical scenarios could be developed and studied.

2.1.2 Analysis of OSW Connection Scenarios

Three different OSW allocation scenarios were developed and analyzed in this task. Two of the three scenarios allocated 6 GW of OSW to zone J and 3 GW of OSW to zone K, whereas a third scenario considered an increased amount of 4 GW of OSW connecting to zone K and the remaining 5 GW of OSW connecting to zone J.

Scenario analysis consisted of reliability security assessment and production cost modeling. In addition to the base scenarios, several sensitivities were also considered varying modeling parameters, such as availability of storage facilities, demand profiles, generation must-run status, etc.

Analytical results including steady state thermal overloads as well as annual OSW curtailment were developed for each scenario. Mitigating approaches, as needed, were developed to address system adverse reliability impacts and reduce OSW curtailment.

2.2 Offshore Assessment

As of the date of this Study, three OSW projects had already been procured and hence, were assumed fixed as Radial connected during the Study. The three procured OSW projects are Southfork (130 MW), Sunrise Wind (880 MW), and Empire Wind (816 MW), resulting in a remaining nominal OSW capacity target of 7.2 GW by 2035.

The Study's offshore assessment task consisted of the following three subtasks:

- Development of illustrative OSW future build-out scenarios
- Preliminary analysis of OSW connection concepts
- Detailed analysis of OSW connection concepts

2.2.1 Development of Illustrative OSW Build-Out Scenarios

For the remainder of targeted 7.2 GW of OSW, five plausible OSW build-out scenarios were considered. The OSW build-out scenarios were developed keeping in mind the uncertainties around OSW project geographic location and size, and timelines for development and construction. Scenarios also take into consideration projects currently in development. Based on differing assumptions related to BOEM wind energy area lease availability, turbine sizing and spacing requirements (that impact overall lease area capacity), and competition for OSW capacity located near Massachusetts and New Jersey, five plausible future OSW build-out scenarios were ultimately created (see Section 4.3). These five OSW build-out scenarios do not represent any preference of the State Team toward specific OSW projects or project locations. Rather they represent a possible range of future outcomes that could occur and are deliberately intended to be geographically diverse while still offering plausible OSW project locations and capacities given the current state of the OSW industry in the Northeastern U.S. as of the date of this report. The five developed OSW build-out scenarios can be found in Annex C.

2.2.2 Preliminary Analysis of OSW Connection Concepts

For each of the five future OSW build-out scenarios, five different connection concepts were studied (Dedicated Radial, Split, Mesh, Shared Substation, and Backbone; details regarding the different concept definitions can be found at Section 5 of this document). The result of this subtask was 25 different offshore connection topologies, each including a phased construction timeline for the 2025, 2030, and 2035 Study Years.

Based upon the sensitivities affirmed through the initial onshore analysis (see Section 3) as to the efficient split between New York City (NYISO Zone J) and Long Island (Zone K), the offshore analysis assumed injections of 6 GW of OSW into New York City and 3 GW of OSW into Long Island. During this phase of the Study, the High Voltage Alternating Current (HVAC) and High Voltage Direct Current (HVDC) technologies selection criteria were established considering limitations associated with onshore grid, landing points and routings to reach the onshore points of interconnections (POIs).

Each of the 25 offshore connection topologies consists of a high-level grid design in which quantity and ratings of main electric power equipment (cables, converters, transformers, etc.) are considered. Given that the results associated with onshore assessment were being developed as a parallel workstream (such as selected POIs and environmental routing), the initial 25 offshore connection topologies were analyzed and ranked qualitatively using industry guidelines.

2.2.3 Detailed analysis of OSW connection concepts

The onshore assessment and environmental assessments completed in parallel with the preliminary analysis of OSW connection topologies led to a refinement of the initial 25 offshore connection topologies down to three feasible connection concepts. The feasible connection concepts of Radial s, Meshed, and Backbone were selected for detailed design and more thorough illustrative analysis.

Recognizing commonalities across many of the plausible OSW build-out scenarios, the Radial, Meshed and Backbone connection concepts were studied further using one illustrative OSW build-out scenario. As a result, the 25 connection topologies were reduced to three variants. Complete conceptual designs were created for each variant, including all major electrical components, cable lengths and sizing, and other associated infrastructure. With quantitative inputs from onshore and environmental studies, capital expenditures (CAPEX), operational expenditures (OPEX), replacement expenditures (REPEX), and LTCOE calculations were completed, including both offshore and onshore equipment. In addition, in order to compare benefits of each variant beyond cost, an availability analysis was also completed for each of the three variants.

A detailed discussion of the complete offshore assessment and key results are included in Sections 4, 5, 7, and 8.

2.3 Environmental Constraints Analysis (Routing Assessment)

A transmission cable routing feasibility assessment (hereafter the Routing Assessment) was performed to address the following research question: what are the environmental and permitting challenges associated with bringing offshore wind energy to existing onshore substations?

The general scope and primary objectives for addressing the research question consisted of the following:

- Identify potentially feasible routes and landing areas to connect offshore power inputs with onshore substations to support an illustrative 6 GW (New York City) / 3 GW (Long Island) transmission strategy.
- Evaluate the environmental and permitting challenges for the representative routes and landing sites.
- Determine the major environmental constraints that might adversely impact the illustrative transmission strategy being examined.

Overall, the feasibility of the transmission strategy was assessed in two steps:

- **Initial assessment**: A screening-level analysis was performed to identify major constraints that might substantially hinder or prevent the installation of a transmission cable along several potential routes.
- **Route Refinement**: Based on the initial analysis and further refinement of other non-environmental aspects of the strategy, a limited number of routing alternatives were carried forward for further evaluation to confirm the feasibility of the illustrative transmission strategy with respect to routing.

2.3.1 Initial Route and Landing Site Identification

To identify and evaluate multiple route alternatives between offshore lease areas and onshore substations, also referred to as POIs, the routes were divided into three primary components:

- Offshore route corridors
- Shore approach segments and landing sites
- Onshore route segments

Representative offshore route corridors were delineated between potential offshore wind lease areas and the nearshore coastal region of New York State. The nearshore segments of the representative routes, identified as the shore approach, connect the offshore route corridors to landing sites along the Long

Island shore and the New York City waterfront. Onshore route segments extend from the shore landing sites to representative POIs identified during the onshore grid substation assessment (see Section 3). Potentially suitable landing sites and potentially feasible onshore routes were initially identified based primarily on a visual interpretation of aerial photographs and GIS data layers. Ultimately, representative route alternatives connecting to 11 different POIs were analyzed, including four POIs in New York City (ConEd interconnections) and seven POIs on Long Island (LIPA interconnections).

2.3.2 Constraint Identification and Review

To identify the potential environmental and permitting challenges for the representative routes and landing sites, GIS data layers of environmental resources and specially designated areas were compiled for all areas that may be affected by the different route segments extending from potential offshore lease areas to the identified POIs. These GIS layers were obtained from publicly available websites and included in a project-specific web mapper that allowed them to be overlaid with each other on base maps in order to consider representative route segments in relation to multiple potential constraints. Representative routes and landing sites were analyzed based on the presence and degree of constraints considered potentially critical to the feasibility of each route segment. Scoring matrices were developed to help visualize and compare the relative feasibility of the representative routes with respect to each critical constraint.

2.3.3 Route Refinement and Supporting Analyses

The results of the screening-level critical constraints analysis were considered in conjunction with other inputs and additional analyses to develop a refined list of representative routes for illustrative purposes. The additional inputs and analyses included:

- Further evaluation of the transmission strategy to yield a revised set of POIs for consideration — four in New York City and four on Long Island.

- Consideration for several specific cable installation methods and electrical engineering parameters.

- Further investigation to identify potential sites for HVDC converter stations and HVAC transformer stations.

- Evaluation of the number of cables and/or trenches that could potentially be installed along nearshore and onshore locations where constraints are greatest (i.e., “bottlenecks” or “restriction points”).

A detailed discussion of the Routing Assessment methodology and key results are included in Section 6. Supporting material developed as part of the Routing Assessment is provided in Annex B - Transmission Cable Routing Assessment Supporting Attachments. The refined list of representative routes was used in the costing analysis discussed in Section 8.

3 Onshore Assessment

3.1 Introduction

New York State recently enacted the CLCPA that requires the State to reach a carbon-free power system by the year 2040. As part of the modeling process for this Study, the State has also set intermediate milestones that involve:

- Connecting 9,000 MW (9 GW) of offshore wind (OSW) by 2035, with an intermediate level of 5.6 GW by 2030 on the glide path to the final targets. This is significantly more than the ~1.8 GW that has been procured to date and is expected to connect by 2025.
- Deploy 3,000 MW (3 GW) of energy storage facilities by 2030, with an interim target of 1.5 GW of storage by 2025.

Figure 3-1 illustrates the targets and milestones considered in the CLCPA.

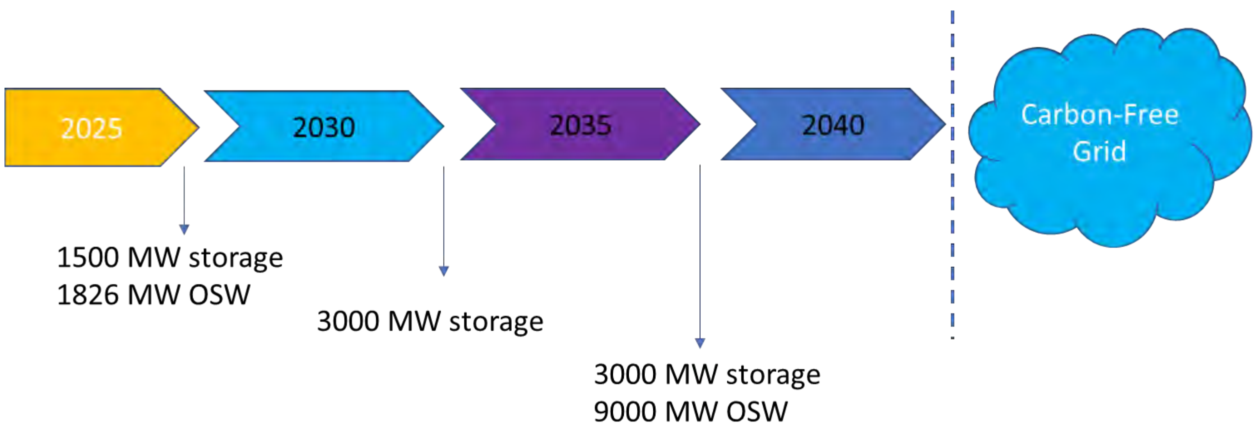


Figure 3-1. Intermediate Milestones Toward a Carbon-Free NYS Grid

One of the key objectives of the Study commissioned by NYSERDA is to identify potential transmission strategies in order to achieve the State goals. As part of the Study, PowerGEM performed onshore analysis to assess strategies and options to connect 9 GW of OSW to zones J and K. The remaining sections in this Chapter 3 of the Study report discuss the development of various scenarios, the analytical approach followed, and the analytical findings.

As part of the onshore analysis, PowerGEM performed reliability security analysis and production cost economic analysis. The analysis performed should not be construed as a replacement of the formal interconnection studies that each OSW project will need to undergo as part of the NYISO interconnection process. The formal interconnection process involves several analytical components that were outside the scope of the Study. Rather, the analysis performed in the Study aimed to provide insights into the capability of the current system to accommodate 9 GW of OSW and present various interconnection options.

Chapter 3 of the Study was prepared by PowerGEM in the course of performing work sponsored by the State Team. Any opinions expressed in this chapter do not necessarily reflect those of the State Team, and any references to specific products, services, process, or methods does not constitute an implied or expressed recommendation or endorsement of it.

This Chapter 3 of the Study report is structured as follows:

- Following this introductory Section 3.1, Section 3.2 discusses the study methodology, technical assumptions, and data used in onshore analysis
- Section 3.3 discusses the initial stage of onshore analysis that involved screening of existing system substations
- Section 3.4 discusses the development of a base OSW allocation (Scenario 1) and presents analytical findings
- Section 3.5 discusses the development of an alternative OSW allocation to zone K (Scenario 2) and presents analytical findings
- Section 3.6 discusses the development of an alternative OSW allocation that connects increased OSW resources to zone K (Scenario 3) and presents analytical findings
- Section 3.7 provides the final conclusions reached in onshore analysis

3.2 Study Methodology & Assumptions

The onshore analysis in the Study proceeded in accordance with the methodology and subject to the assumptions and study parameters outlined in this section.

3.2.1 Study Area

The Study focused primarily on the 115 KV and above portion of the New York State Transmission System (NYSTS), in the Dunwoodie (zone I), New York City (zone J), and LIPA (zone K) areas that are most likely to be affected by the connection of OSW. Specifically, for the LIPA region, the 69 kV and above network was considered in the N-0/N-1 steady-state reliability analysis (in addition to 115 KV and above facilities). These areas are collectively referred to as the Study Area in the remainder of this report.

3.2.2 Study Database

The NYISO provided summer peak 50/50 power flow models and associated contingencies and modeling files for 2024 and 2029 planning years. The models provided were based on the NYISO Class Year 2017 ATBA base case with 2019 FERC-715 2024/2029 system representations.

Starting from the power flow models provided by the NYISO, base cases were developed for each of the 2025, 2030, and 2035 study years. The 2024 summer peak case was used to develop the base case for the 2025 study year. The 2030 and 2035 base cases were developed using the 2029 summer peak case.

The following considerations were taken into account for developing the study base cases:

a) Already procured OSW projects (i.e., Empire, Sunrise, and South Fork projects) were modeled in service at full capacity in all three base models.

b) The Champlain Hudson Power Express (CHPE) project was not considered in any of the study years.[2]

c) Both segments A and B of the AC Transmission PPTN projects were included in all models.

d) The Poseidon OSW model was initially included in the study models. However, in the course of the study, PowerGEM and the State Team were informed that Poseidon has withdrawn and was no longer a valid project. Base models were updated to remove Poseidon from consideration. This will be further discussed in Section 3.5.

e) Two load profiles were used in the study: a) base demand profile, and b) higher demand sensitivity profile. Both profiles followed load forecasts considered in the Pathways to Deep Decarbonization in

[2] Based on Study assumptions regarding availability of non-OSW resources to be dispatched and curtailed, inclusion of the CHPE project would likely have minimal impact on analytical findings of the Study.

New York State study[3] for the 2025, 2030, and 2035 horizon years. Snapshot power flow models, appropriate for reliability analysis, were developed based on the New York Control Area (NYCA) coincidental peak load. Production cost models, appropriate for market analysis, considered the entire annual (i.e., 8760-hour) load profile for each of the study years. NYCA coincidental peak load values considered in the Study are tabulated in Table 3-1. Values in Table 3-1 are after netting out Behind-The-Meter (BTM) PV.

Table 3-1. NYCA Coincidental Peak Load (MW)

Demand Forecast	Study Year		
	2025	2030	2035
Base Demand Profile	29,101	29,711	33,305
Sensitivity Demand Profile	29,159	33,719	36,592

f) Following targets specified in the New York State Energy Storage Roadmap, 1,500 MW of energy storage units were included in the 2025 base case. Energy storage units totaling 3,000 MW were used in the 2030 and 2035 base cases. Initially, energy storage facilities were added to the NYCA backbone system based on load-weighted share of individual substations. In subsequent stages of analysis, storage facilities were moved to different location. Figure 3-2 illustrates the size and location of the storage units added in the base cases.

For purposes of analysis, storage facilities were considered fully dispatchable in their entire range. In production cost analysis, storage units were modeled as four-hour units.

[3] https://climate.ny.gov/-/media/CLCPA/Files/2020-06-24-NYS-Decarbonization-Pathways-Report.pdf. The base demand follows the High Technology Availability case and the higher demand profile leverages information from the Limited Non-energy case.

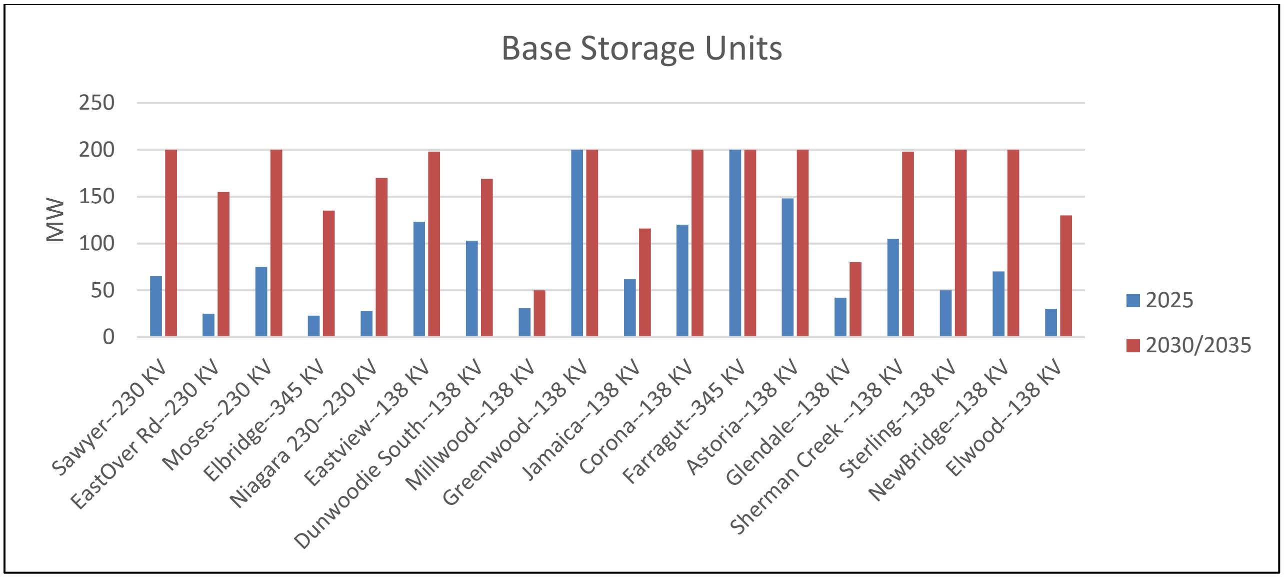


Figure 3-2. Base Case Storage Units

g) NYCA generation retirements posted by NYISO on or before January 2020 were considered in the development of base models. Retirements of peaker units were also considered in accordance with the individual unit compliance plans, as filed. A comprehensive list of generation retirements considered in the Study is included in Attachment 3-I (Annex A).

h) Select upgrades from Local Transmission Plans (LTP) of NYCA Transmission Owners were also considered in the development of the base models. Table 3-2 presents a partial list of system changes considered, based on LTPs filed for zone K (LIPA). A comprehensive list of local upgrades considered in the Study was included in Attachment 3-II (Annex A).

Table 3-2. Partial List of Local Upgrades (LTP) Considered in LIPA

Description	Study Year
King Highway 138 KV Substation	2025, 2030, 2035
East Garden City to Valley Stream new 138 KV ckt	2025, 2030, 2035
Wildwood to Riverhead 69 KV to 138 KV conversion	2030, 2035
Riverhead to Canal new 138 KV ckt	2030, 2035
Syosset to Shore Rd new 138 KV ckt	2030, 2035

i) To avoid generation deficiencies noted in the NYISO 2019 Comprehensive Reliability Plan study, base models for all three study years included a 420 MW non-renewable compensatory unit at

Greenwood 138 KV substation. The unit was considered available for dispatch in its entire range in all analysis.

j) To achieve the policy targets in the CLCPA, a non-OSW build mix was developed during the first quarter of 2020, based on preliminary Clean Energy Standard Cost Study analysis. This information was leveraged to provide the remaining renewable energy build mix, which was added at the NYCA backbone system and modeled as land-based wind and solar units. Total land-based wind and solar MWs considered in the base cases are summarized in Table 3-3.

Table 3-3. Total Solar and Onshore Wind (MW)

Study Year	Solar	Wind	Total
2025	5,027	4,229	9,256
2030	14,242	5,709	19,951
2035	16,842	6,108	22,950

3.2.3 Modeling Assumptions

Phase Angle Regulators (PARs), switched shunts, and load-tap-changing (LTC) transformers were allowed to regulate in pre-contingency conditions; they were locked (non-regulating) in post-contingency conditions. Static var compensator and Flexible AC transmission system devices in NYCA were set to zero reactive power output pre-contingency but were allowed to regulate up to their full output post-contingency.

The ConEd-LIPA wheeling constraint[4] was observed in all study analysis. Flows over the NNC cables were set at zero MW in all analysis. Flows over DC tie lines between LIPA and PJM (Neptune) and ISONE (Cross Sound Cable) were allowed to fluctuate as imported flows; no exports were allowed over the DC lines. The LIPA system was allowed to import (export) from (to) the rest of the NYCA subject only to the applicable pre/post contingency ratings of the Y49 and Y50 tie lines[5] (i.e., no other modeling constraints were applied on LIPA imports or exports over the Y49/Y50 tie lines).

[4] Total of 300 MW over the Jamaica PAR-controlled lines

[5] Unless specifically noted otherwise, post-contingency flows on the Y49 and Y50 tie lines were limited to the LTE ratings of the cables.

3.2.4 Study Methodology

3.2.4.1 Steady-State Reliability Analysis

Steady-state reliability security analysis was performed using the PowerGEM TARA software.

Steady-state thermal N-0, N-1, and N-1-1 analyses were conducted in accordance with NYISO and NERC planning criteria. The planning philosophy whereby normal thermal ratings shall not be violated under pre-contingency conditions (i.e., N-0 or N-1-0) and the applicable emergency rating shall not be violated under post-contingency conditions (i.e., N-1 or N-1-1) was applied. Under post-contingency conditions, the flows on facilities within the Study Area were limited to Short-Term Emergency (STE) ratings for underground cable circuits in the ConEd service area and Long-Term Emergency (LTE) ratings for the remaining underground feeders, overhead circuits and transformers.

N-1-1 analysis was performed allowing for security-constrained reliability re-dispatch between contingencies. After the first contingency and prior to the second contingency, analysis allowed existing online NYCA generation (excluding OSW per study assumptions, as well as nuclear and hydro facilities) and regulating PARs to adjust. PARs, switched shunts, and LTC transformers were modeled as regulating devices in pre-contingency conditions and non-regulating devices in post-contingency conditions following the second contingency.

In accordance with the ConEd transmission planning criteria, N-1-1-0 analysis was also performed. N-1-1-0 analysis limited flows on ConEd facilities within select load areas to pre-contingency ratings. Following the second contingency, the analysis allowed system adjustments, including re-dispatch of generation resources and adjustment of regulating PARs, in preventive or corrective mode, if and as needed. OSW adjustment (i.e., curtailment) was allowed but only as last resort for resolving relevant N-1-1-0 overloads. In other words, an OSW unit was allowed to be curtailed under N-1-1-0 conditions only if the OSW unit was impacting an overload and that specific overload could not be mitigated with adjustment of PARs and/or dispatch of other generation resources. As already stated, OSW curtailment was not allowed under N-0, N-1, and N-1-1 contingency conditions.

Steady-state reliability security analysis was performed for summer peak loading conditions only, consistent with established planning study guidelines. As will be discussed in the next section, production cost analysis is based on an annual period, thus properly accounted for light load conditions.

3.2.4.2 Production Cost Analysis

Production costing analysis was performed using the PowerGEM PROBE LT software.

Production cost analysis is an annual economic-based analysis that simulates detailed hourly operation of a given energy market over an 8760-hour time frame. Production cost modeling (PCM) software performs this simulation by finding the least cost dispatch of a complex system of interconnected generators to reliably meet load in every hour of the day at every location. PCM commits and schedules generation with respect to the expected input costs and operating parameters for each power plant and physical limitations of the transmission system. There are many applications for PCM software; typically, it is used to assist in deciding how much generation to add and where should the generation be placed on the system, study economic benefits of new transmission, and/or to evaluate numerous other future market outcomes such as pricing, transmission congestion, and emissions.

In the context of the Study, the primary objective of the production cost analysis is to determine wind curtailment risks with consideration of renewable variability over time. This enables further evaluation of the suitability of various wind interconnection locations.

Production cost analysis requires additional inputs and assumptions as compared to steady-state reliability analysis. In addition to the transmission model, input data include generator heat rates and operating characteristics, hourly zonal demand for all hours of the study year, renewable energy profiles, emissions rates and costs, and fuel price forecasts. Sources of PCM data for the Study included:

- S&P Global Market Intelligence — primary source for power plant data for NYISO market generators
- NYISO Gold Book — supplemental NYISO power plant data
- eia.gov — specifically forms 860 and 923 as a cross-reference for generator heat rates
- NYISO-provided data — load flow models, including base dispatch profiles
- NYSERDA/State Team — hourly zonal demand profiles, offshore wind profiles, onshore wind and solar profiles, NYISO queue generator information, natural gas prices. Figure 3-3 shows a summary of the natural gas price forecast used in the Study

To meet the primary objectives of the Study, production cost analysis required specific assumptions in addition to those noted in section 3.2.3. A key assumption in the economic analysis is that onshore wind, solar, and hydro will be curtailed before offshore wind. This approach ensures OSW is not reduced due to statewide over-generation scenarios, to properly test zones J/K transmission. Additional base case assumptions in the simulations include:

- All thermal generation, except nuclear, can be re-dispatched and/or decommitted.
- Offshore wind profiles were developed from the NREL Wind Toolkit Database for a 2009 meteorological year.
- Analysis monitored 100 KV and above elements only.
- An offshore wind average capacity factor of 53% was used. This figure was informed by the Clean Energy Standard cost study.

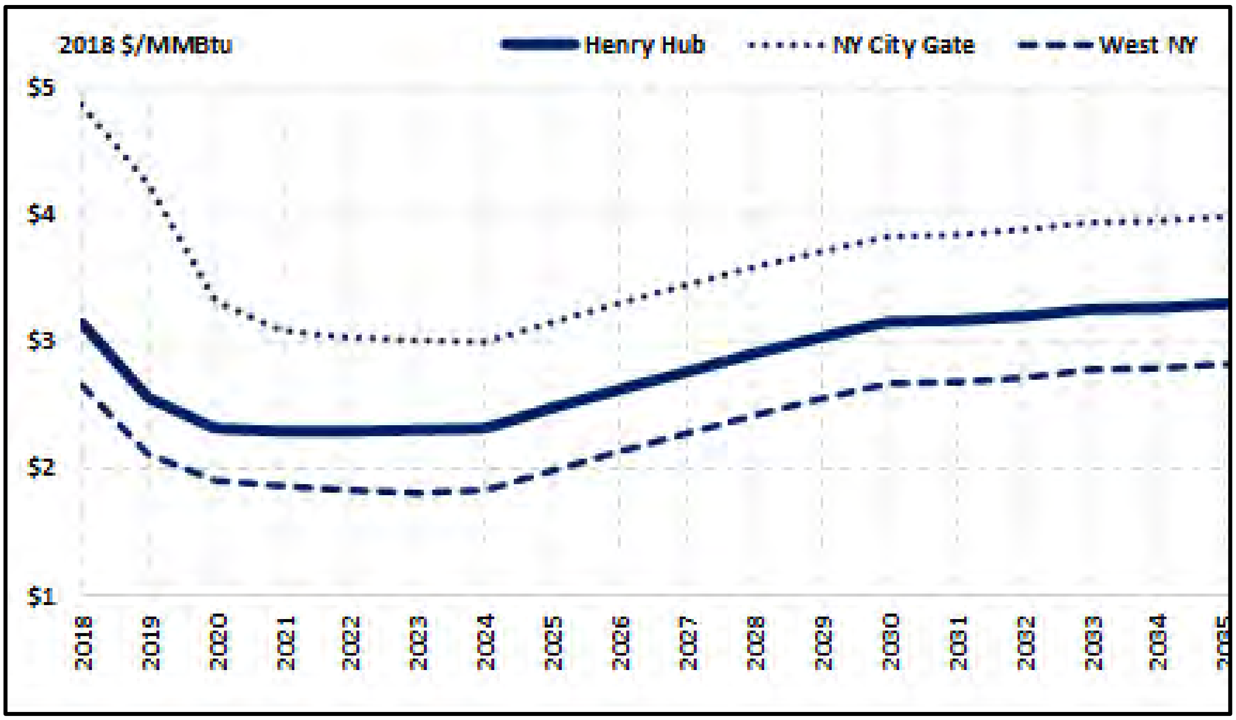


Figure 3-3. Natural Gas Price Forecast (2018$/MMBTU)

3.3 Substation Screening

As the first step in onshore analysis, screening of existing substations was performed to qualitatively evaluate and rank existing substations in zones J and K for the connection of OSW resources. The purpose of screening was to filter the list of substations based on measurable metrics, considered both individually as well as in small clusters, and provide a much reduced, initial list of candidate substations for the connection of OSW.

3.3.1 Screening Methodology

Substation screening was performed based on two steps:

a) Step 1: Linear thermal transfer analysis was performed for every existing substation in zones J and K. Available information on the configuration and connectivity of each substation was also examined. Thermal transfer analysis proceeded by modeling a generation injection on a selected sending node (the source or sending subsystem) and then incrementally scaling generation up, while a subset of existing generation resources (the sink or receiving subsystem) is scaled down accordingly. In the Study, every substation rated at 69 kV and above was considered individually as source, and generation was scaled up against a variety of possible sinks testing system stresses in various directions. The transfer level between the source and the sink continued to increase (while simultaneously simulating contingency events) until the flow on some transmission element exceeds its applicable rating (either pre- or post-contingency), at which point the injection limit at the source was determined. Despite the limitations of thermal transfer analysis, such as dependency on initial dispatch conditions, definition of sources and sinks, etc., it can provide insight into system capabilities and coupled with additional analytical approaches, it can filter existing transfer capabilities as part of a screening approach.

Although the Study did not have a predetermined number of possible OSW connection points, or a minimum or maximum OSW MW injection at any particular station, it became apparent that in order to analyze connection of OSW to a manageable set of substations, a minimum injection threshold needed to be established. For purposes of the Study, a minimum of 300 MW of OSW per injection point was considered throughout the Study, unless otherwise noted. This was partially informed by the sizing of projects in the NYISO interconnection queue at the time of study parameter development; further, at that same time, it was unclear how different amounts of OSW could be split and brought onshore.

As a result of Step 1, 37 substations were selected for further consideration in Step 2.

b) Step 2. Using both power flow and production cost analyses, substations shortlisted in Step 1 were further evaluated. As part of this step, set injections were modeled at each substation, with maximum injections capped at 1,000 MW and 500 MW for 345 kV and 138 kV buses, respectively. Step 2 analysis focused primarily on the loading of the system rated at 100 KV and above, under snapshot (power flow) and annual (production costing) assessments.

The approach to screening substations in production cost modeling was designed with an understanding that it would be infeasible to test every potential combination of 37 substations at different MW levels, as this would result in a really large number (in the order of tens of thousands) of annual production cost simulations. Thus, the production cost modeling approach proceeded as follows:

First, a 2035 base case simulation was completed as a general test, to act as a benchmark case, and to inform next steps. This initial simulation also ensures there are no significant curtailments of the procured 1.8 GW of OSW after adding the Study assumptions but prior to adding additional OSW.

Then, selecting from the initial list of 37 substations, injections totaling an increment of 7.2 GW of OSW at various combinations of substations were added to the model and a complete annual simulation was performed per each configuration. The combination of injection levels and locations was based on voltage, existing OSW injections, and prior PowerGEM experience / system knowledge. The evolution of the process for substation screening via PCM analysis, targeting 7.2 GW for every 2035 scenario, can be loosely summarized as follows:

- Inject ~400 MW OSW at 17 locations (four simulations)
- Several additional simulations that inject ~800 MW OSW at 8 locations, excluding stations that failed screening at 400 MW
- Many additional scenarios, building on prior results, adding 400–1,000 MW per location
    - For example, if a location showed curtailment in multiple 400 MW scenarios, it was likely not tested again and excluded from further consideration
- Upon completion of each simulation scenario, each OSW injection was reviewed for number of hours of curtailment and total MWh curtailed

In total, 26 production cost simulations were completed to test possible combinations of OSW injection points and determine curtailment risks. In all simulations, all existing generation resources, other than nuclear units, were available for re-dispatch and de-commitment. Onshore wind and solar generation were curtailed before OSW, if and as needed. Total curtailment of OSW resources over the annual simulation period was the key metric applied in the ranking of each substation.

Snapshot power flow analysis was also performed. Simulations included full N-0 and N-1 contingency analysis and were performed based on concurrent OSW injections at the shortlisted substations, subject to generation dispatch and PAR optimization. In power flow analysis, dispatch optimization ignored economic cost differences associated with different generation resources.

OSW curtailment from yearly production costing analysis was the primary criterion considered in substation ranking. Results obtained from snapshot power flow analysis were considered as supplemental input.

3.3.2 Screening Results

Using the simulation results from the analytical approach outlined in the previous section, a total of 20 substations were identified that indicated promising performance. The list is provided in Table 3-4. In general, these substations exhibited insignificant or very little OSW curtailment in production costing analysis and little or no concerns in power flow analysis. Some of these substations merited consideration on a case-by-case basis due to special circumstances and general system knowledge.

However, under no circumstances should the list of stations presented in Table 3-4 be considered as a list of stations recommended for OSW interconnection. Rather, the purpose of substation screening in the Study was solely to establish an initial manageable set of possible connection points, so that analytical scenarios could be developed and further studied.

The list of stations that passed Step 1 but were not included in the list from Step 2 is included in Table 3-5. Whereas ultimately not selected as part of the list of candidate OSW connection points, several stations in Table 3-5 might very well merit further consideration under different study and modeling assumptions. Therefore, under no circumstances should the list of substations in Table 3-5 be construed as inadequate or infeasible for connection of OSW resources.

Table 3-4. Substation Screening Results

Name	kV	zone	Name	kV	zone
Farragut	345	J	Brookhaven	138	K
Goethals	345	J	Newbridge Rd.	138	K
Mott Haven	345	J	Northport	138	K
Rainey	345	J	Shore Rd.	345	K
W49th str.	345	J	Syosset	138	K
Academy	345	J	Glenwood	138	K
Astoria	345	J	Pilgrim	138	K
Freshkills	345	J	Port Jefferson	138	K
Gowanus	345	J	Ruland Rd.	138	K
East Garden City	138	K	Shoreham	138	K

Table 3-5. Step 1 Shortlisted Substations, Not Included in Final Screening List

Name	kV	zone	Name	kV	zone
E13th str.	345	J	Corona	138	J
Tremont	345	J	E13th str.	138	J
Astoria	138	J	E179th str.	138	J
Jamaica	138	J	Sherman Creek	138	J
Hudson Ave	138	J	East Garden City	345	K
Greenwood	138	J	Barrett	138	K
Foxhills	138	J	Holbrook	138	K
Parkchester	138	J	Shore Rd.	138	K

3.4 Scenario 1: Base Allocation of 9 GW of OSW Between Zones J and K — Analysis and Results

Onshore analysis considered several different allocations of 9 GW of OSW between zones J and K that will be presented in the remainder of this Chapter 3.

As the first step of the analysis, a base allocation was established to provide a base scenario for the connection of the 9 GW of OSW to zones J and K. As part of the development of the base allocation, all the candidate substations resulting from the substation screening process were assumed to be available for

OSW connection. This section discusses the development of the base allocation, the analysis approach, and presents analytical findings.

3.4.1 Initial Simulations and Development of Scenario 1

In order to develop OSW allocations that exhibited the least number of adverse system impacts, a large number of initial models were developed, where the 9 GW of OSW were allocated to zones J and K in various proportions, ranging from 5 GW to 7 GW of OSW allocated to zone J and the remainder allocated to zone K. Connecting stations and specific MW injections also varied among the models.
Following preliminary screening of the full set of initial models, six models were further developed and were subject to initial test run simulations. All test runs were performed for the 2035 study year. Figure 3-4 shows the zone J/K split considered in the test run simulations. Among the test runs considered, test run #5 indicated the most promising performance, i.e., fewer adverse system impacts based on reliability security analysis. Therefore, the base allocation and scenario was developed based on the OSW allocation and injections considered in test run #5. This allocation will be referred to as Scenario 1 in the remainder of this section. Figure 3-5 shows the approximate locations of the Points of Interconnection (POIs) selected in Scenario 1.

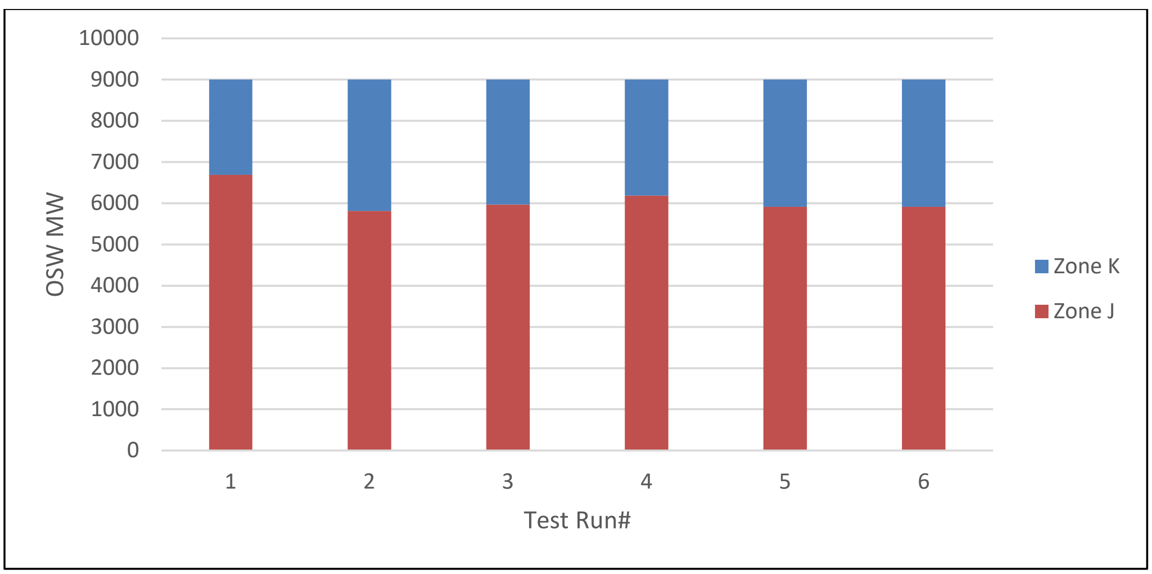


Figure 3-4. Zone J/K OSW Allocations in Test Runs (Including Already Procured OSW)

For the development of Scenario 1 for the 2030 study year, the OSW injections for 2035 were reduced to meet the OSW study targets described in Section 3.1. Regarding study year 2025, the already procured

OSW projects (Empire, Sunrise, and South Fork projects) fully address the study targets for the 2025 study year. Therefore, no additional OSW were considered for the 2025 study year. Table 3-6 summarizes the OSW injections for each study year. Similar information is presented in Figure 3-6.

Figure 3-5. POIs Considered in Scenario 1

Table 3-6. OSW Injections - Scenario 1

Already procured OSW (MW)			
Study Year	Gowanus (Empire) 345 kV	Holbrook (Sunrise) 138 kV	East Hampton (South Fork) 138 kV
2035	816	880	136
2030	816	880	136
2025	816	880	136

Scenario 1 additional OSW injections (MW)									
	Farragut 345 kV	Mott Haven 345 kV	Rainey 345 kV	W49th str 345 kV	Shore Rd 345 kV	Brookhaven 138 kV	Newbridge 138 kV	Northport 138 kV	Syosset 138 kV
2035	1400	1250	1250	1200	500	270	600	400	300
2030	1400	None	1250	None	500	None	300	400	None
2025	None	None	None	None	None	None	None	None	None

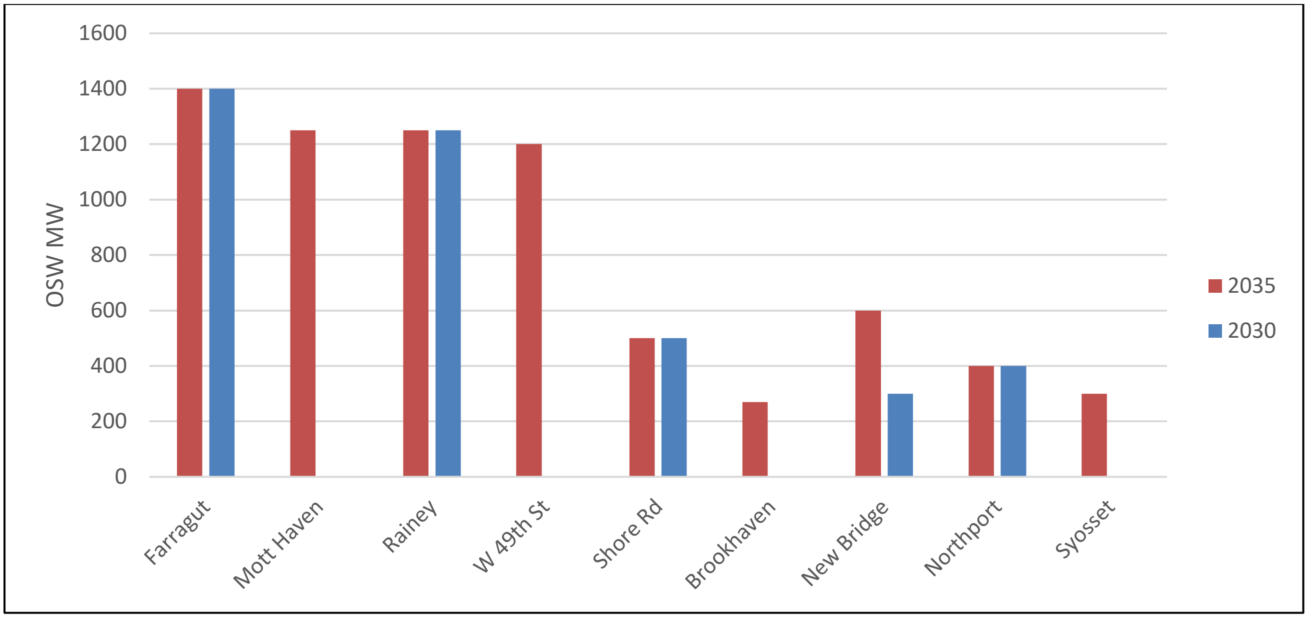


Figure 3-6. Additional OSW Injections - Scenario 1

3.4.2 Base and Sensitivity Conditions

In addition to the base conditions outlined earlier in this and prior sections, various additional sensitivities were considered in both reliability and production cost analysis to further evaluate the performance proposed in Scenario 1. Some of the sensitivities were based on PowerGEM suggestions and some were formed based on feedback from the Study Advisory Group. Table 3-7 outlines some of the different sensitivities considered under Scenario 1. The same sensitivities were also considered in additional scenarios, as will be discussed in subsequent sections.

Table 3-7. Sensitivity Conditions - Scenario 1

Sensitivity	Description	Analysis*	Study Years
Load sensitivity	Sensitivity demand forecast	RS/PCM	All
Ancillary services	Co-optimize Energy & AS (enforce NYISO AS requirements)	PCM	2035
Increased generation	10% non-dispatchable fossil generation	PCM	2030, 2035
No Storage	Remove zone K storage facilities	PCM	2035
Modified zone K	Modified zone K parameters, as described in report	PCM	2035

* RS-Reliability Security, PCM-Production Cost Modeling

3.4.3 Reliability Security Analysis

Following the methodology described in section 3.2, steady state contingency analysis was performed that included N-0, N-1, and N-1-1 analysis, in accordance with established criteria and study practices. N-1-1-0 analysis was also performed for select ConEd Transmission Load Areas (TLA) zones. Steady-state analysis focused primarily on thermal performance of the network. As already stated in section 3.2, OSW resources were considered as non-curtailable/non-dispatchable in reliability analysis; except that OSW curtailment/redispatch was allowed in N-1-1-0 analysis as resource of last resort to mitigate system overloads, if and as needed. All analysis was performed under peak loading conditions.

3.4.3.1 Steady State Thermal Contingency Analysis

Initial simulations were performed with energy storage units located as described in section 3.2. All storage units were considered fully dispatchable within their entire (charge/discharge) range. Contingency analysis results for the 2035 base-load forecast are summarized in Tables 3-8 and 3-9. Very similar results, qualitatively and quantitatively, were observed for the load sensitivity analysis. Tables 3-8 and 3-9 also include recommendations for transmission-based mitigating system upgrades, as needed.

It should be noted that analysis results also showed overloads on Farragut X10 and E13th str. transformers, in zone J. Based on feedback received from ConEd, those overloads were excluded from further consideration, as mitigation plans are already in place.

Table 3-8. Scenario 1: N-1 Contingency Analysis Results

Monitored Facility	Loading %	Rate Base (MVA)	Rate Cont. (MVA)	Contingency	Mitigation System Upgrade
MALVERN---West Hempstead 69 KV	102	47	59	193: EGC6060	Reconductor line
MASPEQUA2---PLNEDGE 69 KV	100	62	74	225: MS 660	Reconductor line

Table 3-9. Scenario 1: N-1-1 Contingency Analysis Results

Monitored Facility	Loading %	Rate Base (MVA)	Rate Cont. (MVA)	Outage	Contingency	Mitigation System Upgrade
Lk Success---SHORE RD2 138 KV #2	134	249	430	138-367	Base Case	Reconductor line
Lk Success---SHORE RD2 138 KV #1	134	249	430	138-368	Base Case	Reconductor line
Riverhead 138/69 KV transformer #1	106	118	145	S_FORK-GEN	138-910	Upgrade transformer

In accordance with the Study scope, an alternative approach to mitigate system adverse impacts was also considered, based on improved positioning and utilization of existing energy storage facilities. As part of the alternative approach, no new storage units were added; instead, some of the already modeled storage units were strategically repositioned. The new locations were selected with the sole purpose to mitigate adverse system impacts to the extent possible and thus reduce the scope of system impacts. Unless otherwise noted, the new locations remained unchanged for any remaining analysis scenarios. Table 3-10 shows the modified sizes/locations considered in the development of the alternative mitigation scenario.

Table 3-10. Revised Sizing/Placement of Storage Facilities

Bus	Initial Placement/Allocation		Revised Placement/Allocation	
	2025	2030/2035	2025	2030/2035
Farragut-345 KV	200	200	None	None
Sherman Creek-138 KV	105	198	None	None
Water St 27 KV-Unit1*	None	None	100	100
Water St 27 KV-Unit2*	None	None	100	100
E13 138 KV- Unit1*	None	None	52.5	99
E13 138 KV- Unit2*	None	None	52.5	99
Sterling-138 KV	50	200	None	None
Elwood-138 KV	30	130	None	None
LK Success-Unit1	None	None	25	100
LK Success-Unit2	None	None	25	100
Riverhead-Unit1	None	None	15	65
Riverhead-Unit2	None	None	15	65

*) Following comments from ConEd, some storage facilities were further revised to their original placement, or considered offline, with no impact to analysis results

Tables 3-11 and 3-12 show thermal overloads in the 2035 study year with the base load forecast and revised placement of energy storage units. Relocation of the storage units addressed 138 kV N-1-1 constraints previously observed. Similar results were observed in the sensitivity scenario based on high-load forecast.

Table 3-11. Scenario 1: N-1 Contingency Analysis Results (Adjusted Storage Facilities)

Monitored Facility	Loading %	Rate Base (MVA)	Rate Cont. (MVA)	Contingency	Mitigation System Upgrade
MALVERN---West Hempstead 69 KV	102	47	59	193:EGC6060	Reconductor line
MASPEQUA2---PLNEDGE 69 KV	100	62	74	225:MS 660	Reconductor line

Table 3-12. Scenario 1: N-1-1 Contingency Analysis Results (Adjusted Storage Facilities)

Monitored Facility	Loading %	Rate Base (MVA)	Rate Cont. (MVA)	Outage	Contingency	Mitigation System Upgrade
None						

For simplicity in reporting, in the remainder of this section, Scenario 1 with adjusted storage facilities as shown in Table 3-10 will be referred to as Scenario 1 and all analytical findings are based on adjusted energy facilities as noted earlier.

Scenario 1 was also studied for the 2030 and 2025 study years. Tables 3-13 through 3-16 present reliability analysis findings for study years 2030 and 2025, based on base load forecast. Unless noted otherwise in subsequent results tables, similar analysis results, qualitatively and quantitatively, were observed for the load sensitivity analysis.

As shown in Table 3-16, an overload was observed under N-1-1 conditions, for study year 2025, on the Carle Place--East Garden City 138 kV line. This constraint was fully resolved through LIPA's LTP included in the modeling of the 2030 and 2035 study years.

Table 3-13. Scenario 1: N-1 Contingency Analysis Results, 2030 Study Year*

Monitored Facility	Loading %	Rate Base (MVA)	Rate Cont. (MVA)	Contingency	Mitigation System Upgrade
MALVERN---West Hempstead 69 KV	101	47	59	193: EGC6060	Reconductor line

*) results in this table reflect load sensitivity analysis; no adverse impacts under base load analysis

Table 3-14. Scenario 1: N-1-1 Contingency Analysis Results, 2030 Study Year

Monitored Facility	Loading %	Rate Base (MVA)	Rate Cont. (MVA)	Outage	Contingency	Mitigation System Upgrade
None						

Table 3-15. Scenario 1: N-1 Contingency Analysis Results, 2025 Study Year

Monitored Facility	Loading %	Rate Base (MVA)	Rate Cont. (MVA)	Contingency	Mitigation System Upgrade
None					

Table 3-16. Scenario 1: N-1-1 Contingency Analysis Results, 2025 Study Year

Monitored Facility	Loading %	Rate Base (MVA)	Rate Cont. (MVA)	Outage	Contingency	Mitigation System Upgrade
CARLE PL-- E.G.C. 138 KV line	105	263	303	138-367	138-366	Addressed by LTP

3.4.3.2 N-1-1-0 Analysis

N-1-1-0 analysis was performed for select ConEd TLA zones. As part of this analysis, OSW resources were considered curtailable as resource of last resort to mitigate system overloads, if and as needed.

Simulations were performed for all three study years using both the base and sensitivity load forecasts. No overloads were observed, and in all simulations, OSW curtailment was minimal (less than 5 MW).

3.4.3.3 Short Circuit Ratio Analysis

Short Circuit Ratio (SCR) analysis was performed to evaluate the relative strength of the system at the selected OSW connection points under consideration. For each connection point, SCR was calculated as the ratio between the system's short circuit capacity and the size of OSW injection. All local generators in the Study Area were assumed offline. SCRs were calculated at the OSW POIs.

Table 3-17 lists short circuit ratios calculated assuming that no transmission outages exist. With all lines in-service, E. Hampton indicated the minimum short circuit ratio among all the connection points tested.

In order to capture impacts of local outages, a similar analysis was performed assuming that a line connected at the connection point under study is out-of-service (line-out conditions). Table 3-18 lists SCR calculated under line-out conditions.

SCR requirements depend on the technology of wind-turbine generators. The traditional requirement for inverter-based projects is to have a SCR higher than five on the high side of the step-up transformers. However, the minimum manufacture required SCR for interconnection of OSW in 2035 is currently unknown.

Table 3-17. SCR at OSW Connection Points — All-Lines-In Conditions

Connection Point	OSW	KV	3PH Fault Current (A)	Fault MVA	OUTAGE Terminal	OSW MW	SCR
Shore Rd	Additional	345	20184	12061	N/A	500	24.12
Syosset		138	21006	5021	N/A	300	16.73
W 49th St		345	28550	17060	N/A	1200	14.21
Mott Haven		345	28971	17312	N/A	1250	13.84
Rainey		345	28647	17118	N/A	1250	13.69
Farragut		345	28705	17153	N/A	1400	12.25
New Bridge		138	26706	6383	N/A	600	10.63
Northport		138	17776	4249	N/A	400	10.62
Gowanus		345	13704	8189	N/A	816	10.03
Brookhaven		138	9292	2221	N/A	270	8.22
Holbrook	Procured	138	12859	3074	N/A	440	6.98
West Bus		138	12760	3050	N/A	440	6.93
East Hampton		69	5249	627	N/A	136	4.61

Table 3-18. SCR at OSW Connection Points — Line-Out Conditions

Connection Point	OSW	KV	3PH Fault Current (A)	Fault MVA	OUTAGE Terminal	OSW MW	SCR
Syosset	Additional	138	16744	4002	SHORE RD1	300	13.34
W 49 St		345	26755	15988	REACM52	1200	13.32
Mott Haven		345	27083	16184	REAC71	1250	12.94
Rainey		345	26841	16039	BUS123	1250	12.83
Farragut		345	27848	16641	BUS138	1400	11.88
New Bridge		138	25705	6144	LCST GRV	600	10.24
Gowanus		345	11035	6594	GOWANUS 42SR	816	8.08
Brookhaven		138	8716	2083	SILLS RD2	270	7.71
Northport		138	12765.60	3051	NRTHPRT2	400	7.62
Shore Rd		345	4183	2499	DUNWOODIE	500	4.99
Holbrook	Procured	138	10999	2629	RULND RD	440	5.97
West Bus		138	9861	2357	HOLBROOK	440	5.35
East Hampton		69	3584	428	BUELL	136	3.14

3.4.4 Production Cost Analysis

Following the methodology described in section 3.2, production cost economic analysis was performed for Scenario 1, as developed, for all three study years.

3.4.4.1 Production Cost Scenario Development and Assumptions

The detailed case set-up with PROBE LT input data for the NYISO market was completed during the initial screening task, supplementing load flow input data used in reliability analysis with data provided by the State Team.

Offshore wind and energy storage injections were consistent with Scenario 1, as developed and discussed in the previous section. Specifically, OSW injections in economic analysis are as listed in Table 3-6 and energy storage size and locations are as listed in Table 3-10.

As already stated in section 3.2, a key assumption in economic analysis is that onshore wind, solar, and hydro would be curtailed before OSW. This approach ensures OSW is not reduced due to statewide over-generation scenarios or other reasons not directly relevant to the Study Area, to properly test zones J/K transmission.

In addition to base and sensitivity simulations, listed in Table 3-7, the following Scenario 1 sensitivities were also performed:

- no energy storage facilities on Long Island (2035 study year).
- modified zone K parameters (2035 study year). In this sensitivity, normal ratings were used for tie lines Y49 and Y50 for both pre- and post-contingency conditions. Further, approximately 400 MW of must-run and minimum reliability non-OSW generation (i.e., non-dispatchable non-OSW generation) was also considered in specific locations. Parameters for this sensitivity were developed reflecting LIPA operational consideration.

3.4.4.2 Production Cost Modeling / Economic Analysis Results

Consistent with Study objectives, the economic analysis focused almost exclusively on successful OSW integration with respect to local transmission; therefore, the key metrics were directly related to OSW curtailment and associated transmission congestion. Table 3-19 identifies curtailment for base and select primary sensitivities studied as part of Scenario 1.

Table 3-19. Curtailment Identified in Economic Analysis

Testing Conditions	Unit-Hours of OSW Curtailment	OSW MWh Curtailed
Base Assumptions (2030)	0	0
Base Assumptions (2035)	15	2,035
No Storage in zone K (2035)	26	3,881
Modified zone K parameters (2035)	176	23,521

The economic analysis identified minimal OSW curtailment in Scenario 1 simulations. As shown in Table 3-19, for the 2035 base case simulation, only 2,035 MWh of curtailment occurred, which is negligible considering the maximum possible OSW production for the year in zones J and K combined is nearly 42,000,000 MWh. All curtailment occurred in zone K regardless of sensitivity.

When applying modified operating parameters, such as the sensitivity with modified zone K parameters, curtailment increases to 23,521 MWh. 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. 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 Figure 3-7, which also accounts for zone K exports, further illustrates that OSW wind production only exceeds the local demand plus Zone K export capability for a few hours of the year. In the figure, this is represented by the small portion of the duration curve that dips below zero. In hours where OSW exceeds demand plus export capability, over-generation may still be absorbed by energy storage facilities.

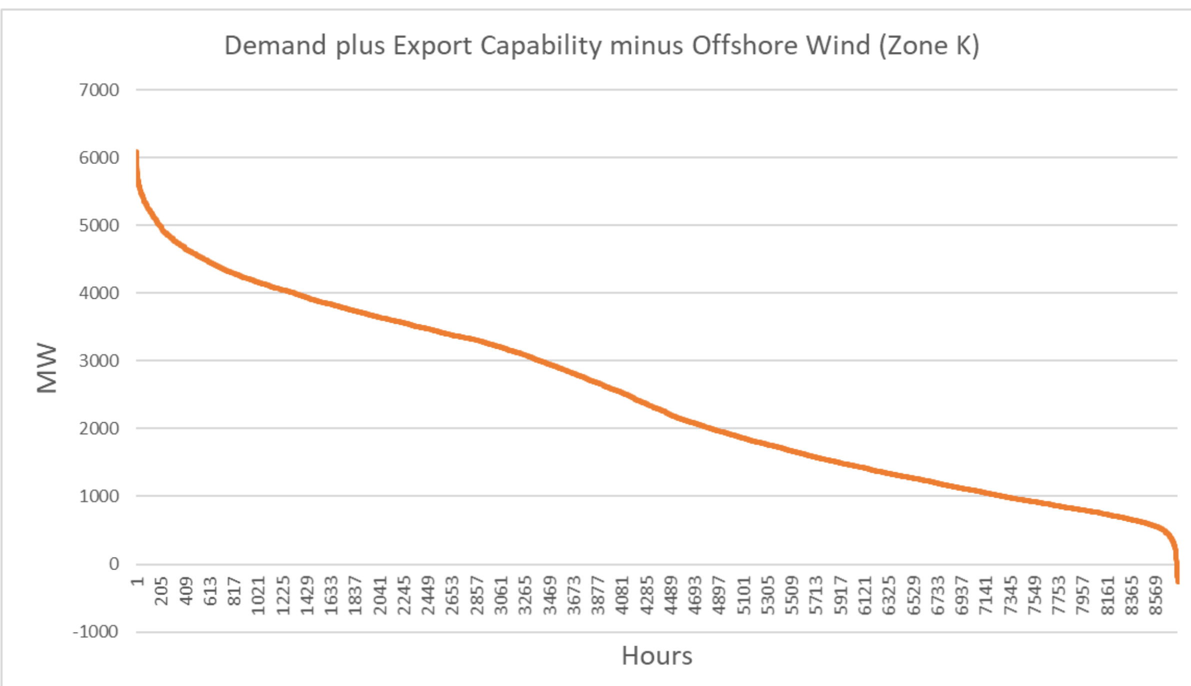


Figure 3-7. Zone K Demand + Exports — OSW (MW)

The two factors explaining the minimal OSW curtailment must be considered in the context of the specific Study assumptions; specifically, the assumption that all onshore renewable generation would be curtailed before OSW and all thermal generation could be decommitted except in the sensitivities as noted.

The additional sensitivities shown in Table 3-7 did not reveal significant OSW curtailment or transmission system weaknesses; in nearly all cases curtailment remained zero or negligible:

- All 2030 scenarios—base case, load sensitivity, and increased thermal generation—showed no OSW curtailment.
- The 2035 high-demand scenario reduced curtailment to only 823 MWh. The reduction in curtailment is expected as more OSW is utilized to serve the increased local demand.
- The 2035 scenario enforcing a minimum level of thermal generation revealed 3,903 MWh of OSW curtailment. Consistent with earlier explanation, even with increased thermal generation, excess production is still able to be exported to other NYISO zones.
- The scenario enforcing NYISO ancillary services requirements showed 2,421 MWh of curtailment. It was considered that enforcing ancillary services might force more thermal generation online and therefore increase offshore wind curtailment. However, since most ancillary service requirements can be met by power plants anywhere in NYISO, offshore wind curtailment was not significantly impacted.
- The 2025 simulation, which includes only procured OSW, also did not show any OSW curtailment.

3.4.5 Scenario 1: Summary of Findings

Scenario 1 provided an initial allocation and connecting stations for the connection of 9 GW of OSW in zones J and K by 2035. Based on the analysis performed, it can be concluded that the system is capable of accommodating a total of 9 GW of OSW, allocated into 6 GW in zone J and 3 GW in zone K, without exhibiting major adverse system impacts or the need for extensive OSW curtailments. Therefore, the full amount of 9 GW of OSW could be connected without the need for major system upgrades, other than substation upgrades for the direct connection of the OSW resources.

3.5 Scenario 2: Alternative Allocation of OSW to Zone K — Analysis and Results

Upon completion of the development and analysis of Scenario 1, an alternative scenario for connecting OSW to zone K was developed. The key underlying and differentiating assumption for the development of this alternative scenario was that only the following substations in zone K were available for connection of OSW (in addition to already procured OSW):

a) Shore Road (138 / 345)
b) East Garden City (138 / 345)
c) Newbridge Road,
d) Ruland Road
e) Syosset
f) Pilgrim

This alternative scenario for connecting OSW to zone K will be referred to as Scenario 2 in the remainder of this section. Clearly Scenario 2 only focuses on the 2030 and 2035 study years; the 2025 study year was studied and reported as part of Scenario 1. This section discusses the development of Scenario 2, the analysis approach, and presents analytical findings.

3.5.1 Development of Scenario 2

Development of Scenario 2 was informed by the fact that the Poseidon project, originally considered connected at Ruland Rd. 138 kV station, was no longer a valid project. In addition, this scenario reduced the number of substations on the north shore of Long Island. Scenario 2 focuses solely on OSW connections to zone K; OSW allocation to zone J remains unchanged from Scenario 1. The overall allocation remains at 6 GW of OSW connecting to zone J and 3 GW of OSW connecting to zone K.

Table 3-20 presents the OSW allocation selected for Scenario 2. Figure 3-8 illustrates the allocation differences between Scenarios 1 and 2 for the 2035 study year. Injections at Brookhaven, Newbridge, and Northport previously considered as part of Scenario 1, were moved to Ruland Rd and East Garden City in Scenario 2. Figure 3-9 shows the approximate locations of the LIPA POIs considered in Scenario 2.

Table 3-20. OSW Injections - Scenario 2

Already procured OSW (MW)								
Study Year	Gowanus (Empire) 345 kV		Holbrook (Sunrise) 138 kV			East Hampton (South Fork) 138 kV		
2035	816		880			136		
2030	816		880			136		
Scenario 2 additional OSW injections (MW)								
	Farragut 345 kV	Mott Haven 345 kV	Rainey 345 kV	W49th str 345 kV	Shore Rd 345 kV	Ruland Rd 138 kV	East Garden City 138 kV	Syosset 138 kV
2035	1400	1250	1250	1200	500	970	300	300
2030	1400	None	1250	None	None	970	300	None

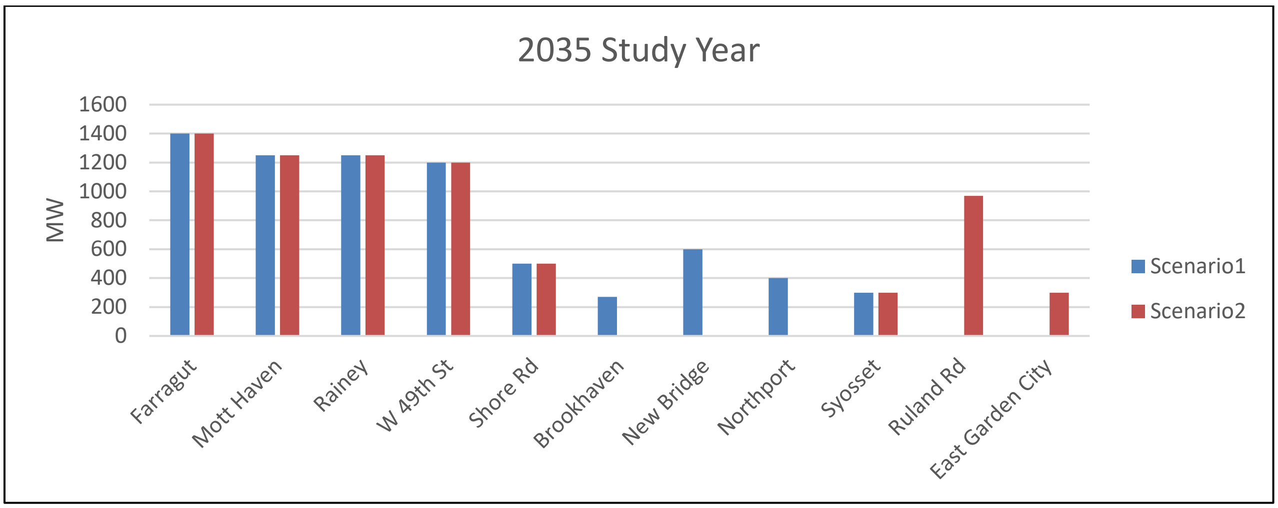


Figure 3-8. Scenario 2 vs. Scenario 1 Allocation (Study Year 2035)

Figure 3-9. LIPA POIs Considered in Scenario 2

Energy storage facilities in Scenario 2 are consistent in size and locations with those in Scenario 1, as listed in Table 3-10. This is because the system overloads that the storage facilities were successful in mitigating appear to be local, likely systemic issues, and thus not immediately impacted by OSW connection points. Therefore, the location and sizing of storage facilities remaining the same continues to help mitigate such system overloads.

3.5.2 Base and Sensitivity Conditions

Same as for Scenario 1, reliability and production cost analyses were performed for base and multiple sensitivity conditions. The various sensitivities considered in the Study were outlined in Table 3-7.

3.5.3 Reliability Security Analysis

Following the methodology described in section 3.2, steady state contingency analysis was performed that included N-0, N-1, and N-1-1 analysis. Steady state analysis focused primarily on thermal performance of the network. All analysis was performed under peak loading conditions.

Tables 3-21 through 3-24 present Scenario 2 reliability analysis findings for study years 2035 and 2030, based on base load forecast. Unless noted otherwise in subsequent results tables, similar analysis results, qualitatively and quantitatively, were observed for the load sensitivity analysis.

System performance under reliability security analysis was almost identical as under Scenario 1. Reallocation of OSW resources as part of Scenario 2 did not introduce any new reliability constraints.

Table 3-21. Scenario 2: N-1 Contingency Analysis Results, 2035 Study Year

Monitored Facility	Loading %	Rate Base (MVA)	Rate Cont. (MVA)	Contingency	Mitigation System Upgrade
MALVERN---West Hempstead 69 KV	102	47	59	193:EGC6060	Reconductor line
MASPEQUA2---PLNEDGE 69 KV	100	62	74	225:MS 660	Reconductor line

Table 3-22. Scenario 2: N-1-1 Contingency Analysis Results, 2035 Study Year

Monitored Facility	Loading %	Rate Base (MVA)	Rate Cont. (MVA)	Outage	Contingency	Mitigation System Upgrade
None						

Table 3-23. Scenario 2: N-1 Contingency Analysis Results, 2030 Study Year*

Monitored Facility	Loading %	Rate Base (MVA)	Rate Cont. (MVA)	Contingency	Mitigation System Upgrade
MALVERN---West Hempstead 69 KV	101	47	59	193:EGC6060	Reconductor line

*) results in this table reflect load sensitivity analysis; no adverse impacts under base load analysis

Table 3-24. Scenario 2: N-1-1 Contingency Analysis Results, 2030 Study Year

Monitored Facility	Loading %	Rate Base (MVA)	Rate Cont. (MVA)	Outage	Contingency	Mitigation System Upgrade
None						

3.5.4 Production Cost Analysis

Production cost analysis completed for Scenario 2 is consistent with the production cost analysis approach, assumptions, and objectives followed for Scenario 1 and described in section 3.4.

3.5.4.1 Production Cost Sensitivities

Offshore wind and energy storage injections are consistent with Scenario 2, as developed and discussed earlier in this section. Specifically, OSW injections in economic analysis are as listed in Table 3-20 and energy storage size and locations are consistent with Scenario 1, as listed in Table 3-10.

In addition to base and sensitivity simulations, listed in Table 3-7, the following Scenario 2 key sensitivity was also performed:

- Modified zone K parameters (2035 study year). In this sensitivity, normal ratings were used for tie lines Y49 and Y50 for both pre- and post-contingency conditions. Further, approximately 400 MW of must-run and minimum reliability non-OSW generation (i.e., non-dispatchable non-OSW generation) was also considered in specific locations.

3.5.4.2 Production Cost Modeling / Economic Analysis Results

Same as for Scenario 1 and consistent with Study objectives, the economic analysis focused almost exclusively on successful OSW integration with respect to local transmission, and therefore the key metrics were directly related to OSW curtailment and associated transmission congestion. Table 3-25 identifies curtailment for select conditions studied as part of Scenario 2.

Table 3-25. Curtailment Identified in Economic Analysis

Testing Conditions	Unit-Hours of OSW Curtailment	OSW MWh Curtailed
Base Assumptions (2030)	0	0
Base Assumptions (2035)	0	0
Modified zone K parameters (2035)	106	22,135

Results of the economic analysis for Scenario 2 continue to show zero or negligible curtailment; there is actually a slight reduction as compared to Scenario 1, which also assumed 3.1 GW OSW connected to zone K, but at different POIs. The reason for the slight reduction is moving OSW from Newbridge (in Scenario 1) to East Garden City (in Scenario 2) eliminating any remaining congestion along the Newbridge-EGC corridor. All curtailment continues to occur in zone K.

Specifically, the sensitivity with modified zone K parameters is the only sensitivity that shows any OSW curtailment with 22,135 MWh curtailed. This represents only 0.053% curtailment of total OSW production.

The same factors discussed in section 4.5.2 explaining the lack of any appreciable OSW curtailment are still applicable under Scenario 2.

The secondary sensitivities, one modeling higher demand and another modeling minimum on-line thermal generation in both Zones J and K, did not reveal significant OSW curtailment or transmission system weaknesses; OSW curtailment remained zero or negligible.

3.5.5 Scenario 2: Summary of Findings

Scenario 2 was developed to provide an alternative OSW allocation for zone K, informed primarily by the withdrawal of the Poseidon project that was modeled connected at Ruland Rd. in prior simulations. Based on the analysis performed, and consistent with Scenario 1 analysis, it can be concluded the system in zone K is capable of accommodating a total of 3 GW of OSW, without exhibiting major adverse system impacts or the need for extensive OSW curtailments. Therefore, 3 GW of OSW could be connected to zone K without the need for major system upgrades, other than substation upgrades for the direct connection of the OSW resources.

3.6 Scenario 3: Alternative Allocation of 4 GW of OSW to Zone K — Analysis and Results

Both Scenarios 1 and 2 were based on an overall OSW allocation of 6 GW to zone J and 3 GW to zone K. Given the uncertainty regarding the availability of cable routings to effect the connection of 6 GW in zone J and the latest OSW project pipeline in the NYISO interconnection queue, an alternative scenario was developed that considered connection of 4 GW of OSW to zone K, with the remaining 5 GW connected to zone J.

The purpose of Scenario 3 was to evaluate any need for and benefits of system expansion, focusing primarily on the potential addition of a new tie-line connecting zone K to zone I and/or zone J, in order to mitigate adverse impacts from connecting an increased allocation of OSW to zone K. This section discusses the development of Scenario 3, the analysis approach, and presents analytical findings.

3.6.1 Development of Scenario 3

Scenario 3 focuses solely on OSW connections to zone K. Compared to previous scenarios, Scenario 3 increases zone K OSW injection by 0.9 GW with a corresponding decrease in zone J OSW injection. Thus, whereas the total OSW injection remains at 9 GW, it is allocated with 5 GW connecting to zone J and 4 GW connecting to zone K.

Scenario 3 was analyzed for the 2035 study year only, under the base loading forecast.

Table 3-26 presents the OSW allocation selected for Scenario 3. Compared to Scenario 2, the incremental injection to zone K was mainly allocated at the East Garden City substation, while the reduction in zone J was taken from the injection at Mott Haven.

Table 3-26. OSW Zone K Injections - Scenario 3

<table>
<tr><td colspan="6">Already procured OSW (MW)</td></tr>
<tr><td>Study Year</td><td colspan="2">Gowanus (Empire)
345 kV</td><td colspan="2">Holbrook (Sunrise)
138 kV</td><td>East Hampton (South Fork)
138 kV</td></tr>
<tr><td>2035</td><td colspan="2">816</td><td colspan="2">880</td><td>136</td></tr>
<tr><td colspan="6">Scenario 3 additional OSW injections in zone K (MW)</td></tr>
<tr><td></td><td>Shore Rd
345 kV</td><td>Ruland Rd
138 kV</td><td>E.G.C.
138 kV</td><td>E.G.C.
345 kV</td><td>Syosset
138 kV</td></tr>
<tr><td>2035</td><td>500</td><td>970</td><td>450</td><td>700</td><td>315</td></tr>
</table>

3.6.2 Reliability Analysis

Following the methodology described in section 3.2, steady-state contingency analysis was performed that included N-0, N-1, and N-1-1 analysis. Steady-state analysis focused primarily on thermal performance of the network. All analysis was performed under peak loading conditions.

Analysis results were similar to those in Scenario 2. No system adverse impacts were observed, other than those in Scenario 2 analysis.

3.6.3 Production Cost Analysis

Production cost analysis completed for Scenario 3 is consistent with the production cost analysis approach, assumptions, and objectives followed for Scenario 2 and described in section 3.5.

3.6.3.1 Production Cost Sensitivities

Offshore wind and energy storage injections are consistent with Scenario 3 as developed and discussed earlier in this section. Specifically, OSW injections in economic analysis are as listed in Table 3-26 and energy storage size and locations are consistent with Scenario 1, as listed in Table 3-10. The wind injections as shown in Table 3-26 for Scenario 3 result in connection of 4 GW of OSW to zone K versus the 3.1 GW assumed in all prior study scenarios.

Five simulations were completed as part of Scenario 3, a core scenario plus four additional sensitivities, listed in Table 3-27. Each simulation is for study year 2035.

3.6.3.2 Production Cost Modeling / Economic Analysis Results

Similar to Scenario 2 and consistent with Study objectives, the economic analysis focused almost exclusively on successful OSW integration with respect to local transmission; therefore, the key metrics were directly related to OSW curtailment and associated transmission congestion. Table 3-27 identifies curtailment for the conditions studied as part of Scenario 3.

Table 3-27. Curtailment Identified in Economic Analysis

Testing Conditions	Zone K Storage	Additional Assumptions	New Tie Line	Zone K OSW Curtailment (MWh)
Core Scenario	Yes	Initial assumptions	No	30,064
Sens. A	No	Initial assumptions	No	151,545
Sens. B	No	Initial assumptions	New 345 kV tie line (from EGC to Dunwoodie)	8,302
Sens. C	Yes	Modified zone K assumptions	No	1,229,206
Sens. D	Yes	Modified zone K assumptions	New 345 kV tie line (from EGC to Dunwoodie)	384,799

In the core scenario, where assumptions remained consistent with base-case simulations in previous scenarios, OSW curtailment increases to 30,064 MWh. This increase is to be expected due to the increase of OSW injections to zone K to 4 GW versus the 3.1 GW in the previous scenarios.

The core Scenario 3 included energy storage. Under Sensitivity A, the assumptions were essentially the same except that storage was removed and curtailment increased to 151,545 MWh. The presence of approximately 530 MW of energy storage reduced curtailment by 121,481 MWh.

Under Sensitivity B, storage was not included, but a new 345 kV tie line from East Garden City to Dunwoodie was added. Under this set of assumptions curtailment was 8,302 MWh. The addition of the tie line reduced curtailment by 143,243 MWh.

Sensitivities C and D return to the base storage assumption, i.e., that storage is expected and modeled, but the case makes adjustments to system modeling parameters. These modified zone K parameters enforce normal ratings on the Y49/Y50 tie lines, even under contingency conditions and require 400 MW of minimum zone K thermal generation on-line during all hours for reliability purposes. Then, simulations are run for two sensitivities—without and then with a new 345 kV tie line (from EGC to Dunwoodie) designed to increase Long Island export capability.

Sensitivity C, without the tie line, results in the highest OSW curtailment measured in any simulation at 1,229,206 MWh. This represents 2.9% curtailment of overall OSW production, and 6.6% curtailment of OSW connected to zone K. Sensitivity D, which adds the tie line, shows 0.92% curtailment of overall OSW production, and 2.1% curtailment of OSW connected to Zone K. Under these operating assumptions, the tie line reduces curtailment by 844,407 MWh per year. Alternative connections points for a new tie, such as from Shore Road 345 kV in parallel with the existing Y50 tie line, could potentially offer similar OSW curtailment mitigation levels.

3.6.4 Scenario 3: Summary of Findings

Scenario 3 was developed to provide an alternative OSW allocation to zone K totaling 4 GW of OSW, in response to increasing uncertainty regarding availability of cable routings to zone J and informed by the OSW project pipeline in the latest NYISO interconnection queue. Based on the analysis performed, with 4 GW of OSW connected to zone K, production cost analysis indicates increased instances of OSW curtailments. Variation of modeling assumptions based on operational considerations, specifically the pre- and post-contingency ratings of the Y49/Y50 tie-lines, could further increase potential curtailments. The addition of a new tie-line between zone K and zone J and/or New York mainland system significantly reduced potential curtailments.

3.7 Summary of Onshore Analysis Findings

Based on the data used, assumptions made, and the analysis performed as part of Onshore Analysis, the following findings were observed:

A) Connecting a total of 9 GW of OSW to zones J and K, allocated 6 GW to zone J and 3 GW to zone K:

- Reliability analysis indicates the system in zones J and K could reliably accommodate the total amount of 9 GW of OSW without major adverse impacts
- Production cost economic analysis indicates that the system in zones J and K can accommodate 9 GW of OSW without significant OSW curtailment
- Therefore, the system could accommodate the 9 GW of OSW without a need for major bulk system upgrades, other than substation upgrades for the direct interconnection of OSW resources

B) Injecting 4 GW of OSW into zone K:

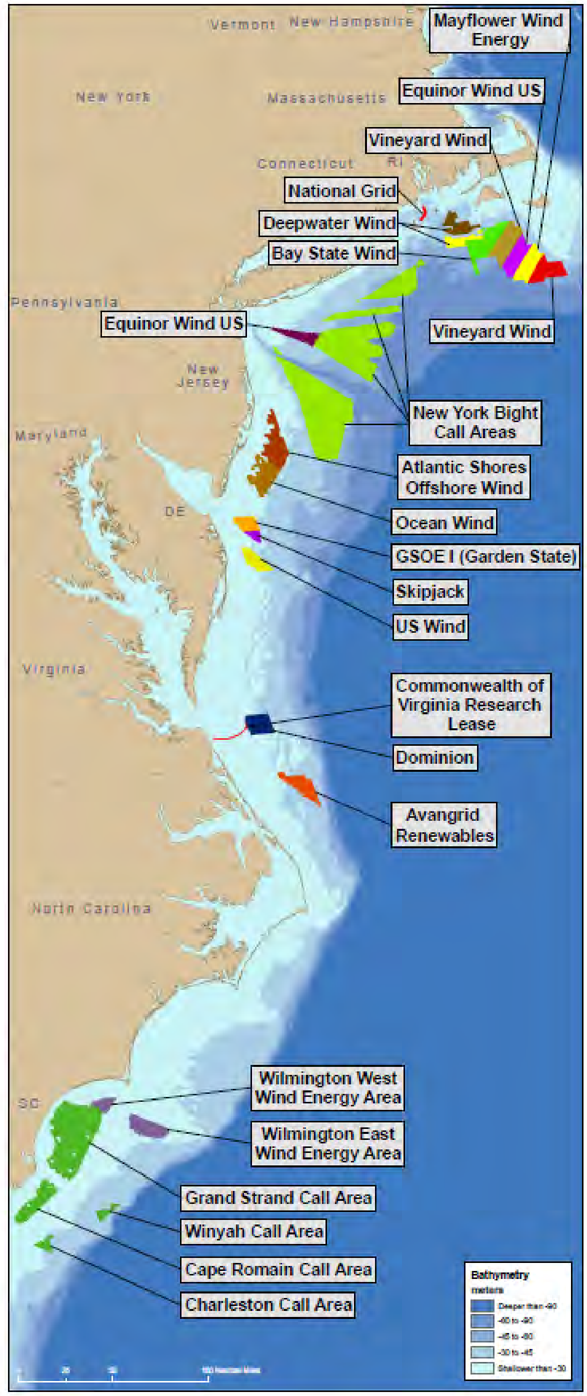
- Reliability analysis indicates that the system in zone K could reliably accommodate the increased amount of 4 GW of OSW without major adverse impacts
- Production cost economic analysis indicates increasing instances of potential OSW curtailment
- A new tie line from zone K appears to significantly mitigate the potential for OSW curtailment

4 Development of OSW Build-Out Scenarios

The offshore wind industry in the United States is primarily driven by two key factors: individual state energy policies, and the availability of Bureau of Ocean Energy Management (BOEM) offshore Wind Energy Areas (WEAs) for development. Figure 4-1. shows the BOEM offshore renewable energy program for the U.S. east coast outer continental shelf, including currently leased BOEM WEAs and draft Call Areas. The draft Call Areas are expected to be finalized into WEAs and auctioned in the coming years.

This section describes the process of developing future OSW build-out scenarios to be used in subsequent Study tasks, including a technology review of HVAC and HVDC design, a summary of general OSW connection concepts, and the preliminary qualitative review process completed.

Figure 4-1. BOEM Offshore Wind Lease Areas and Additional Primary/Secondary Areas of Interest



(source: BOEM)

4.1 Key Assumptions

In order to achieve 9 GW of OSW interconnected to New York by 2035, based on historical progress and the terms of the State's Clean Energy Standard,[6] it is assumed that intermittent amounts of OSW capacity will be added on an approximate year-by-year basis, facilitated by NYSERDA's Offshore Wind Renewable Energy Certificate (OREC) solicitations. For the purposes of this Study, the State Team and DNV GL collaborated to develop the following illustrative schedule for OSW capacity additions:

- Study Year 2025: 1,826 MW of OSW interconnected, comprised the contracted Empire Wind, Sunrise Wind, and Southfork projects

- Study Year 2030: 3,774 MW of additional OSW interconnected, bringing the total to 5,600 GW. This value is one rough potential glidepath on the way to the achievement of 9,000 MW by 2035

- Study Year 2035: 3,400 MW of additional OSW interconnected, bringing the total to 9,000 GW

4.2 Current and Future OSW Project Locations and Capacities

Given the expectations that large OSW projects interconnected to New York State will be constructed in federal waters, it is a given that these projects will be located within BOEM-managed WEAs. Thus, for the purposes of forecasting future OSW build-out scenarios, and recognizing the State's geographic centrality and cost-effective reach to the easternmost lease area in New England, and equivalent distances to the south, as demonstrated in NYSERDA's 2018 procurement, DNV GL evaluated the capacity of all WEAs in the U.S. Northeast previously auctioned and under development, as well as the New York Bight draft Call Areas. This evaluation considered a range of potential turbine spacing and power ratings, and power purchase agreements (PPAs) previously executed and their associated project area requirements. It also considered adding capacity to projects currently in development. It is important to note that given the OSW capacity targets of Massachusetts, Connecticut, and New Jersey, competition for capacity from WEAs exists.

For WEAs, which have already been auctioned, determining their capacity and likely development schedule is reasonably straightforward. For the BOEM draft Call Areas, there is considerable uncertainty regarding what geographic areas will be finalized into WEAs and when they will be auctioned. Thus, in

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[6] New York State Public Service Commission. Case 15-E-0302. Order Adopting Modifications to the Clean Energy Standard. October 15, 2020 nyserda.ny.gov/-/media/Files/Programs/Clean-Energy-Standard/2020/October-15-Order-Adopting-Modifications-to-the-Clean-Energy-Standard.pdf

order to produce a reasonable forecast of future OSW build-out, a high-level review of New York Bight Call Area feasibility was completed to rule out any locations which are unlikely for future development, as well as to determine potential build-out schedules. The results of this high-level review, for the purposes of this Study, include the following related to the New York Bight Call Areas:

- OSW capacity from each of the Hudson Fairway Areas was excluded due to their relatively small size, which limits their economic viability, and unknown risk related to navigational issues.

- "Primary" Call Areas in Hudson North, Hudson Central, and Hudson South were considered most likely to be auctioned first, prior to "Secondary" Call Areas in these locations.

    - Three of the five future offshore wind buildout scenarios included OSW capacity from Primary Call Areas in 2030 and from Secondary Call Areas in 2035.
    - The remaining two of the five future offshore wind buildout scenarios did not include any OSW capacity from Primary or Secondary Call Areas in 2030 and included OSW capacity from only Primary Call Areas in 2035. Thus, these two scenarios did not include any OSW capacity from Secondary Call Areas in any Study Year.

4.3 Five Resulting OSW Future Build-out Scenarios

Based on the evaluation described above, DNV GL created five future OSW build-out scenarios. Maps illustrating the location and relative capacity size of OSW projects totaling 9 GW in 2035 are included in Annex C. These illustrations are not a recommendation for the State Team, nor do they represent any preference of the State Team toward specific projects or project locations. Instead, the maps represent a possible range of future outcomes that could occur and are deliberately intended to be geographically diverse while still consisting of plausible project developments that could reach 9 GW given the current WEA and Call Area environment as of the date of this report. DNV GL's further offshore assessment work considered these five scenarios to better understand how results and conclusions were either similar (to offer a representative view) or differed given varying future build-out possibilities.

5 Preliminary Analysis of OSW Connection Concepts

5.1 OSW Connection Technologies Options

HVAC and HVDC technologies were analyzed as the transmission solutions to deliver the offshore power to onshore. Technical feasibility and costs related to both technologies were used as a basis for the development of the offshore connection concepts.

5.1.1 HVAC Technology

HVAC illustrates the Radial connection approach used by the offshore wind industry to date with more operating experience and industrially mature technology. This technology requires reactive compensation schemes at cable terminals and midpoints in case of transmission distances beyond 70 miles. Long HVAC cable systems (> 70 miles) have also been observed to result in challenges related to harmonics, control interactions, operational configuration management and voltage regulation.

The Study considered 220 kV HVAC technology for dedicated Radial solutions and for establishing a Backbone connection configuration associated with offshore coordinated grid solutions. An illustrative example is provided in Figure 5-1. It should be noted that considering the geographical proximity (under 70 miles) of several anticipated OSW projects, the use of 220 kV HVAC technology for Backbone configuration for planned interconnected offshore network in combination with HVDC technology to deliver the OSW energy to shore proved to be a viable option. This solution has the advantage that the need of costly HVDC circuit breakers (required in a full HVDC Backbone) can be partially eliminated. HVAC technology was considered assuming following specifications:

- Three-phase HVAC cable system rated at 220 kV with maximum transfer capacity of 450 MW requiring multi-parallel HVAC circuits for higher power transfers.
- 70 miles was considered as the viable distance threshold for HVAC technology, meaning that for distances more than 70 miles HVDC technology was considered as an alternative.
- Maximum cable conductor cross section: 1,600 $mm.^2$
- Number of offshore trenches for one three-phase cable system: one.

Figure 5-1. A 220 kV HVAC Dedicated Radial Configuration — Illustrative Example

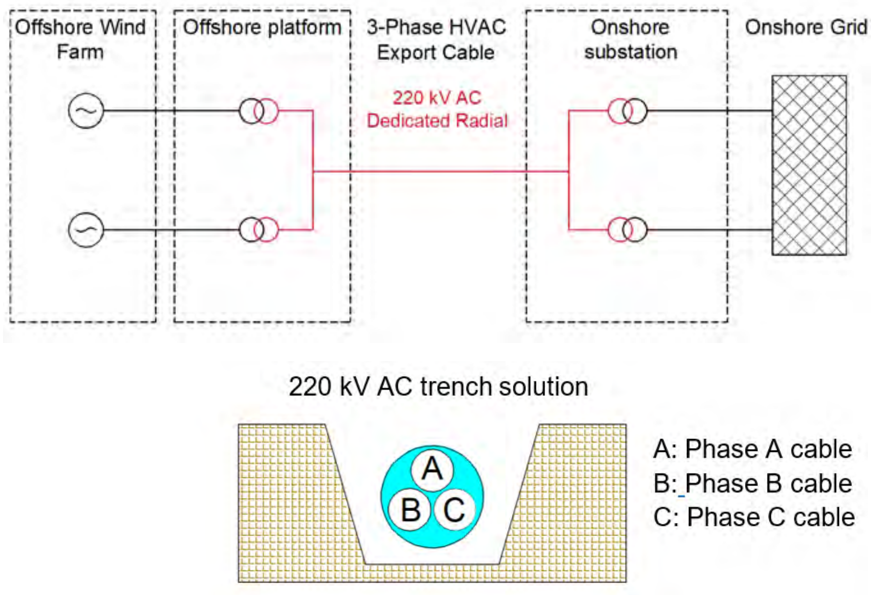


Figure 5-2. shows a more-detailed illustrative schematic of a single line diagram for a 220 kV HVAC OSW project Radially connected to the onshore grid.

Figure 5-2. Single Line Diagram of 220 kV HVAC OSW Project Grid Connection — Illustrative Example

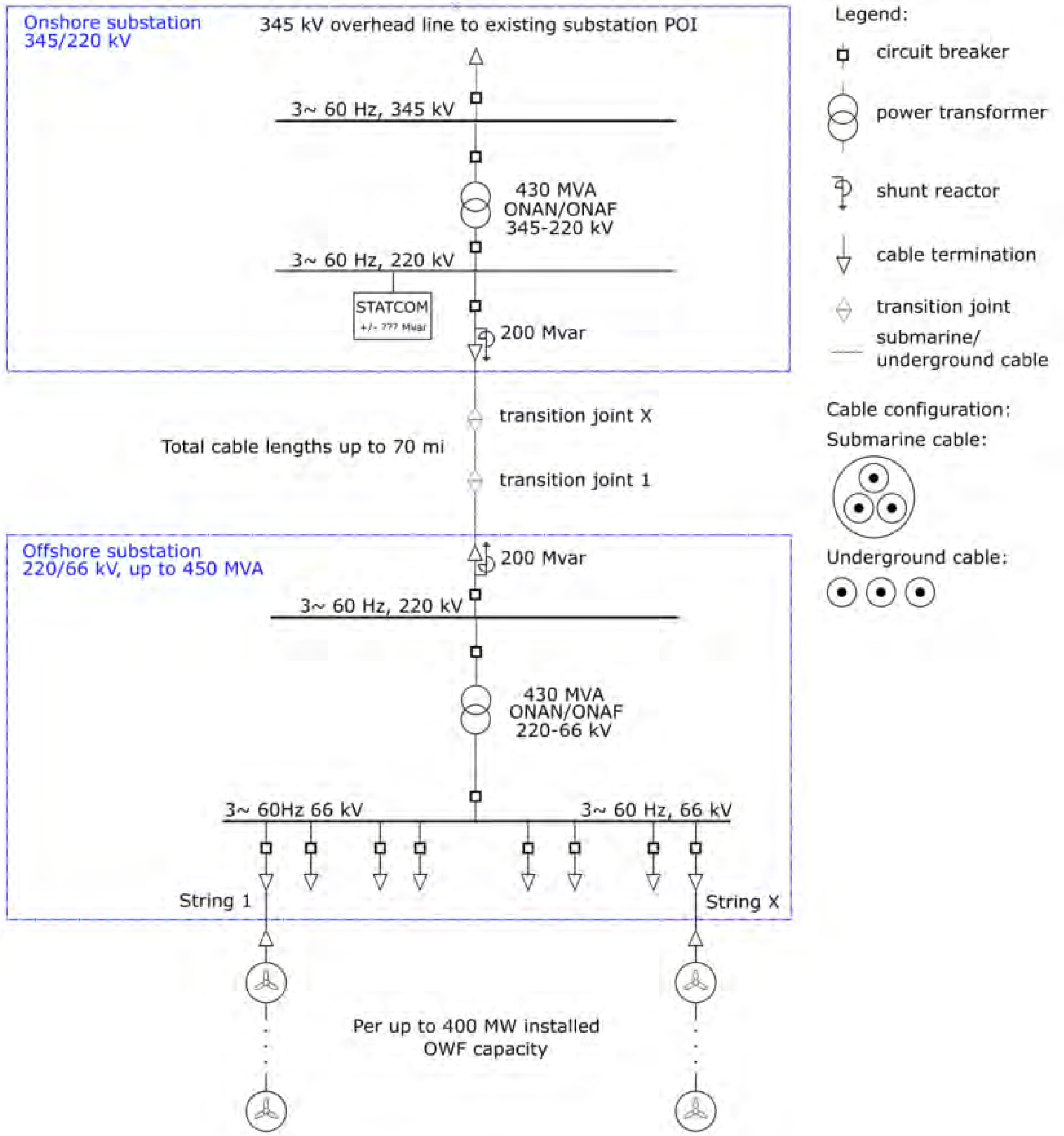
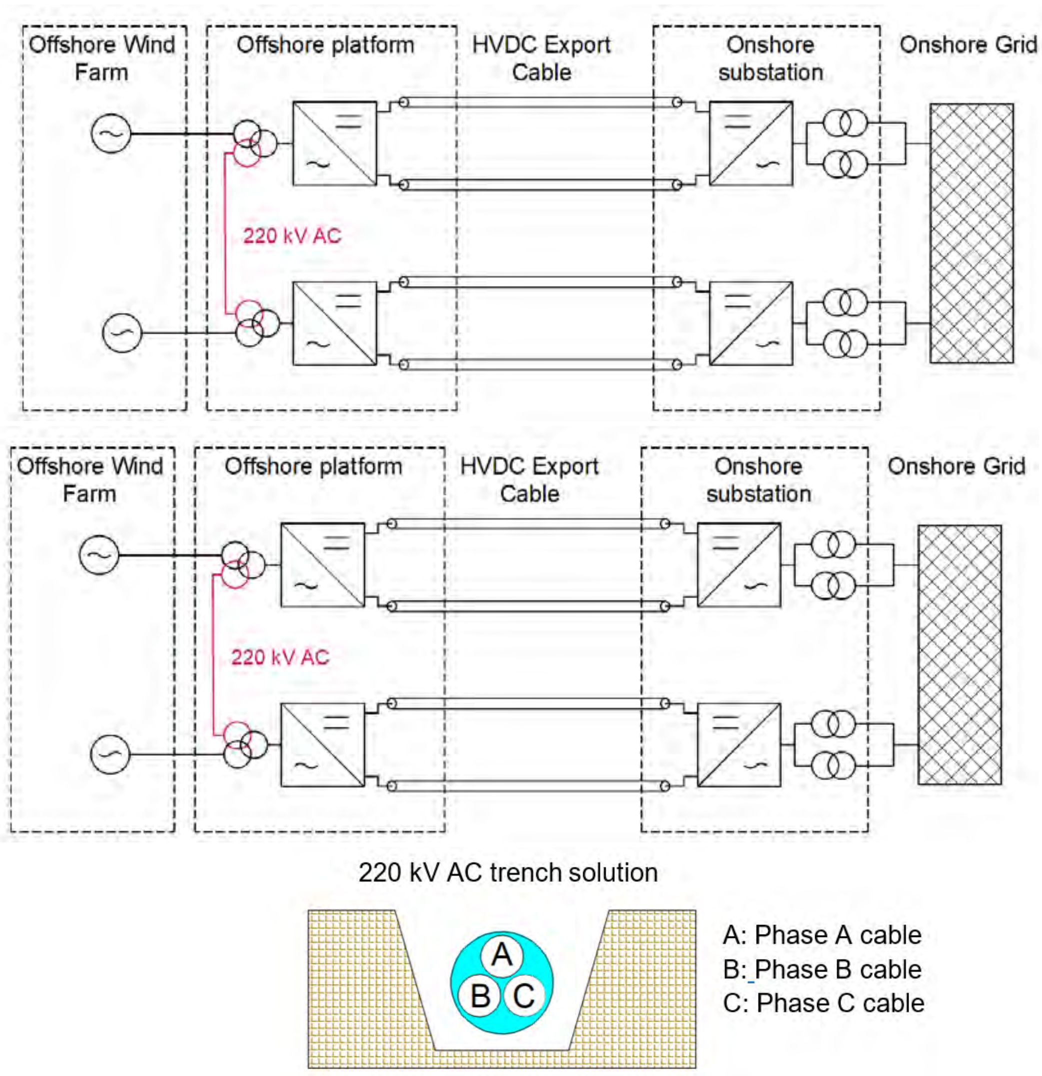


Figure 5-3. shows the application of the 220 kV HVAC line as an interconnection in order to realize Meshed OSW projects where both projects have a stand-alone HVDC connections to the onshore POI.

Figure 5-3. HVDC-Connected OSW Projects with 220 kV HVAC Meshed Option — Illustrative Example



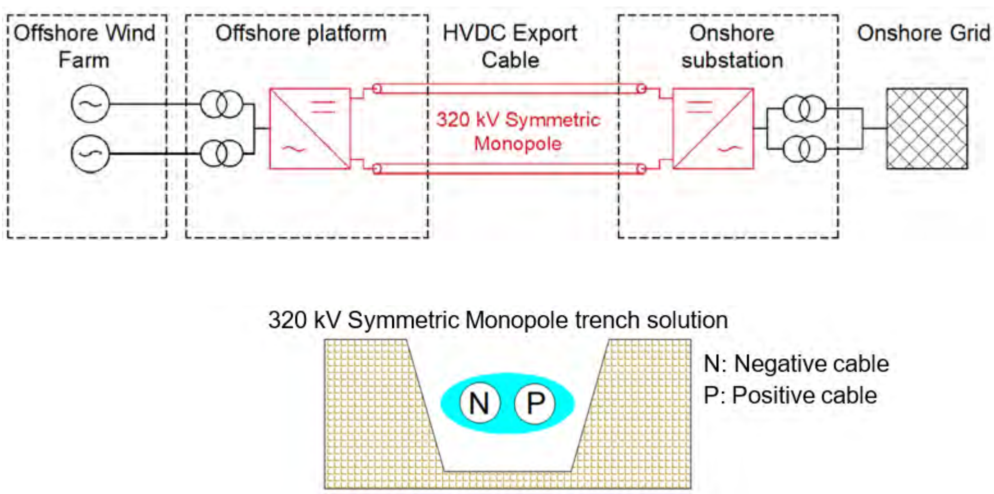
5.1.2 HVDC Technology

HVDC converters can be divided in two main technologies: Line Commutated Converters and insulated bipolar transistor based Voltage Source Converters (VSC). Since line commutated converters need to be connected to a relatively strong AC network, which is rare in coastal urban regions, VSC technologies are the superior and technically feasible HVDC option for OSW connections. VSC technologies can also be controlled to provide voltage and frequency support to the onshore grid and have black-start capabilities. For the purpose of this Study, 320 kV symmetric monopole and 525 kV symmetric bi-pole HVDC technologies were considered.

The 320 kV HVDC symmetric monopole technology consists of a two-cable system with the maximum rating limited to the allowed maximum contingency level of 1,310 MW,[7] though the technology was considered for connections ratings up to 1,400 MW. Both monopole cables can share the same trench as illustrated in Figure 5-4. Specifications associated with the 320kV HVDC technology considered for this Study are as follows:

- Voltage level: ±320 kV
- Maximum transmission power: 1,300 MW
- Maximum cable conductor cross section: 2,500 mm2
- Maximum cable system length in proposed connection designs: 168 miles
- Number of offshore trenches: one

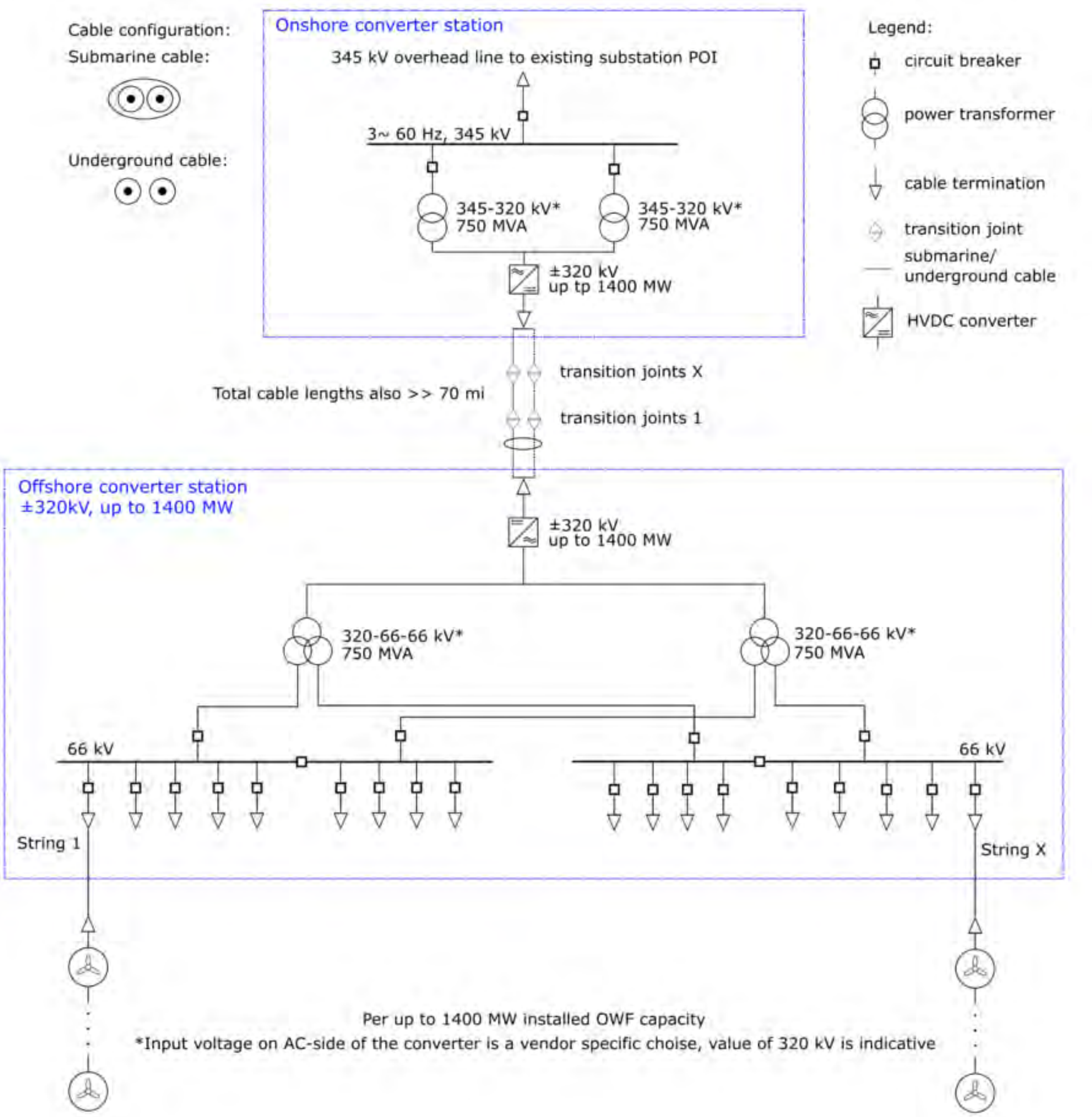
Figure 5-4. 320 kV Symmetric Monopole HVDC Schematic and Trenching - Illustrative Example



[7] Refer to Section 5.2.3 for more details

Figure 5-5. shows a more-detailed illustrative schematic of a single line diagram for a 320 kV symmetric monopole HVDC for a sample OSW project Radially connected to the grid.

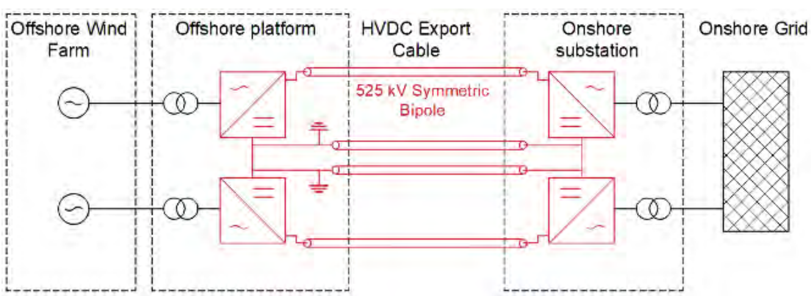
Figure 5-5. Single Line Diagram of 320 kV HVDC OSW Project Symmetric Monopole Grid connection — Illustrative Example



The 525 kV symmetric bi-pole HVDC technology is a four-cable system consisting of a two-pole configuration with two dedicated metallic returns. This configuration allows for 50% redundancy as each pole can work independently. Each pole can be connected to a different onshore POI by sharing metallic returns. This topology was considered for OSW ratings higher than 1,400 MW. While there is no precedent for use of 525kV symmetric bi-pole HVDC technology for export of offshore energy to the onshore grid, the Study assumes that such technology will be available for implementation by 2030. As illustrated in Figure 5-6., the bipolar cable system requires two trenches, one cable per trench to allow for the 50% redundancy in case of cable failure on either one of the poles. Specifications associated with the 525 kV symmetric bi-pole HVDC technology considered for this Study are follows:

- Voltage level: ±525 kV
- Maximum transmission power: 1,700 MW
- Maximum cable conductor cross section: 2,500 mm2
- Maximum cable system length in proposed connection concepts: 106 miles
- Number of offshore trenches: two

Figure 5-6. 525 kV Symmetric Bi-pole HVDC Schematic and Trenching — Illustrative Example



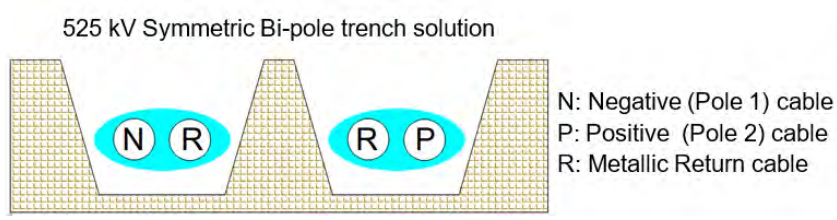
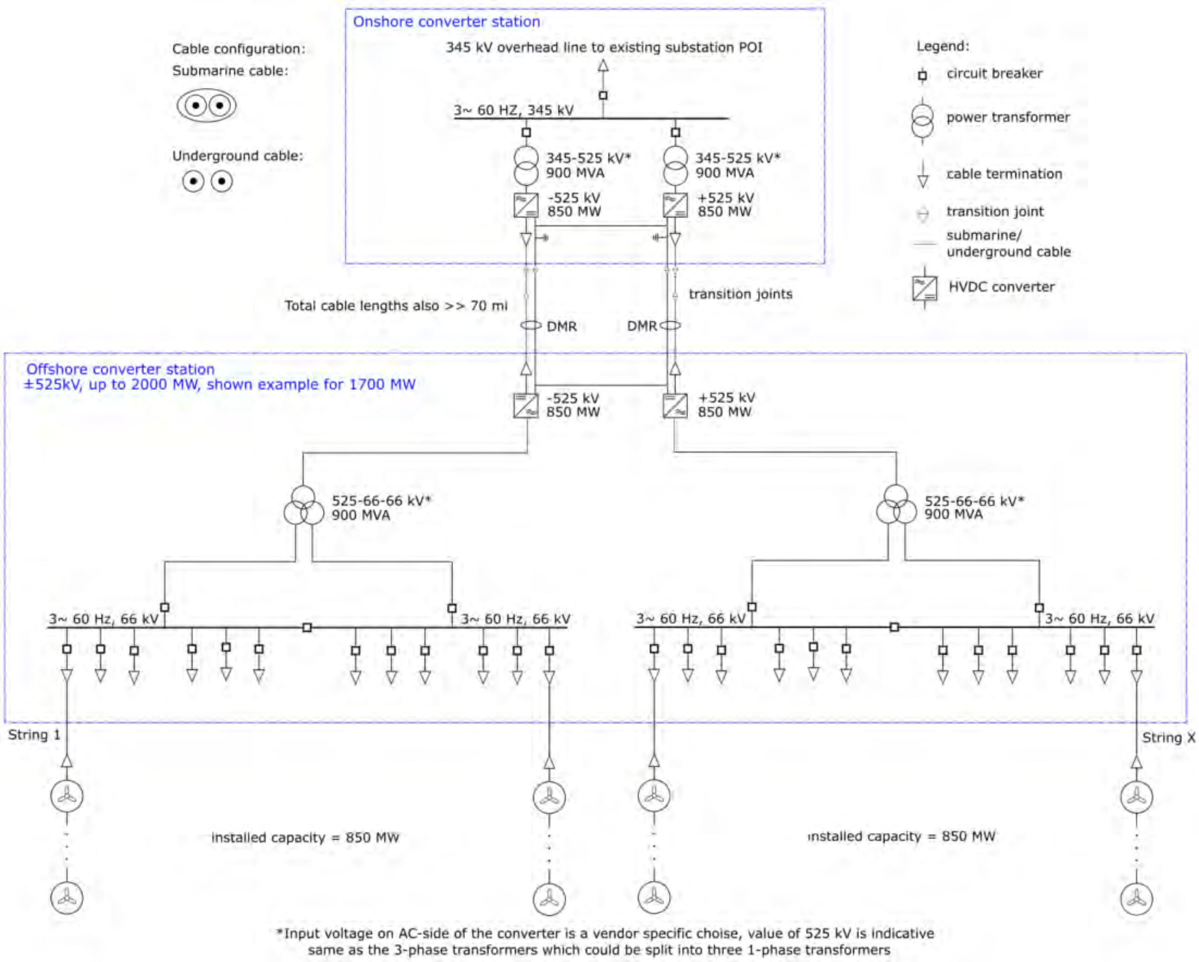


Figure 5-7. shows a more-detailed illustrative schematic of a single line diagram for a 525 kV symmetric bi-pole HVDC technology Radially connected to the grid.

Figure 5-7. Single Line Diagram of 525 kV HVDC OSW Symmetric Bi-pole Grid Connection — Illustrative Example



The maturity of HVDC technology is also comparable to that of HVAC systems. Several HVDC OSW projects are already operational or under commissioning. Hence, HVDC offshore systems possess a sufficiently high-technology readiness level to be considered for development of future offshore transmission. Unlike HVAC technology, HVDC cables do not have any distance restrictions.

5.2 OSW Connection Concept Design and Preliminary Analysis

Theoretically, there are many different design options to connect the planned 9.0 GW offshore wind to the onshore grid of New York State. In this Study, we developed OSW connection designs using the POIs identified as part of the onshore assessment described in Section 3 and the five connection concepts illustrated in Table 5-1.

5.2.1 Design Criteria

For the purpose of this Study, the offshore connection concepts were assumed to be constrained by the following limiting criteria:

Technology limitation:

- The power rating of each 220 kV HVAC cable circuit should not exceed 400 MW. The length of HVAC cables should not be longer than 70 miles.
- The power rating of a ±320 kV monopole HVDC circuit should not exceed 1,400 MW.
- The power rating of each ±525 kV bi-pole HVDC circuit should not exceed 2,650 MW, which corresponds to approximately 2.5 kA current in each individual cable conductor.

Location-specific and environmental limitations:

- Aggregated power injection in each selected onshore substation will be limited to a specific amount as determined by the onshore analysis Scenario 2 presented in Section 3.
- Number of cables extending from offshore to onshore are limited to specific numbers as determined by the environmental and permitting analysis presented in Section 6.

NYCA Operating Reserve Requirement:

In order to ensure reliability and resiliency, grid operators and planners attempt to plan the network in a manner that limits how much generation power can be lost due to outages and/or contingencies. These limits are typically determined based on the available operational reserves and operational reserve locational requirements defined by applicable reliability guidelines and standards. Currently, NYISO's operating reserve requirement for the NYCA region is 1,310 MW, which is equal to NYCA's existing most severe operating capability loss.[8]

Many factors could lead to a change in the locational operating reserve requirements in future years. Since there is a lot of uncertainty about how these requirements might be set. The Study assumes the 1,310 MW of operating reserve requirement (also referred to as the largest single contingency limit) will remain intact during the Study horizon.

Offshore Connection Concepts

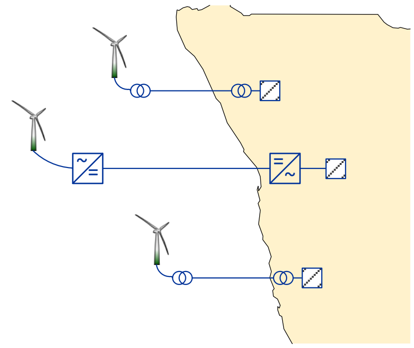
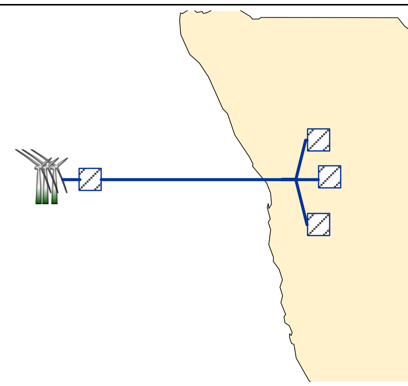
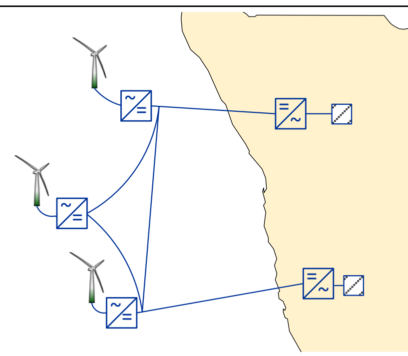
Offshore connection concepts are determined by such factors as:

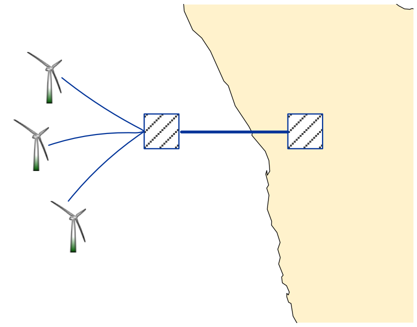
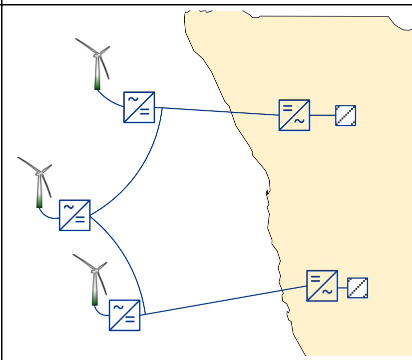
(i) the location of an OSW project
(ii) the relative proximity of adjacent OSW project
(iii) OSW project size (e.g. smaller projects < 400 MW or larger projects > 400 MW)
(iv) the type and capacity of electrical cables used (typically approximately 400 MW for HVAC technologies each or 1,200 MW of HVDC technologies)
(v) distance from the OSW project to the shore (typically within < 70 miles HVAC designs will be cost-effective, whereas > 70 miles HVDC designs may be more cost effective)
(vi) environmental and permitting considerations that may dictate cable routes
(vii) capacity available at an onshore substation (POI)
(viii) adequacy of the transmission system into which a POI is integrated to distribute power

Give the foregoing factors, up to five connection concepts are possible as listed in Table 5-1.

[8] Even though operating reserve locational requirements for Zone J and K are lower than 1,310 MW, for the purpose of the Study, NYCA operating reserve requirement was considered - For further information on the locational reserve requirements, please see the document at the following link:
http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

Table 5-1. Connection Concept Descriptions

OSW Connection Concept	Description	Illustrative Figure
Dedicated Radial Design	Each OSW project is connected to the onshore grid via a dedicated Radial connection, which can be either HVAC (for distances to onshore POI up to ~70 miles) or HVDC for distances over ~70 miles. Note this design relies on (i) the capacity of the export cable from the OSW project to shore (maximum capacity of that export cable limited to e.g., 400 MW HVAC or 1,200 MW HVDC), and (ii) the available capacity of the POI on the onshore grid. This approach offers a simplicity in design and the smallest total amount of cable laid offshore but does not provide any redundancy or associated reliability benefits.	
Split Design	In this design, one OSW project is connected by a single export cable circuit to the shore, which will be further split to two or more onshore substations. Note, this design relies on (i) the capacity of the export cable from the OSW project to shore (maximum capacity of that export cable limited to e.g., 400 MW HVAC or 1,200 MW HVDC), and (ii) the available capacity of the POI on the onshore grid. This design is usually applied when an individual onshore substation is not able to absorb the full amount of power injection, offering additional interconnection optionality.	
Mesh Design	In this design, multiple OSW projects are interconnected in a Meshed offshore grid, which is further connected to the onshore grid by two or more connections. Note, this design relies on close or adjacent project areas that can efficiently gather energy, and onshore substations that are capable of interconnecting significant energy capacity associated with multiple projects, to fewer onshore substations. This design balances the additional costs of interconnecting the offshore array with the potential advantage of increased redundancy and reliability.	

OSW Connection Concept	Description	Illustrative Figure
Shared Substation Design	In this design, multiple OSW projects are connected to one offshore hub (shared substation) before being further connected to the onshore grid. Note, this design relies on (i) smaller OSW projects that can aggregate to a common export cable to shore (maximum capacity of that common cable limited to e.g., 400 MW HVAC or 1,200 MW HVDC) and (ii) relies on a POI on the onshore grid that can handle significant injections of energy. This design minimizes the cable landfall footprint but adds reliability risk given the lack of redundancy.	
Backbone Design	In this design the OSW projects are interconnected in an offshore grid, which is connected to the onshore grid as a multi-terminal system (non-Meshed). Note, this design relies on close or adjacent project areas and onshore substations that have the capacity to host significant injections of energy associated with multiple projects to fewer onshore substations. This design balances the additional costs of interconnecting the OSW projects in an offshore grid with the potential advantage of increased redundancy and reliability.	

5.2.2 Preliminary Review of Connection Concepts

For each of the five future OSW build-out scenarios, five different connection concepts described in Table 5-1. above were developed, resulting in a total of 25 different connection topologies. Informed by early stages of the onshore system analysis, the Study assumed injections of 6 GW of OSW into New York City and 3 GW of OSW into Long Island.

The initial 25 offshore connection topologies were analyzed and ranked qualitatively and quantitively using existing industry guidelines and adopted practices accounting for potential benefits, risks, and LTCOE.

Qualitative analyses involved comparing the 25 connection topologies from the following aspects:

- Resiliency and Redundancy: The ability of the conceptual OSW connection topologies to collect and deliver rated power after a failure event in one component (i.e., N-1 event) assuming no over-sizing of components.

- Expandability**:** The modular flexibility of a connection topology to expand into an interconnected system without the need of upgrading components; together with the flexibility of component replacement or dismantling without having a major impact to the rest of the offshore grid.

- Operational Benefits**:** Standardization and compatibility of the connection topologies and technologies, together with the capability of the offshore connection scheme to provide additional supplementary benefits such as voltage support and control capabilities of power flows toward the onshore grid.

The quantitative analysis involved calculation of the LTCOE considering costs as well as performance components as described:

Costs: The CAPEX, OPEX, and REPEX were estimated using cost data at the component level, including components at onshore landing substation. REPEX was factored in due to the substation's secondary and auxiliary equipment age, or that the equipment will become obsolete over 10 to 15 years, whereas electrical power equipment is typically designed to have a lifetime of 35 years. It should be noted that these cost estimates were subsequently updated for three detailed design variants as part of the detailed assessment of OSW connection concepts task. The methodology, key assumptions, and results of this work is presented in Section 8.

Performance: Performance includes component availability and energy losses within power transformers, converters and cables. Component availability was calculated considering downtime due to planned and unplanned outages on cables, converters, and transformers.

Summary tables showing consolidated results across all five OSW build-out scenarios are presented in the following section. Results of the qualitative review for each of the individual OSW build-out scenarios are included in Annex D.

Table 5-2. Summary of Preliminary Review

Connection Concept	Average LTCOE ($/MWh)	Operational Benefits	Resilience & Redundancy	Implementation given OSW geographic uncertainty
Dedicated Radials	Lowest	Moderate	Weak	Easy
Split				
Shared Substations	Middle	Weak	Moderate	Very Challenging
Mesh	Higher	Strong	Strong	Complex but possible
Backbone				

Table 5-3. Conclusions Based on Preliminary Review

Connection Concept	Preliminary Observations
Dedicated Radials	Lowest LTCOE and simplest rollout given uncertainty with OSW project geography and capacity. Weak resilience and redundancy and moderate operational benefits. Operationally, grid support would be certain with DC connection. Preliminary review does not include onshore costs - depending on number/location of POIs, onshore grid reinforcement costs may be high, making these concepts less attractive.
Split	
Shared Substations	LTCOE in the middle of the range observed across all connection concepts. Phased rollout would be extremely difficult given uncertainty in OSW project geography and capacity. Moderate resilience and redundancy due to the length and number of cables; weakest/riskiest operationally due to large amount of AC cables.
Mesh	Higher LTCOE and potentially complex phased rollout (but possible with appropriate planning) but offers strong resilience and redundancy and strongest operational benefits. Offers grid supports which can improve utilization of offshore POIs and optimize onshore grid reinforcement.
Backbone	Higher LTCOE and complex phased rollout, but strong resiliency and redundancy. The operational benefits are high, but slightly less that Mesh.

5.3 Findings

Key initial observations associated with the preliminary analysis of the OSW connection concepts for New York State can be summarized as follow:

- As shown in Annex D, the qualitative ranking of each connection concepts was generally consistent across all five OSW build-out scenarios. Meaning, the OSW project location uncertainty (represented by the five differing OSW build-out scenarios considered which reflect existing and prospective future lease areas) does not significantly impact the preliminary assessment of the five OSW project connection concepts.

- The overall benefits and relative cost comparisons of each connection concept remained consistent in all build-out scenarios, which suggests that a single representative scenario can be utilized for detailed analysis and costing with minimal sensitivity risk of compromise to findings.

- Radials offer the lowest total footprint in terms of offshore cable lengths (miles) of all design concepts and across all future buildout scenarios examined in this study.

- Radials and split concept designs have lower LTCOE, though offer less operational benefits, resiliency and redundancy, across all future OSW buildout scenarios. Radials and split concepts were observed with very similar performance during the preliminary review, under the Study conditions.

- Moving from Radial connections to a substation sharing concept, where individual OSW projects connect to an offshore substation(s) built outside a specific project development to reduce the number of required export cables to onshore POIs, is problematic given BOEM WEA and selected project location uncertainty. Planning for a Mesh or Backbone connection concept is complex given the uncertainty, but achievable.

- Mesh and Backbone concept designs provide extra operational benefits, resiliency and redundancy, but with an extra LTCOE cost.

- Moving from Radials to a networked strategy (either substation sharing, Mesh, or Backbone), the coordinated offshore network should encompass at least three OSW projects with minimum aggregate rating of approximately 3 GW to be financially feasible.

- Radial connections can be later converted to Mesh or Backbone with upfront preparation and investment such as additional control and protection functionality for future Meshed integration, OSW project substation platform sizing and design with reserve space for circuit breaker bays and future cable connection. Cost associated with such preparations will vary depending on the chosen methods for Meshing but is expected to fall in the range of 5% of overall platform cost for an AC Mesh connection and 10% of overall platform cost for a DC Mesh connection.

- Given the previously mentioned observations, Radials, Meshed and Backbone connection concepts are shortlisted for further detailed analysis as presented in Section 7.

6 Environmental and Permitting Analysis (Routing Assessment)

6.1 Assessment Approach

The transmission cable routing feasibility assessment (Routing Assessment) was based on a review of environmental and permitting constraints for multiple representative routes to determine the feasibility of routing for an illustrative transmission strategy suggested by the analysis in Section 3 of injecting 6 GW into New York City POIs and 3 GW into Long Island POIs. This section describes the methodology and major assumptions used to perform the Routing Assessment. Section 6.1.1 explains how preliminary routes and landing sites were identified for analysis based on POIs associated with an example base allocation of 9 GW (Scenario 1 described in Section 3.4), and lists all route segments and landing sites that were considered as part of this assessment. Section 6.1.2 describes the process used to identify route constraints, assess the feasibility of routes, and develops a refined set of representative routes based on POIs associated with an example alternative allocation of 9 GW (Scenario 2 described in Section 3.5). Section 6.1.3 presents additional inputs and supporting analyses considered in assessing the feasibility of installing multiple cables along multiple routes, which is necessary to support the illustrative transmission strategy. The results of these analyses are presented in Section 6.2.

6.1.1 Initial Route and Landing Site Identification

This section describes the approach to identify preliminary representative routes and associated landing sites. To evaluate multiple route alternatives between offshore lease areas and onshore substations, also referred to as POIs, the routes were divided into three primary components:

- Offshore route corridors (segments between lease areas and nearshore waters).
- Shore approach and landing sites (segments between the offshore corridors and shore crossings).
- Onshore routes (segments between landing sites and POIs).

To assist the analyses, a project-specific web-based mapping application (web mapper) was established using an Esri ArcGIS Portal web platform. Spatial data resources obtained from publicly available websites were downloaded and integrated into the project’s Enterprise Geodatabase (using industry standard Microsoft SQL Server and ArcGIS for Enterprise). In some instances where data files were large or challenging to acquire, authoritative map services were linked with the web mapper (for example, National Oceanographic and Atmospheric Administration raster nautical charts and automatic identification system vessel density grids). This allowed for review of authoritative geographic information system (GIS) data without directly downloading the information.

6.1.1.1 Offshore Route Corridors

During an initial screening-level assessment, four representative offshore route corridors were delineated, extending from the potential offshore wind lease areas to the nearshore coastal region of New York State including:

- ***Atlantic North Corridor:*** Extends from the lease areas identified as Massachusetts Region, South Fork, and Sunrise on Figure 6-1.

- ***Atlantic Central Corridor:*** Extends from the lease areas identified as Empire, Empire Buildout, Expansion, and Hudson Central on Figure 6-1.

- ***Atlantic South Corridor:*** Extends from the lease areas identified as Hudson South and New Jersey Region on Figure 6-1.

- ***Long Island Sound Corridor:*** Extends through Long Island Sound from the *Atlantic North Corridor* on Figure 6-1.

Corridors were identified, as opposed to specific offshore routes, to account for similarity of constraints throughout the given corridor and the relative flexibility to adjust a given route in open ocean to avoid obstructions and other constraints. Multiple potential lease areas were grouped and included in the representative offshore route corridors where the lease areas were located near each other and where cable routes would follow a similar general direction to reach potential POIs on Long Island and in New York City.

In refining the representative routes considered for further analysis in this Routing Assessment, the Study focused on approaches primarily from the south shore of Long Island and New York Harbor; however, New York State recognizes that routing through Long Island Sound likewise offers a similarly feasible potential corridor between offshore wind lease areas and POIs in New York City or on Long Island. The three representative offshore route corridors (Figure 6-1) further analyzed for illustrative purposes are as follows: the Atlantic North Corridor, the Atlantic Central Corridor, and Atlantic South Corridor.

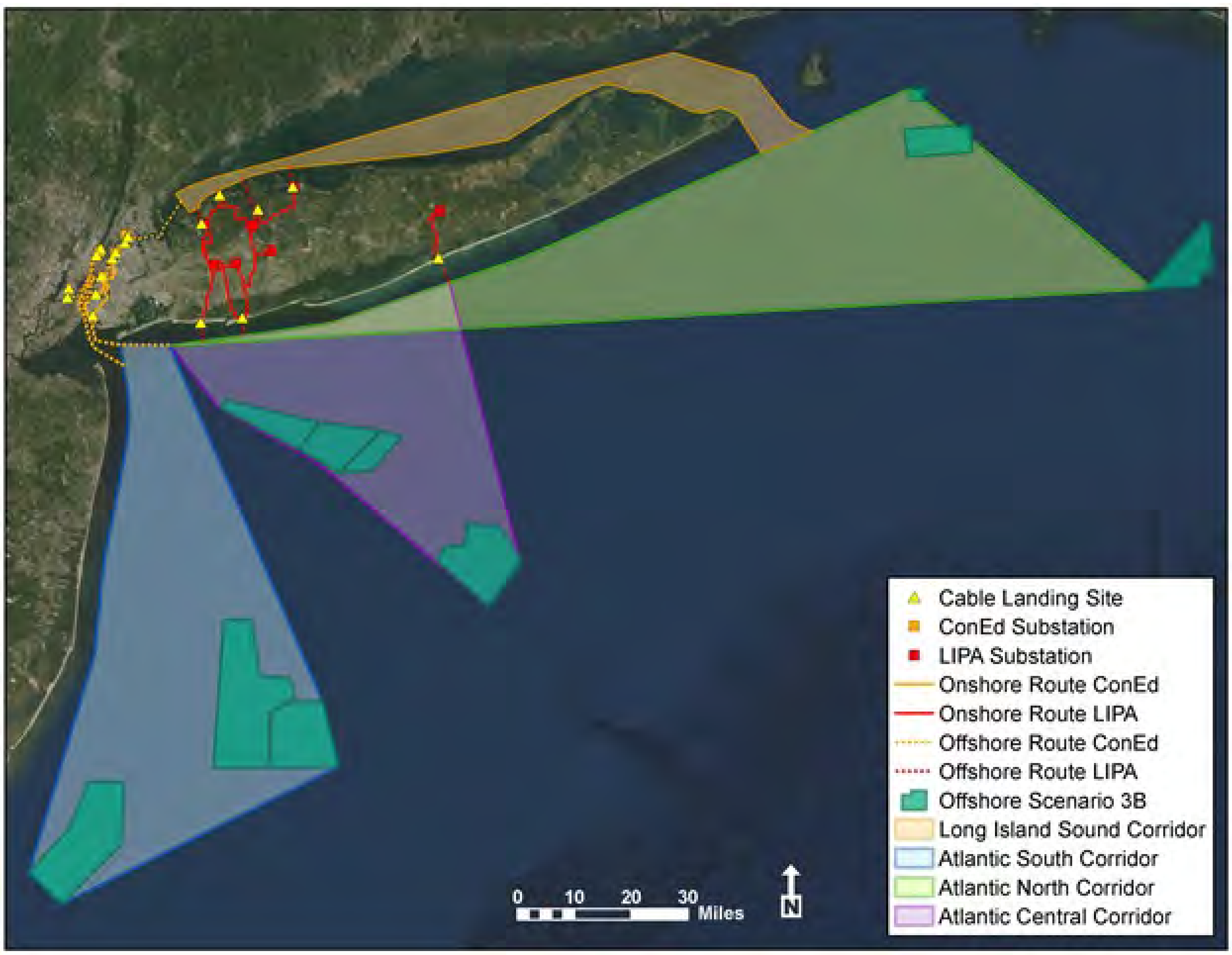
To limit the number of route iterations within each corridor, the potential lease areas associated with the Atlantic South Corridor were assumed to connect only with POIs in New York City (via New York

Harbor). Also, excluding routes through Long Island Sound, potential leases associated with the Atlantic North Corridor were assumed to connect only with Long Island POIs.

Figure 6-1 shows representative offshore route corridors, shore approach and landing sites, and onshore routes for cable interconnection from offshore lease to POIs in New York City and Long Island. These assumptions notwithstanding, the Study authors recognize that a multitude of offshore origins and connections to shore are possible and so again, affirm that the representative study is one of many feasible approaches to integrate OSW projects into New York and this presentation does not confer a recommendation of the State Team to the use of these corridors or any individual routes.

Figure 6-1. Overview of Analyzed Route Segments

Source: WSP 2020; DNVGL 2020; ESRI 2020. (See Annex B, Part 1: GIS Data Source List for full list of figure references.)



6.1.1.2 Shore Approach and Landing Sites

The nearshore segments of the representative routes, identified as the shore approach, connect the representative offshore route corridors to landing sites along the Long Island shore and the New York City waterfront (Figure 6-2). Some shore approach and landing site configurations also include crossings of intracoastal bays and tidally influenced waterbodies (e.g., East River). Potential landing sites were initially identified based primarily on a visual interpretation of aerial photographs considering the following general criteria:

- Access to landing site (for construction equipment)
- Suitable location for horizontal directional drilling (HDD), including size and type of area
- Proximity of landing site to POIs
- Adjacent public right-of-way (ROW) and/or transmission corridor to POI that could potentially accommodate cable colocation
- Avoidance or limited extent of open water and potential wetland crossings (i.e., bays, tidal wetlands/marshes), as feasible
- Separation distance between landing sites to support reasonably distinct onshore route alternatives

Most landing sites were identified as locations closest to a POI where a shore crossing could potentially be feasible. In addition, several other landing site alternatives were included for site-specific reasons. For example, although not considered as a POI in this analysis, the waterfront near the Gowanus substation was identified as a landing site given the potential available workspace and to avoid East River constraints.

6.1.1.3 Onshore Routes

Onshore route segments of the identified representative routes extend along the terrestrial environment, from a shore landing site to a POI (Figure 6-2). Potential onshore routes were initially identified based on GIS data layers and visual interpretation of aerial photographs. Existing infrastructure (e.g., transmission lines, aqueduct, pipeline, and sewer mains) was identified to determine if the corresponding ROWs would potentially be suitable for adjacent placement or colocation of the cable. In addition, the following general criteria was considered in selecting potential onshore routes:

- Presence of adjacent public ROW, transmission corridor, or railroad corridor wide enough to support a tractor trailer delivering equipment.
- Preference for roads and transmission corridors that offered a continuous, more direct route.
- Avoidance of residential neighborhoods, where possible.

Onshore route segments included in the refined list of representative routes are shown in Figure 6-2.

6.1.1.4 Route Refinement

Following screening-level critical constraint analysis and ranking of routes (see Annex B, Part 2: Preliminary Route Feasibility Scoring Matrices for additional details), further evaluation of the transmission strategy yielded a revised set of POIs for consideration. Accounting for the updated set of POIs, potentially feasible routes were evaluated more closely with consideration for several engineering parameters and a more detailed analysis of potential sites for HVDC converter stations and HVAC transformer stations. In some cases, routes and/or landing sites were shifted to improve their feasibility. Based on this additional analysis, a revised set of feasible representative routes was identified for illustrative purposes.

Transmission Strategy Adjustments

The initial list of POIs identified for the preliminary routing analysis included nine substations — four in New York City (ConEd service area/electrical system) and five on Long Island (LIPA service area/electrical system). These initial POIs were associated with the example base allocation of 9 GW (Scenario 1) described in Section 3.3 that could inject 6 GW into New York City and 3 GW into Long Island. The list of POIs was adjusted based on the development of the example alternative allocation of 9 GW (Scenario 2) described in Section 3.4, which could also inject 6 GW into New York City and 3 GW into Long Island through a different configuration of Long Island POIs than the example base allocation. Therefore, the final illustrative list of eight POIs analyzed as part of the Routing Assessment consisted of the following, associated with the Alternative Allocation (Scenario 2) configuration:

- New York City (ConEd) POIs
    - Farragut
    - Mott Haven
    - Rainey
    - West 49th
- Long Island (LIPA) POIs
    - East Garden City
    - Ruland Road
    - Shore Road
    - Syosset

Preliminary results indicated that routing to all identified POIs was potentially feasible (see Annex B, Part 2: Preliminary Route Feasibility Scoring Matrices for details) via a diversity of access routes, including routes extending through the Long Island Sound, though additional research was warranted for suitable converter station sites along some routes. In the representative design, the Planning Study authors have utilized southern routes to simplify costing analysis, but affirm that the routes utilized in the representative study do not reflect either an optimal route selection or the recommendations of the State Team.

All evaluated shore approach segments and associated Long Island and New York City landing sites included as part of the refined list of representative routes are listed in Table 6-1 and Table 6-2.

Figure 6-2 shows shore approach routes, landing sites, and onshore routes for cable interconnection to New York City and Long Island.

Figure 6-2. Shore Approach Routes, Landings, and Onshore Routes to New York City and Long Island

Source: WSP 2020; DNVGL 2020; ESRI 2020. (See Annex B, Part 1: GIS Data Source List for full list of figure references.)

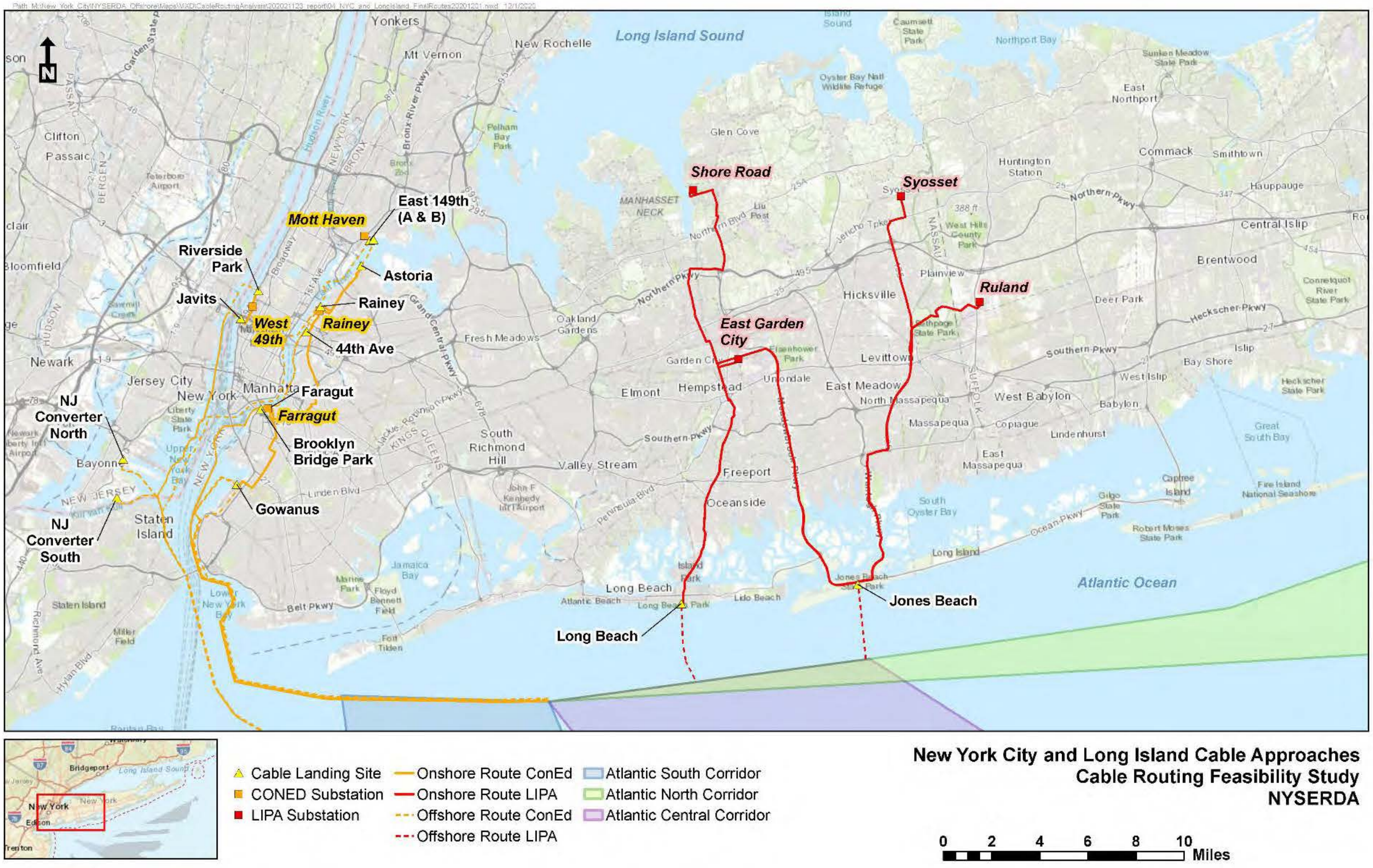


Table 6-1. Analyzed Offshore Route Corridors, Shore Approach and Landing Sites, and Points of Interconnection for NYC Routes

Offshore Route Corridor	Atlantic South Corridor							Atlantic Central Corridor	
Shore Approach and Landing Site	Riverside (Narrows West & NJ Converter-South)	Riverside (Narrows West & NJ Converter-North)	Javits Center Pier	44th Ave	Brooklyn Bridge Park	149th Street (Narrows West)	Rainey Park & 149th Street via Astoria (Narrows East)	Gowanus (Pierline segment)	Gowanus (Bay Ridge Flats segment)
Point of Interconnection	West 49th	West 49th	West 49th	Rainey	Rainey	Mott Haven	Mott Haven	Farragut	Farragut

Table 6-2. Analyzed Offshore Route Corridors, Shore Approach and Landing Sites, and Points of Interconnection for LI Routes

Offshore Route Corridors	Atlantic Central Corridor					Atlantic North Corridor
Shore Approach and Landing Site	Jones Beach	Jones Beach	Jones Beach	Long Beach	Long Beach	Jones Beach
Point of Interconnection	Syosset	Shore Road	East Garden City	Shore Road	East Garden City	Ruland Road

6.1.2 Constraint Identification and Review

This section summarizes the offshore and onshore issues evaluated in this assessment, with a focus on those considered more critical to the feasibility of a given representative route. Offshore constraints pertain to the offshore segments of the routes within the open ocean. Shore approach and landing site constraints pertain to the nearshore areas of the Atlantic Ocean and Long Island Sound, the shore landing itself, as well as any bay/intracoastal and tidally influenced waterbody crossings. Onshore constraints pertain to the terrestrial portion of a route extending from the landing site to the POI, but do not consider the landing site or the substation at the POI. To identify constraints for the different route segments, GIS data and resource layers were compiled for all applicable resources and specially designated areas that may be affected by the potential cable routes within an area extending from potential offshore lease areas to the identified POIs. These GIS layers were included in the project-specific web mapper that allowed them to be overlaid on base maps and charts for the surrounding terrestrial and marine environment. Tables 6-3 and 6-4 present GIS-based data layers evaluated as potential constraints for the Routing Assessment. A summary description and source information for each layer are presented in Annex B, Part 1: GIS Data Source List. Using the web mapper, potential cable routes were assessed to identify existing constraints for specific resources, including designated areas, political boundaries, and other geographical features crossed by the routes.

Table 6-3. GIS Data Layers Evaluated as Potential Constraints to Offshore Corridors, Shore Approach Route Segments, and Landing Sites

Coastal Management Programs	Offshore Dredge Material Disposal / Dumping Grounds
New York State and Federal (National Oceanographic and Atmospheric Administration [NOAA]/U.S. Fish and Wildlife Service) Endangered, Threatened and Special Concern Species	U.S. Department of Defense (DoD) Mission Compatibility
NOAA Essential Fish Habitat (EFH)	Submarine Transit Lanes
Shellfisheries	Naval Undersea Warfare Testing Range
New York State Critical Environmental Areas	Military Installations, Ranges and Training Areas
New York State Department of State Significant Coastal Fish and Wildlife Habitats	DoD Operation Areas
Submerged Aquatic Vegetation	Federal - Coastal Storm Risk Management
Natural Heritage Communities	Coastal Project Offshore Sand Borrow Areas
Critical Habitat	Property Ownership
Habitat Area of Particular Concern	Land Type
Important Bird Areas	Coastal Barrier Resource Areas
North Atlantic Right Whale Areas	Vessel Monitoring System Data
Currents/Bottom Stress	Aquaculture
Sand Waves	Unexploded Ordnance
Hardbottom	Anchorage Areas
Water Depth	Fish Trap Areas/ Lobster Pot Areas
Sediment Grain Size Distribution	Shipping Lanes
Potential Contamination	Aids to Navigation
Cultural Resources	Artificial Reefs
New York State Heritage Areas	Pilot Boarding Areas
Wrecks/Obstructions	Danger Zones and Restricted Areas
National Historic Register/Landmarks	Traffic Separation Schemes/Traffic Lanes and Precautionary Areas
Cable Crossings (Electrical Transmission and/or Telecommunication)	Maintained Navigation Channels
Pipeline Crossings	Vessel Traffic
Sewer Lines	Vessel Activity and Marine Infrastructure
	Bureau of Ocean Energy Management Lease Areas and New York State Call Areas

Table 6-4. GIS Data Layers Evaluated as Potential Constraints to Onshore Route Segments

Important Bird Areas Federal Lands Recognized Ecological Complexes Priority Marine Activity Zones Ecologically Significant Maritime and Industrial Areas Significant Maritime Industrial Areas Special Natural Waterfront Areas Coastal Barrier Resource System Boundaries Indian Territories Public Fishing and Recreational Use Areas National Historic Landmarks National Register of Historic Places New York State Parks, Historic Sites, and Heritage Areas New York State Department of Environmental Conservation (NYSDEC) Trails and Lands New York State Local Waterfront Revitalization Communities Primary Aquifers	U.S. Environmental Protection Agency Superfund National Priorities List Sites NYSDEC Remediation Sites Critical Environmental Areas National Oceanographic and Atmospheric Administration (NOAA) and New York State Critical Coastal Habitats Existing Infrastructure: Telecommunication Cables, Roadways, Railways, Transmission Lines, Sewer Lines Farmland Tidal Wetlands Waterbodies NYSDEC Freshwater Wetlands/Check Zones Federal Emergency Management Agency Flood Hazard Zones New York State Tax Parcel Data National Land Cover Database County Parcel Data

The resources and spatial features that potentially pose a significant challenge to power cable installation were then grouped into critical constraint categories with similar attributes or designations. The constraints deemed most critical to routing a cable from an offshore wind energy lease area to POI are discussed in the following section. The critical constraint categories are listed in 6-5. A description of each critical constraint category is summarized below according to route segment. The results of the constraints analysis for specific routes and landing sites are also presented, as applicable.

Table 6-5. Critical Constraint Categories for Each Route Segment

Critical Constraint Category	Route Segment		
	Offshore	Shore Approach/ Landings	Onshore
Infrastructure Crossings (including need for horizontal directional drilling)	✓	✓	✓
Designated Marine Zones (traffic lanes, danger zones)	✓		
Department of Defense Areas	✓		
Sensitive Habitats	✓	✓	✓
Marine Geology and Oceanography	✓	✓	
Other Regulatory Constraints (e.g., additional State approvals)	✓	✓	
Stakeholder Concerns	✓	✓	✓
Landing Site Complexity		✓	
Navigation Channels, Anchorage Areas, and U.S. Army Corps of Engineers Coastal Storm Risk Management Projects		✓	
Contaminated Sediments		✓	✓
Cultural Resources		✓	✓
Route Distance			✓
Available Land for Converter Station			✓
Parkway/Highway (permitting constraint)			✓

Assumptions and analytical limitations affecting more than one critical constraint category or route segment include the following:

- Substrate at all potential offshore and onshore specialized crossings is assumed to be suitable for specialized routing methods. Site-specific assessments would be needed to confirm this assumption.
- Only publicly available data for infrastructure (e.g., sewer, aqueduct, subway, gas pipeline, telecommunication cable, and electrical transmission line) were considered. Site-specific assessments would be needed to confirm the presence and exact location of existing utilities along the routes.

6.1.2.1 Critical Constraints for Offshore Route Corridors

Infrastructure Crossings

Numerous subsea cables exist along the seafloor in the Atlantic Ocean. Crossing these existing cables add complexity to cable installation and an increased risk of liability. Crossings would require measures to protect both new and existing cables that would need to be agreed on with the cable owners and the regulatory agencies. These agreements include considerations such as construction methodology and depth/type of cover and are typically required before permits/easements are granted.

The burial depth of existing cables in these offshore areas likely varies and no comprehensive database on the depth of existing cables has been identified. In recent decades, federal regulatory guidance for projects in or near New York State has specified that cables located in open marine waters shall be buried a minimum of four feet below the seafloor in areas with soft sediments and a minimum of two feet in areas of rock or other hard substrate (USACE 2009, 2017, 2019; 49 CFR §195.248). This excludes designated navigation channels and anchorage areas, which require greater depth of cover but generally do not overlap with the identified offshore corridors. Recent comments from the New York State Department of Environmental Conservation (DEC) on offshore wind cable burial depth recommend that offshore cables should be buried at least six feet deep to avoid interactions with fishing gear [1]. Some existing cables may have been installed at shallower depths prior to the recent burial depth guidelines and/or may have been affected by natural submarine sediment transport processes (erosion or deposition), which have altered the actual burial depth.

Designated Marine Zones

There are multiple designated marine zones within the Atlantic Ocean on approach to New York State waters. Examples of such zones that may need to be crossed by cables include shipping lanes/fairways associated with major ports, as well as navigation Safety and Security Zones [2]. Installation of a cable across these zones is likely not precluded but would require coordination with regulatory agencies and maritime stakeholders to ensure navigation is not impacted during installation. Additionally, zones identified as Safety and Security Zone: Danger Area may contain old mines and other unexploded ordnance and therefore may require geophysical surveys prior to cable routing.

Department of Defense Areas

Routes within the Atlantic Ocean would route through U.S. Department of Defense's (DoD) Operating Areas (OPAREA) and would require coordination with the DoD. U.S. military vessels (surface and subsurface) use the OPAREAs for training, testing, and qualifying systems (e.g., onboard radar systems) [3]. The DoD also uses areas surrounding the OPAREAs for military activities, including specific submarine transit lanes. These areas and lanes are identified on navigation charts or through publicly available data, but others may not be.

Based on current publicly available GIS data for DoD wind mission compatibility, none of the cable routes cross offshore wind exclusions areas, although there are portions of routes that are in areas with site-specific stipulations. However, graphics presented at a November 2018 DoD Mission Compatibility Assessment, New York Bight Task Force meeting identify an alternate set of proposed boundaries for wind exclusion and site-specific stipulation zones that differ from the publicly available GIS data [4]. As a result, additional areas considered in this Routing Assessment may be within proposed DoD wind exclusion areas, such that cable installation associated with offshore wind activities may be prohibited by the DoD due to interference with current operations. In other instances, installing cables in an OPAREA may need further coordination or site-specific stipulations such as time-of-year construction restrictions to avoid interference with specific missions or training.

Sensitive Offshore Habitats

A cable route in the Atlantic Ocean would cross several sensitive habitats, including New York State and federally listed threatened and endangered (T&E) species habitats. Species-specific seasonal restrictions and best management practices (BMPs) would likely be required to avoid or minimize adverse impacts for work in these areas. Consultation with the following agencies would be required:

- NOAA National Marine Fisheries Service (NMFS) under Section 7 of the Endangered Species Act for marine T&E species.
- U.S. Fish and Wildlife Service (USFWS) under Section 7 of the Endangered Species Act for terrestrial T&E species, including avian species which may be in the marine environment.
- NYSDEC under 6 New York Codes, Rules, and Regulations (NYCRR) Part 182 for New York State T&E species.
- NOAA NMFS under the Marine Mammal Protection Act of 1972 for marine mammals.
- NOAA NMFS under the Magnuson-Stevens Fisheries Conservation and Management Act for Essential Fish Habitat.

Marine Geology and Oceanography

The geological characteristics of the Atlantic Ocean within the analyzed offshore corridors are generally understood to be conducive to cable installation (i.e., predominantly sandy substrate with some areas of sand/silt/clay mixtures and patches of coarse-grained gravel, find-grained silt, rocky outcrops, and mud deposits [5][6]). Seasonal storms and winter conditions in the open ocean waters can delay installation and cause scour around installed cables.

Further Regulatory Constraints

Routing cables in the Atlantic Ocean in or near a state’s territorial waters may require Coastal Management Program (CMP) consistency review and concurrence under the federal Coastal Zone Management Act of 1972. Such review and concurrence may be required if a state determines that the installation of a cable along a given route may have a reasonably foreseeable effect on the state’s coastal resources, including activities outside state waters that may impact coastal uses. For example, routing a cable into New York Harbor may require consistency review and concurrence under CMP for New York and New Jersey as a result of potential impacts on those state waters and associated users. These two state consistency reviews would likely be required even assuming the cable route only crossed through the waters of New York State because of the proximity of the route to the coastal resources of the other state, which could result in potential effects on those state resources during installation and/or operation of the cable. Similar considerations would be required of a cable route through the Block Island and Long Island Sounds, including a potential consistency review by Massachusetts, Rhode Island and Connecticut. Multiple state consistency reviews increase the risk of concerns to a route, which could significantly delay cable installation and/or require route realignment. Additionally, Local Waterfront Revitalization Program (LWRP) review may apply. LWRPs are a subset of the New York CMP and contain more detailed implementation plans for local communities in the State's coastal policies.

Potential Stakeholder Concerns

Marine waters within the Atlantic Ocean support high levels of commercial and recreational fishing [7]. A cable route that crosses or is adjacent to productive fishing grounds is likely to generate concern. Certain commercial and recreational fishing grounds may not be mapped and, therefore, would require input from fisheries representatives to identify. Also, high concentrations of recreational and commercial marine vessels are present in the offshore waters approaching New York Harbor [8], and in association with other ports, harbors and marinas along New York's coast. Marine vessel operators and representatives may have concerns regarding cable placement in such high traffic areas, especially if navigation may be impacted during installation. Other offshore stakeholders including, but not limited to, environmental non-governmental organizations and communities reliant on coastal/offshore resources may also have concerns if it is perceived that cable installation and operation may negatively impact regionally important resources.

6.1.2.2 Critical Constraints for Shore Approach and Landing Sites

Infrastructure Crossings

As with the offshore corridors, existing submarine cables may also need to be crossed by new transmission cables through nearshore areas to landing sites. Additional linear infrastructure may be crossed during the shore approach and landings, including pipelines, and through New York Harbor in particular, transportation tunnels supporting train, road, and subway systems. Specialized crossing methods, including HDD and/or armoring, may be required to suitably protect both the new cable and existing infrastructure. Therefore, crossing this existing infrastructure may present a logistical challenge for cable installation and an increased risk of liability, but such crossings are expected to be feasible if measures to protect both the existing infrastructure and new cables are agreed upon by the new cable owner, the existing infrastructure owner and the regulatory agencies. These agreements include considerations such as construction methodology, depth/type of cover, and separation distance from the existing infrastructure. Such agreements are typically required before permits and easements would be granted for a new cable.

Sensitive Habitats

Several sensitive habitats in New York State's nearshore coastal waters present constraints for installation of cables in the approach to a landing site. Such sensitive habitats may include State- and federally listed T&E species habitats.

Sensitive habitats that may be affected during intracoastal (back-barrier) bay crossings include tidal wetland marsh and eelgrass meadows, as well as New York State Significant Coastal Fish and Wildlife Habitat and Critical Environmental Areas [9].

As with the offshore environment, the presence of these sensitive habitats in the nearshore and at the landing sites would likely result in species-specific seasonal restrictions and BMPs to avoid or minimize adverse impacts on the sensitive habitats. Specialized crossing methods may be required, including trenchless methods such as HDD or the jack-and-bore technique. Such methods can substantially reduce impacts on certain environmental features but can be more costly and require much more time than typical installation methods (e.g., open trenching). Consultation with the following agencies would be required:

- NOAA NMFS under Section 7 of the Endangered Species Act for marine T&E species
- USFWS under Section 7 of the Endangered Species Act for terrestrial and avian T&E species
- NYSDEC under 6 NYCRR Part 182 for NYS T&E species
- NOAA NMFS under the Marine Mammal Protection Act of 1972 for marine mammals
- NOAA NMFS under the Magnuson-Stevens Fisheries Conservation and Management Act for Essential Fish Habitat

Marine Geology and Oceanography

The Atlantic Ocean nearshore environment south of Long Island is highly dynamic as a result of winds, waves, and currents that are constantly shifting seafloor sediments in this area. Placement of a cable in these environments may present challenges to maintain cable burial depth requirements over time. Additionally, shallow bedrock or exposed hardbottom structure may be present in some areas of New

York Harbor. It may be challenging to meet burial depth requirements during cable installation in these areas, such that armoring the cables may be necessary.

Further Regulatory Constraints

As with the offshore environment, cable routing in the nearshore area on approach to a landing site may trigger the need to obtain CMP consistency review and concurrence under the federal Coastal Zone Management Act of 1972 from multiple states if cable installation adjacent to a state's territorial waters/coastal zone boundary is determined to have a reasonably foreseeable effect on the state's coastal resources. Additionally, specific to cable installation into New York Harbor, some potential routes may cross into New Jersey waters and trigger the need to obtain all applicable state permits in addition to other New York State and federal regulatory approvals necessary for the project. The need for additional regulatory approvals increases the risk of objection to and delay of a project.

Potential Stakeholder Concerns

Several reasonably anticipated stakeholder concerns regarding installation of cables through nearshore areas to a landing site are similar to those in the offshore environment. These include potential concern from commercial or recreational fisheries, the maritime community, and communities reliant on coastal/offshore resources. Marine waters on approach to New York City and Long Island landing areas support high levels of commercial and recreational fishing. A cable route that crosses or is adjacent to productive fishing grounds is likely to generate concerns. Additionally, marine vessel operators and representatives may have concerns regarding cable placement in New York Harbor high traffic areas, especially if a new cable crosses any navigation channels and/or anchorage areas. Concerns could include, but not be limited to, navigation impacts during cable installation and burial depth of the new cable during the operation phase. There are likely to be additional stakeholder concerns over the shore approach and landings, including intracoastal bay crossings. These include potential impacts on shellfishing grounds, marsh habitats, and water quality.

Landing Site Complexity

Cable shore crossings have a varied level of complexity depending on the natural and engineered features present along the waterfront at the landing sites. For example, the barrier islands along the south shore of Long Island require crossing the back-barrier bay (intracoastal) in several locations. At landing sites in New York City, existing coastal structures present greater technical challenges as the depth and extent of waterfront facility foundations may not be known and there is a potential for encountering unanticipated buried structures. Additionally, landing sites within areas of increased development may have substantial technical difficulties associated with limited staging area for installation equipment, regulatory restrictions, and stakeholder concerns.

Navigation Channels/Anchorage Areas/U.S. Army Corps of Engineers Project Areas

Multiple federally designated navigation channels and anchorages may need to be crossed along a shore approach to a landing site. In some cases, these features can be avoided, but for most routes into New York City crossing several channels or anchorages is likely necessary. In recent decades, regulatory guidance for New York State required a minimum burial depth for cables and pipelines of 15 feet below the seafloor or authorized channel depth (whichever is deeper) in navigation channels and anchorage areas (USACE 2009, 2017, 2019; 49 CFR §195.248). In addition, there are numerous U.S. Army Corps of Engineers (USACE) Coastal Storm Risk Management projects along Long Island's Atlantic Ocean shoreline, mainly consisting of beach nourishment. Further, navigation channels are present within several bays around Long Island. Any cable that crosses part of a Coastal Storm Risk Management project, navigation channel, or anchorage area would require a USACE Section 408 authorization under Section 14 of the Rivers and Harbors Act for alteration of a public work. The USACE, in consultation with other maritime stakeholders, may require route adjustments or impose project-specific requirements such as minimum depth of cover that may significantly increase the cost and/or delay a project. Non-designated channels and anchorages are also a potential constraint, but these were not mapped as part of this analysis.

Contaminated Sediments

Sediments in New York Harbor and its adjacent waterways may contain contaminated sediments, in part as a result of historical industrial activities in those areas as well as the presence of a significant number of combined sewer overflows [10]. Contaminant modeling would likely be required for sediments identified by the DEC as having Class C concentrations (i.e., high contamination: acute toxicity to aquatic life). Additionally, strict BMPs may be required to control sediment plumes during cable installation. As many of these contaminated areas are likely not mapped, sediment sampling along potential cable routes would be necessary to determine the potential presence and level of contamination.

Cultural Resources and Wrecks/Obstructions

Cable routes through nearshore waters may be constrained by shipwrecks and other obstructions, some of which may be considered cultural resources. To reach New York City landing sites, a cable route would cross through the viewshed of many waterfront sites of historical significance [9], which would therefore be affected by installation activities. Accordingly, there is the potential for extensive New York State Historic Preservation Office (SHPO) review to ensure avoidance of cultural resources and minimization of visual impact from designated sites. The SHPO is likely to require marine archeological surveys along a proposed route, which may reveal more potential historical features than are currently mapped. Generally, these cultural resources are avoidable, but route adjustments may be necessary following surveys and/or during construction if unanticipated objects are encountered.

6.1.2.3 Critical Constraints for Onshore Routes

Infrastructure Crossings

Specialized crossing methods would likely be required along several onshore routes, including trenchless methods such as HDD and the jack-and-bore technique. Such methods can substantially reduce impacts on certain environmental and infrastructure features but can be more costly and require much more time than typical installation methods (e.g., open trenching). Sufficient equipment staging areas are also necessary for specialized crossings to be feasible. For this Routing Assessment, locations assumed to require trenchless technologies include bridge crossings over water, other roadways, or railroads; existing utility crossings; and intersection with a major arterial roadway. Site surveys to determine soil conditions and precise location of existing utilities would be necessary during a future crossing design phase to confirm the appropriate crossing method.

Sensitive Habitats

Several sensitive habitat constraints for installation of cables through onshore areas are similar to those encountered at potential landing sites (including intracoastal bay crossings). These habitats include tidal and freshwater wetlands and wetland buffers, which fall under the purview of the USACE (Section 404 of the Clean Water Act) and NYSDEC (e.g., Tidal Wetlands Act and Freshwater Wetlands Act). Additional sensitive habitats may be crossed along onshore cable routes. These include Important Bird Areas, Coastal Barrier Resource System, Special Groundwater Protection Areas, and Coastal Critical Habitat. References for GIS layer data sources are presented in Annex B, Part 1: GIS Data Source List. Trenchless construction techniques, as previously described for onshore infrastructure crossings, can avoid or minimize impacts to these sensitive habitats.

Potential Stakeholder Concerns

Potential stakeholder concerns regarding installation of onshore cables and associated equipment include, but are not necessarily limited to, construction noise, traffic restrictions/congestion, natural resource impacts, and effects on visual aesthetics. For the screening analysis, the number of municipal jurisdictions crossed by a route was used as one proxy for estimating the potential that stakeholder concerns could pose a major constraint for cable installation. This corresponds to the number of municipal and county reviews and approvals that would be required, which increases the risk of project delay due to local stakeholder concerns. Further, compared to routes through commercial and industrial areas, a greater number of stakeholders are expected to raise concerns for routes through residential areas, particularly neighborhoods with single-family homes. Therefore, routes were analyzed for the type of 2016 National Land Cover Database classification crossed by the routes on Long Island and for the type of zoning classification crossed by routes in New York City. The length of route that passes through low- and medium-density developed areas was calculated as an indicator of passing through or near highly residential areas.

Contaminated Sites

Historical industrial activities have led to localized, inactive areas of contaminated sediments in New York City and Long Island, such as those containing polyfluoroalkyl substances (PFAs), polychlorinated biphenyls (PCBs), and heavy metals. Construction in or through these areas may require specialized construction methods, additional monitoring, and possibly remediation, which could potentially delay a project prior to and during construction.

Cultural Resources

Section 106 of the National Historic Preservation Act and Section 14.09 of the New York State Historic Preservation Act requires consultation with the SHPO. Additional consultation with the New York State Museum would be required under Section 233 of the New York State Education Law for construction on State lands. A majority of these onshore routes pass within or close to known historic properties listed on the National Register of Historic Places (NRHP). Successful permit acquisition to install cables along these routes may require more extensive cultural resource investigation. Some routes pass through State parks but remain within the footprint of existing infrastructure. Additionally, there is a possibility of encountering previously unidentified archaeological resources throughout most of Long Island as it hosts several sensitive archaeological areas. It is assumed that this potential increases for longer onshore routes.

Onshore Route Distance

The overall distance of the route may be considered a critical issue because of the greater cost that may be incurred and greater risk of encountering unforeseen issues associated with a relatively longer route through a given environment or jurisdiction. Both the extended length and unforeseen issues could delay regulatory approval and/or extend construction timelines.

Converter Station Parcels

Long Island and New York City consist of densely developed urban and suburban areas. Open, undeveloped areas are often encumbered by environmental and permitting constraints such as wetlands, parks, or other protected areas. Initially, parcel centroids from New York State tax data were used in GIS to identify vacant parcels of: at least two acres for HVAC transformer stations, and at least five acres for HVDC converter stations within 0.5 mile of the identified onshore routes. The five-acre parcel size for an HVDC converter station was considered sufficient to handle power input of at least 1.3 GW at +/-320 kV. When this analysis returned no suitable parcels along certain onshore routes in New York City, the criteria were widened to include vacant parcels of 2.5 acres or larger within one mile of the New York City onshore routes. The smaller 2.5-acre space is consistent with the area provided on offshore converter station platforms, though more expensive installation equipment and multi-floor construction may be required. With respect to the HVAC transformer stations, two acres were considered reasonably conservative to accommodate the minimum 1.2 acres expected to be necessary for the equipment.

Parkway/Highway Permitting

While parkway and highway ROWs on Long Island and in New York City often present a relatively wide corridor that could be used for installing onshore cables, a major permitting constraint is introduced through the need for approval from both New York State Department of Transportation (DOT) and the Federal Highway Administration (FHWA), which partially funds these major roads. Additionally, the New York State Parks Department owns Long Island parkways (including causeway segments) as they are Controlled Access Expressways. The Accommodation Plan and New York State law (17 NYCRR 131 in accordance with 23 CFR §645.211) does not generally permit utilities along expressways, parkways, or interstate highways except for those special cases in which installation of power cables within the ROW was permitted [11]. To be granted permission, the applicant must conduct alternative alignment analyses and prove that installation along other public ROWs that permit utility colocation are not feasible. Approval is not guaranteed, can result in uncertain timeline extensions, and in addition to several State department approvals, the FHWA must approve the installation through the National Environmental Policy Act process [11].

6.1.2.4 Critical Constraint Scoring

Scores were assigned to critical constraints along each evaluated route, reflective of the relative degree of potential challenge to the feasibility of a route due to the given constraint. The purpose of the scoring exercise was to provide a tool for identifying which routes (and route segments) had substantial constraints that warranted consideration, and to consider the comparative merits of route alternatives to a given POI when more than one representative route to the POI was identified. Four separate feasibility scoring matrices were developed in two stages:

1. A screening-level matrix for 21 routes to New York City (Con Ed) POIs
2. A screening-level matrix for 26 routes to Long Island (LIPA) POIs
3. A refined route matrix for eight routes to Con Ed POIs
4. A refined route matrix for 12 routes to LIPA POIs

For screening-level matrices, see Annex B, Part 2: Preliminary Route Feasibility Scoring Matrices; for refined route matrices, see Annex B, Part 3: Refined Route Feasibility Scoring Matrices. Within each matrix, critical constraint categories for each route were assigned a number (one through six) to reflect the relative challenge of installing a cable along a route segment with regards to the particular constraint. For visual purposes, the numbers are represented by color. For example, a value of one is represented as dark green and reflects that no significant constraints were identified for that category on the given route segment. A value of six is represented as black, indicating the challenges associated with that constraint are considered potentially insurmountable for the given route segment.

The individual constraint scores were then summed for each route. The overall scores were considered when comparing two or more routes to a given POI. However, the intent was not to identify a single optimal route because several routes to multiple POIs would be required to achieve the identified transmission strategy. Rather, the overall scores were considered to help develop a relative understanding of the challenges associated with each representative route. A summary of results of the constraint scoring for the refined set of representative routes and landing sites are discussed in Section 6.2.

6.1.3 Additional Inputs and Supporting Analyses

This section summarizes additional inputs and analyses used to develop the refined list of representative routes following the screening-level analysis of critical constraints and transmission strategy adjustments.

6.1.3.1 Engineering Considerations

The feasibility of routes was further reviewed based on additional engineering parameters and guidelines pertaining to the logistics of cable installation from the shore approach to the POIs and the characteristics of the cables associated with the OSW connection technologies identified in Section 5.1. Engineering considerations applied to the routing analysis are presented as follows.

Shore Approach and Landing Site Engineering Considerations:

- The HVDC cables extending from the offshore lease areas were assumed to be 320 kV symmetric monopole circuits with either a dual-core or a two-single-core bundled configuration in a single trench. The HVAC cables were assumed to be 220 kV three-phase circuits with a three-core or three-single-core bundled (trefoil) configuration in a single trench.
- To allow for maintenance following installation of cables in open marine waters, a minimum separation distance of at least twice the water depth is generally applied, providing room to lay a spliced loop next to the existing line [12]. In shallow or constrained nearshore waters, suitable cable spacing depends on factors such as the number of cables, induction effects, cable alternating current versus direct current, length, installation method, depth of cover, sequence/timing, and concerns about resiliency/reliability [12]. For purposes of this assessment, a minimum in-water cable spacing of 200 ft was assumed.
- Suitable geologic conditions are necessary to perform HDDs in the marine environment. Certain sediments along a potential HDD route, particularly gravel and cobble, can increase the risk of an inadvertent release of drilling fluid (i.e., a frac-out) or failure of the HDD bore hole ([14][15]). With suitable geologic conditions and straight horizontal alignment, an HDD of one mile in the marine environment (water-to-water or water-to-land) is feasible; this was the limit assumed for the routing assessment. However, if conditions are favorable, a longer drilling distance may be feasible (e.g., [16][17]).
- For HDD at landing sites:
    - A workspace with a length of at least 300 ft was considered preferable for suitable pullback distance behind possible landing/transition sites. A workspace shorter than 200 ft would be difficult and shorter than 150 ft was considered unsuitable. Adequate workspace width is also necessary to support HDD operations and depends on factors such as equipment used and the number and spacing of cables to be brought ashore for a given landing site.
    - Crossing under bulkheads increases the distance of an HDD and the entry/exit points must extend farther from the shoreline to provide a bending radius compatible with the HDD casing material. For shorelines with revetments, the minimum distance is generally shorter than for bulkheads, as bulkheads would typically extend deeper.
    - Minimum cable separation distance at landfall was assumed to be 30 feet. It can be less depending on onshore cable installation guidelines and the comfort level of the offshore installer to drill at distances closer than 30 feet from an installed cable.

Onshore Route Engineering Considerations:

- At the onshore portion of the landing site, it was generally assumed a circuit with three single-core cables would be installed, with each cable in its own conduit in a concrete filled duct bank. A single 35 kilovolt (kV) circuit duct bank would be approximately 7 feet by 2 feet and can be installed vertically or horizontally. Duct bank dimensions for a 345 kV for a double circuit in this analysis would be approximately 7 feet by 5 feet and can be installed vertically or horizontally. A single-circuit duct bank would be approximately 7 feet by 5 feet.
- Duct bank separation of 15 feet was generally assumed to maintain thermal independence for up to three parallel HVAC or HVDC circuits.
- Where necessary to conserve space and/or minimize magnetic fields (e.g., at certain HDD crossings), it was assumed single-core HVAC cables could be bundled in trefoil formation with a minimum spacing of 2.6 ft from similarly configured HVAC circuits. This assumed a minimum burial depth of five feet. More than 2.6-ft inter-circuit spacing would likely be required for more than two parallel HVAC circuits.
- Concrete manholes of approximately 30 feet by 10 feet by 10 feet were assumed necessary for every two to four bends of the cables.
- Onshore route segments where open trenching was potentially not feasible were reviewed by engineers to examine the feasibility of trenchless methods. Based on the engineering analysis, some route segments were shifted to make trenchless methods more feasible.
- Specialized trenchless land-to-land crossings were assumed to require an open area for laydown and pull back operations/equipment that is approximately 50 feet wide by 200 feet long. For shorter crossings, working areas for jacking and receiving pits to support jack and bore (i.e., auger boring) methods were also considered.
- Routes were also modified to avoid extensive colocation with utilities and infrastructure where practicable, particularly utilities and infrastructure with continuous metal components subject to induction of electrical current from HVAC line issues (e.g., pipelines, aqueducts, and subways), as well as avoiding potential conflicts with existing structural foundations and subsurface structures (e.g., bridge piers, buildings, basements, and tunnels [19]).
- During the initial representative route identification, installation of overhead HVAC and HVDC lines was assumed for certain onshore segments that were colocated with existing overhead alternating current lines and/or railroad ROW. Due to ROW spatial constraints and simplify the Study's separate costing exercise, overhead HVAC and HVDC lines were omitted from the final representative route assumptions.
- During the initial representative route identification, installation of overhead HVAC and HVDC lines was assumed for certain onshore segments that were co-located with existing overhead alternating current lines and/or railroad ROW. Due to ROW spatial constraints and to simplify the Planning Study's separate costing analysis, overhead HVAC and HVDC lines were omitted from the final representative route assumptions.

6.1.3.2 Converter Station and Transformer Parcels

Based on the initial screening analysis, land parcels suitable for converter stations were not identified along certain example HVDC routes. At least one suitable parcel was considered necessary for route feasibility, so a more extensive search for suitable land was conducted. This expanded search was conducted by BJH Advisors, a real estate planning firm. BJH considered currently utilized properties within manufacturing zoning districts that are generally in an appropriate location for the utility use, of suitable size, and not subject to conflict with known development plans. However, no representation is made that they can be acquired or that, upon further screening, would be found appropriate for this use. For consistency, the same search criteria were applied for all onshore routes in New York City and one route on Long Island where HVDC lines are identified as part of the Planning Study's representative transmission strategy.

If no parcels were identified during the expanded search, the onshore HVDC route was not considered further if there was at least one other feasible route option to the given POI. If there were no feasible routes identified to a POI due to lack of suitable converter station parcel, further efforts were made to review parcel options until at least one representative route with at least one feasible converter station was identified for each POI. This included consideration of parcels in New Jersey along the New York Harbor waterfront.

6.1.3.3 Routing Restriction Point Analysis

Initial routing analyses focused on identifying the feasibility of transmission cable routes to each POI considering installation of an individual cable circuit. However, the illustrative transmission strategy would require installing multiple cables/circuits along certain routes/corridors. Therefore, further analysis was conducted for the refined list of representative routes to estimate the number of cables and/or trenches that could potentially be installed at locations where physical constraints are greatest (i.e., bottlenecks or restriction points).

It was assumed that the offshore cable corridors in the Atlantic Ocean have enough space to accommodate any number of cables that could feasibly be used to transfer power to shore.

Factors used to determine the number of cables/trenches that appear feasible for the shore approach corridors included the following:

- The width of the waterway, defined by the presence of land features, was a fundamental constraint for shore approach route segments.
- Water depth was considered, where shallow waters may present logistical challenges for cable installation but could be more favorable to avoid user conflict in certain areas.
- Existing infrastructure (e.g., bridge foundations) and physical obstructions (e.g., rock outcrops and wrecks) must also be avoided, though it may be possible to cut through or remove smaller

obstructions of historic significance after appropriate cultural analysis and documentation has been completed.

- Specially designated areas such as navigation channels and anchorage areas were avoided to the the extent possible.
- Minimum cable spacing of 200 feet was assumed for multiple transmission cables to allow for suitable maintenance workspace and system resiliency. See Section 6.1.3.1 for a discussion of engineering considerations regarding cable spacing.

Factors used to determine the number of cables/trenches that appear feasible at the landing sites included the following:

- The amount of open land that would be suitable as a temporary workspace and staging area was reviewed with consideration for current uses.
- Waterfront infrastructure was considered with respect to shore landing methods and necessary workspace (e.g., where longer HDD might be necessary to pass under a bulkhead).
- A 30-foot cable spacing was assumed for multiple cable landings at the same site. See Section 6.1.3.1 for a discussion of engineering considerations regarding cable spacing.

Factors used to determine the number of cables/trenches that appear feasible along the refined list of onshore routes included the following:

- Cables were assumed to remain within public ROW where possible. In New York City, the width of the ROW was identified by measuring the width of the linear corridors between land parcels in tax parcel data layers.
- On Long Island, specific parcel boundary data were not available. Therefore, ROW corridors were identified based on Esri World Imagery (Clarity) data layer, which is a basemap layer with hybrid reference overlay of multiple layers depicting the clearest and/or most accurate imagery from the Esri archive (Annex B, Part 1: GIS Data Source List). Since representative data of ROW width were not available, a conservative approach using only the road width was used.
- Larger duct bank sizes and spacing were considered to accommodate multiple cables. For example, to support two 345 kV circuits, a seven-foot duct bank width was used with a spacing of 15 feet between duct banks. Therefore, a total width of 30 feet was used to represent the placement of four 345 kV circuits. See Engineering Considerations Section for additional discussion of engineering considerations regarding cable circuits and duct banks.

6.1.3.4 The Narrows Cable Limitations

To support a transmission strategy that assumes multiple cable routes through New York Harbor, a preliminary evaluation was conducted to determine the number of transmission cables that could feasibly be installed through The Narrows, the natural waterway in New York City connecting Lower New York Bay to Upper New York Bay. As part of this investigation existing data were evaluated to determine critical constraints for the installation of electrical power cables through The Narrows, including the following:

- Spatial constraints such as existing infrastructure
- Seabed conditions
- Operational requirements for installation and cable repair
- Regulatory requirements

Our evaluation considered the following sources of information:

- Publicly available GIS data layers
- Publicly available reports describing the geology and providing sediment data for the study area
- Literature regarding industry standards for cable installation
- Intertek's (2020) presentation *Anbaric Export Cables into New York Harbor, Cable routing through The Narrows and Export Cable Installation* [12]
- Applicable laws and regulations

Based on the identified constraints, anticipated minimum cable spacings were applied to the potentially available width of submerged lands through the narrowest portion of The Narrows to estimate a total number of cables that may feasibly be installed. Different factors that may increase or decrease the feasible number of cables are also discussed.

6.2 Assessment Results

This section discusses the findings of the feasibility assessment following application of the methodology as previously described. Section 6.2.1 summarizes the major environmental and permitting constraints that apply to routes crossing through the Study's representative offshore route corridors. Section 6.2.2 summarizes the major environmental and permitting constraints identified for the example shore approach segments and landing sites. Section 6.2.3 summarizes the major environmental and permitting constraints identified for example onshore routes and the potential converter station sites. The discussion in sections 6.2.1 through 6.2.3 is organized based on the general location of the POIs (i.e., in New York City or on Long Island). Finally, section 6.2.4 provides a synthesis of the various analyses and a summary of how the Routing Assessment has addressed the State Team's questions regarding the feasibility of the routes considering environmental and permitting constraints and opportunities.

6.2.1 Constraints Analysis for Representative Offshore Corridors

This section summarizes critical constraints applicable to route segments crossing the four previously identified offshore corridors. Figure 6-3 shows several of the GIS layers of features present in the offshore New York Bight and New Jersey area that could constrain the routes through the offshore corridors. Based on distance between lease areas and potential POIs, lease areas associated with the following offshore corridors were assumed to potentially connect to Long Island POIs as follows:

- **Atlantic North Corridor** — connecting to a southern Long Island shore approach
- **Atlantic Central Corridor** — connecting to a southern Long Island shore approach only

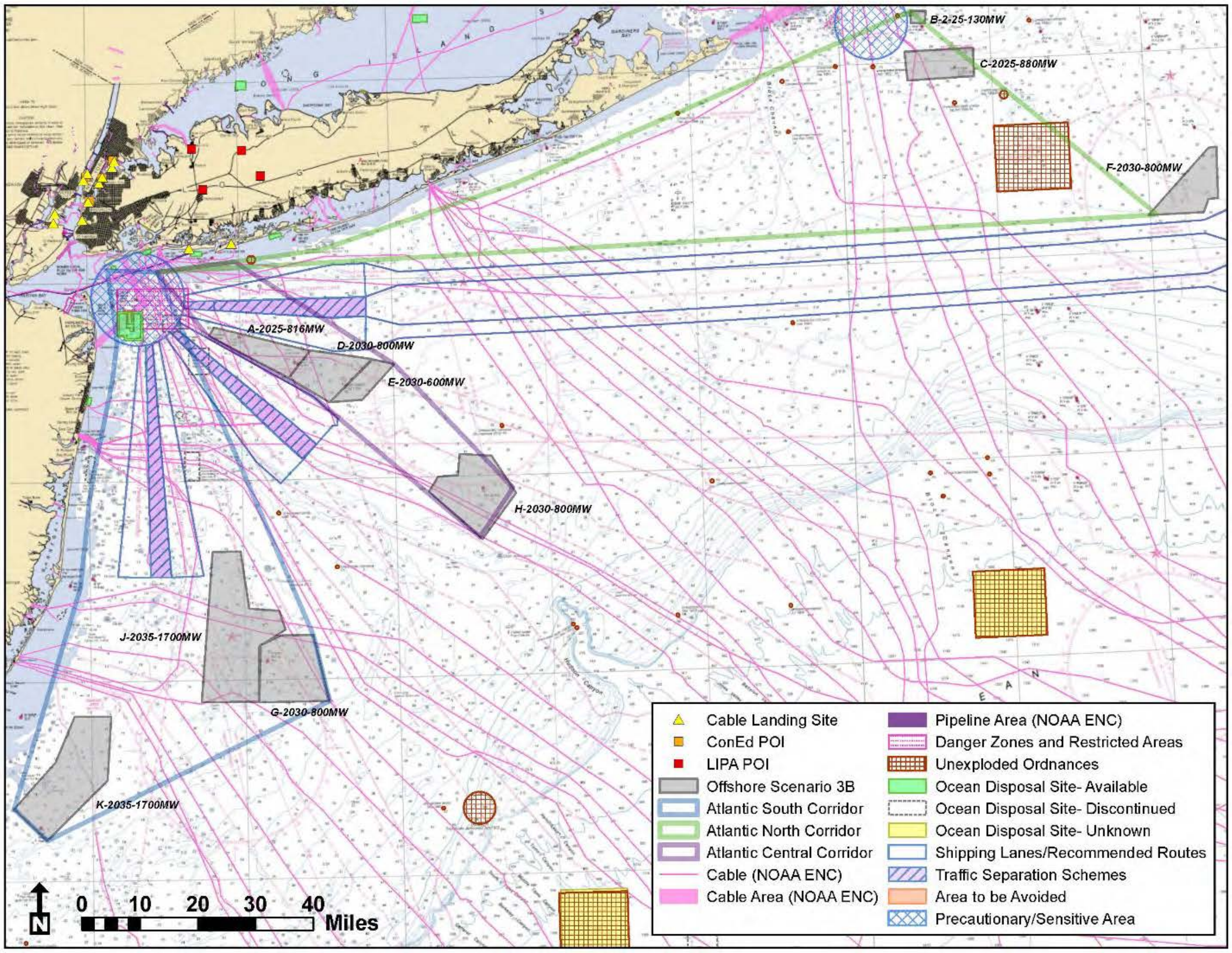
Similarly, the lease areas associated with the following offshore corridors were assumed to potentially connect to New York POIs:

- **Atlantic Central Corridor** — connecting through New York Harbor
- **Atlantic South Corridor** — connecting through New York Harbor

The corridors leading to the same collection of POIs (i.e., on Long Island or in New York City) were evaluated in comparison to each other with respect to the level of constraints. Please see Annex B, Part 2: Preliminary Route Feasibility Scoring Matrices for tables that present a visual representation of the relative constraint scoring and ranking for all evaluated routes through the offshore corridors to POIs on Long Island and in New York City.

Figure 6-3. Constraints in the Offshore Segment adjacent to New Jersey and Long Island

Source: WSP 2020; DNVGL 2020; NOAA ENC 2018, 2020; NOAA RNC 2020. (See Annex B, Part 1: GIS Data Source List for full list of figure references.)



6.2.1.1 Infrastructure Crossings

<u>Long Island</u>

Due to the number of existing cables that land along the south shore of Long Island or route into Rhode Island, a cable route through the Atlantic North Corridor has the most infrastructure crossings for interconnection to Long Island. A cable route through the Atlantic Central Corridor has the least number of crossings for interconnection to Long Island, mainly because it has the shortest distance and the most direct route to the Long Island mainland.

<u>New York City</u>

A cable route through the Atlantic South Corridor has the highest number of infrastructure crossings on an approach to New York City POIs. This is due to the large number of existing cables that land along the New Jersey shoreline, most notably on Long Beach Island and within Manasquan, which must be crossed on approach to New York City. A cable route through the Atlantic Central Corridor contains the least number of infrastructure crossings in the offshore area since a cable from the offshore lease area may be run parallel to many of the existing cables located within this region as they are also routing to New York City.

6.2.1.2 Designated Marine Zones

<u>Long Island</u>

For interconnection to Long Island, a cable within the Atlantic Central Corridor crosses the most designated marine zones. Routing through the Atlantic Central Corridor to the Long Island coast would require crossing the Nantucket to Ambrose Shipping Lanes (Fairways North and South). A cable within the Atlantic North Corridor on approach to Long Island could generally be routed to avoid designated marine zones.

<u>New York City</u>

A cable through the Atlantic South Corridor would likely cross the most designated marine zones for interconnection to New York City; though, a cable through the Atlantic Central Corridor would also cross a high number of designated marine zones. The number of zones crossed may vary for specific routes as some designated marine zones could be avoided. For example, features such as the Ambrose to Barnegat Shipping Lanes can potentially be avoided when routing a cable from the Hudson South lease areas, but this would likely result in increased cable length. There is a risk of encountering unexploded ordnance (mines) in the charted Danger Area east of Sandy Hook, New Jersey, and south of Rockaway Beach, New York; a cable route could avoid the area, but may require a longer route into New York City. Generally, all Atlantic Ocean routes into New York City must cross the charted Precautionary Area where traffic from all shipping lanes converge on approach into New York Harbor.

6.2.1.3 Department of Defense Areas

<u>Long Island</u>

A cable through any of the Atlantic Ocean corridors for interconnection on Long Island would cross several DoD areas. It is likely that all routes for interconnection to Long Island must cross the

Narragansett OPAREA and a Naval Undersea Warfare Testing Range. Additionally, a cable through the Atlantic North Corridors may also need to cross a submarine transit lane that extends south from Block Island, Rhode Island. Routing around the submarine transit lane is potentially feasible but this would lead to an increase in the route distance.

<u>New York City</u>

Routing a cable through the Atlantic Central Corridor crosses the most DoD constraints for interconnection to New York City, including the Atlantic OPAREA, a submarine transit lane, and a Naval Undersea Warfare Testing Range. Based on currently available GIS data, the Atlantic South Corridor has the least number of DoD constraints as a cable within this corridor would only cross the Atlantic City OPAREA. This assumes the DoD does not redesignate some or all of this OPAREA as an offshore wind exclusion area. This redesignation consideration has been under review since 2018.

6.2.2 Constraints Analysis for Shore Approach and Landing Sites

This section summarizes critical constraints applicable to the shore approach and landings for the evaluated routes. The following figures depict several of the GIS layers for the critical constraints considered in the feasibility assessment with respect to the shore approach route segments and landing sites (Figure 6-4, Figure 6-5, Figure 6-6). The first figure, Figure 6-4, shows several constraints along the shore approach routes and at landing sites along the Atlantic Ocean and intracoastal waterway for cable interconnection to western Long Island.

Figure 6-4. Constraints on the Atlantic Ocean for Shore Approach and Landings at Long Beach and Jones Beach

Source: WSP 2020; DNVGL 2020; NOAA ENC 2018, 2020; PLATTS 2009; MARCO 2019; SCFWH 2013; NY NHC 2018; ESRI 2020. (See Annex B, Part 1: GIS Data Source List for full list of figure references.)

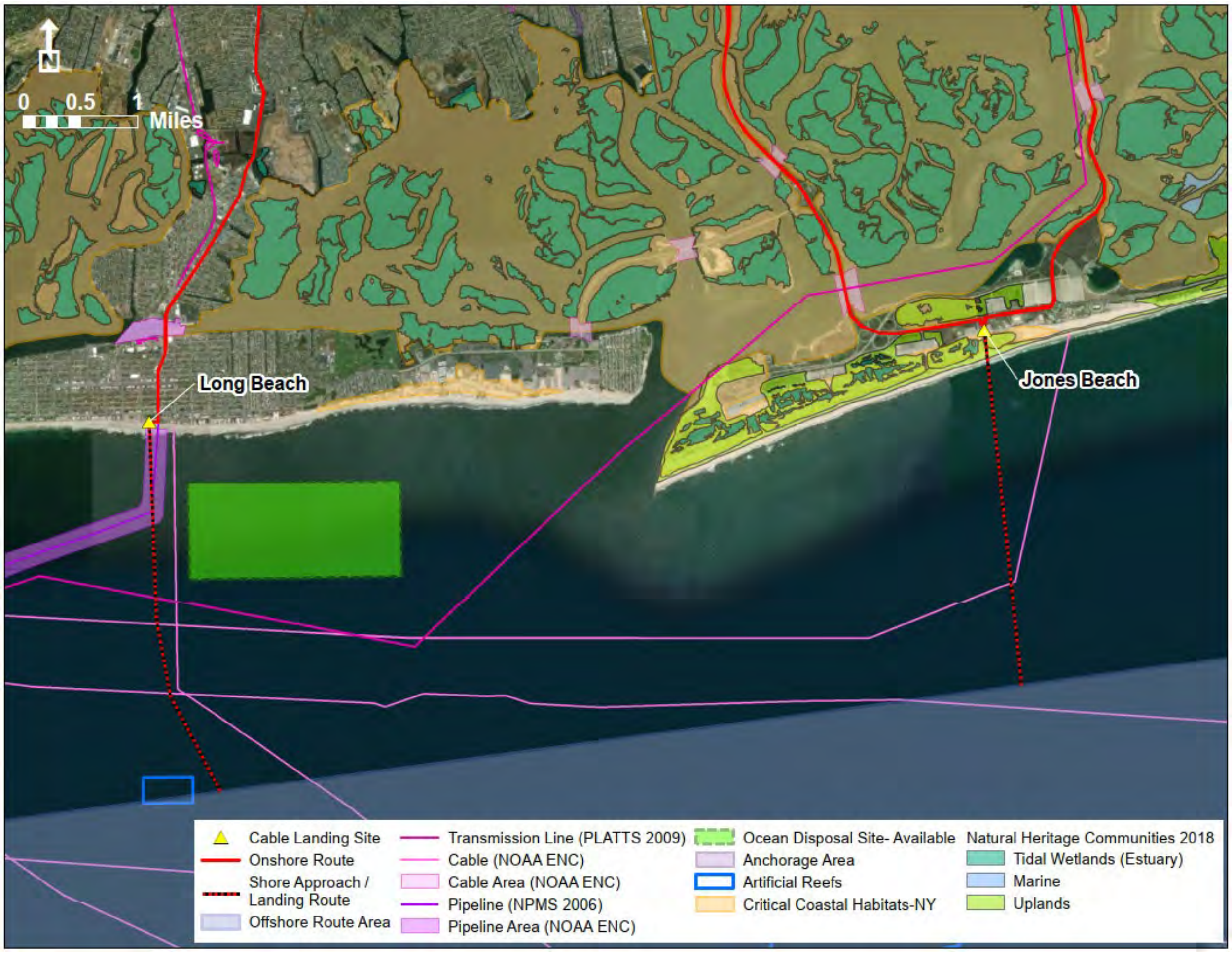


Figure 6-5 shows several constraints along the shore approach routes and at landing sites within Lower New York Bay for cable interconnection to New York City.

Figure 6-5. Constraints within Lower New York Bay for Shore Approach and Landings

Source: WSP 2020; DNVGL 2020; NOAA ENC 2018, 2020; NOAA CCH 2018; PLATTS 2009; NPMS 2006; NYC Aqueducts 2020; NYC Subways 2017; ESRI 2016, 2020. (See Annex B, Part 1: GIS Data Source List for full list of figure references.)

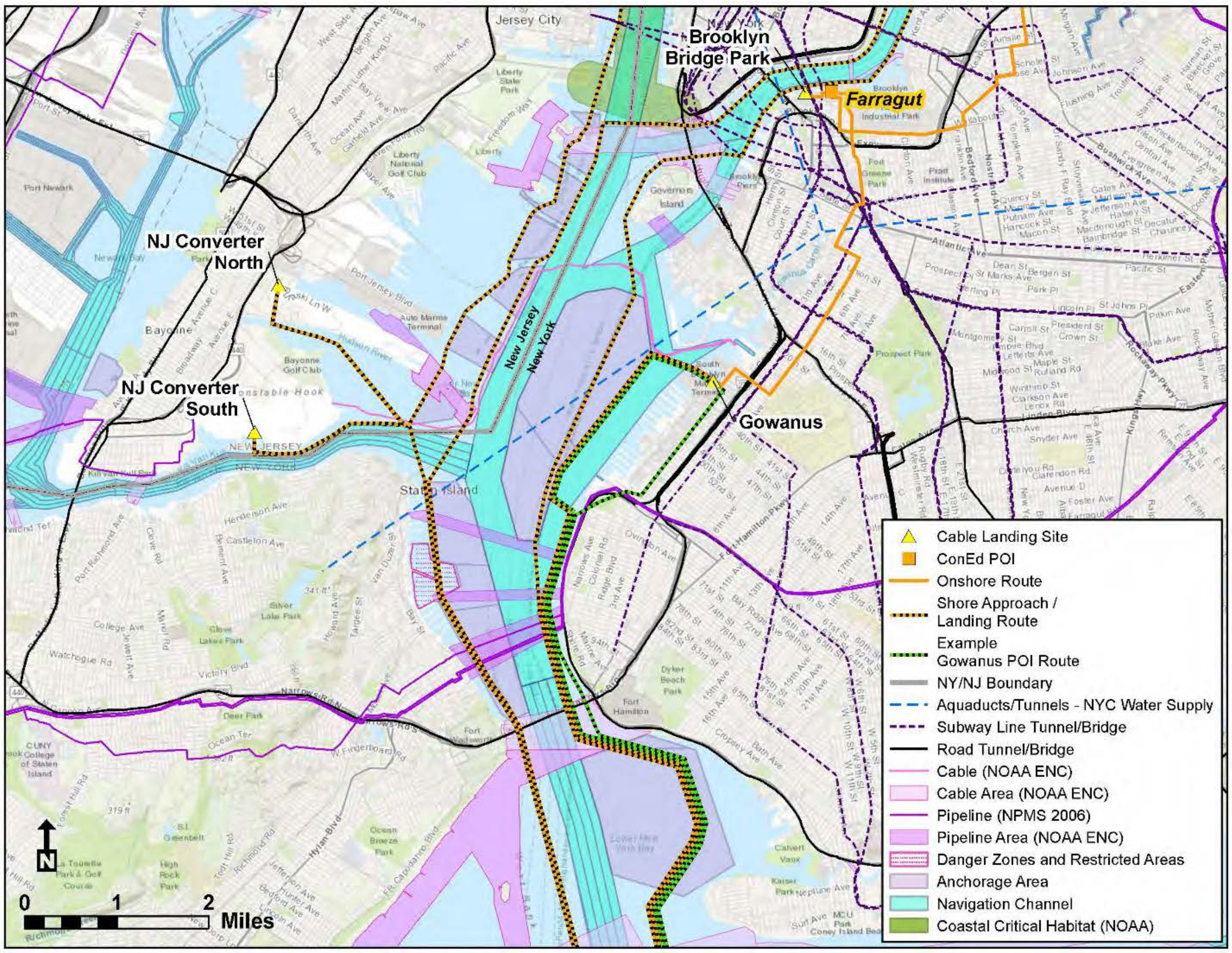
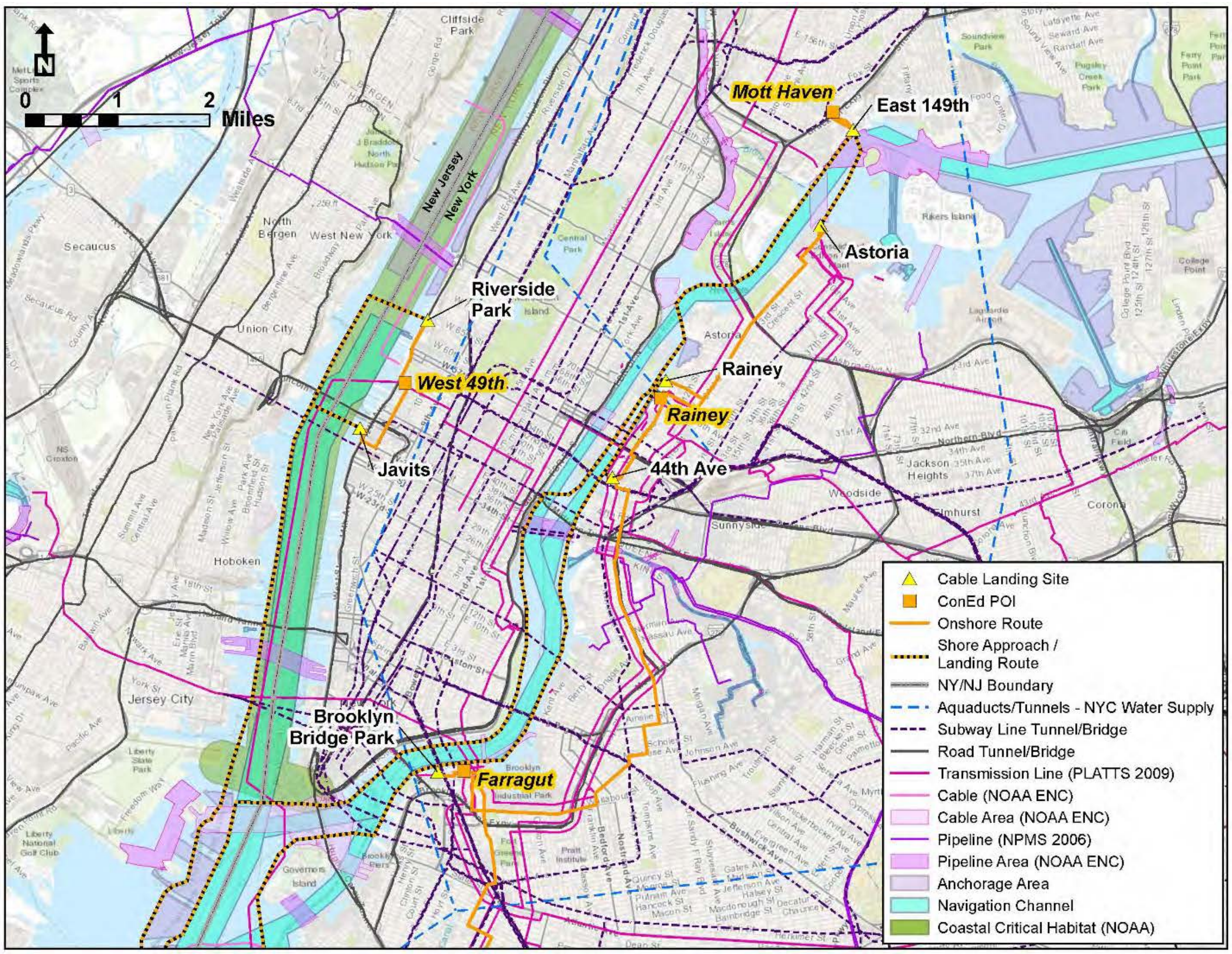


Figure 6-6 shows several constraints along the shore approach routes and at landing sites within the Hudson River and East River for cable interconnection to New York City.

Figure 6-6. Constraints within the Hudson River and East River for Shore Approach and Landings

Source: WSP 2020; DNVGL 2020; NOAA ENC 2018, 2020; NOAA CCH 2018; PLATTS 2009; NPMS 2006; NYC Aqueducts 2020; NYC Subways 2017; ESRI 2016, 2020. (See Annex B, Part 1: GIS Data Source List for full list of figure references.)



6.2.2.1 Infrastructure Crossings

Long Island

A Long Beach shore approach and landing would have the most infrastructure crossings for all the Long Island sites. Just south of the Long Beach shoreline in the Atlantic Ocean are several existing cables that must be crossed and one pipeline that exists but potentially could be avoided. Landing at Jones Beach requires about 25% less infrastructure crossings than Long Beach. Multiple cable bundles south of the eastern part of Long Island must be crossed in addition to two sewer outfalls at Jones Beach and channels under Wantagh and Meadowbrook parkways as part of back bay crossings.

New York City

There is a large amount of existing infrastructure present on approach to landing sites in New York City. As a result, shore approach routes with increased distance would cross more existing infrastructure. This would add to the complexity of a given route, which may present significant logistical challenges.

Shore approaches to landing sites in the East River would encounter the most infrastructure constraints particularly for an offshore route from the Atlantic Ocean. To get to the East River an in-water route must cross the existing infrastructure in Lower and Upper New York Bay including multiple pipelines and cables within The Narrows. While this would present logistical challenges, the largest infrastructure constraint for the East River is a result of the numerous transportation tunnels that exist between Manhattan and the Brooklyn shoreline. In the area spanning from Governors Island to the Farragut landing site, five subway tunnels and one road tunnel exist that must be crossed. Additional transportation tunnels are present south of Roosevelt Island within the East River and would constrain an approach to the 44th Avenue/Rainey Park landing sites.

Initial investigation into the depth of these tunnels and the amount of cover, identified that while some do likely have sufficient cover, or are within bedrock, others have limited cover and/or no information was obtained. As result a more detailed investigation would be necessary to ensure the depth of the existing tunnels and the amount of cover to ensure that cable installation to required depths in these areas could be completed while still maintaining necessary setbacks from the existing infrastructure. Furthermore, consultations with the various infrastructure owners would be required to identify if approval to cross these features could be obtained. A shore approach and landing at Gowanus has the least amount of infrastructure crossings for the New York City landings at about 26 crossings, four less than the other shore approach and landings.

6.2.2.2 Sensitive Habitats

Long Island

For shore approach and landing sites on Long Island, areas such as Jones Beach contain an increased number of sensitive habitats. Along the south shore barrier island at Jones Beach, endangered nesting shorebird habitat exists. Additionally, the back-barrier bay areas are classified as New York State Significant Coastal Fish and Wildlife Habitat and contain unique emergent tidal marsh and eelgrass meadow habitats. The landing site at Long Beach along the south shore of Long Island, likely has the least habitat constraints for Long Island, as the area has increased development and fewer sensitive habitats.

New York City

Sensitive habitats were examined and analyzed for shore approach and landing sites in New York City; however, no major constraints were identified for these areas. For further detail, see Annex B, Part 3: Refined Route Feasibility Scoring Matrices.

6.2.2.3 Marine Geology and Oceanography

Long Island

Marine geology and oceanography were examined and analyzed for shore approach and landing sites on Long Island; however, no major constraints were identified for these areas. For further detail, see Annex B, Part 3: Refined Route Feasibility Scoring Matrices.

New York City

For a New York City shore approach and landing, routes that extend north through the East River have the largest potential geologic and oceanographic (i.e., hydrologic) constraints. Shallow bedrock is likely present within areas of the East River. With shallow bedrock, cable burial depth requirements may be difficult to achieve and maintain over time. As a result, armoring of a cable may be necessary. Exact locations and depth of bedrock throughout East River was not identified through a search of publicly available GIS data layers and documents, so further investigations are likely necessary to obtain this information. Additionally, the East River is a tidal channel with strong currents that have a high potential for causing seafloor scour around an installed cable as well as logistical challenges during cable installation. Shore approaches and landings in other areas of New York City such as Lower/Upper New York Bay and the Hudson River present fewer geological constraints as initial investigations indicate that these areas are generally dominated by unconsolidated sediments.

6.2.2.4 Further Regulatory Constraints

Long Island

Further regulatory constraints were examined and analyzed for shore approach and landing sites on Long Island; however, no major constraints were identified for these areas. For further detail, see Annex B, Part 3: Refined Route Feasibility Scoring Matrices.

New York City

Shore approaches along the east side of Ambrose Channel, while within New York State waters are in proximity to New Jersey's coastal zone boundary, such that New Jersey CMP consistency review and concurrence would likely be required. Additionally, shore approaches along the west side of Ambrose Channel and within New Jersey State waters would require all applicable New Jersey state permits in addition to all other necessary federal and New York State regulatory approvals for the project.

6.2.2.5 Potential Stakeholder Concerns

Long Island

For shore approach routes and landing sites on the south shore of Long Island that are located adjacent to or through commercial or recreational fishing grounds, stakeholder concerns are likely. This would include commercial shellfishing areas such as the back-barrier bay regions adjacent to the Jones Beach approach and landing site that potentially support shellfishing activities. Additionally, stakeholder concerns are likely from communities reliant on coastal/offshore resources such as Long Beach, where activities such as surfing and beachgoing are part of the cultural identity of the area.

New York City

The largest stakeholder group that may be significantly affected by any shore approach and landing within New York City is likely the maritime community given the high number of vessels in the area and the diverse maritime user groups. Marine vessel operators and maritime industry representatives are expected to have concerns regarding cable placement in New York Harbor's high-traffic areas, particularly where a potential cable route crosses any navigation channels and/or anchorage areas. Concerns would include, but not be limited to, navigation impacts during cable installation and burial depth of the potential cable. While all shore approach and landings in New York City waterways may raise concerns with specific marine groups, it is likely that routes along or through especially busy anchorages, channels, and pier terminals would be scrutinized the most due to increased risk of anchor strike/snag on a cable in these areas and associated mariner liability.

6.2.2.6 Landing Site Complexity

Long Island

Shore approach and landing sites along the south shore of Long Island present increased landing site complexity as a result of the need to cross the barrier island and the back-barrier bay at multiple locations along a given route. A landing at Jones Beach would require the most crossings of the back-barrier bay, with three crossings being necessary for a route along either the Meadowbrook Parkway or the Wantagh Parkway. Designated cable areas exist within several of these back-barrier bay crossings, which indicates that cables likely have been installed, and caution would be needed for any cable installation in the same area to avoid impacting existing cables. Potential methods for crossing the back-barrier bay areas were evaluated at a high level:

- Attaching a cable to the bridges along the parkways or other roadways: Preliminary investigation of DOT regulations suggests that attaching a cable to the parkway bridges is likely not feasible. The DOT further indicated attaching cables to the Wantagh and Meadowbrook Parkway bridges have not been permitted in the past. Additionally, one of the bridges on each parkway as well as the bridge connecting Long Beach and Smith Point to the Long Island mainland is a drawbridge, which precludes attaching a cable.
- HDD under back-barrier bay areas: HDD is likely feasible to cross some of the back-barrier bay areas. However, adequate space for staging an HDD at some crossings (i.e., some crossings on the Wantagh and Meadowbrook Parkways) is likely limited and would not be feasible.
- Trenching across back-barrier bay areas: Open trenching at these water crossings is potentially feasible if HDD cannot be completed. But this method is likely to receive increased regulatory scrutiny as a result of seafloor disturbance and impacts on water quality.

Landings along the Atlantic Ocean would also be complex as a result of the need to install the cable at sufficient depths under the dynamic beach and nearshore areas. However, cable landings have been successfully installed along New York's Atlantic Ocean shoreline in the past (e.g., USACE 2019a).

New York City

Landing site complexity in New York City is mainly driven by the presence of existing waterfront structures and limited available space to support the installation of cables at many of the potential landing site. At every landing site considered as part of this analysis there was a coastal protection structure (i.e., bulkhead or revetment). In most cases bulkheads were present, which increased the landing site complexity as installation methods such as HDD are likely required to penetrate beneath the lowest point of the structure in order to avoid impact on the structure. Accordingly, installing a cable using HDD requires a large staging area for equipment and installation activities. Given the density of development in New York City, finding available space for these staging areas is more challenging compared to Long Island landing sites. As a result, all the landing sites in New York City have increased landing site constraints. Landing sites with major constraints due to complexity include Riverside Park and 149th Street landings. The landing sites of Gowanus and Rainey Park are less complex relative to other New York City landings but still likely present logistical challenges.

6.2.2.7 Navigation Channels/Anchorage Areas/U.S. Army Corps of Engineers Project Areas

Long Island

Shore approach and landings along the south shore of Long Island would likely cross USACE Coastal Storm Risk Management beach nourishment projects that are authorized at each of the landing locations: Jones Beach and Long Beach. As a result, a cable landing at these locations would likely require an additional USACE Section 408 authorization for alteration of a public work in addition to other State and federal regulatory approvals, but this extra approval does not necessarily present a major regulatory constraint. A Jones Beach shore approach and landing would be further constrained by the need to cross three marked navigation channels in the back-barrier bay area. While navigation charts do not appear to indicate that these are federally designated/maintained channels, one or more of them are main or secondary routes marked by beacons or buoys that are maintained seasonally by State or private interests (NOAA 2020b), such that crossings may still be subject to greater avoidance and burial requirements.

New York City

New York City's waterways contain several anchorage areas and navigation channels that support various maritime activities. Any shore approach in New York City would likely have to cross or route adjacent to multiple anchorage areas or navigation channels on route to a landing. As a result of the presence of these navigation channels and anchorages in virtually all of New York City's waterways, longer shore approaches are likely to have increased navigation constraints. Accordingly, shore approaches that route through Lower New York Bay and Upper New York Bay and into the East River have increased navigation constraints due to the need to cross or route adjacent to more of these designated areas. Additionally, routing outside of anchorage areas or navigation channels within New York Harbor still poses a significant risk of encountering other types of constraints such as conflicts with private berth owners if a cable would cross between their property and a channel or the potential presence of debris and unmarked obstructions that may exist in the unmaintained areas.

An analysis was conducted to determine the number of cables that could potentially be routed through The Narrows using 300-foot (Figure 6-7) and 200-foot (Figure 6-8) cable spacings. The submerged areas both east and west of the Ambrose navigation channel were considered viable for placement, assuming placement at least 100 feet from the shoreline and excluding the 25-yard Safety and Security Zones (SSZs) around the Verrazano Bridge towers. Two different cable spacings were assessed: a 300-foot distance between cables (Figure 6-7) and a 200-foot distance between cables (Figure 6-8). These spacing distances were identified based on industry guidance for cable spacing. In particular, water depths within The Narrows approach 100 feet, so a minimum spacing of 200 feet reflects guidance to provide space that is at least twice the water depth [13]. The spacing is also generally consistent with considerations made in a related study conducted by Intertek (2020). [12]

Three separate routing scenarios were considered. The scenarios considered were as follows:

- **East1 Scenario:** The east side of The Narrows from the Ambrose Channel to the Brooklyn shoreline with the shoreline buffer and SSZ restriction previously described.
- **East2 Scenario:** Similar to East1 Scenario, but also excluding Safety Zone 165.172 that extends 110 yards around a point approximately 70 yards southeast of the eastern Verrazano Bridge tower.
- **West Scenario:** The west side of The Narrows from the Ambrose Channel to the Staten Island shoreline with the shoreline buffer and SSZ restriction previously described.

To clarify the difference between the East1 and East 2 Scenario, the East 1 Scenario assumes it is feasible to route through Safety Zone 165.172 if suitable safety precautions are observed to avoid the related obstruction(s), and pending consultation with the U.S. Coast Guard and/or Captain of the Port of New York/New Jersey. Based on the assumptions for the analysis of these three scenarios, it is feasible to potentially install between eight and 11 separate cables or cable bundles (i.e., circuits) through The Narrows (Table 6-6) assuming suitable planning and coordination between regulatory agencies, developers, and other affected parties. Other constraints in New York Harbor are likely to further limit the number of transmission cables/circuits that could feasibly be installed through the harbor. At a minimum, The Narrows has the capacity to support a solution of six separate cables/circuits identified as part of the illustrative transmission strategy.

Table 6-6. Cable Routes through the Narrows

Cable Spacing[1]	Number of Cables per Routing Scenario			Total Number of Cables for The Narrows	
	East1 Scenario: East Side of The Narrows	East2 Scenario: East side of The Narrows excluding Safety Zone 165.172[2]	West Scenario: West Side of The Narrows	East1 & West Scenario	East2 & West Scenario
200-foot	5	5	6	11	11
300-foot	4	4	4	8	8

[1]In addition to cable spacing, a 25-yard area surrounding the Verrazano Bridge supports was excluded pursuant to Safety and Security Zone 165.169 and a 100-foot setback from coastal protection structures was identified to provide a buffer from shore.

[2]Scenario East2 excludes Safety Zone 165.172 to the southeast of the eastern Verrazano Bridge Foundation.

Figure 6-7. Cable Spacing of 300 ft through The Narrows

Source: WSP 2020; NOAA ENC 2018, 2020; NOAA RNC 2020. (See Annex B, Part 1: GIS Data Source List for full list of figure references.)

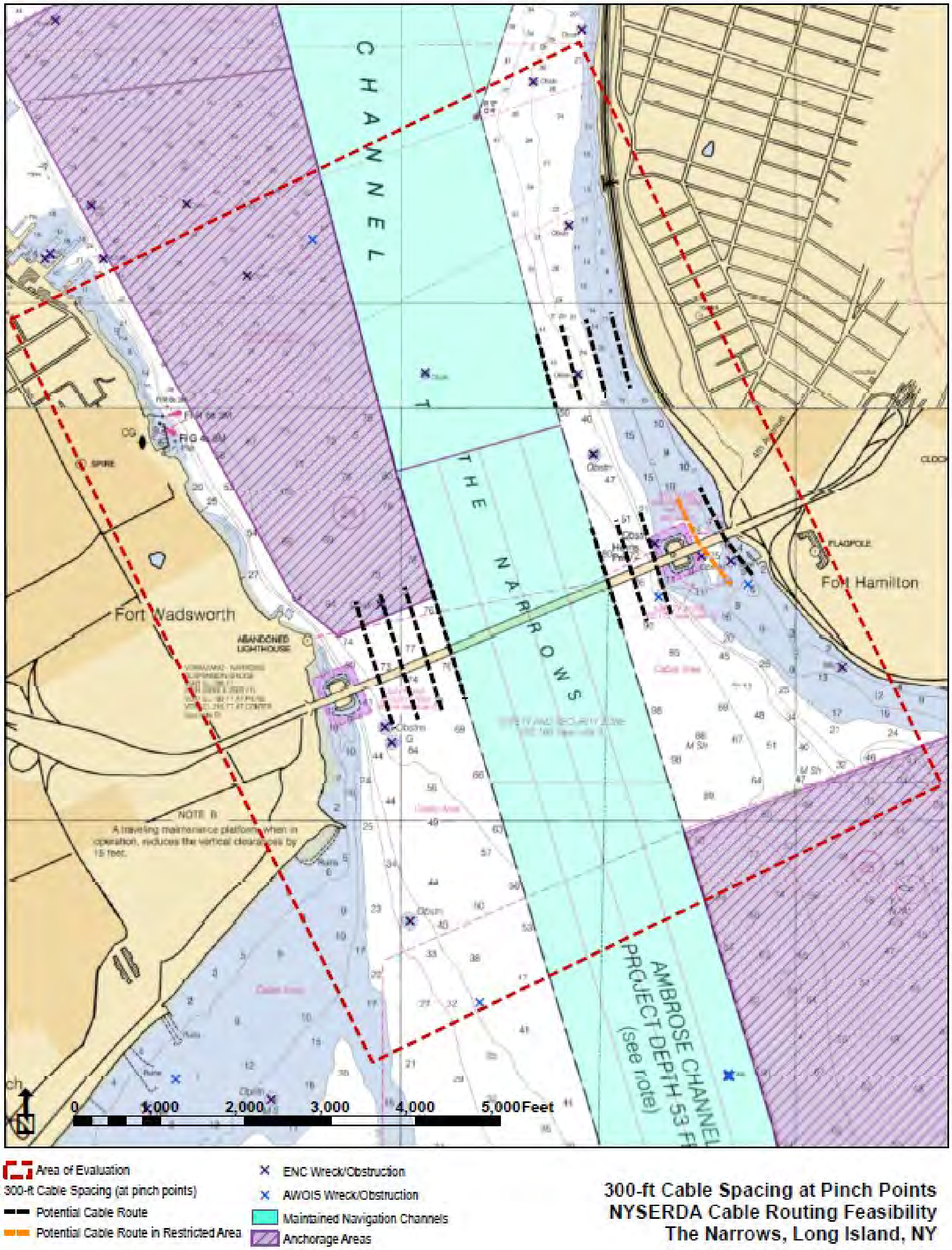
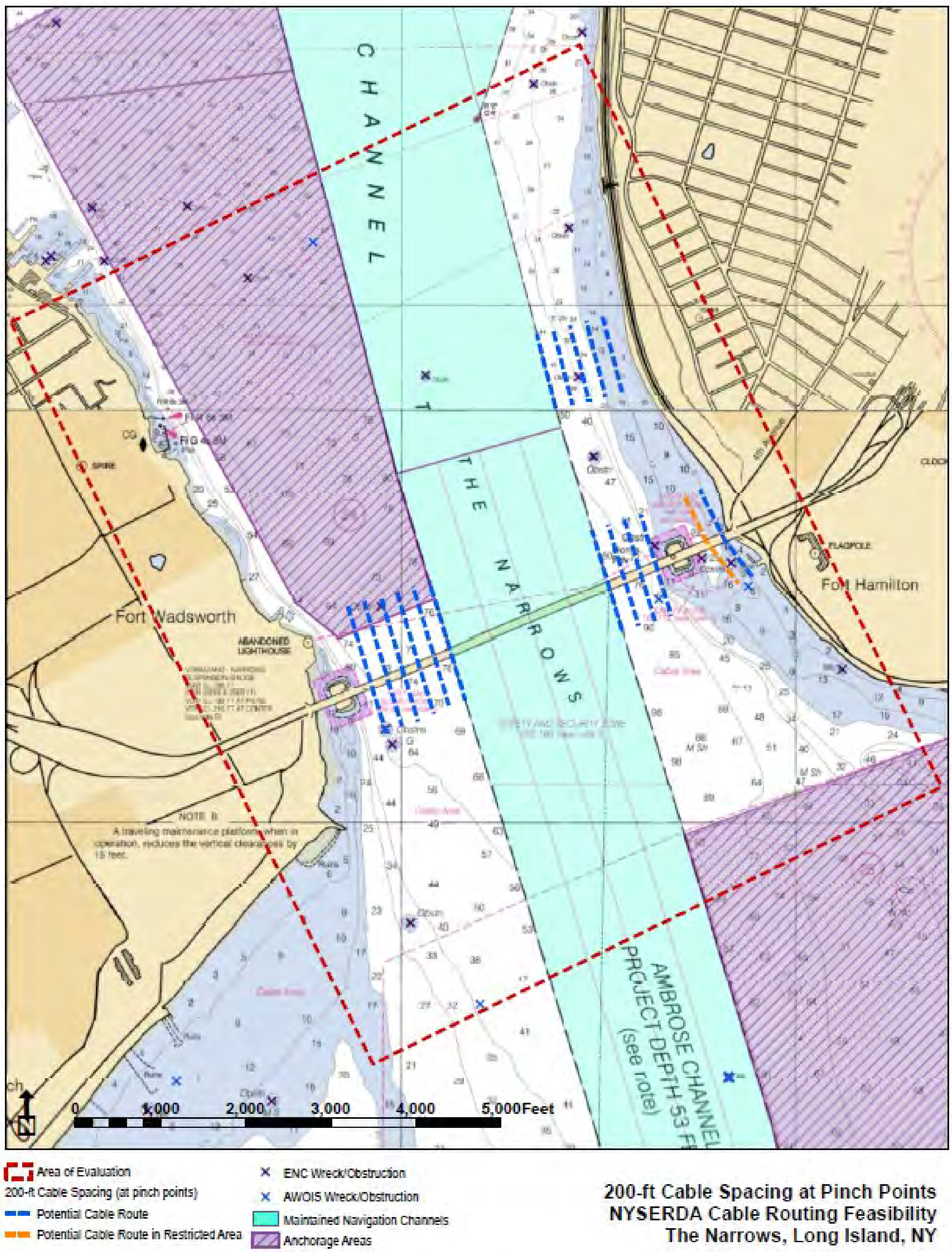


Figure 6-8. Cable Spacing of 200 ft through The Narrows

Source: WSP 2020; NOAA ENC 2018, 2020; NOAA RNC 2020. (See Annex B, Part 1: GIS Data Layer List for full list of figure references.)



6.2.2.8 Contaminated Sediments

Long Island

Contaminated sediments were examined and analyzed for shore approach and landing sites on Long Island; however, no major constraints were identified for these areas. For further detail, see Annex B, Part 3: Refined Route Feasibility Scoring Matrices.

New York City

New York City's waterways have elevated sediment contamination as a result of discharges for historic industrial activities as well as combined sewer overflows. In general, the longer the shore approach route though New York waterways the increased potential for contamination. The Hudson River itself is a DEC remediation area. Additionally, the Superfund sites of Gowanus Canal and Newtown Creek connect directly to Upper New York Bay and the Lower East River. A site that likely contains a reduced level of contaminates is Lower New York Bay, since it is outside of Upper New York Bay and further from historic industrial activities; however, potential for contamination still exists. Site-specific sediment sampling is likely necessary to confirm whether sediment contamination exists.

6.2.2.9 Cultural Resources and Wrecks/Obstructions

Long Island

Cultural resources and wrecks/obstructions were examined and analyzed for shore approach and landing sites on Long Island; however, no major constraints were identified for these areas. For further detail, see Annex B, Part 3: Refined Route Feasibility Scoring Matrices.

New York City

There are many shipwrecks in westernmost Long Island Sound and the northern East River. As a result, there is the potential for extensive SHPO review to ensure avoidance of cultural resources. The SHPO is likely to require that marine archeological surveys to be completed, which may reveal additional targets that are not currently mapped. Additionally, shore approach routes in New York City would also pass many sites of historical significance along the shoreline that would be within the viewshed of any installation activities. Accordingly, there is the potential for extensive SHPO review to ensure avoidance of visual impact from designated sites.

6.2.3 Constraints Analysis for Onshore Routes and Converter Station Sites

This section summarizes critical constraints applicable to the evaluated onshore routes, including potential converter station sites for HVDC circuits. The following Figures depict several of the GIS layers for the critical constraints considered in the feasibility assessment with respect to the onshore cable route segments and converter station sites (Figure 6-9 through Figure 6-11). Figure 6-9 shows several constraints for the onshore routes for cable interconnection to Long Island.

Figure 6-9. Constraints for Onshore Routes on Long Island

Source: WSP 2020; DNVGL 2020; PLATTS 2009; NHD 2018; NWI 1979; NYSDEC 1999; NRHP2017; NYSOGIS 2017; DEC CEA 2020; DEC Rem 2010; ESRI 2020. (See Annex B, Part 1: GIS Data Source List for full list of figure references.)

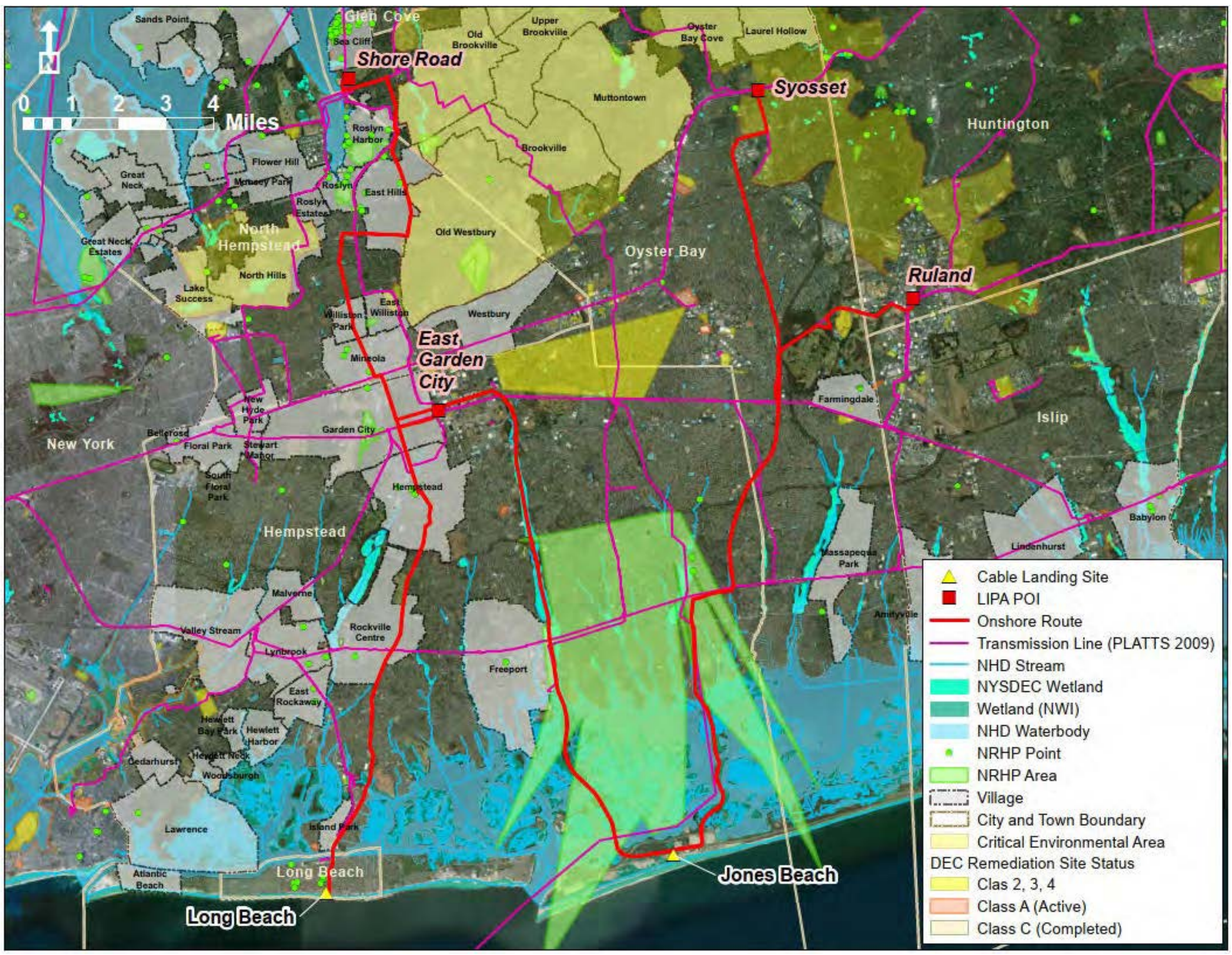


Figure 6-10 illustrates several constraints for the onshore routes in Brooklyn, Queens, and Manhattan for cable interconnection to New York City.

Figure 6-10. Constraints for Onshore Routes in Brooklyn, Queens, and Manhattan

Source: WSP 2020; DNVGL 2020; PLATTS 2009; NPMS 2006; NRHP2017; NYC Aqueducts 2020; NYC Subways 2017; NYC Sewer 2019; DEC Rem 2010; ESRI 2020. (See Annex B, Part 1: GIS Data Source List for full list of figure references.)

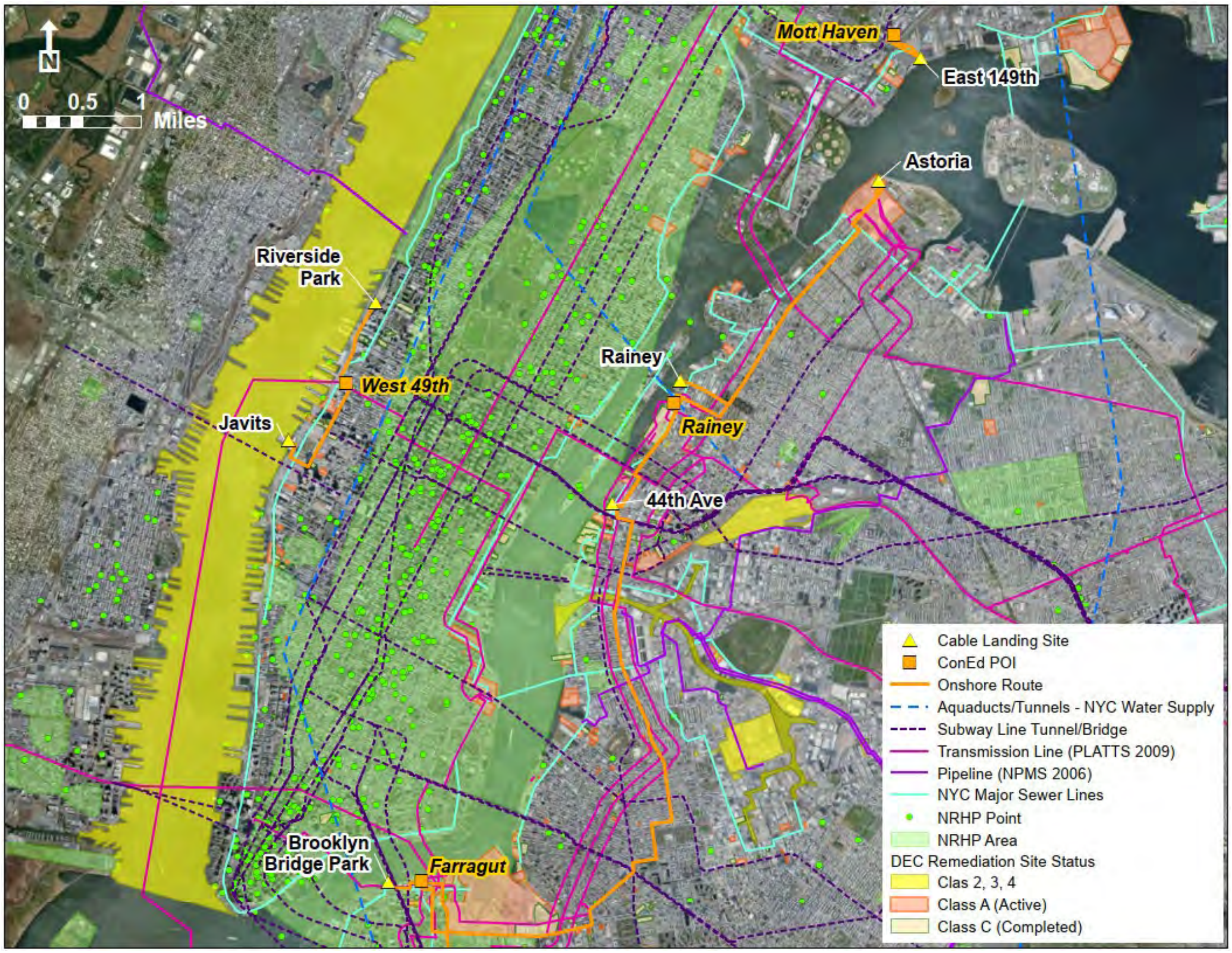


Figure 6-11 shows several constraints for the onshore routes in Brooklyn for cable interconnection to New York City.

Figure 6-11. Constraints for Onshore Routes in Brooklyn

Source: WSP 2020; DNVGL 2020; PLATTS 2009; NPMS 2006; NRHP2017; NYC Aqueducts 2020; NYC Subways 2017; NYC Sewer 2019; DEC Rem 2010; ESRI 2020. (See Annex B, Part 1: GIS Data Source List for full list of figure references.)

6.2.3.1 Infrastructure Crossings

<u>Long Island</u>

A majority of the existing transmission lines on Long Island are alternating current overhead cables that do not require infrastructure crossings to intersect. However, the highways and major arterial roads on Long Island represent a significant portion of the infrastructure crossings. The longer onshore routes have an increased number of infrastructure crossings. Jones Beach to Syosset has an extensive number of infrastructure crossings at 10 (Figure 6-12a). Nine out of 10 of those crossings are required because the Seaford-Oyster Bay Expressway has numerous small bridges that transect major and minor arterial roadways. Due to thermal constraints, the cables cannot be attached to the underside of the bridge and an HDD or other specialized drilling technique must be used to cross the roadway. The shortest Long Island onshore route, Long Beach to East Garden City, has the fewest infrastructure crossings, with only one.

The most constrained restriction point for onshore routes on Long Island is along North and South Long Beach Road for Long Beach Landing to East Garden City POI and Long Beach Landing to Shore Road POI (location C on Figure 6-13). The routes extend along this road for 3.65 miles and the road width ranges from 40-feet to 28-feet wide. The measurement is conservative and does not include sidewalks or grassy areas that may be contained within the ROW. From the public data available, there does not appear to be any colocation of other utilities along this ROW, still making it feasible for installation of two circuits. Additionally, both Shore Road routes (from Long Beach and Jones Beach) are constrained to two circuits at Glen Cove Avenue (location D on Figure 6-13). The remaining three Long Island routes are wide enough to support four to six circuits (Table 6-7).

New York City

Unlike Long Island, most of the infrastructure crossings in New York City were necessary to transverse existing utilities. Routes requiring the fewest infrastructure crossings are those for which the landing is close to the POI. These POIs include West 49th Street (one infrastructure crossing) and Rainey (one infrastructure crossing). Gowanus to Farragut and Brooklyn Bridge Park to Rainey onshore routes require the most infrastructure crossings, with eight and 13, respectively. Brooklyn Bridge Park to Rainey must cross Newtown Creek in addition to crossing the Buckeye Pipeline and an aqueduct as well as numerous other underground transmission lines and sewer utility lines (Figure 6-12b). Gowanus to Farragut also crosses an aqueduct and various underground transmission and sewer lines. It was expected that the longer route, Brooklyn Bridge Park to Rainey (7.91 miles) would have more infrastructure crossings than Gowanus to Farragut (4.94 miles). In addition to length, the crossings for Gowanus to Farragut are more condensed (crossing multiple existing utility lines per HDD) rather than spread out (crossing a single utility line per HDD) in the Brooklyn Bridge Park to Rainey route.

For the restriction point analysis on New York City onshore routes, the most constrained route portions are those originating and terminating at or near Farragut: Gowanus to Farragut and Brooklyn Bridge Park to Rainey (location G on Figure 6-14 and Table 6-7). The ROW bordering Farragut POI, John Street is about 42-feet wide for 0.19 miles. This width is enough to accommodate two circuits based on a review of

GIS data layers that indicate no other utility lines are present. The restriction points in the remainder of the New York City onshore routes are wide enough to support four circuits in horizontal alignment (Table 6-7).

Figure 6-12 (a and b). Onshore Routes for Long Island and New York City with the Highest Number of Specialized Crossings (Jones Beach to Syosset; Brooklyn Bridge Park to Rainey)

Source: WSP 2020; PLATTS 2009; NPMS 2006; NYC Aqueducts 2020; NYC Sewer 2019; ESRI 2020. (See Annex B, Part 1: GIS Data Source List for full list of figure references.)

Table 6-7. Right-of-Way Restriction Point Results

Route	Restriction Point	Width[a] (feet)	Number of Circuits[b]	Letter in Figure 23 and 24
Jones Beach to Ruland Road	Wantagh Avenue	65	6	A
Jones Beach to Syosset	South Woods Road at Substation	42	4	B
Long Beach to East Garden City, Shore Road	N. Long Beach Road at McDermott Road	28	2	C
Jones Beach to Shore Road	Glen Cove Avenue	28	2	D
Jones Beach to East Garden City	Stewart Avenue	75	6	E
44th Avenue to Rainey	Vernon Boulevard	45	4	F
Gowanus to Farragut/Brooklyn Bridge Park to Rainey	John Street	20	2	G
Rainey Park to Mott Haven	35th Avenue between 12th and Vernon Boulevard	44	4	H
Javits Center Pier and Riverside Park to West 49th	West 49th	33	4	I

[a] Roadway only; does not include sidewalk or grassy right-of-way.
[b] Number based on horizontal alignment; potential for more with vertical alignment.

Figure 6-13. Location of Right-of-Way Restriction Point Results on Long Island

Note: Blue letters match road widths presented in the table above.

Sources: WSP 2020; PLATTS 2009; ESRI 2020. (See Annex B, Part 1: GIS Data Source List for full list of figure references.)

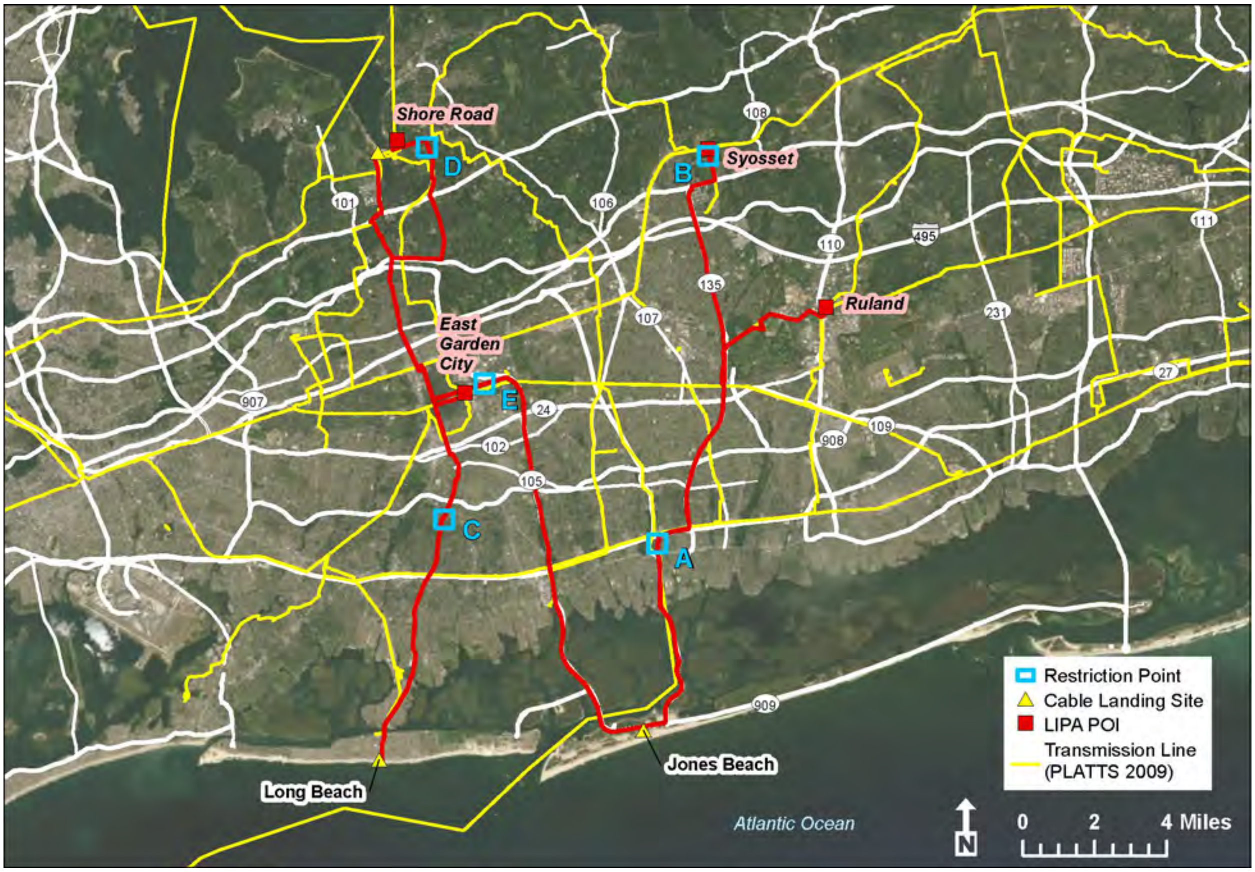
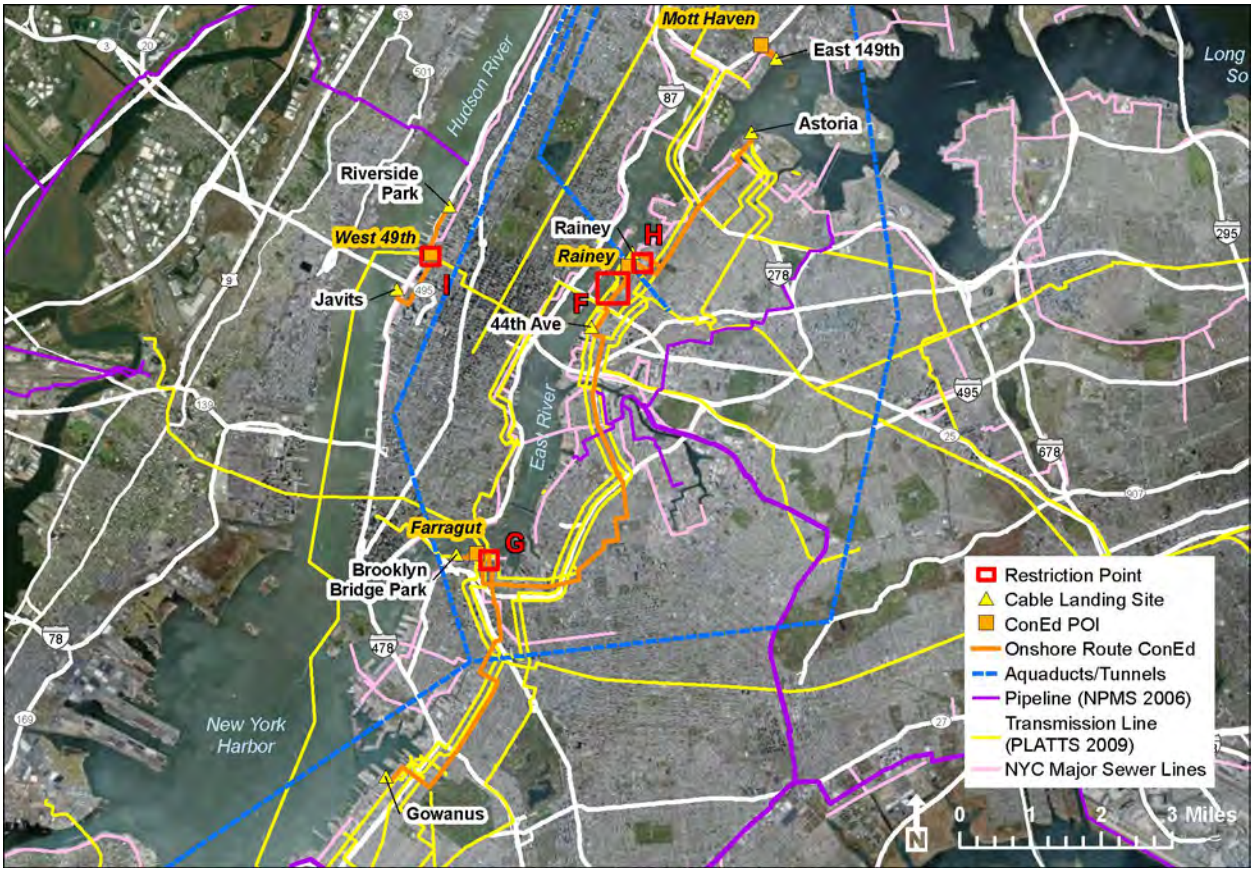


Figure 6-14. Location of Right-of-Way Restriction Point Results in New York City

Note: Red letters match road widths presented in the table above.

Sources: WSP 2020; PLATTS 2009; NPMS 2006; NYC Aqueducts 2020; NYC Sewer 2019; ESRI 2020. (See Annex B, Part 1: GIS Data Source List for full list of figure references.)



6.2.3.2 Wetlands and Sensitive Habitats

Long Island

Overall, the more developed an area, the less existing wetlands and sensitive habitats. Therefore, the Long Island routes that cross the least wetlands and sensitive habitats are those landing in Long Beach and terminating at East Garden City and Shore Road POIs. While the back-bay crossings of Long Beach to East Garden City and Long Beach to Shore Road pass through Important Bird Areas and mapped National Wetlands Inventory areas, these crossings are few in number and relatively short. Long Beach to Shore Road also passes through some of the Tidal Wetlands Boundary. Onshore Long Island routes that cross the most wetlands and sensitive habitat are those that extend from Jones Beach along the Meadowbrook Parkway: Jones Beach to East Garden City and Jones Beach to Shore Road. The three back bay crossings are similar to those on the Jones Beach Causeway routes; however, once on land the

Meadowbrook Parkway is surrounded by the wetlands of Meadowbrook Creek for just over five miles. All the locations where routes pass through wetlands or sensitive habitat do so within the boundaries of existing infrastructure and impact to these areas should be minimal.

New York City

Wetlands and sensitive habitats were examined and analyzed for onshore routes in New York City; however, no major constraints were identified for these areas. For further detail, see Annex B, Part 3: Refined Route Feasibility Scoring Matrices.

6.2.3.3 Potential Stakeholder Concerns

Long Island

In part due to the increased length of onshore routes on Long Island, the potential for stakeholder concerns are greater than in New York City. The longest onshore route, Jones Beach to Shore Road has highest potential for stakeholder concerns. The Jones Beach to Shore Road route crosses through nine local municipalities. Nearly three quarters (13.07 of 17.89 miles) of the Jones Beach to Shore Road route also crosses low- and medium-intensity developed land, which was assumed to be indicative of residential areas, including single-family homes. Though the Jones Beach to Syosset route is not one of the longest routes analyzed, more than 70% (13.33 of 18.48 miles) of the route crosses low- and medium-intensity developed land. Increased distances through the low- and medium-intensity developed land is expected to potentially affect more residential areas, thereby increasing the potential for stakeholder concerns from homeowners and tenants along the route.

New York City

Potential stakeholder concerns were examined and analyzed for onshore routes in New York City; however, no major constraints were identified for these areas. For further detail, see Annex B, Part 3: Refined Route Feasibility Scoring Matrices.

6.2.3.4 Contaminated Sites

Long Island

The presence of contaminated sites was examined and analyzed for onshore routes on Long Island; however, no major constraints were identified for these areas. For further detail, see Annex B, Part 3: Refined Route Feasibility Scoring Matrices.

New York City

New York City has a much higher concentration of contaminated sites than Long Island. The routes of East 149th to Mott Haven and Riverside Park to West 49th do not skirt or intersect any contaminated sites. Rainey Park to Mott Haven lands and transverses through the DEC Remediation Site CE Astoria manufactured gas plant. The contaminants of concern on the site are coal tar, its components (benzene, toluene, ethylbenzene, xylene, and polycyclic aromatic hydrocarbon), and PCBs. This route would require consultation and permitting with the State Superfund Program. Another route, Brooklyn Bridge Park to Rainey, borders much of the DEC Remediation Site the Brooklyn Navy Yard Industrial Park. Contaminants of concern found on this site are arsenic, benzo(a)pyrene, mixed xylene, PCBs, lead, and naphthalene, but because the analyzed route not crossing into the site, consultation and permitting by the Volunteer Cleanup Program may not be required. Another area of concern along the Brooklyn Bridge Park to Rainey route is the DEC Remediation Site Newtown Creek. Contaminants of concern for this site include PCBs and heavy metals from oil storage facilities, inactive hazardous waste disposal sites, active manufacturing facilities, spills, and other uncontrolled sources from the industry in the upland areas surrounding its banks. Specialized crossing through Newtown Creek would require consultation and permitting with the State Superfund Program.

6.2.3.5 Cultural Resources

Long Island

For all routes, the onshore cables would be installed in the public ROW alongside an NRHP site or National Historic Landmark but would not directly impact the sites. All routes originating at the Jones Beach landing site cross significant portions of Jones Beach State Park and the Causeways and Parkways System. Additionally, Jones Beach to Ruland Road traverses some of Beth Page State. Since the representative routes are colocated with existing public ROW to the extent practicable, impact on cultural resources should be minimal.

New York City

Brooklyn and Manhattan counties have more dense areas of NRHP and NYS National Register sites than Queens and the Bronx. Onshore New York City routes that avoid most cultural resources are Riverside Park to West 49th and East 149th to Mott Haven. Gowanus to Farragut is one of the routes that physically intersects the most NYS National Register sites including Greenwood Cemetery, Fort Green Historic District, and DUMBO Industrial District. Brooklyn Bridge Park to Rainey also passes through the Fulton Ferry District, DUMBO Industrial District, along Brooklyn Navy Yard, and under the Queensboro

Bridge. Similar to Long Island, the rest of the routes may skirt or pass NRHP sites or parks, but impact to the actual sites should be minimal.

6.2.3.6 Converter Station Parcels

Long Island

Overall, there were more available parcels on Long Island. Parcel size requirements were mostly smaller on Long Island due to the ability to use HVAC (except for Jones Beach to Ruland Road) instead of the HVDC needed for the New York City routes. However, only one suitable option was identified for the Jones Beach to Syosset route. The POIs with the most viable transformer station options were Shore Road and East Garden City POIs from both Long Beach and Jones Beach landings.

New York City

The extremely dense development in New York City presented significant obstacles for successfully converting direct current to alternating current. The lack of available converter station parcels in New York City prevented some routes from being advanced for further analysis and consideration from the screening-level stage. A real estate planning firm, BJH advisors, was engaged to conduct a more thorough search for suitable parcels in New York City. Onshore routes that crossed through Queens presented the most number of feasible parcel options, including 44th to Rainey (five locations), Brooklyn Bridge Park (five locations) to Rainey, and Rainey Park to Mott Haven (nine locations).

6.2.3.7 Parkway/Highway Permitting

Long Island

Parkways, highways, and expressways were used heavily when routing on Long Island to avoid wetlands, sensitive habitats, and residential areas. Although Long Beach to Shore Road and Long Beach to East Garden City are not short routes, they each only intersect two highways, Sunrise Highway, and Southern State Parkway. The longest colocation of a cable route with a highway are Jones Beach to Syosset at 14.66 miles (4.92 miles on the Wantagh Parkway and 9.74 miles on the Seaford-Oyster Bay Expressway). These routes would likely require extensive consultation and permitting with the New York State Parks, DOT, and FHWA.

New York City

Parkway/highway intersection in New York City onshore routes is less when compared to Long Island. Gowanus to Farragut and Brooklyn Bridge Park to Rainey routes were the most constrained for highway permitting. When routing cables from Gowanus to Farragut, the Brooklyn Queens Expressway would be crossed under twice and the Prospect Expressway once. Similarly, the Brooklyn Bridge Park to Rainey route would cross under the Brooklyn Queens Expressway twice, the Long Island Expressway once, and the Queensboro Bridge once. Since these routes are crossing under the expressways and not directly impacting the roadway, permitting should be less involved than what is necessary on Long Island.

6.2.4 Synthesis and Summary of Findings

This Routing Assessment identified and evaluated the environmental and permitting challenges associated with bringing offshore wind energy to existing onshore substations (i.e., POIs). This was accomplished by identifying potentially feasible routes and landing areas to connect offshore power inputs with onshore POIs; evaluating the environmental and permitting challenges for the representative routes and landing sites; and determining the major environmental constraints that might adversely impact the illustrative transmission strategy.

The iterative feasibility assessment process included an initial screening level analysis performed to identify critical environmental and permitting constraints associated with potential routes from offshore wind lease areas to POIs, followed by a more detailed analysis for a refined set of representative routes to confirm the feasibility of an illustrative OSW transmission strategy for injecting 6 GW into New York City POIs and 3 GW into Long Island POIs. Supporting analyses were conducted to identify the approximate number of cables that could be installed through restricted points along the potential cable routes/corridors.

The overall environmental and permitting feasibility of the refined set of representative routes is summarized for interconnections with Long Island POIs and New York City POIs, including comparative ranking to identify more favorable route alternatives at a screening level and highlight the permitting challenges in terms of the major route constraints. This is followed by a set of declarative statements that summarize several findings of this Routing Assessment.

It is noted that not all route alternatives were included in the refined analysis, and the representative routes do not necessarily reflect a preferred or optimal solution for the transmission strategy. Other potentially feasible routes were identified in the preliminary route feasibility analysis, such as alternative routes to Long Island and New York City POIs through Long Island Sound, particularly recognizing the strong POIs in the City’s northern boroughs and cumulative constraints associated with longer cables in constrained waterways through New York Harbor. However, the refined set of representative feasible routes was developed for illustrative purposes.

6.2.4.1 Refined Routes Constraint Summary

The scoring matrices for the refined set of representative routes (see Annex B, Part 3: Refined Route Feasibility Scoring Matrices) reflect adjustments that improved the feasibility of certain routes, such as shifts to avoid colocating with long sections of railway. Potentially major constraints were still identified for most identified routes. However, these challenges may be overcome with suitable planning and outreach efforts. Thus, the results of the analysis for these routes supports a finding that the representative transmission strategy is feasible.

For routes to Long Island POIs from an Atlantic North Corridor or Atlantic Central Corridor, potentially major constraints along the offshore and shore approach segments include DoD operation area crossings, numerous infrastructure (utility) crossings, multiple or extensive sensitive habitats, navigation channel and/or USACE Coastal Storm Risk Management project crossings, and potential concerns from fisheries and/or coastal communities. Potentially major constraints along the onshore segments for several routes include infrastructure crossings (e.g., roadways requiring HDD), numerous stakeholders (i.e., routes through or near multiple municipalities and/or residential areas), and an extensive permitting process associated with colocating along parkways and highways. For some route segments, the presence of wetlands or other sensitive onshore habitat, the proximity of multiple designated cultural resources, or the limited availability of suitable converter/transformer station land were also major routing constraints. Further, onshore route distances of 15 miles or longer were considered a major constraint for some routes as distance increases the risk of encountering multiple and/or unanticipated challenges.

For routes to New York City POIs from the Atlantic South Corridor or Atlantic Central Corridor, potentially major offshore constraints include numerous crossings of linear infrastructure (utilities) and designated marine zones (e.g., traffic lanes and danger zones). Potentially major constraints exist in every critical constraint category for the nearshore approach segment of the routes through New York Harbor to New York City POIs, including marine geology, landing site complexity, presence of sensitive habitat, multiple infrastructure crossings (e.g., linear utilities and tunnels), numerous navigation channels/anchorages, potentially high levels of sediment contaminants, high likelihood of requiring additional regulatory approval from New Jersey, numerous submerged wrecks/obstructions, and high likelihood of concerns from some stakeholders (e.g., marine vessel operators). The major constraints for onshore portions of the routes vary greatly depending primarily on the length of the onshore segment. The number of major infrastructure crossings (e.g., roadways requiring HDD), the presence of multiple designated cultural resources, permitting requirements for colocating with parkways/highways, and the limited availability of suitable converter station land are examples of major constraints that affect some of the routes to New York City.

Because several of these routes are necessary to support the illustrative transmission strategy examined in this Routing Assessment, overall ranking of the refined set of representative routes was not warranted. However, while all the refined routes are potentially feasible, a comparison of scores for two route options leading to the same POI can be informative for considering which option would be more challenging. These differing scores mainly reflect different landing site alternatives. For example, routing to the East Garden City POI via Jones Beach is considered more constrained overall than routing via Long Beach partly because of greater number of wetlands/sensitive habitats, more navigation channel crossings, higher likelihood of stakeholder concerns, and permitting requirements for extensive colocation with parkways/highways. Still, the Long Beach landing poses more challenges than the Jones Beach landing, such as more infrastructure crossings and higher likelihood of stakeholder concerns for the shore crossings.

For multiple routes to a single New York City POI, the route option that scores better overall (i.e., has fewer constraints) is generally the route that has a shorter onshore segment—although they typically have a longer shore approach segment. The routes with the longer onshore segments provide feasible alternatives, should further investigation and stakeholder outreach indicate that routes with a longer shore approach segments are more challenging than anticipated.

6.2.4.2 Findings

The Routing Assessment supports the following declarative statements regarding routing transmission cables from offshore wind energy areas to New York State POIs:

- The Planning Study's illustrative transmission strategy (6 GW to New York City and 3 GW to Long Island), which assumes four POIs in New York City and four POIs on Long Island, is feasible in terms of cable routing.

- There is enough space along the representative onshore routes to accommodate the cables needed to support the illustrative transmission strategy. A maximum of two to six, two-cable HVDC or three-cable HVAC circuits can likely be accommodated at the narrowest (i.e., most restricted) points of the analyzed onshore routes.

- Siting six cables through New York Harbor to the representative POIs identified as part of the transmission strategy is feasible given suitable planning and coordination with the maritime community, but each individual cable (or circuit) installation becomes cumulatively more challenging.

- Major environmental and permitting constraints identified for cable routing through the representative offshore route corridors are as follows:
    - Infrastructure Crossings (linear utilities)
    - Designated Marine Zones
    - DoD Areas
- Major environmental and permitting constraints identified for cable installation along the shore approach and landing segments of the representative cable routes are as follows:
    - Long Island
        - Infrastructure Crossings (i.e., linear utilities)
        - Presence of Sensitive Species or Habitat
        - Potential Stakeholder Concerns (e.g., fisheries/coastal communities)
        - Landing Site Complexity (e.g., back-bay crossings)
        - USACE Coastal Storm Risk Management Projects
    - New York City
        - Infrastructure Crossings (i.e., linear utilities)
        - Marine Geology and Oceanography (e.g., seabed, erosion, bedforms)
        - Further Regulation (i.e., additional state approval requirements)
        - Potential Stakeholder Concerns (e.g., maritime community)
        - Landing Site Complexity (e.g., shore structure crossings, dense development)
        - Navigation Channels and Anchorage Areas
        - Contaminated Sediments
        - Cultural Resources and Wrecks/Obstructions
- Major environmental and permitting constraints identified for cable installation along the onshore segments of the representative cable routes are as follows:
    - Long Island
        - Infrastructure/Specialized Crossings
        - Wetlands; Sensitive Habitats
        - Jurisdictions/Stakeholders
        - Cultural Resources
        - Available Land (Converter/Transformer Station)
        - Parkway/Highway Permitting
    - New York City
        - Infrastructure/Specialized Crossings
        - Contaminated Sites
        - Cultural Resources
        - Available Land for Converter Station
        - Parkway/Highway Permitting

7 Detailed Analysis of OSW Connection Concepts

In parallel with the onshore assessment task, the initial offshore assessment was completed as described in Section 4. Subsequent to the onshore assessment and initial offshore assessment, the environmental constraints analysis was completed as described in Section 6. Each of these Study tasks provided results and initial observations, which facilitated a more detailed evaluation of OSW connection concepts and their associated costs and benefits.

7.1 Basis for Detailed Analysis

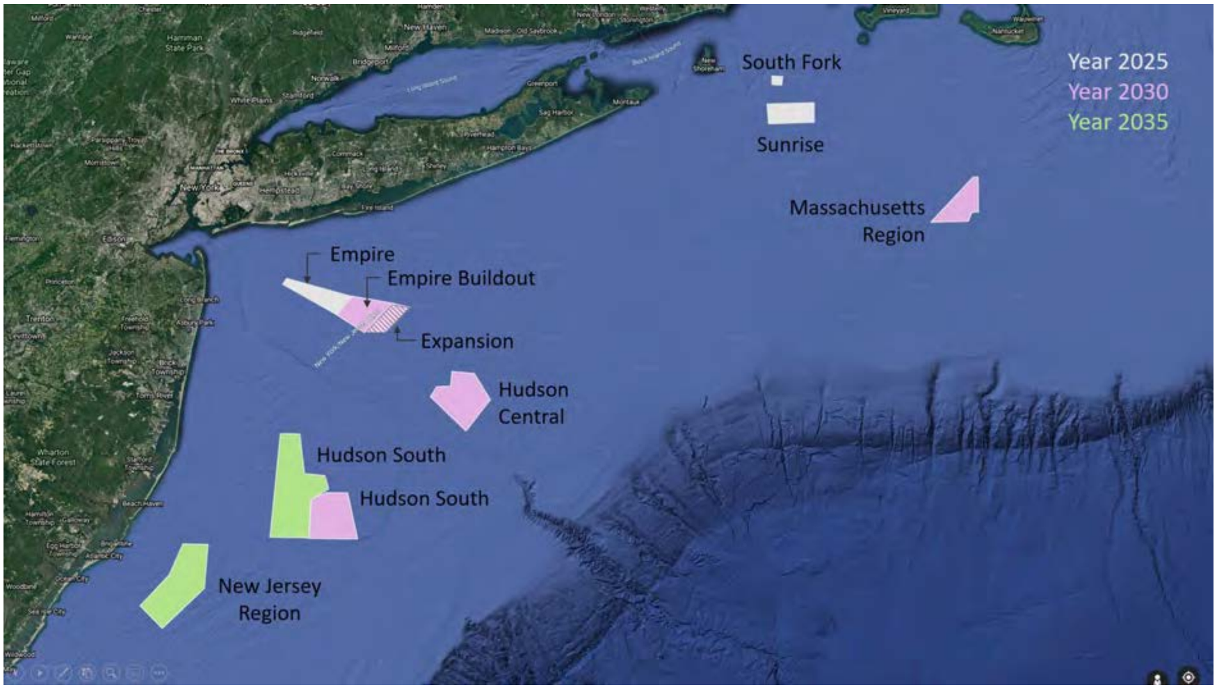
In order to complete a more detailed assessment of OSW connection concepts, it was necessary to re-evaluate initial OSW connection concepts considering findings associated with cable routing limitations, identified feasible landing areas, and onshore POIs as presented in sections 3 and 6. As part of this detailed assessment, the Study elected to focus attention on just one OSW build-out scenario (out of the five OSW build-out scenarios previously defined and presented in Annex C), as shown in Figure 7-1, with the following labeling of lease areas.

2025 Study Year	2030 Study Year	2035 Study Year
South Fork (So) Sunrise (Su) Empire (E)	Massachusetts Region (L) Empire (E) Buildout Empire (E) Expansion Hudson Central (HC) Hudson South (HS) I	Hudson South (HS) II New Jersey Region (A)

The decision to focus on one illustrative OSW build-out scenario was made to reduce complexity since the preliminary OSW connection assessment concluded that OSW project location uncertainty, as represented in the Study by the five differing OSW build-out scenarios considered, does not materially impact the relative performance of the five OSW transmission connection concepts. Thus, it is expected that the overall Study conclusions would not vary if a different future OSW build-out scenario were selected for this detailed OSW connection concept analysis.

The selection of one illustrative future OSW build-out scenario is not indicative of a State Team preference or recommendation by the Study authors.

Figure 7-1. OSW Project Locations for Detailed Analysis of OSW Connection Concepts



The onshore assessment and environmental and permitting analysis identified limitations and opportunities that frame the offshore concepts interfaces. Starting from the OSW project arrangement illustrated in Figure 7-1, topology concepts for the OSW connections were fine-tuned iteratively, considering the following:

- Onshore POIs with sufficient available additional injection capacity as determined by the analysis presented in Section 3 to avoid and/or minimize the onshore grid upgrades.
- Restrictions of the available cable trenches, especially to New York City, according to Section 6.
- Limitations of the lease area size and the corresponding maximum offshore capacity that can be assumed from these areas.

Figure 7-2 exhibits the injection levels to be used for each POI in New York City and Long Island as identified in Section 3, Scenario 2.

Figure 7-2. OSW MW Injection Levels for Select Onshore POIs for Study Year 2035 (Does not Reflect Offshore Power Already Procured for 2025)

As concluded from the preliminary analysis presented in Section 5, the detailed analysis of OSW connection concepts focuses on Radial, Meshed, and Backbone configurations. Design characteristics of each of the shortlisted connection variants are summarized in Table 7-1 for ease of comparison. Each of the three variants is discussed in more details in the following subsections.

Table 7-1. Details of Three Illustrative Connection Concept Variants

Variant	V1	V2	V3
Connection concept	**Radial**	**Meshed**	**Backbone**
Total cable system length (HVAC / HVDC)	732.8 mi (176 mi / 556 mi)	891.7 mi (335 mi / 556 mi)	913.5 mi (345 mi / 576 mi)
Maximum rated capacity	7,200 MW added to already procured 1,826 MW = 9,026 MW	7,200 MW added to already procured 1,826 MW = 9,026 MW	7,200 MW added to already procured 1,826 MW = 9,026 MW
Connection technology	220kV AC 320kV DC	220kV AC 320kV DC	220kV AC 320kV DC
Need for onshore transmission reinforcement	No	No	No
Required number of trenches NYC/LIPA	6/7	6/7	6/7
Max. MW injection to the POIs	1,310 MW	1,310 MW	1,310 MW
Degree of redundancy	Intra OSW partial redundancy for 2 AC connected OSW projects[9]	Intra OSW partial redundancy for 2 AC connected OSW projects Inter OSW partial redundancy for 4 OSW projects[10]	Intra OSW partial redundancy for 3 AC connected OSW projects Inter OSW partial redundancy for 4 OSW projects

7.2 Variant 1 (Radial)

Under the Radial Connection Concept (Variant 1) shown in Figure 7-3, all OSW projects will be connected to the grid separately using dedicated lines. Grid connection technology was selected depending on the distance between lease areas and the offshore grid. For lease areas located within 70 miles radius of the relevant onshore POIs, 220kV HVAC technology was considered while ±320kV HVDC technology (symmetric monopole) was assumed for those located outside the 70 miles radius.

Due to the power rating limitation of the HVAC cables, two HVAC connection cables are required for each of the two OSW projects of lease area E, resulting in partial redundancy for these two OSW projects.

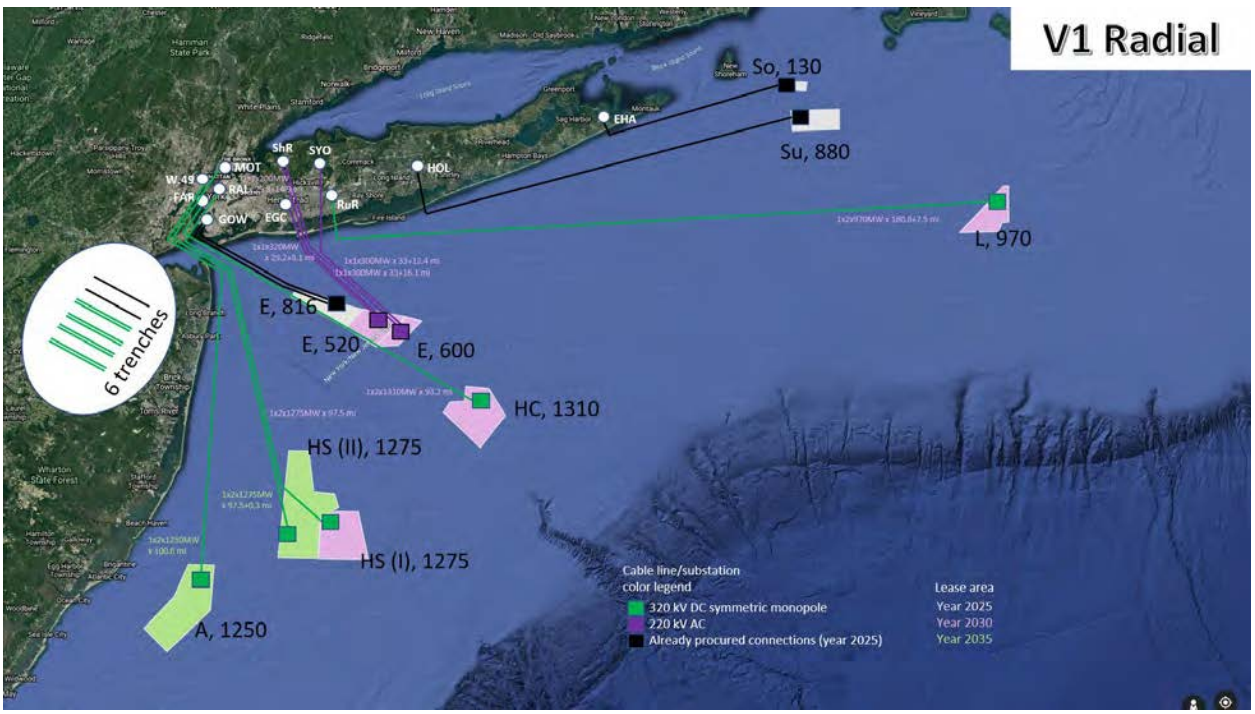
[9] For all Variants, partial redundancy is inherent with the two 2030 OSW projects of Lease Area E (connected to LI). In case of an outage of one cable, up to a certain wind speed level the remaining cable can carry a part of the energy of the damaged cable. While this does not fulfill the N-1 principle it does provide a partial redundancy.

[10] For Variant 2 and 3, partial redundancy is inherent for the four OSW projects connected to NYC given that between these projects is 220 kV HVAC connections. In case of an outage of a grid connection, up to a certain wind speed level the generated wind energy can be redistributed to the remaining grid connections. However, since no over ratings are considered, the redistribution is not possible at higher wind speeds. Thus, while this does not fulfill the N-1 principle it does provide a partial redundancy.

In addition, by converting the two HVDC pole cables, used for OSW projects in lease area A, HS and HC, into a bundled cable, each HVDC circuit from these lease areas occupy only one cable trench reducing the total number of trenches for AC and DC cables to 6. This connection topology meets the six-trench constraint to NYC identified in Section 6. In total, the cable length of Variant 1 amounts to 733 miles, consisting of 176 miles of HVAC cable and 557 miles of HVDC cable.

It should be noted that, in order to comply with the restrictions on the number of available cable trenches and the identified onshore POI MW injection levels, as obtained from the parallel analyses presented in Section 3 and 6, and still be able to use a Radial solution, the OSW total power assigned to individual lease areas for Study years 2030 and 2035 was adjusted compared to what was initially assumed in the initial OSW build-out scenarios.

Figure 7-3. Variant 1 (Radial) Connection Concept, Study Year 2035

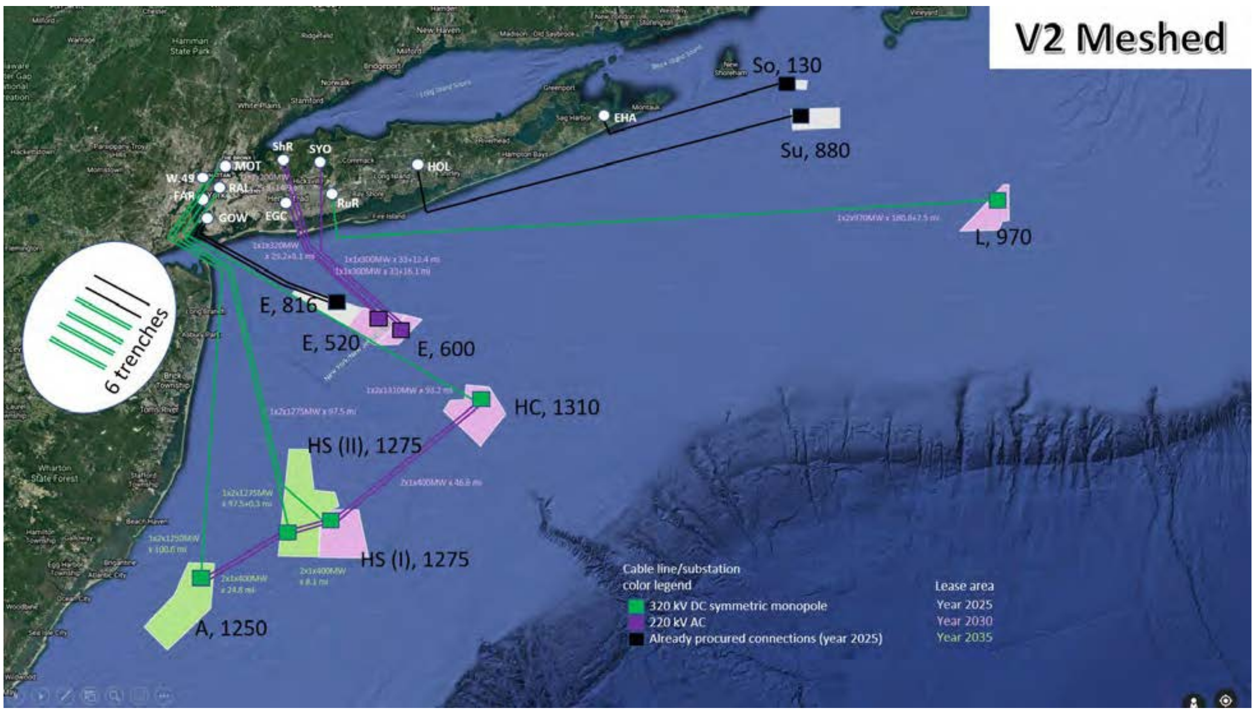


7.3 Variant 2 (Meshed)

The Meshed Connection Concept (Variant 2) shown in Figure 7-4 is similar to the Radial Connection Concept (Variant 1), with additional 220 kV AC double circuits between Lease Sites A, HS (II), HS (I), and HC. Similar to Variant 1, HVAC technology was assumed for lease areas within 70-mile radius of relevant onshore POIs. The additional 220 kV AC circuits are intended to increase the degree of redundancy of the grid connections and thus the availability of the OSW projects. For this Variant 2 concept, apart from the additional 220kV AC circuits connecting the lease areas, the offshore platform designs for the corresponding OSW projects would also have to be larger and equipped with an additional 220 kV busbar and transformer bays, as compared to Variant 1.

This design meets the six-trench constraint to NYC via the Narrows identified in Section 6. The total cable length of Variant 2 amounts to 893 miles, consisting of 336 miles of HVAC cable and 557 miles of HVDC cable.

Figure 7-4. Variant 2 (Meshed) Connection Concept, Study Year 2035

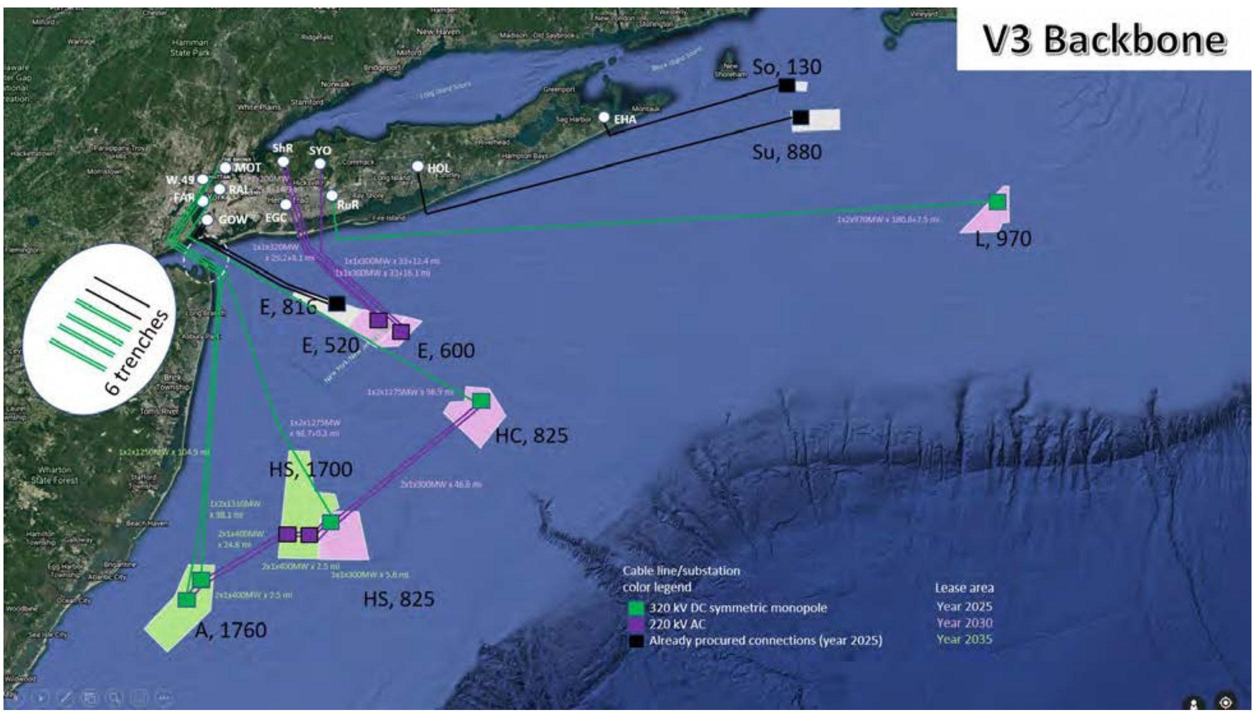


7.4 Variant 3 (Backbone)

The Backbone Connection Concept (Variant 3) shown in Figure 7-5 is the third of the shortlisted offshore topology concepts being evaluated for collecting and delivering OSW power. The offshore lease areas E and L are connected identically as compared to Variants 1 and 2. For the other lease areas, not all hypothetical OSW projects receive a stand-alone grid connection. Rather, the ±320 kV HVDC grid connections for OSW projects labeled as A 1,760, HS 825, and HC 825 are assumed to be oversized to be able to transfer the rated power of the OSW project HS 1,700 to New York City. Compared to Variants 1 and 2, this connection concept includes the installation of additional two offshore platforms, one HVDC converter platform for A 1,760 and one HVAC platform for HS 1,700 (showing in total two HVAC platforms for the Backbone concept) in order to be able to divide the power between the New York City POIs, to comply with the POIs' MW injection limits while retaining the ±320 kV HVDC maximum power transfer limit of 1,400 MW. To distribute the output power of HS 1,700 to the other outlets, double 220 kV HVAC submarine cables are assumed, similar to Variant 2, resulting in a partial redundancy and slightly increased availability.

Similar to other variants, Variant 3 converts the two HVDC pole cables to a bundled cable in a single trench allows the design to meet the six-trench constraint to New York City identified in Section 6. In total, the cable length of Variant 3 amounts to 914 miles, consisting of 346 miles of AC cable and 568 miles of DC cable.

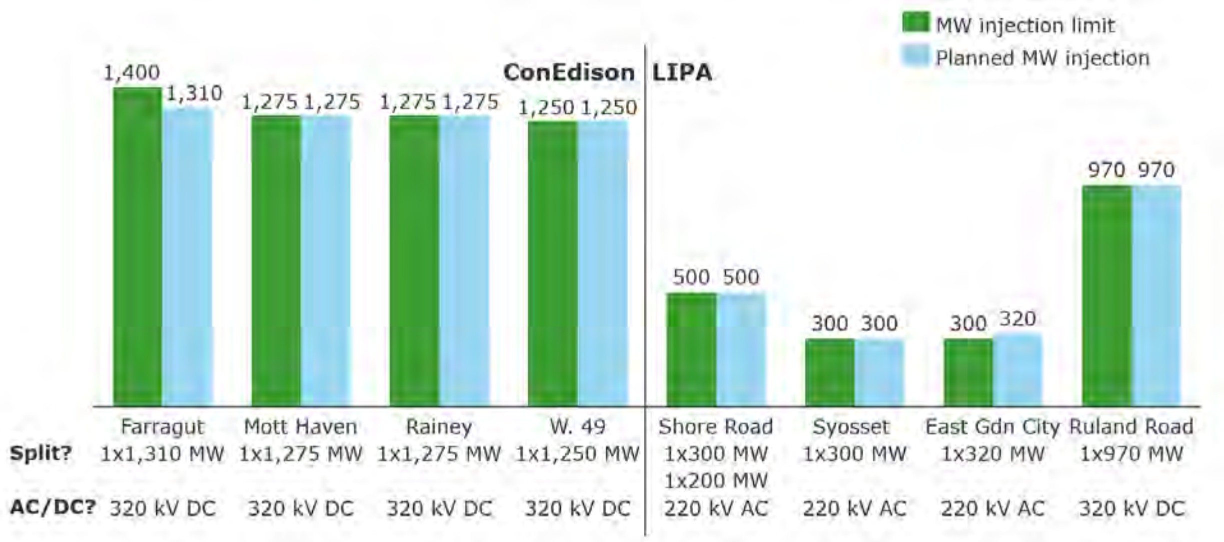
Figure 7-5. Variant 3 (Backbone) Connection Concept, Study Year 2035



7.5 Planned MW injections into the POIs

Figure 7-6 illustrates the magnitude of offshore power that is connected to each individual onshore POI for Study Year 2035 as the result of OSW connection concepts Variant 1 (Radial), Variant 2 (Meshed) and Variant 3 (Backbone). None of the POIs' MW injection limits are exceeded except for a marginal excess at East Garden City (20 MW). The OSW power split between New York City and Long Island is 5,926 MW and 3,100 MW, respectively for the full 9.026 GW build-out of OSW considered.

Figure 7-6. OSW Power Connected to Each Shortlisted POI Under Variant 1 (Radial), Variant 2 (Meshed) and Variant 3 (Backbone) Connection Concept, Study Year 2035



As shown in Figure 7-3 throughFigure 7-5, all 3 Variants use the same connection configuration for POIs on Long Island.

Specific to NYC, Variant 1 and Variant 2 use the following connection configuration:

- OSW project HC 1310 MW to Farragut substation
- OSW project HS (I) 1275 MW to Rainey substation
- OSW project HS (II) 1275 MW to Mott Haven substation
- OSW project A 1250 MW to West 49 substation

Specific to NYC, Variant 3 uses the following connection configuration:

- OSW project HC 825 MW via 1275 MW cable connection (which carries energy from other OSW projects) to Rainey substation
- OSW project HS (I) 825 MW via 1275 MW cable connection (which carries energy from other OSW projects) to Mott Haven substation
- OSW project HS (II) 1700 MW without stand-alone connection
- OSW project A 1760 MW
    - o via 1250 MW cable connection to West 49 substation
    - o via 1310 MW cable connection to Farragut substation

7.6 Routes for Landing Points to the Grid POIs

Based on the three OSW connection concepts described, eight viable cable routes were identified (See Section 6). The identified onshore routes are identical among the three offshore connection concept variants (Radial, Meshed, and Backbone). Each route consists of AC or DC cables from landing points to the onshore POI along with transformer or converter stations, as applicable.

Table 7-2. Routes for Landing points to grid POIs — Variant 1, 2, 3

ConED		LIPA	
Route	**Technology**	**Route**	**Technology**
Gowanus to Farragut	HVDC	Long Beach to Shore Road	HVAC
E 149th to Motthaven	HVDC	Jones Beach to Syosset	HVAC
44th Ave to Rainey	HVDC	Jones Beach to Ruland Road	HVDC
Riverside to W. 49th	HVDC	Long Beach to E. Garden City	HVAC

8 Cost and Availability Analysis

A detailed cost estimate and availability analysis was completed for each of the three OSW connection concepts or variants described in Section 7. The cost assessment includes all cost of the transmission systems from the OSW projects via the landing points to the onshore POI stations. This section is structured as follows:

- The cost assessment related to onshore routes of the OSW connections, i.e. from the landing points to the POI stations, is presented in Section 8.1. This cost is referred to as onshore cost in the rest of the Study and is the same for all three variants. The onshore cost studied here does not include any upgrade or reinforcement of the existing onshore grid, given such system upgrades were not determined to be a necessity in the onshore assessment (Section 3).

- The unit cost of major offshore components for each variant is presented in Section 8.2.

- The results of onshore and offshore cost assessments are combined and presented in Section 8.2.3.

- The assumption and methodology used for the availability assessment, as well as the availability results are presented in Section 8.3.

Unless stated otherwise explicitly, M is used to represent million in quantities to make the tables and figures more succinct throughout this section. For example, a million U.S. dollars will be shorten as M$.

8.1 Onshore Costs

The accuracy of the cost estimates is dependent upon the various underlying assumptions, inclusions, and exclusions. Actual costs may differ and can be significantly affected by factors such as changes in the external environment, the manner in which the relevant constructions and/or upgrades are executed and managed, and other factors that may directly or indirectly impact the estimate basis. Cost estimation provided is based on the specific input data, assumptions, and methodology used. In the eventuality that actual data and relevant attributes differ from what has been assumed for this assessment, the cost estimates may differ from what has been documented.

8.1.1 Methodology, Assumption, Exclusions, and Risks

The onshore cost assessment has been conducted based on the following assumptions and methodology:

- Methodology:
  - If available, material prices were obtained using historical data and escalated for 2020 prices accordingly. No escalation was considered beyond 2020.
  - There is 8% sales tax included in both material and service-related costs.
  - Historical data were used to estimate the weight of engineered steel pole. Cost of steel was assumed to be $2.2 per pound.
  - DNV GL's in-house cost database was used to provide the CAPEX data of onshore HVDC converter stations, and the cost data were further adjusted for the Study area based on an early study for Empire State Connector [18].
  - A parcel of five acres was considered for each onshore HVDC converter station and a parcel of two acres was assumed for each onshore HVAC transformer station.

- Key assumptions:
  - Construction cost including mobilization/de-mobilization, construction of duct bank (all-inclusive conduit, steel, etc.), manhole, testing of cable, and lying the cable in conduits,
  - HVAC material estimates account for three phases (e.g., three surge-arrester, 3x2 terminations, 3x2 riser poles), whereas HVDC estimates account for two poles.
  - Duct for single circuit cable (with dimension of 7'x 2') and for double circuit (with dimension of 7'x 5') as a guideline, however these were adjusted for the size of HVDC/HVAC cables for different transmission line routes.
  - One termination pole per phase is assumed on either side of duct,
  - Surge arrestor is included on termination poles.
  - Excavation for trenches was assumed to be done by excavating machine, additional cost factor was included for HDD wherever identified in the route.
  - Three manholes per mile along the cable route
  - One mobilization and de-mobilization for construction crew
  - Financial security for performance and warranty was assumed to be ~5% of total cost.

- Exclusions:
  - Cost for any upgrade of substation A-frame/termination/equipment
  - Cost associated with land, environmental, regulatory, and facility application delays due to stakeholder issues, regulatory or permitting approvals and mitigations
  - Costs associated with right of way (ROW), development of new roads, maintenance of existing roads, and tree clearing
  - Environmental mitigation cost, e.g., hazardous materials and contaminated waste removal
  - Extra duct provision in duct bank
  - Cost related to relocate the existing utilities and constructions in ROW
  - Cost for underground/overhead facilities and mitigation plan
  - Underground survey cost

- Work associated with unforeseen environmental and geotechnical issues
- Survey related free and cost
- Cost related to spare equipment
- Cost for energized cable work and helicopter-assisted tower erection
- cost of temporary feeders and temporary power supply
- Hotline work
- Temporary line
- Helicopter work
- Other contingency costs

- In addition to what has been excluded in the onshore cost estimate, following might have material impact on the provided cost estimate:

  - Construction period was assumed to be summer and fall months; winter construction factor was not included. Seasonal or weather-related impacts were not considered.
  - Due to limited access to detailed specifications and engineering data, cost estimates associated with some material items and construction activities such as HVAC and HVDC power cable, engineering steel pole, foundation, and duct bank cost prices may be less accurate compared to others. It is understood that the cost of such items and activities may vary and could affect the accuracy of the estimate.
  - Assumed transmission line foundation and duct bank design may change after geo-tech results, which could affect the provided cost estimation.
  - Additional permits due to transmission lines crossing roads and/or railway.
  - Community opposition due to transmission lines and cables crossing residential and commercial communities.
  - More changes in pole location due to residential/commercial area and underground facilities.

8.1.2 Onshore Cost Estimate Results

Based on the three OSW connection concepts described in Section 7, eight cable routes were identified and evaluated from a cost standpoint. The identified onshore routes are identical among the three offshore connection concept variants (Radial, Meshed, and Backbone) described in Section 7. Each route consists of AC or DC cables from landing points to the onshore POI along with transformer or converter stations, as applicable.

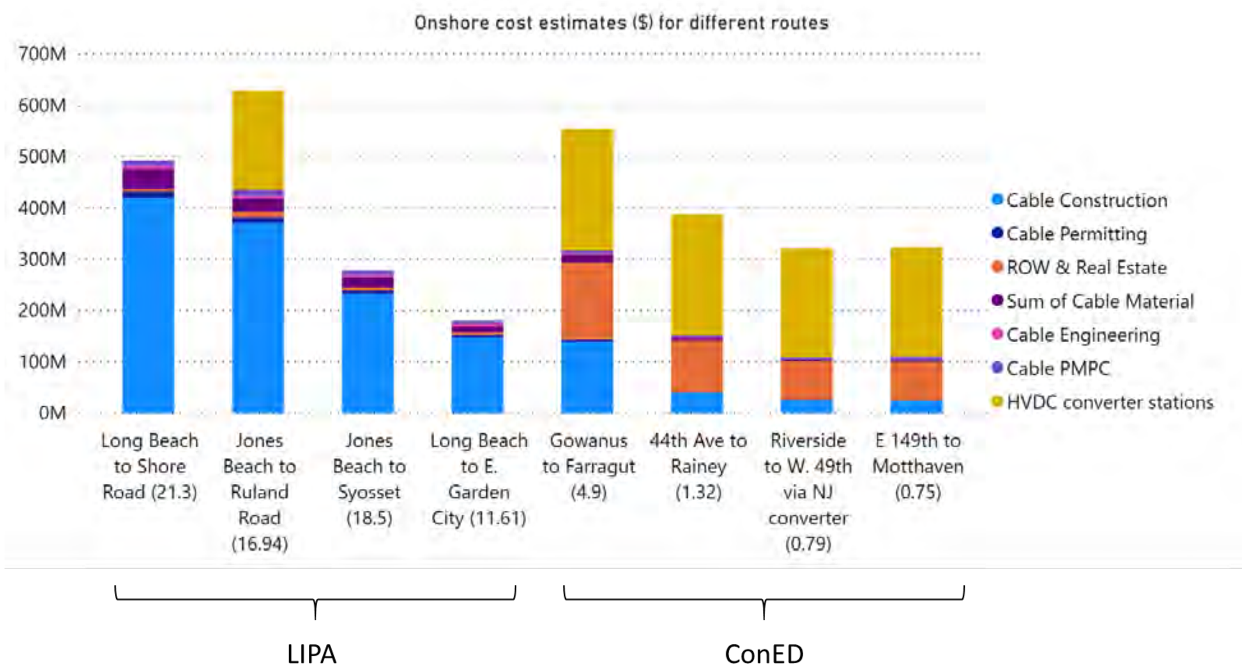
The costs are illustrated in Figure 8-1 with the following key observations:

- For the five routes involving HVDC converter stations, the costs of HVDC converter stations are the largest or second largest cost item.

- For the routes in LIPA area, the major cost component is related to construction of underground AC and DC cables due to relatively long onshore cable lengths.

- The ROW and real estate costs contribute substantially to the four HVDC routes in the ConED area, driven by the larger parcel areas and high land cost in the area.

Figure 8-1. Cost Estimate of the Eight Onshore Cable Routes



M=U.S. $millions

Numbers in (parenthesis) after the route names indicate the cable lengths in miles

Table 8-1 presents the detailed cost estimate buildup for each of the eight onshore cable routes. The column Cable Size specifies the configuration of underground AC and DC cables, including voltage level, conductor material, number of cables, and conductor size. For example, cell text 2x2250mm2 Cu 320kV HVDC specifies that the cable route consists of HVDC cable section with two single-core 320 kV HVDC cables, copper conductor with cross-section of 2250 mm^2 each.

Table 8-1. Onshore Cable Routes and Cost Estimate Overview

Route #/Name	Underground cable							Converter/ Transformer Stations	ROW & Real Estate	Total Cost Ex Land
	Cable Size	DC / AC Cable Length (Mile)	Material	Construction	Engineering	*PMPC	Permitting			
Gowanus to Farragut	2x3x1400mm2 Cu 345 kV HVAC	0/4.94	$14.79 M	$138.61 M	$2.56 M	$6.78 M	$4.16 M	$236.70 M	$150.00 M	$403.59 M
E 149th to Motthaven	2x2250mm2 Cu 320kV HVDC and 2x3x1400mm2 Cu 345kV HVAC	0.45/0.3	$3.71 M	$23.46 M	$0.69 M	$6.02 M	$0.70 M	$213.25 M	$75.00 M	$247.83 M
44th Ave to Rainey	2x3x1400mm2 Cu 345 kV HVAC	0/1.32	$5.60 M	$39.43 M	$1.40 M	$33.18 M	$1.18 M	$236.70 M	$100.00 M	$287.48 M
Riverside to W. 49th via NJ converter	2x3x1400mm2 Cu 345 kV HVAC	0/0.79	$3.41 M	$24.85 M	$0.37 M	$3.44 M	$0.75 M	$213.25 M	$75.00 M	$246.07 M
Long Beach to Shore Road	3x800 mm2 Cu & 3x500 mm2 Cu 220 kV HVAC	0/21.3	$38.63 M	$418.95 M	$6.27 M	$10.70 M	$12.57 M		$4.80 M	$487.12 M
Jones Beach to Syosset	3x800mm2 Cu 220kV HVAC	0/18.5	$19.85 M	$232.64 M	$4.53 M	$8.44 M	$6.98 M		$4.80 M	$272.44 M
Jones Beach to Ruland Road	2x1800mm2 Cu 320 kV HVDC and 3x3x2500mm2 Cu 138 kV HVAC	16.62/0.32	$26.15 M	$370.00 M	$4.87 M	$12.03 M	$11.10 M	$193.14 M	$11.00 M	$617.29 M
Long Beach to E. Garden City	1x3x800mm2 Cu 220 kV HVAC	0/11.61	$13.19 M	$147.23 M	$3.80 M	$6.76 M	$4.42 M		$4.80 M	$175.40 M
Total			$125.34 M	$1,395.17 M	$24.50 M	$57.35 M	$41.85 M	$1,093.02 M	$425.40 M	$2,737.22 M

The cost data as listed in Table 8-1 will be used in the combined onshore/offshore cost assessment as follows:

- The aggregated ROW and real estate cost is ~ $425 million, as most of the intended area are at least partially owned by public entities in the New York State, it is not likely that land will/can be procured using commercial real estate price. During the later parts of this report, land costs are excluded from the cost assessment.
- The aggregated onshore cost excluding the land cost is ~ $2,737 million, and this cost item will be used among the three offshore variants.

8.2 Offshore Costs

8.2.1 General Assumptions

Offshore cost estimation includes procurement cost, installation cost, and project overhead cost. Procurement cost includes direct material cost, labor cost, R&D cost, and profit margins. The project overhead cost covers the cost related to project management, surveys, and studies.

Market fluctuations and location-specific cost drivers are excluded from the offshore cost estimation. The cost estimation for 2020 is based on historical cost data from year 2017. The cost of each OSW project could be impacted by certain specific cost drivers such as required ancillary services, redundancy level, the scope of service contract, ambient temperatures, water depth, and cable routing. Except for offshore platforms, those specific drivers will not be considered at each OSW project level, instead they were considered on an average basis.

In the majority of cases, the primary focus will be the technical performance parameters of the offshore electrical components specifically power and voltage ratings for HVDC converters and cables. The cost estimation will generally not differentiate among alternative implementations that offer the same functionalities and performances, for instance:

- When applied in VSC HVDC applications, both XLPE (cross-linked polyethylene) cable and mass impregnated cable can be used and have similar performances.

- Various solutions of offshore HVDC platforms can be used such as jacket, jack-up, and gravity-based structures (GBS).

8.2.2 Unit Cost Data of Key Offshore Components

In this subsection, the unit cost data for major offshore components are presented. The offshore component cost is then broken down to different cost elements with their corresponding percentage contribution to total. The cost elements include the cost of equipment, installation and transportation, civil works, project management, right of ways, risk contingency, and profit margin. For the important component categories, high-level cost breakdowns are also provided in stacked totem charts.

HVDC and HVAC Cables

- For HVDC cables, two separate cables (positive and negative pole) which will be laid in parallel to connect the HVDC converter station with symmetric monopole topology. Two metallic return cables were considered if the topology of bi-pole with metallic return was selected for the HVDC converters.

- For HVAC cables, the underground section was assumed to use three single core cables whereas the submarine section was assumed as one three core cable.

- The total cost of cables includes procurement cost, installation and transportation cost, project overhead cost and ROW cost.

The unit cost data of HVDC and HVAC cables at various voltage and power ratings are listed in Table 8-2 and Table 8-3, where for each configuration the cost data of submarine cables are provided.

Table 8-2. Unit Cost Data of HVDC Submarine Cables

Voltage (kV)V	Rating of the Pair (MW)	CAPEX for Two Poles (M$/Mile)
±320	1,000	2.9
	1,300	3.1

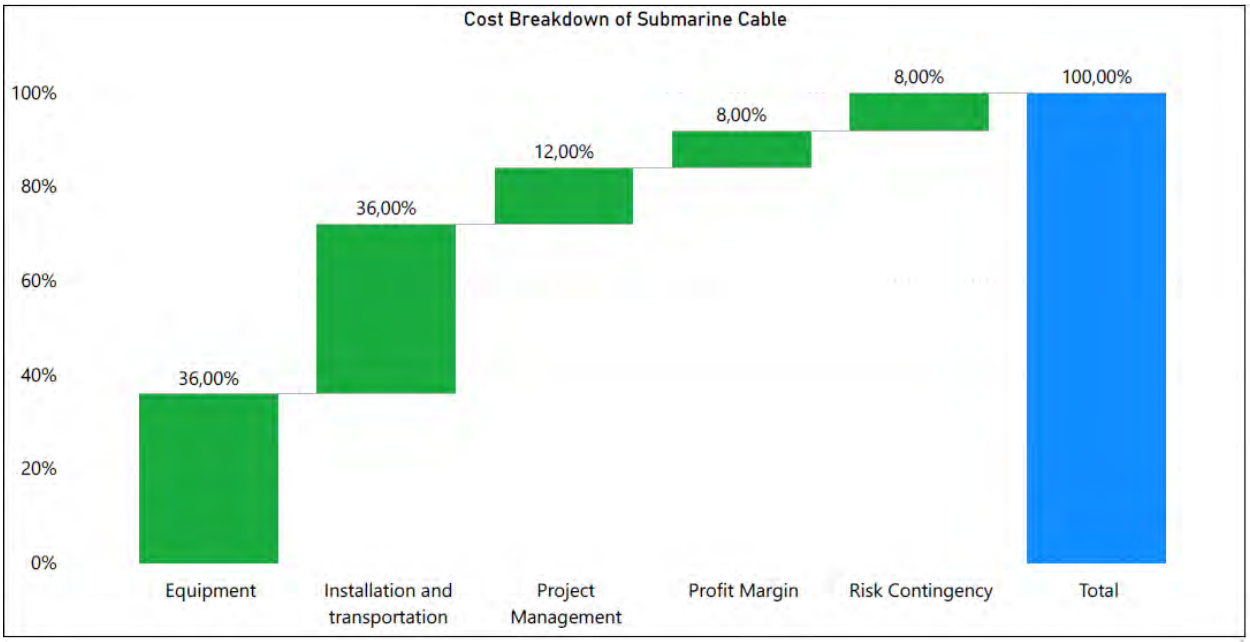
Table 8-3. Unit Cost Data of HVAC Submarine Cables

Voltage (kV)	Rating of the Pair (MW)	CAPEX for three-core submarine cables (M$/Mile)
220	300	2.5
	400	2.7
	500	2.9

OPEX is assumed to be approximately 2.5% of the CAPEX for submarine cables, and 0.05% for underground cables.

Typical cost breakdown for the submarine cables is shown in Figure 8-2. It is worth noting that within the cost breakdown for submarine cables, the cost of the equipment (cables) is equal to those of installation and transportation.

Figure 8-2. CAPEX Breakdown for Submarine Cables



HVDC converter stations

The unit cost data of Half-Bridge (HB) VSC converter stations are listed in Table 8-4. It is worth highlighting the following:

- **Impact of converter configuration:** The majority of the awarded HB VSC based OSW projects have chosen the symmetric monopole configuration; therefore, it was assumed the cost data from various sources are mainly based on the symmetric monopole configuration. With the increase of power rating, voltage levels, and requirement for higher redundancy in the HVDC projects, it is foreseeable that some OSW projects might adapt configurations such as rigid bipole or bipole with metallic return. The change from symmetric monopole to bipole will incur higher cost for the converter stations due to more expensive converter transformers, additional switchgears, electrodes, and increased complexity of control and protections.

- **Impact of physical location:** The cost of offshore converters is expected to be substantially higher than onshore converters with the identical technical parameters, mainly caused by the offshore related requirement.

Table 8-4. Unit Cost Data of Half-Bridge (HB) VSC HVDC Converter Station

Voltage (kV)	Rating (MW)	CAPEX (M$)	
		Onshore HB VSC	Offshore HB VSC
±320	1,000	212.2	265.3
	1,300	260.0	325.0

In addition, the cost data provided herein is intended to cover the entire converter station, including the converter transformers, DC reactors, AC/DC yards, gas insulated switchgear (GIS), control and protection system.

OPEX for converter stations was assumed to be 0.07% of the CAPEX for the onshore stations, and 2% for the offshore stations. Typical cost breakdown for offshore and onshore converter stations are shown in Figure 8-3 and Figure 8-4, respectively.

Figure 8-3. CAPEX Breakdown for Offshore VSC Converter Stations

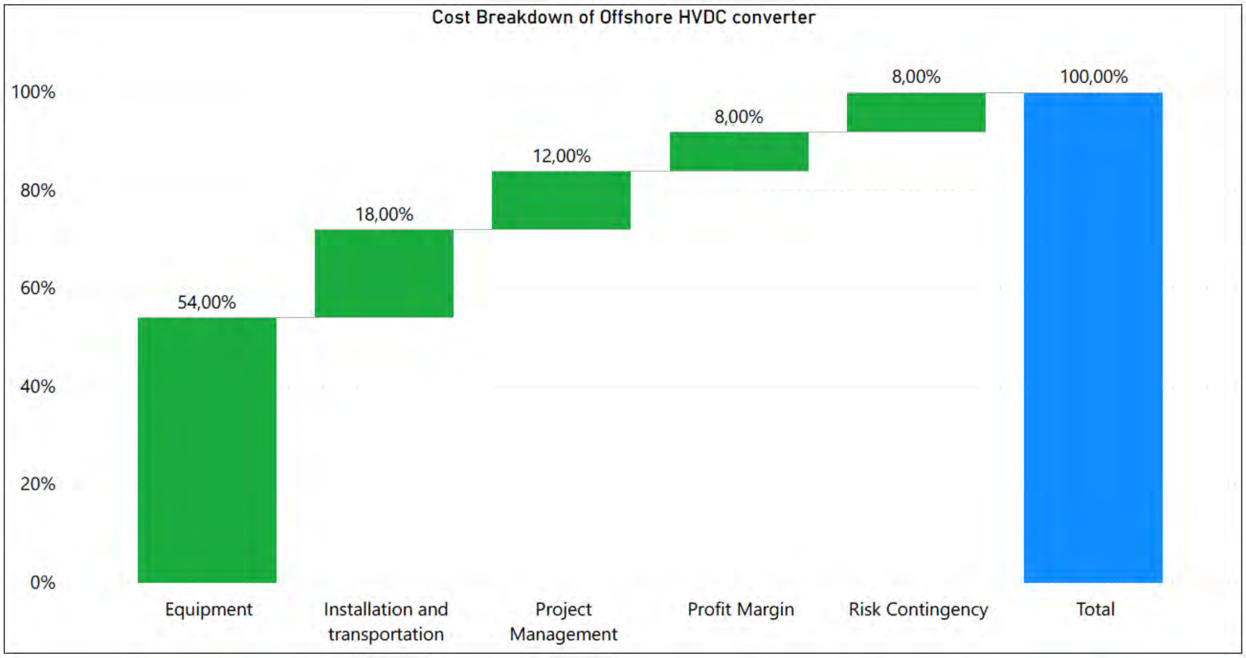
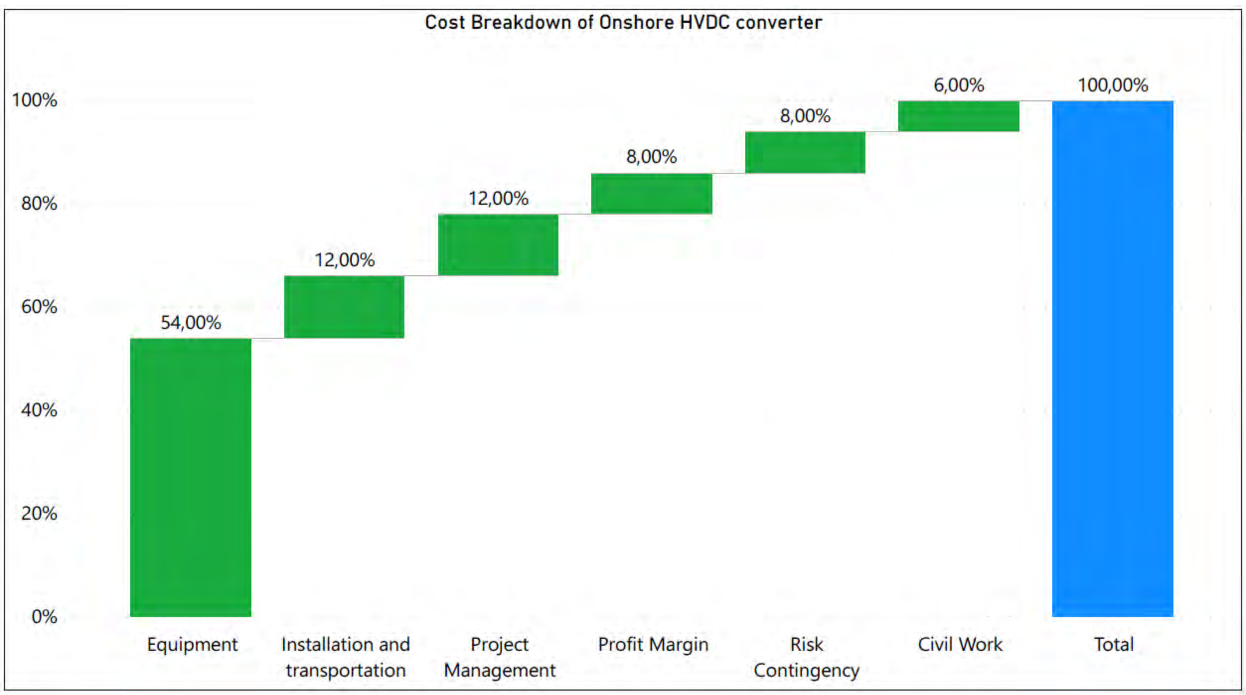


Figure 8-4. CAPEX Breakdown of Onshore VSC Converter Stations



Offshore HVAC and HVDC Platforms

The unit cost data for offshore HVAC and HVDC platforms are provided in Table 8-5 and Table 8-. Due to the high-level characteristics of the Study, no detailed studies were carried out to determine specific sites or foundation structures for proposed offshore platforms. Therefore, the cost specified here and used in later sections is generic data which represents the mean values of a relatively wide cost range for each of the power and voltage ratings. Note, the following factors should be considered when applying this cost data:

- **Platform design**. The type of platform design will impact the platform cost. There are three main types of platform structural design: jacket, jack-up, and GBS. Jacket is expected to be in the lower range of the cost interval, while jack-up and GBS designs are traditionally more expensive.
- **Water depth**. The platform cost will increase with the water depth; a taller substructure is needed for deeper water.
- **Geological condition on the seabed**. More complex seabed increases the installation cost.
- **Weather conditions**. Higher wind and/or wave load will increase the need for a stronger and heavier substructure.
- **Installation concept**. The transportation and installation cost will differ depending on the installation concept.

    - Heavy lift. The lifting capacity of the crane vessel is the main constraint associated with heavy lift installations. Large topsides must be installed as prefabricated topside modules and assembled in the field.
    - Float-over installation concept exceeds the maximum capacity of heavy lift vessels and allows platform topsides to be installed as one integrated package without a crane vessel. Hence, an integrated topside can be completed onshore, which reduces the substantial costs of doing commissioning offshore.
    - GBS concept has the lowest transportation and installation cost, however the structure (semi-submersible) is more complicated and hence with higher construction cost.

Table 8-5. Unit Cost Data of Offshore HVAC Platforms

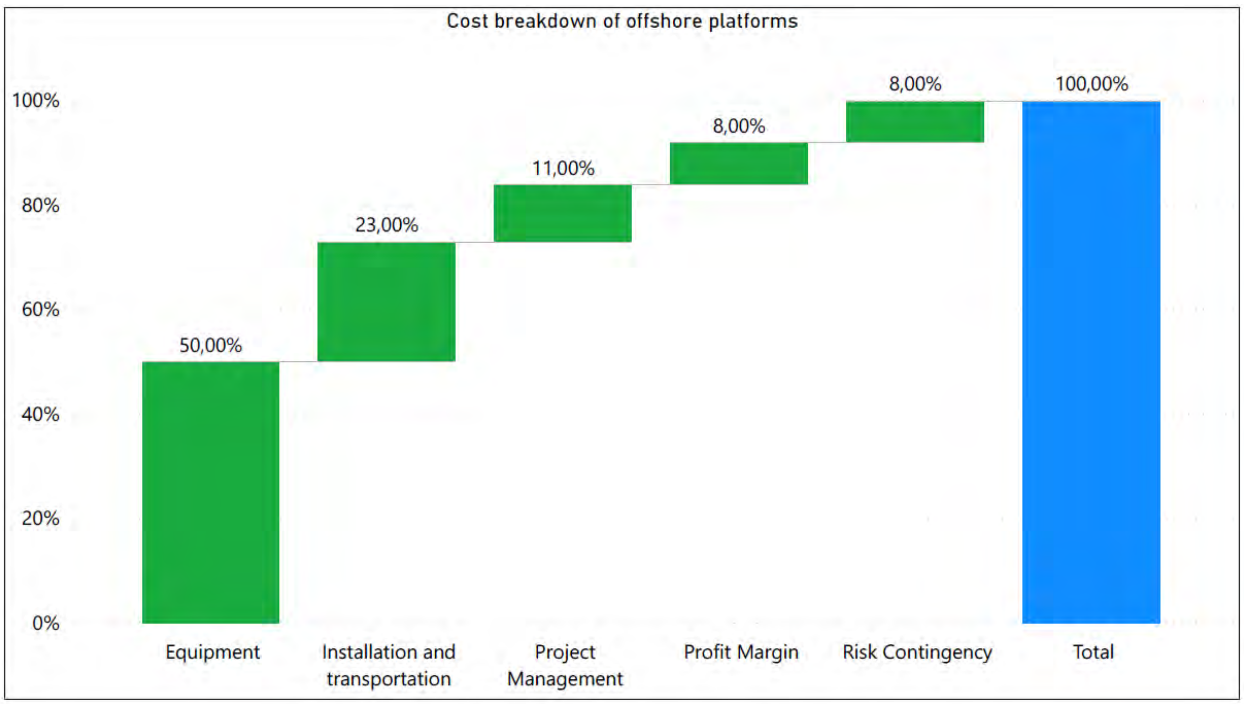
Voltage (kV)	Rating (MVA)	CAPEX (M$)
220	300-500	62.7

Table 8-6. Unit Cost Data of Offshore HVDC Platforms

Voltage (kV)	Rating (MW)	CAPEX (M$)
±320	1,000	337.7
	1,300	407.3

OPEX for offshore platforms is about 2% of the CAPEX including installation. A typical cost breakdown for offshore platforms is shown in Figure 8-5.

Figure 8-5. CAPEX Breakdown for Offshore Platforms



8.2.3 Combined Onshore and Offshore Cost Assessment

Using the unit cost data as defined in Section 8.2.2 and the connection designs in Sections 7.1 through 7.4, the overall CAPEX/OPEX/REPEX of the offshore grids to connect 7.2 GW OSW projects were calculated for the three variants (V1: Radial, V2: Meshed, and V3: Backbone). Those, together with the onshore cost estimate results, are listed in Table 8-6 in 2020 nominal dollars. The cost breakdown of the three variants are further illustrated as waterfall bar charts in Figure 8-6, Figure 8-7, and Figure 8-8, respectively.

Table 8-6. The Comparison of Combined CAPEX of the Three Variants

	V1 Radial		**V2 Meshed**		**V3 Backbone**	
	CAPEX (M$)	Item Count or Cable Length (Mile)	CAPEX (M$)	Item Count or Cable Length (Mile)	CAPEX (M$)	Item Count or Cable Length (Mile)
HVAC submarine cable	376	225	767	457	773	474
HVDC Submarine Cable	1,627	885	1,627	885	1,657	901
HVDC Offshore Converter	1,373	5	1,373	5	1,373	5
AC Transformers	28	8	28	8	46	12
Reactive Compensation	47	8	115	20	175	30
HVAC Offshore Platform	228	4	228	4	433	8
HVDC Offshore Platform	1,710	5	1,710	5	1,710	5
Onshore Cost	2,737		2,737		2,737	
Total CAPEX	**8,127**		**8,586**		**8,905**	

Figure 8-6. CAPEX Breakdown of V1 Radial

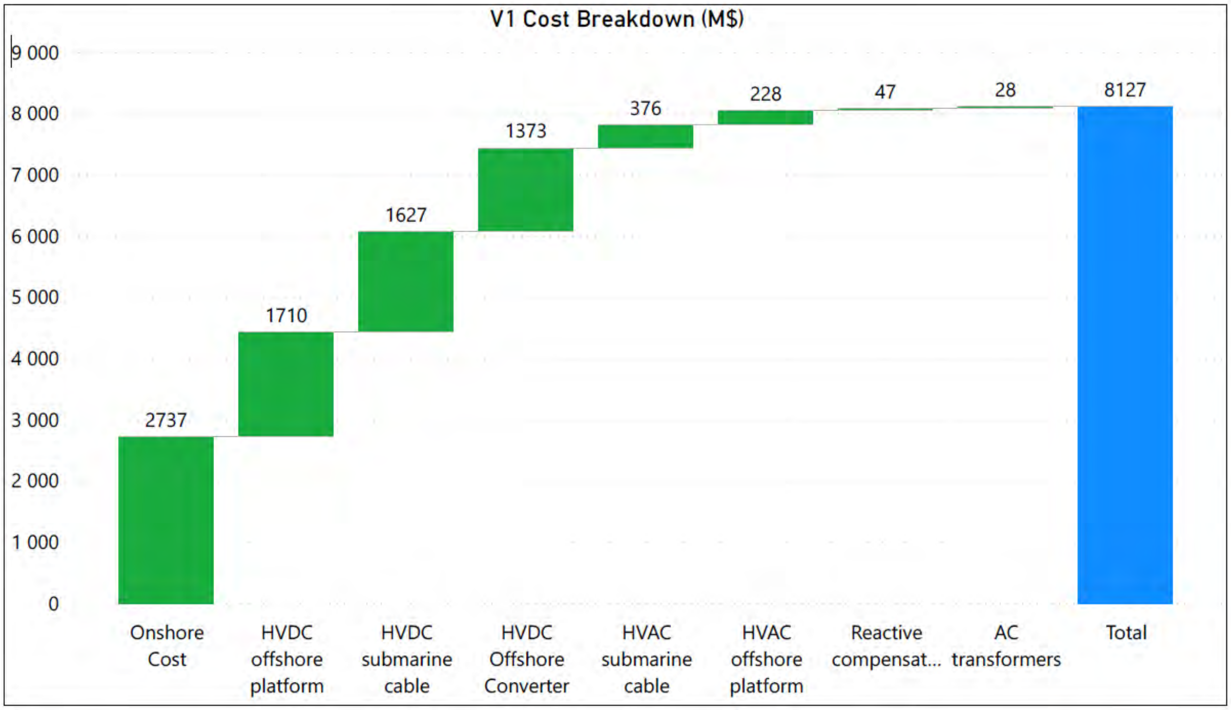


Figure 8-7. CAPEX Breakdown of V2 Meshed

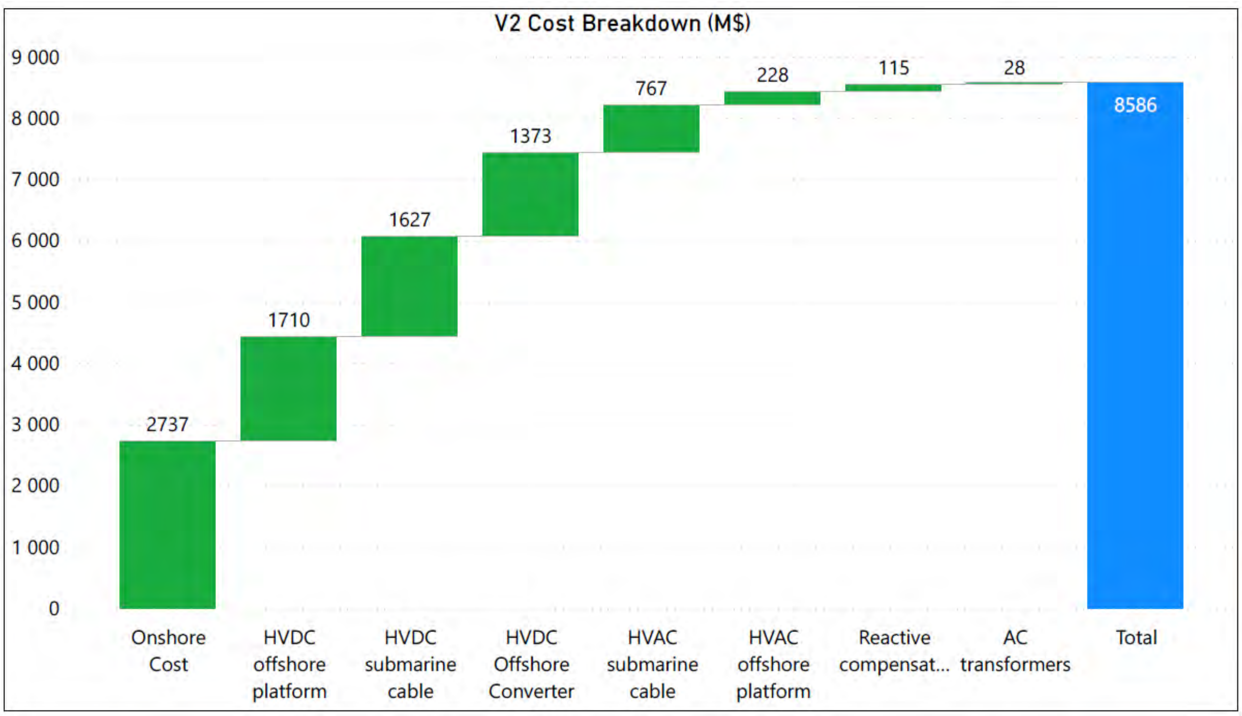
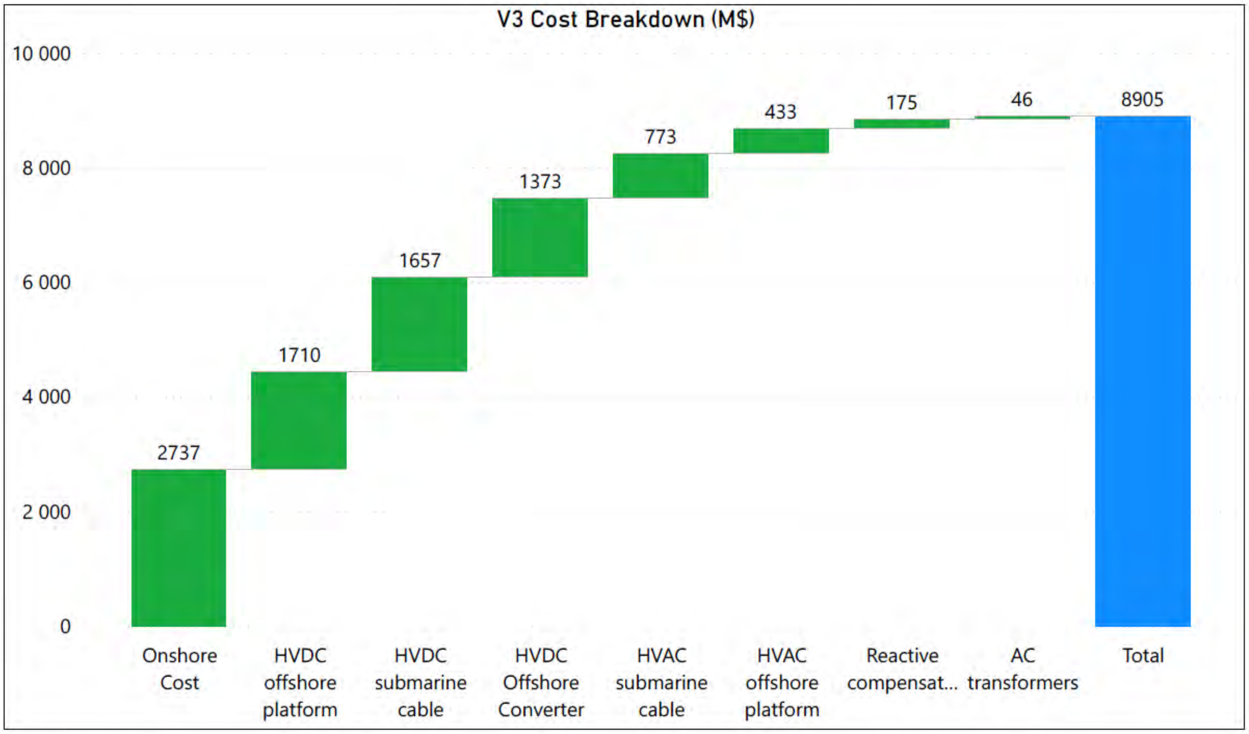


Figure 8-8. CAPEX Breakdown of V3 Backbone



The OPEX and REPEX of the three variants are listed in Table 8-7. The REPEX is estimated to be $15.5 million per platform in nominal 2020 values, occurring two times over the project lifetime.

Table 8-7. OPEX and REPEX of the Three Variants

	OPEX (M$/year)	REPEX (M$)
V1 Radial	127	278
V2 Meshed	138	278
V3 Backbone	144	402

It should be noted that the onshore and offshore cost estimates provided in previous sections will be impacted by factors such as local seabed soil, wind and wave conditions, and market and supply chain fluctuations. Those factors could result in a ±30% error band on the cost estimate; furthermore, the uncertainty on future cost reduction of power transmission system componentry could result in an additional ±9.5% uncertainty. These factors together suggest a total uncertainty associated with the cost estimates of ±39.5%.

8.2.4 Levelized Transmission Cost of Energy (LTCOE)

An industry standard approach to calculate the costs of generating electricity and compare energy production technologies at conceptual stage is using a levelized cost of generating electricity. This is an overarching comparison parameter where the summation of discounted CAPEX, REPEX, and OPEX are divided by the discounted electricity generation. It is important to note that in the context of this study, only transmission costs have been evaluated, not other large cost drivers like the turbine and turbine foundation costs. In order to compare the different transmission costs with their estimated electricity generation, the LTCOE has been introduced. It follows the same principles as the LCOE, but only considers the costs evaluated in this study. The LTCOE is the ratio of lifetime costs to lifetime electricity generation, both discounted. The LTCOE reflects a price of electricity required for the total 7.2GW buildout, where revenues would equal transmission costs, including a return on capital invested equal to the discount rate. The formula applied is:

$$LTCOE = \frac{\sum_{t=1}^{n} \frac{C_t + M_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where:

LTCOE	= Levelized Transmission Cost of Energy
C_t	= Capital expenditures in the year t
M_t	= Operations and Maintenance expenditures in year t
E_t	= electricity generation in year t
r	= discount rate, equal to the weighted average cost of capital (WACC)
n	= economic life of the system

Capital expenditures in nominal 2020 values are provided in Table 8-6. The capital expenditures have been split by investments related to the wind generation capacity operational by 2030 and by 2035. The costs have been made real by applying an inflation rate per year of 1.45%, which equals the average

OECD producer price indices over the period 2015 to 2020. It is assumed that investments are made two years before start of operations.

Operations and maintenance expenditures in nominal 2020 values are provided in Table 8-7. The split is made between the 2030 and 2035 operational wind generation capacity and costs have been inflated accordingly. REPEX has been included twice over the project lifetime.

The net present value of the total costs has been calculated by discounting the costs with a discount rate equal to the WACC of 7.5%, reflecting 55% debt, 45% equity, a cost of equity of 12%, a cost of debt of 5% and a corporate tax rate of 21%. An economic life of the overall system has been set to 25 years.

The electricity generation in each year has been estimated by multiplying the total installed production capacity in that year with a net capacity factor, the hours in a year and accounting for losses from blade degradation.

Main assumptions:

Total installed production capacity	=	7.2 GW
Net capacity factor (Radial design)	=	53%
Hours in year (including leap years)	=	8,766 hours
Losses from blade degradation	=	0.06% per year

The net capacity factor is defined as the capacity factor measured at POI, therefore it accounts for transmission losses and availability (availability values presented in Section 8.3).

This gives an estimated yearly electricity generation from the Radial design in a year with the full 7.2 GW operational of 33.2 TWh per year, reducing to 32.7 GWh per year after 25 years of operations due to assumed losses from blade degradation over the project lifetime.

The electricity generation in each year is discounted with the same discount factor of 7.5%. This might be observed counter intuitive as electricity generation is not a monetary value but is explained by electricity generation reflects future revenues, meaning the time value of money needs to be considered.

Table 8-8 provides the LTCOE of the three variants. The LTCOE of Radial is 31.5 $/MWh and the LTCOE of the Meshed is 33.3 $/MWh. This means the Meshed design would require an estimated 1.8 $/MWh higher electricity price over the 25 years of operating 7.2 GW in capacity than the Radial design to cover transmission costs, including a return on capital invested equal to the discount rate.

Table 8-8. LTCOE of the Three Variants

	7.2 GW of OSW Projects	
	LTCOE Estimate ($/MWh)	**Uncertainty Range ($/MWh)**
V1 Radial	31.5	22.6 - 44.0
V2 Meshed	33.3	23.9 - 46.5
V3 Backbone	35.1	25.2 - 49.0

The baseline uncertainty in the onshore and offshore cost estimates of ±30% combined with the ±9.5% uncertainty due to the technology learning curve applied to model reduction in costs over time, directly translates into the LTCOE uncertainty, presented in the second column of Table 8-8. The Meshed design has all the components from the Radial design plus added cables and reactive compensation. This means there is no situation where the Meshed design would have a lower LTCOE than the Radial design due to uncertainty span in the estimates.

8.2.5 Sensitivity of LTCOE results to the WACC

Offshore wind is very capital-intensive and has zero fuel costs. The weighted average cost of capital (WACC) applied as discount rate has therefore a critical role in the LTCOE calculations. The main purpose of the LTCOE in this study is to provide a comparative ratio of lifetime costs to lifetime electricity generation to compare the different designs. Every design is evaluated using the same discount rate of 7.5%.

There is, however, large uncertainty in what the WACC will be in 10 to 15 years from now. In today's low-interest environment, a discount rate of 7.5% is considered relatively high, as it reflects 55% debt, 45% equity, a cost of equity of 12%, a cost of debt of 5% and a corporate tax rate of 21%. Currently observed in the market is a reducing risk perception for offshore wind, resulting in higher leverage and lower cost of debt. In order to quantify the impact of the WACC, a sensitivity has been analyzed where the WACC is set to 5%, which implies 70% leverage, 10% cost of equity and 3.7% cost of debt. The LTCOE for the Radial, Meshed, and Backbone variants are reduced by 18%, all else equal.

8.3 Offshore Topology Availability Analysis

8.3.1 Availability Calculation Methodology

An important aspect in comparing grid concepts is the expected availability of the link. The average annual transmission availability is expressed in terms of available transmission capacity, outage times and, ultimately, the respective energy not transmitted. The transmission availability is generally defined as the ratio of the time integral of available power capacity over the time integral of an uninterrupted year's power capacity [20].

$$Transmission\ Availability = \frac{Transmitted\ Energy}{Total\ Available\ Energy}$$

where Total Available Energy is defined as: $E_{normal} + \sum E_{i,planned} + \sum E_{i,unplanned}$

where E_{normal} is the energy actually transmitted in *no-outage* condition, $E_{i,planned}$ is the energy that would have been transmitted during *planned-outages* condition periods(e.g. planned maintenance), and $E_{i,unplanned}$ is the energy that would have been transmitted during *unplanned-outage* periods (e.g. forced outage due to export cable failure).

The latter definition of availability is used to determine the performance of each of the 3 OSW connection concepts developed (Radial, Meshed, and Backbone). Usually an availability target is set as an incentive scheme for grid developers and owners: typical values of availability target are set around 97% to 98% [21].

To estimate the annual transmission availability, it is crucial to know the reliability (i.e., the failure probability) of the transmission assets (i.e., cables, joints, terminations, etc.). The failure of an asset has a fundamental impact on the forced outage of the respective transmission that can last for an extended period of time, until repair. The transmission availability is calculated by considering annual forced and planned outage times of the main components: the converter stations/transformers and the cables. A typical availability study considers:

- Probability of a failure
- Outage duration in case of a failure
- Remaining or redundant capacity during outage time

Cable outage statistics are typically expressed as a failure rate or mean time between failures (MTBF). The only publicly available repository of cable failure rates is the Conseil International des Grands Réseaux Electriques brochure [22]. Please note it is not recommended to use these values to compute the MTBFs of a system in realistic absolute terms to predict failures; however, it is considered reasonable to adopt these values for a comparative analysis between different grid concepts.

For the reliability calculation, a distinction is made between the type of component (e.g., joint, cable, or termination) and the type of failures due to internal causes (e.g., degradation of insulation material, poor installation practice, bad cable manufacturing, etc.) or external causes (e.g., damage by an anchor or a digging machine, etc.). Furthermore, a distinction is made between different voltage ratings, insulation material, AC and DC cables, underground or submarine, and various cable protection (installation or burial) methods.

To account for the mean time to recovery, the outage time between the occurrence of a failure and the repaired circuit being taken back into service again have been considered. Generally, these are divided in three parts [23]:

- Fault identification and restoration time
- Preparation and waiting time
- Repair and commissioning

After an outage has occurred on a specific link (planned or unplanned) the remaining unaffected part of the system can continue its transmission operation. The remaining power export capacity of the system during an outage is thus determined by the specific system topology. The presence of redundant links can generally increase the remaining capacity during outages. For the specific three OSW connection concepts evaluated, it is assumed the export capabilities during an outage follow a best-path approach, i.e., the power transmitted to shore is maximized compatibly with the redundant and existing link capacity, regardless of possible different control and operation strategies. The available wind power fluctuation is always considered for both normal and outage conditions.

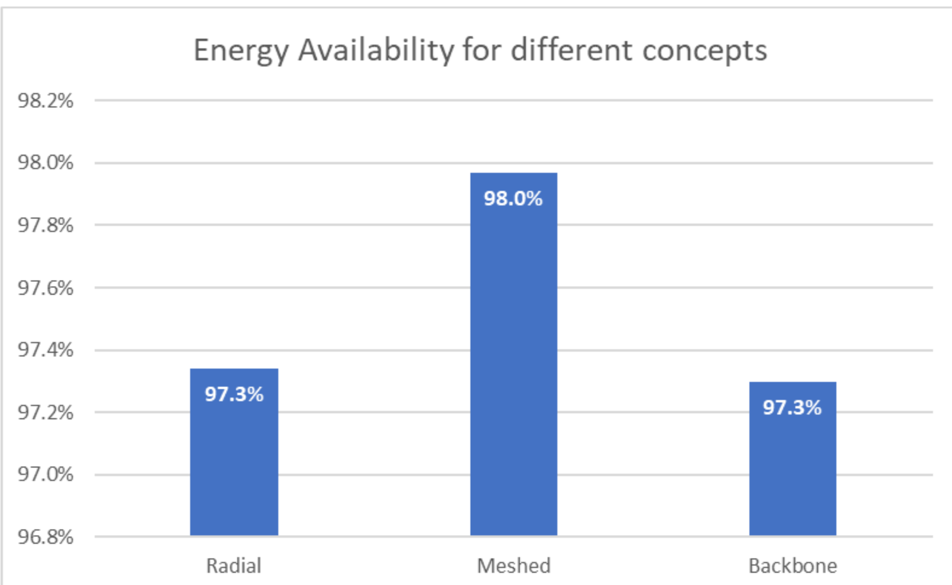
The information about the outage times (planned and unplanned) together with the remaining power export capacity during the respective outage, allows for the calculation of the $E_{i,unplanned}$, $E_{i,planned}$, and E_{normal} previously mentioned and the total transmission availability.

The model developed by DNV GL for availability calculation is periodically benchmarked with real cases and publicly available data (e.g., National Grid ESO report for the Nordic Sea OWF [24]).

8.3.2 Availability Results

The expected availabilities for different concepts are shown in Figure 8-9.

Figure 8-9. Energy Availability for Three Variants

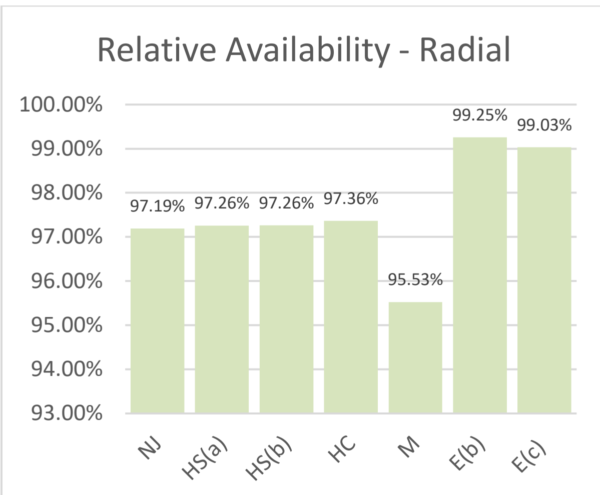


The scenarios have been compared on an annual outage time and energy availability basis. For the actual transmission availability calculations, wind energy profiles and associated net capacity factors for hypothetical OSW projects were provided by NREL. In all cases, the submarine cable configuration impacts the availability calculation, together with the number of necessary joints and technology (AC/DC) used.

A summary of the calculated results is given in the following points:

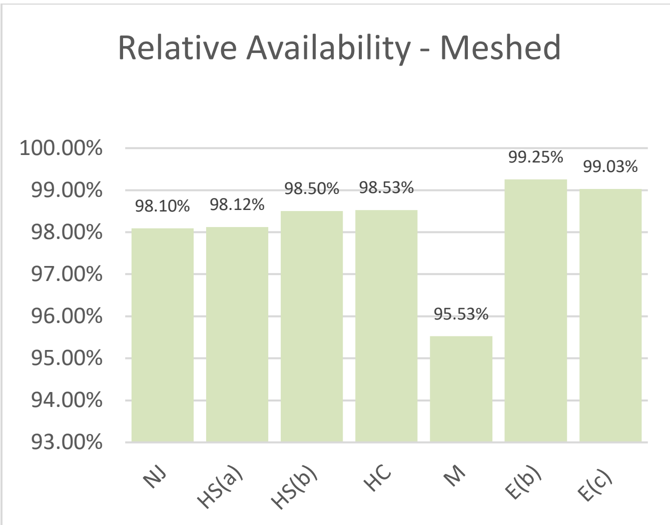
- **Radial concept**: The concept shows a total calculated availability of 97.3% for the entire 7.2 GW studied. All the links to shore are, in fact, point-to-point links. The failure of a link generates the total loss of the energy produced by the respective OSW project connected. A breakdown of the individual connector availabilities is shown in Figure 8-10.

Figure 8-10. Transmission Availability Calculated for the Individual Connections of the Radial Concept



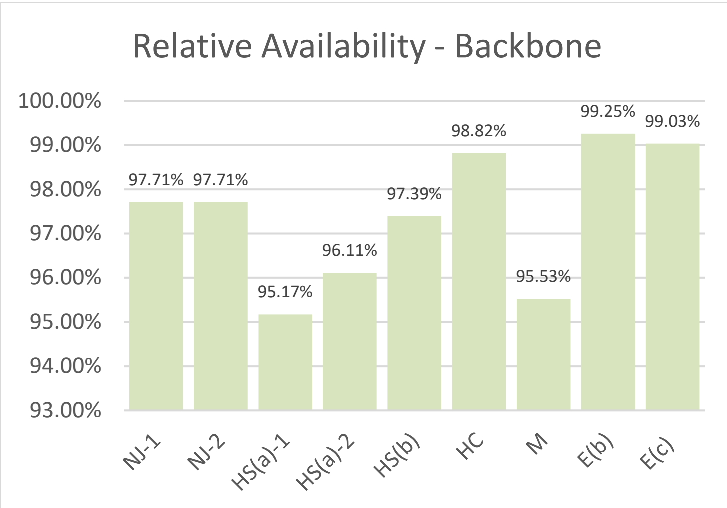
- **Mesh concept**: This concept resulted in the highest calculated availability of 98.0%. This result is mainly attributed to the added redundancy for the energy transmission given by the interconnected OSW projects. The calculated availability reflects on the total 7.2 GW, while Meshing is only part of the design for four OSW projects feeding into New York City. This explains why the Mesh concept shows only a marginal increase in availability when compared to the Radial concept. Moreover, the Mesh links are energized and floating during no contingency and only transmit power during contingency when lower than maximum wind allows for available capacity on adjacent interconnectors. These factors have been considered. A breakdown of the individual connector availabilities is shown in Figure 8-11.

Figure 8-11. Transmission Availability Calculated for the Individual Connections of the Meshed Concept



- **Backbone concept**: The Backbone concept resulted in total availability comparable to the Radial concept. Despite providing interconnection between OSW projects and added redundancy, the reconfiguration of offshore connections (to match onshore POI threshold and maximum single contingency) require that the Backbone length of submarine cables continuously transmit power. This has an impact on availability calculations as the MTBF and mean time to recovery of the Backbone are considered. The main difference with the Mesh is that the Backbone interconnectors are continuously transmitting while in the Mesh concept the interconnectors are transmitting only in case of contingency. In addition, some platforms (HS(a)-1 and HS(a)-2) only reach the shore via platform-interlink routing, even in normal operation condition. This results in a longer route and the transmission is more susceptible to contingencies. A detailed breakdown of the individual transmission availabilities for every platform is given in Figure 8-12. Please note, for the Backbone concept, additional platforms are present when compared to the Radial and Meshed cases.

Figure 8-12. Transmission Availabilities Calculated for the Individual OSW in the Backbone Concept



The result of the transmission availability analysis show that the Mesh concept leads to the highest reliability among the three investigated concepts. The Backbone concept, despite adding redundancy due to the presence of inter-links between platforms, showed comparable reliability to the Radial concept.

9 Findings

Overall, the onshore analysis identified scenarios for injecting of 6 GW of OSW into New York City and 3 GW into Long Island that minimized onshore transmission system upgrades and that involved very limited OSW curtailment. However, if more OSW capacity (~ 4GW) is injected into Long Island, there is expected to be an increased risk of OSW energy curtailment and that onshore system upgrades are likely needed and may necessitate the addition of a new tie-line in order to export offshore wind energy from Long Island.

A transmission cable routing feasibility assessment was conducted to evaluate the environmental and permitting challenges of routing transmission cables from potential offshore lease areas to substations identified in the onshore grid assessment previously mentioned. Major potential constraints were identified for many of the illustrative route segments, but these challenges may be overcome with suitable planning and outreach efforts. Thus, the assessment supports a finding that the illustrative routings examined in the Study are feasible. Other key findings of the routing assessment include the following:

- The analyzed onshore routes could feasibly accommodate between two and six separately installed cable circuits.
- Six separate cables (or circuits) could feasibly be installed through New York Harbor to the analyzed substations.
- Given the complexity of bringing cables into New York City, either via New York Harbor or Long Island Sound, coordination of transmission will be needed regardless of the offshore transmission configuration concept and alternative approaches for bringing offshore wind energy into New York City should also be explored to manage the potential risk.

As part of the offshore transmission assessment, uncertainties around the future development of OSW projects, including their locations and area sizes, were considered by developing five illustrative OSW build-out scenarios. These scenarios represent a possible range of geographically diverse future outcomes that could potentially occur. For each OSW build-out scenario, five offshore transmission connection concepts (Radial, Split, Shared Substation, Meshed, and Backbone) were developed. Preliminary analysis of the assumed OSW build-out scenarios along with the OSW connection concepts was indicative of the following key observations:

- The relative benefits and cost comparisons of OSW connection concepts remained consistent in all assumed OSW build-out scenarios, which suggests that a single representative OSW build-out scenario can be utilized for detailed analysis and costing to determine the relative performance of the OSW connection concepts with minimal risk of compromising key findings.

- For OSW networked connection concepts (i.e. substation sharing, Mesh, or Backbone) to be economically justifiable, the networked connection concept should encompass at least three OSW projects with minimum aggregate rating of approximately 3 GW.

- Uncertainty related to the availability of wind energy areas (WEAs) makes it challenging to pivot from an OSW's Radial connection concept to other OSW networked connection concepts.

    - However, these challenges could be overcome by proper upfront preparation and investments (e.g., over-sizing cables, converters and additional breaker positions).

    - In addition, among all OSW connection concepts studied, the Meshed connection concept was observed to be the most flexible considering WEA uncertainty.

    - Furthermore, moving from a Radial connection concept to substation sharing connection concept is expected to be relatively more challenging given WEA and OSW project location uncertainty.

- Close coordination with BOEM to make more WEAs available will foster more competitive OSW procurements and facilitate the potential development of networked offshore transmission systems.

- With the key findings in mind, and considering that Radial and split connection concepts were observed to have very similar performance in the preliminary assessment, the Radial, Meshed, and Backbone connection concepts were shortlisted for the further detailed offshore analysis that included detailed LTCOE and availability assessments.

Detailed calculations were conducted for the shortlisted OSW connection concepts including both the wet-side and dry-side (between the landing points and onshore grid substations) components. Furthermore, to provide a better comparison between the three shortlisted OSW connection concepts by considering the magnitude of OSW energy that they would deliver to the onshore grid, LTCOE was calculated to reflect the cost of transferring the OSW energy for each delivered MWh of OSW energy to the onshore grid.

Offshore Radial and Meshed connection concepts were observed to result in lower LTCOE compared to the Backbone connection concept. In addition, OSW Meshed connection concept resulted in a higher availability and operational benefits among the three shortlisted OSW connection concepts.

Provided draft Call Areas in the New York Bight become WEAs, 9 GW of OSW connected to New York's electricity system by 2035 is possible. Though more technical assessment should be completed to more robustly evaluate solutions, the Study finds there exists feasible options for offshore cable concepts and routing, cable landfall and onshore cable routing, and existing substations for the interconnection of 9 GW of OSW. For all options, smart systematic planning is key to cost-effective outcomes.

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Annex A: Onshore Assessment Supporting Attachments

Attachment 3.I

Retirements and Deactivations

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station Unit	Zone	PTID	Location Town	Location Cnty	Location St	In-Service Date YYYY-MM-DD	Name Plate Rating (V) MW	2019 CRIS (A) MW SUM	2019 CRIS (A) MW WIN	2019 Capability (B) MW SUM	2019 Capability (B) MW WIN	DUAL	Unit Type	Fuel (U) Type 1	Fuel (U) Type 2	2018 Net (C) Energy GWh	Retire or Deactivate?	Stusy Year 2025	Stusy Year 2030	Stusy Year 2035	Comment
																			Retirement/Deactivation were shown by "x" sign				
R1701	Somerset Operating Company, LL	Somerset	A	23543	Somerset	063	36	1984-08-01	655.1	686.5	686.5	685.9	692.5		ST	BIT		593.0	Y	x	x	x	RETIRE
R1067	Binghamton BOP, LLC	Binghamton (RET - 1/9/18)	C	23790	inghamton	007	36	2001-03-01	47.7	43.8	57.2	0.0	0.0	YES	CC	NG	KER	3.5	Y	x	x	x	RETIRE
R1082	Cayuga Operating Company, LLC	Cayuga 1	C	23584	Lansing	109	36	1955-09-01	155.3	154.1	154.1	151.0	151.0		ST	BIT		81.6	Y	x	x	x	Coal retirement/Mothball Outage
R1083	Cayuga Operating Company, LLC	Cayuga 2 (IIFO - 7/1/18)	C	23585	Lansing	109	36	1958-10-01	167.2	154.7	154.7	0.0	0.0		ST	BIT		17.4	Y	x	x	x	Coal retirement/IIFO
R1445	Lyonsdale Biomass, LLC	Lyonsdale (IIFO - 4/1/18)	E	23803	Lyonsdale	049	36	1992-08-01	21.1	20.2	20.2	0.0	0.0		ST	WD		0.0	Y	x	x	x	RETIRE
R1150	Entergy Nuclear Power Marketing	Indian Point 2	H	23530	Buchanan	119	36	1973-08-01	1,299.0	1,026.5	1,026.5	1,016.1	1,025.9		NP	UR		8,000.5	Y	x	x	x	Deactivated
R1151	Entergy Nuclear Power Marketing	Indian Point 3	H	23531	Buchanan	119	36	1976-04-01	1,012.0	1,040.4	1,040.4	1,037.9	1,039.9		NP	UR		8,333.5	Y	x	x	x	Deactivated
R1008	Astoria Generating Company L.P.	Astoria GT 01	J	23523	Queens	081	36	1967-07-01	16.0	15.7	20.5	14.2	18.9		GT	NG		1.0	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1009	Astoria Generating Company L.P.	Gowanus 1-1	J	24077	Brooklyn	047	36	1971-06-01	20.0	19.1	24.9	18.8	24.4		GT	FO2		0.3	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1010	Astoria Generating Company L.P.	Gowanus 1-2	J	24078	Brooklyn	047	36	1971-06-01	20.0	17.1	22.3	19.4	24.9		GT	FO2		0.2	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1011	Astoria Generating Company L.P.	Gowanus 1-3	J	24079	Brooklyn	047	36	1971-06-01	20.0	17.2	22.5	17.7	22.9		GT	FO2		0.2	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1012	Astoria Generating Company L.P.	Gowanus 1-4	J	24080	Brooklyn	047	36	1971-06-01	20.0	17.1	22.3	16.7	21.3		GT	FO2		0.1	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1013	Astoria Generating Company L.P.	Gowanus 1-5	J	24084	Brooklyn	047	36	1971-06-01	20.0	16.5	21.6	17.2	22.3		GT	FO2		0.1	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1014	Astoria Generating Company L.P.	Gowanus 1-6	J	24111	Brooklyn	047	36	1971-06-01	20.0	18.0	23.5	16.6	21.4		GT	FO2		0.1	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1015	Astoria Generating Company L.P.	Gowanus 1-7	J	24112	Brooklyn	047	36	1971-06-01	20.0	17.6	23.0	17.6	22.4		GT	FO2		0.1	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1016	Astoria Generating Company L.P.	Gowanus 1-8	J	24113	Brooklyn	047	36	1971-06-01	20.0	16.1	21.0	15.9	20.9		GT	FO2		0.0	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1017	Astoria Generating Company L.P.	Gowanus 2-1	J	24114	Brooklyn	047	36	1971-06-01	20.0	17.9	23.4	17.0	22.5	YES	GT	FO2	NG	1.9	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1018	Astoria Generating Company L.P.	Gowanus 2-2	J	24115	Brooklyn	047	36	1971-06-01	20.0	18.8	24.6	18.3	24.1	YES	GT	FO2	NG	1.8	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1019	Astoria Generating Company L.P.	Gowanus 2-3	J	24116	Brooklyn	047	36	1971-06-01	20.0	20.6	26.9	19.1	24.9	YES	GT	FO2	NG	1.9	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1020	Astoria Generating Company L.P.	Gowanus 2-4	J	24117	Brooklyn	047	36	1971-06-01	20.0	19.3	25.2	17.3	23.1	YES	GT	FO2	NG	0.8	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1021	Astoria Generating Company L.P.	Gowanus 2-5	J	24118	Brooklyn	047	36	1971-06-01	20.0	18.6	24.3	18.0	23.4	YES	GT	FO2	NG	0.6	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1022	Astoria Generating Company L.P.	Gowanus 2-6	J	24119	Brooklyn	047	36	1971-06-01	20.0	20.3	26.5	19.5	24.9	YES	GT	FO2	NG	1.0	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1023	Astoria Generating Company L.P.	Gowanus 2-7	J	24120	Brooklyn	047	36	1971-06-01	20.0	19.6	25.6	19.1	24.7	YES	GT	FO2	NG	1.0	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1024	Astoria Generating Company L.P.	Gowanus 2-8	J	24121	Brooklyn	047	36	1971-06-01	20.0	17.7	23.1	17.7	22.9	YES	GT	FO2	NG	0.4	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1025	Astoria Generating Company L.P.	Gowanus 3-1	J	24122	Brooklyn	047	36	1971-07-01	20.0	17.7	23.1	16.9	21.9	YES	GT	FO2	NG	0.9	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1026	Astoria Generating Company L.P.	Gowanus 3-2	J	24123	Brooklyn	047	36	1971-07-01	20.0	17.7	23.1	17.1	22.6	YES	GT	FO2	NG	0.7	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1027	Astoria Generating Company L.P.	Gowanus 3-3	J	24124	Brooklyn	047	36	1971-07-01	20.0	19.8	25.9	18.0	23.8	YES	GT	FO2	NG	1.0	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1028	Astoria Generating Company L.P.	Gowanus 3-4	J	24125	Brooklyn	047	36	1971-07-01	20.0	17.9	23.4	16.2	21.4	YES	GT	FO2	NG	1.0	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1029	Astoria Generating Company L.P.	Gowanus 3-5	J	24126	Brooklyn	047	36	1971-07-01	20.0	19.0	24.8	17.3	22.8	YES	GT	FO2	NG	1.4	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1030	Astoria Generating Company L.P.	Gowanus 3-6	J	24127	Brooklyn	047	36	1971-07-01	20.0	17.6	23.0	15.5	21.0	YES	GT	FO2	NG	0.7	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1031	Astoria Generating Company L.P.	Gowanus 3-7	J	24128	Brooklyn	047	36	1971-07-01	20.0	18.1	23.6	18.1	23.9	YES	GT	FO2	NG	0.5	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1032	Astoria Generating Company L.P.	Gowanus 3-8	J	24129	Brooklyn	047	36	1971-07-01	20.0	19.0	24.8	16.9	23.9	YES	GT	FO2	NG	0.5	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1033	Astoria Generating Company L.P.	Gowanus 4-1	J	24130	Brooklyn	047	36	1971-07-01	20.0	16.8	21.9	18.9	24.4		GT	FO2		0.2	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1034	Astoria Generating Company L.P.	Gowanus 4-2	J	24131	Brooklyn	047	36	1971-07-01	20.0	17.3	22.6	17.6	22.5		GT	FO2		0.2	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1035	Astoria Generating Company L.P.	Gowanus 4-3	J	24132	Brooklyn	047	36	1971-07-01	20.0	17.6	23.0	16.6	20.4		GT	FO2		0.1	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1036	Astoria Generating Company L.P.	Gowanus 4-4	J	24133	Brooklyn	047	36	1971-07-01	20.0	17.1	22.3	16.5	22.3		GT	FO2		0.1	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1037	Astoria Generating Company L.P.	Gowanus 4-5	J	24134	Brooklyn	047	36	1971-07-01	20.0	17.1	22.3	16.4	22.1		GT	FO2		0.1	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1038	Astoria Generating Company L.P.	Gowanus 4-6	J	24135	Brooklyn	047	36	1971-07-01	20.0	18.6	24.3	18.1	23.0		GT	FO2		0.1	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1039	Astoria Generating Company L.P.	Gowanus 4-7	J	24136	Brooklyn	047	36	1971-07-01	20.0	16.6	21.7	17.2	21.7		GT	FO2		0.0	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1040	Astoria Generating Company L.P.	Gowanus 4-8	J	24137	Brooklyn	047	36	1971-07-01	20.0	19.0	24.8	17.4	21.9		GT	FO2		0.2	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1041	Astoria Generating Company L.P.	Narrows 1-1	J	24228	Brooklyn	047	36	1972-05-01	22.0	21.0	27.4	19.3	24.9	YES	GT	FO2	NG	6.4	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1042	Astoria Generating Company L.P.	Narrows 1-2	J	24229	Brooklyn	047	36	1972-05-01	22.0	19.5	25.5	17.1	23.8	YES	GT	FO2	NG	3.6	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1043	Astoria Generating Company L.P.	Narrows 1-3	J	24230	Brooklyn	047	36	1972-05-01	22.0	20.4	26.6	18.3	24.9	YES	GT	FO2	NG	4.0	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1044	Astoria Generating Company L.P.	Narrows 1-4	J	24231	Brooklyn	047	36	1972-05-01	22.0	20.1	26.3	18.8	24.9	YES	GT	FO2	NG	2.7	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1045	Astoria Generating Company L.P.	Narrows 1-5	J	24232	Brooklyn	047	36	1972-05-01	22.0	19.8	25.9	19.9	24.9	YES	GT	FO2	NG	3.0	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1046	Astoria Generating Company L.P.	Narrows 1-6	J	24233	Brooklyn	047	36	1972-05-01	22.0	18.9	24.7	16.5	22.2	YES	GT	FO2	NG	3.0	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1047	Astoria Generating Company L.P.	Narrows 1-7	J	24234	Brooklyn	047	36	1972-05-01	22.0	18.4	24.0	19.4	24.9	YES	GT	FO2	NG	6.1	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1048	Astoria Generating Company L.P.	Narrows 1-8	J	24235	Brooklyn	047	36	1972-05-01	22.0	19.9	26.0	17.5	23.2	YES	GT	FO2	NG	4.6	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1049	Astoria Generating Company L.P.	Narrows 2-1	J	24236	Brooklyn	047	36	1972-06-01	22.0	19.4	25.3	19.2	24.8	YES	GT	FO2	NG	3.4	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1050	Astoria Generating Company L.P.	Narrows 2-2	J	24237	Brooklyn	047	36	1972-06-01	22.0	18.7	24.4	16.4	22.9	YES	GT	FO2	NG	3.4	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1051	Astoria Generating Company L.P.	Narrows 2-3	J	24238	Brooklyn	047	36	1972-06-01	22.0	18.4	24.0	17.5	23.8	YES	GT	FO2	NG	3.4	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1052	Astoria Generating Company L.P.	Narrows 2-4	J	24239	Brooklyn	047	36	1972-06-01	22.0	18.4	24.0	17.9	24.2	YES	GT	FO2	NG	7.0	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1053	Astoria Generating Company L.P.	Narrows 2-5	J	24240	Brooklyn	047	36	1972-06-01	22.0	19.9	26.0	18.1	24.4	YES	GT	FO2	NG	4.8	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1054	Astoria Generating Company L.P.	Narrows 2-6	J	24241	Brooklyn	047	36	1972-06-01	22.0	18.1	23.6	16.3	21.9	YES	GT	FO2	NG	2.8	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1055	Astoria Generating Company L.P.	Narrows 2-7	J	24242	Brooklyn	047	36	1972-06-01	22.0	20.7	27.0	18.5	24.9	YES	GT	FO2	NG	6.6	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1056	Astoria Generating Company L.P.	Narrows 2-8	J	24243	Brooklyn	047	36	1972-06-01	22.0	17.5	22.9	16.3	21.9	YES	GT	FO2	NG	6.4	Y	x	x	x	Unavailable in Ozone Season (May1st~Sept30st)
R1101	Consolidated Edison Co. of NY, Inc	59 St. GT 1	J	24138	Manhattan	061	36	1969-06-01	17.1	15.4	20.1	15.5	21.6	YES	GT	KER	NG	0.2	Y	x	x	x	Unavailable-black start only
R1102	Consolidated Edison Co. of NY, Inc	74 St. GT 1	J	24260	Manhattan	061	36	1968-10-01	18.5	19.0	23.5	19.0	19.9		GT	KER		0.2	Y	x	x	x	Unavailable-black start only
R1103	Consolidated Edison Co. of NY, Inc	74 St. GT 2	J	24261	Manhattan	061	36	1968-10-01	18.5	20.1	25.7	18.9	21.2		GT	KER		0.2	Y	x	x	x	Unavailable-black start only
R1109	Consolidated Edison Co. of NY, Inc	Hudson Ave 3	J	23810	Brooklyn	047	36	1970-07-01	16.3	16.0	20.9	16.7	19.5		GT	KER		0.2	Y	x	x	x	Retire by 2023/IIFO
R1110	Consolidated Edison Co. of NY, Inc	Hudson Ave 4	J	23540	Brooklyn	047	36	1970-07-01	16.3	13.9	18.2	0.0	0.0		GT	KER		0.1	Y	x	x	x	RETIRE
R1111	Consolidated Edison Co. of NY, Inc	Hudson Ave 5	J	23657	Brooklyn	047	36	1970-07-01	16.3	15.1	19.7	14.7	19.0		GT	KER		0.2	Y	x	x	x	Retire by 2023
R1342	Helix Ravenswood, LLC	Ravenswood 01	J	23729	Queens	081	36	1967-07-01	18.6	8.8	11.5	7.8	6.4		GT	NG		0.2	Y	x	x	x	Retire by 2023
R1343	Helix Ravenswood, LLC	Ravenswood 10	J	24258	Queens	081	36	1970-08-01	25.0	21.2	27.0	16.7	23.7	YES	JE	KER	NG	2.1	Y	x	x	x	Retire by 2023
R1344	Helix Ravenswood, LLC	Ravenswood 11	J	24259	Queens	081	36	1970-08-01	25.0	20.2	25.7	16.7	24.4	YES	JE	KER	NG	2.6	Y	x	x	x	Retire by 2023
R1345	Helix Ravenswood, LLC	Ravenswood 2-1 (IIFO - 4/1/18)	J	24244	Queens	081	36	1970-12-01	42.9	40.4	51.4	0.0	0.0	YES	JE	NG	KER	0.2	Y	x	x	x	IIFO, 2018 RNA/CRP
R1346	Helix Ravenswood, LLC	Ravenswood 2-2 (IIFO - 4/1/18)	J	24245	Queens	081	36	1970-12-01	42.9	37.6	47.8	0.0	0.0	YES	JE	NG	KER	0.0	Y	x	x	x	IIFO, 2018 RNA/CRP
R1347	Helix Ravenswood, LLC	Ravenswood 2-3 (IIFO - 4/1/18)	J	24246	Queens	081	36	1970-12-01	42.9	39.2	49.9	0.0	0.0	YES	JE	NG	KER	0.0	Y	x	x	x	IIFO, 2018 RNA/CRP
R1348	Helix Ravenswood, LLC	Ravenswood 2-4 (IIFO - 4/1/18)	J	24247	Queens	081	36	1970-12-01	42.9	39.8	50.6	0.0	0.0	YES	JE	NG	KER	0.0	Y	x	x	x	IIFO, 2018 RNA/CRP
R1349	Helix Ravenswood, LLC	Ravenswood 3-1 (IIFO - 4/1/18)	J	24248	Queens	081	36	1970-08-01	42.9	40.5	51.5	0.0	0.0	YES	JE	NG	KER	0.0	Y	x	x	x	IIFO, 2018 RNA/CRP
R1350	Helix Ravenswood, LLC	Ravenswood 3-2 (IIFO - 4/1/18)	J	24249	Queens	081	36	1970-08-01	42.9	38.1	48.5	0.0	0.0	YES	JE	NG	KER	0.0	Y	x	x	x	IIFO, 2018 RNA/CRP
R1351	Helix Ravenswood, LLC	Ravenswood 3-4 (IIFO - 4/1/18)	J	24251	Queens	081	36	1970-08-01	42.9	35.8	45.5	0.0	0.0	YES	JE	NG	KER	0.0	Y	x	x	x	IIFO, 2018 RNA/CRP
R1397	Long Island Power Authority	Glenwood GT 01	K	23712	Glenwood	059	36	1967-04-01	16.0	14.6	19.1	11.6	13.5		GT	FO2		0.0	Y	x	x	x	Retire by 2023
R1421	Long Island Power Authority	Northport GT	K	23718	Northport	103	36	1967-03-01	16.0	13.8	18.0	12.1	11.8		GT	FO2		0.1	Y	x	x	x	Unavailable-black start only
R1429	Long Island Power Authority	Port Jefferson GT 01	K	23713	t Jefferson	103	36	1966-12-01	16.0	14.1	18.4	12.2	15.7		GT	FO2		-0.1	Y	x	x	x	Unavailable-black start only
R1443	Long Island Power Authority	West Babylon 4	K	23714	st Babylon	103	36	1971-08-01	52.4	49.0	64.0	48.9	64.8		GT	FO2		1.9	Y	x	x	x	Retire by 2020

Attachment 3.II

Transmission Upgrades

Description	Zone	KV	Action	Assumption
Install a new 138 kV Circuit from the East Garden City substation to the Valley stream substation	K	138	A generic representation of this project will be considered in all cases.	Specification of the new line was considered similar to the existing line-214 MVA (S/N) and 298 MVA (S/E) ratings
Install 2-Ohm Series Reactor on the 69 kV Whiteside to Stewart Manor circuit to mitigate thermal constraints on the circuit	K	69	A generic representation of this project will be considered in all cases.	
Construct a new 69 kV substation. 69 kV supply will come from tapping the existing East Garden City to Meadowbrook Hospital circuit.	K	69	Modeled based on the CY19 ATBA cases in all study years	
Install a new 138 kV circuit from the Syosset substation to the Shore Rd substation.	K	138	A generic representation of this project will be included in 2030 and 2035 cases.	New line was considered from Syosset to Shore Rd with 0.0019+j0.02586 impedance with 396 MVA (SN) and 482 MVA (SE) ratings.
Install a 27 MVAR capacitor bank at the 69 kV Deer Park substation.	K	69	Modeled based on the CY19 ATBA cases	
Install a 27 MVAR capacitor bank at the MacArthur substation.	K	69	Modeled based on the CY19 ATBA cases	
Construct a new 138 kV substation. 138 kV supply will come from tapping the existing Pilgrim to West Bus circuit.	K	138	Already modeled	
Convert the existing Wildwood to Riverhead circuit from 69 kV to 138 kV.	K	138	A generic representation of this project will be included in 2030 and 2035 cases.	Specification of the new line was considered similar to the existing line-297 MVA (S/N) and 327 MVA (S/E) ratings
Install a new 138 kV circuit from the Riverhead substation to the Canal substation	K	138	A generic representation of this project will be included in 2030 and 2035 cases.	Specification of the new line was considered similar to the existing line-239 MVA (S/N) and 272 MVA (S/E) ratings
Tie feeders B-3402 and C-3403 continue to be on a long term outage	J	345	None	B-3402 and C-3403 feeders are considered out of service in all study case.
Addition of a 345/138 kV PAR controlled Rainey –Corona feeder	J	345/138	None	It was assumed that the PAR corresponds to the existing PAR in power flow cases from Bus#126819 to Bus#126820
Install a third 345/115kV transformer and second 115/34.5kV transformer	E	345/115	Modeled in all study years	
Ratings of the followings elements were changed based on CY19 ATBA case: Pilgrim-Ruland Rd 138 KV ckt Ruland Rd-South Farmingdale 69 KV ckt Canal- South Hampton 69 KV ckt Canal-Canal SR 69 KV South Hampton-Canal SR 69 KV West Bus- Kings 138 KV	K	138 &69 KV	Modeled in all study years	Corrections were applied based on CY19 ATBA case provided by NYISO.

Annex B: Transmission Cable Routing Assessment Supporting Attachments

Annex B - Part 1
GIS Data Source List

Included herein is a multiple-page table that provides a description of and source information for publicly accessible GIS-based data layers that were considered as part of the transmission cable routing feasibility assessment (Routing Assessment).

LANDING FEASIBILITY FOR POTENTIAL POINTS OF INTERCONNECTION IN NEW YORK CITY AND LONG ISLAND, NEW YORK - GIS DATA SOURCE LIST

Resource/Area	Year	Description	Web link/ Source
Environmental Areas			
DEC Remediation Sites	2010	This dataset includes a boundary for a subset of sites which are currently included in one of the Remedial Programs being overseen by the Division of Environmental Remediation.	https://gis.ny.gov/gisdata/inventories/details.cfm?DSID=1097
EPA Superfund Sites/Brownfields	2018	Locations of the EPA's list of National Priority List superfund sites and brownfields within New York.	https://www.epa.gov/superfund/national-priorities-list-npl-sites-state
North Atlantic Right Whale Critical Habitat/Seasonal Management Areas.	2019	This dataset depicts the boundaries of the North Atlantic Right Whale Critical Habitat in ESRI shapefile format for the NOAA Fisheries Service's Greater Atlantic Regional Fisheries Office (GARFO). Additionally, data representing Seasonal Management Area locations where regulations implement speed restrictions in shipping areas at certain times of the year along the coast of the U.S. Atlantic seaboard.	https://www.greateratlantic.fisheries.noaa.gov/educational_resources/gis/index.html
DEC NY Shellfish Closures	2020	Shows certified, seasonally certified and uncertified shellfish growing areas on Long Island. Shellfish closures on Long Island as described in Part 41 of 6NYRR.	https://www.arcgis.com/apps/webappviewer/index.html?id=d98abc91849f4ccf8c38dbb70f8a0042
Shellfish Aquaculture Lease Sites	2014	Identifies operating marine aquaculture facilities based on the best available information from state aquaculture coordinators and programs. Additionally, for this analysis specific information was obtained on the Suffolk County Aquaculture Lease Program.	https://www.northeastoceandata.org/ https://gis3.suffolkcountyny.gov/shellfish/
Significant Coastal Fish and Wildlife Habitats (SCFWH)	2013	Statutory boundaries of Significant Coastal Fish and Wildlife Habitats (SCFWH) as identified and recommended by Environmental Conservation and designated by Department of State.	https://gis.ny.gov/gisdata/inventories/details.cfm?DSID=318
Natural Heritage Communities (NY NHC)	2019	Features represent element occurrences of significant natural communities (ecological communities), as recorded in the New York Natural Heritage Program's Biodiversity Database (Biotics).	http://gis.ny.gov/gisdata/inventories/details.cfm?DSID=1241
DEC Critical Environmental Areas	2020	This data set contains areas that have been designated as Critical Environmental Areas (CEAs) under 6 NYCRR Part 617 - State Environmental Quality Review (SEQR).	https://gis.ny.gov/gisdata/inventories/details.cfm?DSID=1330
Important Bird Areas	2017	The Important Bird Area (IBA) Program in the US is administered by the Audubon Society in partnership with Birdlife International. This data set contains available boundaries and associated attributes for Important Bird Areas (IBAs) in the United States, identified as of September 2017.	https://www.northeastoceandata.org/
Threatened and Endangered Species	2019	NYS or Federally listed Threatened and Endangered species and associated Critical Habitat.	https://noaa.maps.arcgis.com/apps/webappviewer/index.html?id=1bc332edc5204e03b250ac11f9914a27 https://ecos.fws.gov/ipac/ https://gisservices.dec.ny.gov/gis/erm/ https://www.northeastoceandata.org/
NOAA Critical Coastal Habitat (CCH)	2018	This dataset is a compilation of the NOAA National Marine Fisheries Service and the U.S. Fish & Wildlife Service designated critical habitat in coastal areas of the United States. Critical habitat is defined as: (1) Specific areas within the geographical area occupied by the species at the time of listing that contain physical or biological features essential to conservation, which may require special management considerations or protection; and (2) specific areas outside the geographical area occupied by the species if the agency determines that the area itself is essential for conservation.	https://marinecadastre.gov/data/
Essential Fish Habitat	2020	The spatial representations of fish species, their life stages and important habitats including Habitat Areas of Particular Concern.	https://www.fisheries.noaa.gov/resource/map/essential-fish-habitat-mapper
Cultural Resources			
National Historic Landmarks/National Register of Historic Places Points/Polygons (NRHP)	2017	Point Locations and Polygon features. A current, accurate spatial representation of all historic properties listed on the National Register of Historic Places is of interest to Federal agencies, the National Park Service, State Historic and Tribal Historic Preservation Offices, local government and certified local governments, consultants, academia, and the interested public.	https://mapservices.nps.gov/arcgis/rest/services/cultural_resources/nrhp_locations/MapServer
New York State Heritage Areas	2012	New York State Heritage Areas Data include boundaries of twenty Heritage Areas designated in Parks, Recreation and Historic Preservation law.	https://gis.ny.gov/gisdata/inventories/details.cfm?DSID=1188
NYS National Register Site	2018	Data include buildings, structures, objects, historic districts listed in the National Register. Archeological sites and properties determined eligible for listing are not included.	http://gis.ny.gov/gisdata/inventories/details.cfm?DSID=429
NYS State Park or Historic Site	2018	State Park and Historic Site Boundaries - Data include boundaries of state park and historic site facilities.Facility types include state parks, marine parks, boat launch sites, historic sites, historic parks, and park preserves.	http://gis.ny.gov/gisdata/inventories/details.cfm?DSID=430
Wrecks and Obstructions (NOAA AWOIS and ENC)	2020	The Automated Wreck and Obstruction Information System (AWOIS) is an automated file that contains information on wrecks and obstructions, and other significant charted features in coastal waters of the United States subject to NOS Hydrographic Surveys.	https://nauticalcharts.noaa.gov/data/wrecks-and-obstructions.html

LANDING FEASIBILITY FOR POTENTIAL POINTS OF INTERCONNECTION IN NEW YORK CITY AND LONG ISLAND, NEW YORK - GIS DATA SOURCE LIST

Resource/Area	Year	Description	Web link/ Source
Infrastructure			
NYC Aqueducts/Water Tunnels	2020	NYC water Tunnels/ Aqueduct lines from the NYC H2O Hub website.	Extracted from: https://storymaps.arcgis.com/collections/8a62c7993b4f4f40b49b3ac09671ce3c?item=1 https://services9.arcgis.com/jzHsRPm3d1aMJuBp/ArcGIS/rest/services/NYC_H2O_WaterSystemMap3/FeatureServer/2
Interstates/Major Highways	2016	U.S. Major Highways represents the major highways of the United States. These include interstates, U.S. highways, state highways, and major roads. This dataset is from the Census 2000 TIGER/Line files.	From ESRI ArcGIS base data. Can also find at: https://catalog.data.gov/dataset/tiger-line-shapefile-2016-nation-u-s-primary-roads-national-shapefile
Submarine Cables	2015/ 2018	These data depict the occurrence of submarine cables in and around U.S. navigable waters. The purpose of this data product is to support coastal planning at the regional and national scale. NASCA published in 2015 and NOAA published in 2018.	https://marinecadastre.gov/data/
Pipelines	2006	National Pipeline Mapping System GIS data representing the linear locations of gas/utility pipelines. Data acquired in 2006 (newer data is available). Also added a pipeline route for Lower NY Bay Lateral pipeline in Raritan Bay.	https://www.npms.phmsa.dot.gov/
Railways	2017	U.S. National Transportation Atlas Railroads represents a comprehensive database of the nation's railway system at 1:100,000 scale.	https://railroads.dot.gov/maps-and-data/maps-geographic-information-system/maps-geographic-information-system
NYC Subways	2017	New York City subway lines. Data layer name DOITT_SUBWAY_LINE_04JAN2017.	https://data.cityofnewyork.us/Transportation/Subway-Lines/3qz8-muuu
Transmission Lines (PLATTS)	2009	Platts Transmission lines representing the linear locations of transmission/utility lines carrying electricity.	https://www.spglobal.com/platts/en/products-services/electric-power/gis-data
New York City Sewer Atlas	2019	New York City Sewer Atlas Data contains date for the NYC sewer system.	http://openseweratlas.tumblr.com/data
Physical Features			
Conmap sediment grainsize	2005	The purpose of the CONMAPSG sediment layer is to show the sediment grain size distributions. The maps depicted in this series are old and do not accurately depict small-scale sediment distributions or sea-floor variability. This data layer is supplied primarily as a gross overview and to show general textural trends.	https://cmgds.marine.usgs.gov/publications/of2005-1001/htmldocs/datacatalog.htm https://cmgds.marine.usgs.gov/publications/of2005-1001/data/conmapsg/conmapsg.htm
Long Island Soils	2017	The SSURGO database contains information about soil as collected by the National Cooperative Soil Survey over the course of a century.	https://www.nrcs.usda.gov/wps/portal/nrcs/detail/soils/survey/?cid=nrcs142p2_053627
Bathymetric Contour	2020	Bathymetry contours covering the project area, from NOAA Navigation Charts at varying scales	NOAA ENC Direct to GIS. https://encdirect.noaa.gov/
Tidal Wetlands	1974	New York State tidal wetlands south of the Tappan Zee Bridge, as of 1974, for tidal wetlands trend analysis.	https://gis.ny.gov/gisdata/inventories/details.cfm?DSID=1139
Statewide Seagrass	2018	Polygons representing coverage of New York State Seagrass areas (data exported in October 2018 from an ArcGIS REST Service)	https://services6.arcgis.com/DZHaqZm9cxOD4CWM/ArcGIS/rest/services/NYStatewideSeagrass/FeatureServer
National Hydrography Dataset (NHD) Flowlines and Waterbodies	2018	USGS National Hydrography Dataset (NHD) Flowline, linear features and waterbodies, polygon area feature. The National Hydrography Dataset (NHD) is a feature-based database that interconnects and uniquely identifies the stream segments or reaches that make up the nation's surface water drainage system.	https://www.usgs.gov/core-science-systems/ngp/national-hydrography
National Wetland Inventory Wetlands	1979	This data set represents the extent, approximate location and type of wetlands and Deepwater habitats in the United States and its Territories. These data delineate the areal extent of wetlands and surface waters as defined by Cowardian et al. (1979).	https://www.fws.gov/wetlands/
NYSDEC Freshwater Wetlands and Check zones	1999	Regulatory Freshwater Wetland areas. These data are a set of ARC/INFO coverages composed of polygonal and linear features. Coverages are based on official New York State Freshwater Wetlands Maps as described in Article 24-0301 of the Environmental Conservation Law.	https://gis.ny.gov/gisdata/inventories/details.cfm?DSID=1274
Primary aquifers	2011	This layer is intended to identify Primary Aquifers at a scale of 1:24,000 or smaller.	https://gis.ny.gov/gisdata/inventories/details.cfm?DSID=1232
FEMA Flood Zones	2018	The National Flood Hazard Layer (NFHL) data incorporates all Flood Insurance Rate Map (FIRM) databases published by the Federal Emergency Management Agency (FEMA), and any Letters of Map Revision (LOMRs) that have been issued against those databases since their publication date. It is updated on a monthly basis. The FIRM Database is the digital, geospatial version of the flood hazard information shown on the published paper FIRMs.	https://msc.fema.gov/portal/home
Long Island Sound Hard Bottom Model	2014	The hard bottom model is defined as an area with depth less than 9.624 meters, structural complexity greater than 0.257, LPI greater than 40.769, and sediment grain size less than 0.1157 mm. This model captures 94% known hard bottom versus 6% random locations.	The Nature Conservancy (TNC) http://maps.tnc.org/gis_data.html
Bottom Current Stress	2016	Waves and currents create bottom shear stress, a force at the seabed that influences sediment texture distribution, micro-topography, and habitat. Seabed disturbance occurs as a result of bottom shear stress, the combined force waves and currents exert on the sea floor.	USEPA, Supplemental Environmental Impact Statement for the Designation of Dredged Material Disposal Site(S) in Eastern Long Island Sound, Connecticut and New York. https://www.epa.gov/sites/production/files/2016-11/documents/elis_fseis_-_full_report_with_appendices_submitted_04nov16.pdf
Land Cover NLCD	2016	The National Land Cover Database (NLCD) provides nationwide data on land cover and land cover change at a 30m resolution with a 16-class legend based on a modified Anderson Level II classification system.	https://www.mrlc.gov/data/type/land-cover

LANDING FEASIBILITY FOR POTENTIAL POINTS OF INTERCONNECTION IN NEW YORK CITY AND LONG ISLAND, NEW YORK - GIS DATA SOURCE LIST

Resource/Area	Year	Description	Web link/ Source
Offshore Features			
Aids to Navigation	2017	Structures intended to assist a navigator to determine position or safe course, or to warn of dangers or obstructions to navigation. This dataset includes lights, signals, buoys, day beacons, and other aids to navigation.	https://marinecadastre.gov/data/
Anchorage Areas	2017	An anchorage area is a place where boats and ships can safely drop anchor. These areas are created in navigable waterways when ships and vessels require them for safe and responsible navigation.	https://marinecadastre.gov/data/ https://inport.nmfs.noaa.gov/inport/item/48849
Coastal Maintained Channel	2015	This layer shows coastal channels and waterways that are maintained and surveyed by the U.S. Army Corps of Engineers (USACE). These channels are necessary transportation systems that serve economic and national security interests.	https://marinecadastre.gov/data/
Danger Zones and Restricted Areas	2017	These data represent the location of Danger Zones and Restricted Areas within coastal and marine waters, as outlined by the Code of Federal Regulations (CFR) and the Raster Navigational Charts (RNC).	https://marinecadastre.gov/data/ https://inport.nmfs.noaa.gov/inport/item/48876
Ocean Disposal Sites	2018	In 1972, Congress enacted the Marine Protection, Research, and Sanctuaries Act (MPRSA, also known as the Ocean Dumping Act) to prohibit the dumping of material into the ocean that would unreasonably degrade or endanger human health or the marine environment. Virtually all material ocean dumped today is dredged material (sediments) removed from the bottom of waterbodies in order to maintain navigation channels and berthing areas.	https://marinecadastre.gov/data/
Artificial Reefs	2019	These are polygon locations of Mid-Atlantic artificial reefs. They were compiled from various sources, primarily lat/long coordinates of reef corners found on public web sites.	http://portal.midatlanticocean.org/data-catalog/fishing/
Pilot Boarding Area	2018	Pilot boarding areas are locations at sea where pilots familiar with local waters board incoming vessels to navigate their passage to a destination port.	https://marinecadastre.gov/data/
Unexploded Ordnances	2018	Unexploded ordnances are explosive weapons (bombs, bullets, shells, grenades, mines, etc.) that did not explode when they were employed and still pose a risk of detonation, potentially many decades after they were used or discarded.	https://marinecadastre.gov/data/
Shipping Lanes	2020	Shipping fairways and separation zones on approach to major ports.	https://www.nauticalcharts.noaa.gov/data/gis-data-and-services.html#enc-direct-to-gis
USACE Borrow Areas	2018	US Army Corps Borrow Area locations for beach nourishment projects.	https://geospatial-usace.opendata.arcgis.com/datasets/aed16678ea814ddc8fdb5d96f723d90b
USACE Coastal Storm Risk Management Project	2018	USACE Coastal Systems Portfolio Initiative (CSPI) Project Reliability and Phase data. Coastal Risk reduction projects.	https://geospatial-usace.opendata.arcgis.com/datasets/fec7341a4b2b4e43bc1f6258057fd115
Vessel Traffic	2017	Vessel transit counts for all vessels that carry Automatic Identification System (AIS) transponders. AIS are a navigation safety device that transmits and monitors the location and characteristics of many vessels in U.S. and international waters in real-time.	https://www.northeastoceandata.org/data-explorer/
NOAA Navigation Charts	2020	NOAA Navigation Chart tiles, downloaded from NOAA RNC Tile service	https://tileservice.charts.noaa.gov/tileset.html#50000_1-locator
Department of Defense			
DOD Offshore Wind Mission Compatibility Assessments	2014	This data set represents the results of analyses conducted by the Department of Defense to assess the compatibility of offshore wind development with military assets and activities.	https://marinecadastre.gov/data/ https://coast.noaa.gov/arcgis/rest/services/MarineCadastre/OceanEnergy/MapServer/4
Submarine Transit Lanes	2015	Submarine transit lanes are areas where submarines may navigate underwater, including transit corridors designated for submarine travel.	https://www.northeastoceandata.org/data-explorer/
Naval Undersea Warfare Testing Range	2009	The Naval Undersea Warfare Testing Range consists of waters nearshore waters of Rhode Island Sound, Block Island Sound, and coastal waters of New York, Connecticut, and Massachusetts. The Testing Range located is an area is used for research, development, test, and evaluation of Undersea Warfare systems, and, as necessary, to support other Navy and DoD operations.	https://www.northeastoceandata.org/data-explorer/
DoD Operations Area	2015	An OPAREA is an ocean area defined by geographic coordinates with defined sea surface and subsurface training areas and associated special use airspace, and includes danger zones and restricted areas.	https://www.northeastoceandata.org/data-explorer/
Fisheries			
Commercial Fishing Vessel Trip Report Data: Fixed Gear/Mobile Gear	2017	These data are collected by observers through NOAA's Northeast Fisheries Observer Program. Raw data are not shared due to the confidentiality of the program. Fixed gear types include gillnets, hand lines, longlines, pots and traps. Mobile gear types include trawls, dredges, and purse seines.	https://www.northeastoceandata.org/data-explorer/
Commercial Fisheries Vessel Monitoring System Data	2015	This dataset broadly characterizes the density of commercial fishing vessel activity for fisheries in the northeastern U.S. based on Vessel Monitoring Systems (VMS) from fishing vessels. The National Marine Fisheries Service (NMFS) describes VMS is a satellite surveillance system primarily used to monitor the location and movement of commercial fishing vessels in the U.S.	https://www.northeastoceandata.org/data-explorer/
DEC public fishing lakes ponds	2012	This is a shapefile that displays the locations of top lakes and ponds for fishing in New York State, as determined by fisheries biologists working for the New York State Department of Environmental Conservation.	https://gis.ny.gov/gisdata/inventories/details.cfm?DSID=1252
DEC public fishing rivers streams	2012	This is a shapefile that displays the locations of top rivers and streams for fishing in New York State, as determined by fisheries biologists working for the New York State Department of Environmental Conservation.	https://gis.ny.gov/gisdata/inventories/details.cfm?DSID=1252
New York Recreational Uses - Recreational Fishing	2014	DOS staff worked with NOAA's Coastal Services Center (CSC) to design and develop a participatory mapping process. Leaders from 30 partner organizations and other knowledgeable individuals were invited to participate in one of five offshore use workshops conducted during the summer of 2011. At the workshops, DOS and CSC trained organizational contacts and knowledgeable individuals to work with their colleagues, constituents, and memberships to collect ocean use information.	http://portal.midatlanticocean.org/

LANDING FEASIBILITY FOR POTENTIAL POINTS OF INTERCONNECTION IN NEW YORK CITY AND LONG ISLAND, NEW YORK - GIS DATA SOURCE LIST

Resource/Area	Year	Description	Web link/ Source
Reference Boundaries			
NY State Parks	2018	State Park and Historic Site Boundaries - Data include boundaries of state park and historic site facilities. Facility types include state parks, marine parks, boat launch sites, historic sites, historic parks, and park preserves.	https://gis.ny.gov/gisdata/inventories/details.cfm?DSID=430
DEC Lands	2019	Lands under the care, custody and control of DEC, including Wildlife Management areas, Unique Areas, State Forests, and Forest Preserve.	https://gis.ny.gov/gisdata/inventories/details.cfm?DSID=1114
New York Protected Areas Database	2017	The New York Protected Areas Database (NYPAD) is intended to be the most comprehensive geospatial dataset of protected lands in New York State. Protected lands are defined as those lands which are protected, designated, or functioning as conservation lands, open space, natural areas, or recreational areas through fee ownership, easement, management agreement, current land use, or other mechanism.	http://www.nypad.org/
State/County/City/Town/Village Boundaries	2017	A vector polygon GIS file of boundaries in New York State. NYS_Civil_Boundaries.gdb	http://gis.ny.gov/gisdata/inventories/details.cfm?DSID=927
Federal Lands	2014	U.S. National Atlas Federal Land Areas represents the federally owned or administered land areas (for example, National Wildlife Refuges, National Monuments, and National Conservation Areas) of the United States.	http://nationalmap.gov/small_scale/atlasftp.html
Indian Territories	2020	A vector polygon GIS file of all Indian Territory boundaries in New York State.	http://gis.ny.gov/gisdata/inventories/details.cfm?DSID=927
Federal Consistency Geographic Location Descriptions	2018	These data represent state geographic location descriptions (GLDs) for state coastal management programs.	https://inport.nmfs.noaa.gov/inport/item/51544
NY Local Waterfront Revitalization Communities	2018/ 2016	This dataset delineates the boundaries of communities with an approved Local Waterfront Revitalization Program (LWRP) under the NYS Coastal Management Program. Including the specific boundaries for the NYC LWRP	https://gis.ny.gov/gisdata/inventories/details.cfm?DSID=1284 https://www1.nyc.gov/site/planning/data-maps/open-data.page#zoning_related\
Coastal Barrier Resource Systems Boundaries	2019	This map layer shows areas designated as undeveloped coastal barriers in accordance with the Coastal Barrier Resources Act, which encourages conservation of hurricane-prone, biologically rich coastal barriers by restricting federal expenditures that encourage development.	https://www.northeastoceandata.org/data-explorer/
New York State Tax Parcel Centroid Data	2020	Tax parcel centroids with a concise set of attributes for all counties in New York State.	http://gis.ny.gov/gisdata/inventories/details.cfm?DSID=1300 Statewide Parcel Map Program, NYS ITS GIS Program Office
Submerged Lands Act Boundary	2010	The Submerged Lands Act boundary defines the seaward limit of a state's submerged lands and the landward boundary of federally managed OCS lands. In the BOEM Atlantic Region it is projected 3 nautical miles offshore from the baseline.	https://metadata.boem.gov/geospatial/OCS_SubmergedLandsActBoundary_Atlantic_NAD83.xml
U.S. Maritime Boundary	2013	Territorial sea boundary at 12 nautical miles.	https://www.nauticalcharts.noaa.gov/data/gis-data-and-services.html#enc-direct-to-gis National Oceanic and Atmospheric Administration (NOAA), National Ocean Service (NOS), Office of Coast Survey (OCS)
County Parcels	2018	Kings/Nassau/Suffolk County tax map parcels and ownership data.	http://gis.ny.gov/parcels/ https://lrv.nassaucountyny.gov/map/?s=62&b=13&l=46 https://gis3.suffolkcountyny.gov/gisviewer/
BOEM Lease Areas and NY Call Areas	2019	Active renewable energy leasing areas on the Atlantic OCS as well as the BOEM Call Areas of New York State.	https://www.boem.gov/Renewable-Energy-GIS-Data/

Annex B - Part 2

Preliminary Route Feasibility Scoring Matrices

Below is a map (Figure A) showing preliminary representative routes that were subject to a screening-level analysis during the transmission cable routing feasibility assessment (Routing Assessment). Following the map, two matrices – one for New York City points of interconnection (POIs) and one for Long Island POIs – present the results of the preliminary route feasibility scoring for potential critical constraint categories. Each matrix is split across two pages (11" by 17" format). Blue-shaded headers are carried over onto each page for ease of review.

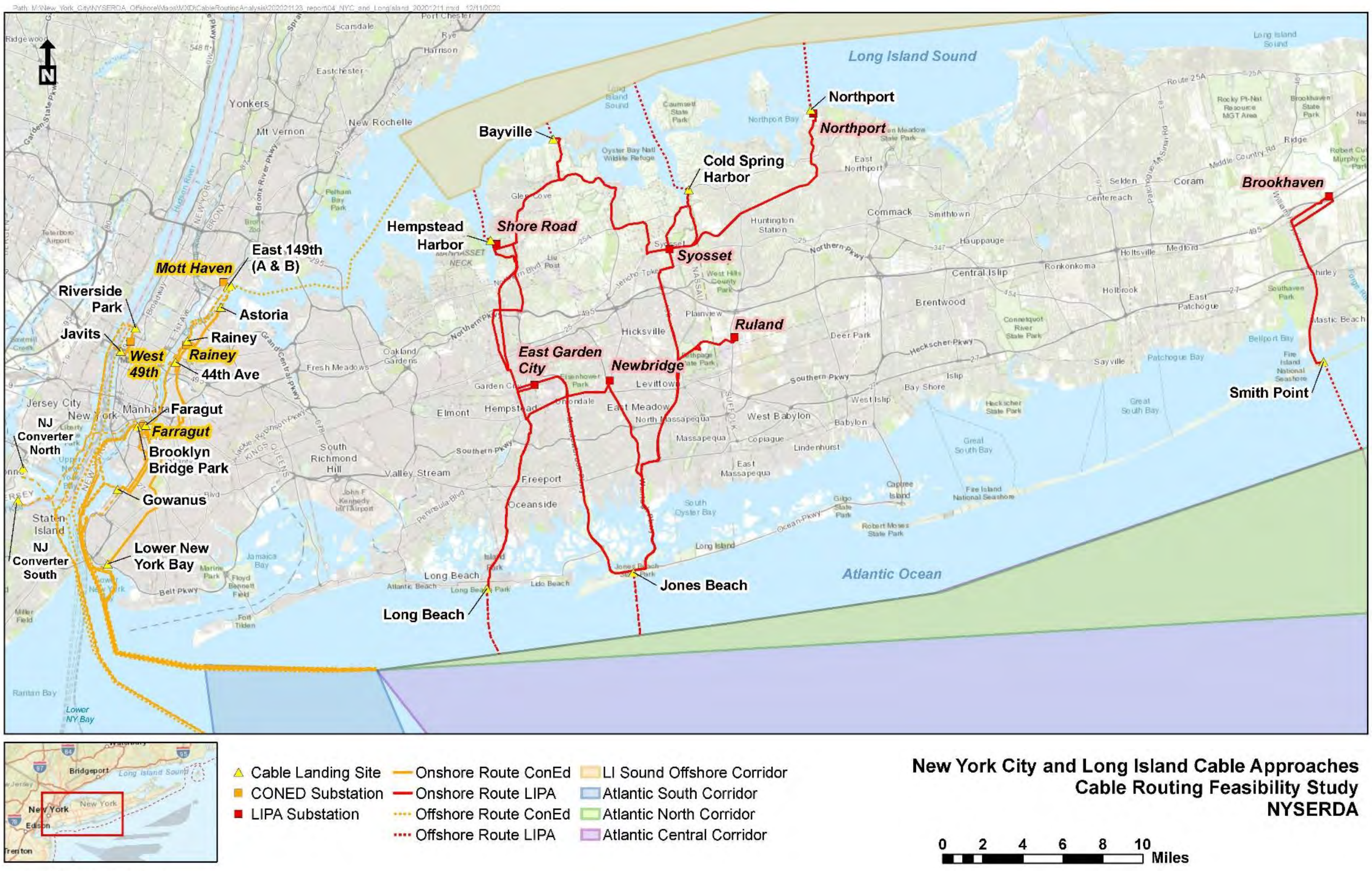
The matrix identifies the preliminary routes split into three segments – (1) offshore, (2) shore approach and landing site, and (3) onshore. The blue-shaded column headers identify the name of each route segment. The scoring for each route segment is presented for each critical constraint category; color coding was applied as a visual aid. The color key at the top-center of each matrix denotes the score value and description of each corresponding color. The total score and relative rank for each representative route can be found at the bottom of the second page of each matrix.

To the right of the color-coded scoring section, in the middle of the page, a column titled "Scoring Explanations" describes the criteria used to assign scores for each constraint category. Farthest to the right, a column titled "Specific Route Scoring Comments" provides a summary of details considered when assigning constraint scores for specific route segments.

Figure A. Preliminary Shore Approach Routes, Landing Sites, and Onshore Routes

Representative shore approach routes, landing sites, and onshore routes for cable interconnection to New York City and Long Island.

Sources: WSP 2020; DNVGL 2020; ESRI 2020. (See Attachment 1 GIS Data Layer List for full list of figure references.)



PRELIMINARY ROUTE FEASIBILITY SCORING IN NEW YORK CITY - CRITICAL CONSTRAINTS MATRIX

Color Key (with scoring)

Score	Description
1x	No constraints present
2x	Low constraints present
3x	Moderate constraints present
4x	Major constraints present
5x	Substantial constraints present
100x	Challenges considered potentially insurmountable

Lease Area/Region	Hudson North									Hudson South			New Jersey						Massachusetts		
Offshore Route	Atlantic Central Corridor									Atlantic South Corridor									Long Island Sound Corridor		
Shore Approach and Landing Site	Lower New York Bay	Gowanus	Farragut (Narrows East)		Farragut (Narrows West)	Rainey	149th Street	Riverside (Narrows West)	Riverside (Narrows East)	Lower New York Bay	Gowanus	Farragut (Narrows East)		Farragut (Narrows West)	Rainey	149th Street	Riverside (Narrows West)	Riverside (Narrows East)	Rainey	Astoria	149th Street
Point of Interconnection	Farragut	Farragut	Farragut	Rainey	Farragut	Rainey	Mott Haven	West 49th		Farragut	Farragut	Farragut	Rainey	Farragut	Rainey	Mott Haven	West 49th		Rainey	Rainey	Mott Haven
Considerations																					
LEASE TO POI: Approximate route distance in miles (AC Feasibility: +/- 70 miles)	99	100	99	106	94	104	108	99	103	127	128	127	134	107	132	136	126	131	200	200	197

Segment	Consideration	Scoring explanations (Note that the group of NYC routes are ranked against each other for each consideration. The criteria that defines each rank may not be directly comparable to Long Island routes presented in separate matrix.)	Specific Route Scoring Comments
LEASE TO POI	Approximate route distance in miles (AC Feasibility: +/- 70 miles)	Grey: less than 70 miles No color: more than 70 miles	
OFFSHORE ROUTE SEGMENT	Infrastructure Crossings (linear utilities)	Green: no crossings Light Green: lower number of crossings > 15 Yellow: moderate number of crossings 15 to 25 Orange: high number of crossings 25 to 35 Red: very high number of crossings 35+	Light Green: Atlantic Central Corridor > 15 crossing varies by route Yellow: Long Island Sound Corridor ~ 17 crossings Orange: Atlantic South Corridor ~27 crossings
OFFSHORE ROUTE SEGMENT	Designated Marine Zones (traffic lanes, danger zones)	Green: no navigation features present in area Light Green: Route generally avoids navigation features but some in area Yellow: Likely must cross a navigation feature Orange: Must cross multiple navigation features Red: Significant impact to navigation anticipated	Light Green: Long Island Sound some ferry traffic, Newport, RI Precautionary Area Yellow: NY Bight traffic lanes or precautionary area on Atlantic Approach to NY Harbor Orange: NJ Shore traffic lanes or precautionary area on approach to NY Harbor and Danger Zone (mines) on NY Harbor approach
OFFSHORE ROUTE SEGMENT	Department of Defense Areas	Green: none present Light Green: present in area but can be avoided or no restrictions apply Yellow: must cross a Department of Defense (DoD) area where site specific stipulations apply Orange: must cross a DoD area where site specific stipulations apply and/or multiple other features apply Red: DoD exclusion area present that must be crossed	Yellow: along Jersey Shore OPAREA exists Orange: in Atlantic and on approach to Long Island (LI) Sound OPAREA, Sub lane, testing range exist
OFFSHORE ROUTE SEGMENT	Sensitive Habitats (presence of sensitive species or habitat exists)	Green: no sensitive habitat present Light Green: some sensitive habitat exists but can be avoided Yellow: sensitive habitat exists in the entire area Orange: increased sensitive habitat designations in area or adjacent Red: high number of sensitive habitats must be crossed	Yellow: Atlantic in this area is biologically important area (BIA) for North Atlantic Right Whale (NARW) Orange: entire Atlantic in this area is BIA for NARW and in LI Sound DEC Critical Environmental Area and NYSDOS Significant Coastal Fish and Wildlife Habitat area must be crossed/routed adjacent to
OFFSHORE ROUTE SEGMENT	Marine Geology and Oceanography (seabed, erosion, bedforms, etc.)	Green: highly suitable conditions for cable installation cable burial very easily achieved/maintained Light Green: generally suitable conditions for cable installation cable burial easily achieved/maintained Yellow: moderately suitable conditions for cable installation potential difficulty to achieve/maintain cable burial Orange: difficult conditions may exist for cable installation do to structure difficult to achieve/ maintain cable burial Red: cable may not be installed/maintained to required depths due to potential bedrock or moraine armoring may be required	Light Green: Atlantic is generally soft sediments go for cable installation Red: Long Island Sound Corridor presence of rock reefs at moraines may make cable burial difficult to achieve, armoring may be required. Strong current also exits in entrance to Long Island Sound.
OFFSHORE ROUTE SEGMENT	Further Regulatory Constraints (triggering additional state approvals)	Green: no trigger possible Light Green: trigger of additional state review is not likely Yellow: trigger of additional state coastal management programs is possible Orange: trigger of state coastal management program(s) will occur Red: trigger of state permitting (i.e. Section 401) review will occur	Light Green: unlikely to trigger additional state approvals when coming from Atlantic Central Corridor Yellow: Atlantic South Corridor can reroute to avoid NJ state waters but crossing offshore of NJ waters may trigger coastal management program if determined to impact state users (i.e. fishermen)
OFFSHORE ROUTE SEGMENT	Stakeholder Concerns (Fisheries /Marine Vessel Operators)	Green: no concerns anticipated Light Green: some concerns anticipated Yellow: moderate concern anticipated Orange: potential opposition anticipated Red: high level of opposition anticipated	Yellow: Atlantic from commercial fishermen and marine vessel operators possible Orange: Long Island Sound from commercial fishermen, marine vessel operators and CT on impacts on their coastal waters
SHORE APPROACH AND LANDING ROUTE SEGMENT	Infrastructure Crossings (linear utilities and tunnels)	Green: no crossings Light Green: lower number of crossings > 10 Yellow: moderate number of crossings 10 to 20 Orange: high number of crossings 20 to 30 Red: very high number of crossings 30+	Light Green: Long Island Sound 149th ~9 crossings, Astoria ~10 crossings Yellow: Lower NY Bay ~21 crossings, Long Island Sound Rainey ~14 crossings Orange: Gowanus ~26 crossings, Farragut ~29 crossings, Red: Rainey ~37 crossings, 149th Street ~41 crossings, Riverside East Narrows ~33 crossings, Riverside West Narrows ~34 crossings
SHORE APPROACH AND LANDING ROUTE SEGMENT	Sensitive Habitats (presence of sensitive species or habitat exists)	Green: no sensitive habitat present Light Green: some sensitive habitat exists but can be avoided Yellow: sensitive habitat exists in the entire area Orange: increased sensitive habitat designations in area or adjacent Red: high number of sensitive habitats must be crossed	Yellow: Several sensitive habitats (e.g., EFH) must be crossed, including winter flounder spawning and anadromous fish migratory areas. Endangered sturgeon species in area (Atlantic/Shortnose) Orange: Hudson River is critical habit for Atlantic Sturgeon
SHORE APPROACH AND LANDING ROUTE SEGMENT	Marine Geology and Oceanography (seabed, erosion, bedforms, etc.)	Green: highly suitable conditions for cable installation cable burial very easily achieved/maintained Light Green: generally suitable conditions for cable installation cable burial easily achieved/maintained Yellow: moderately suitable conditions for cable installation potential difficulty to achieve/maintain cable burial Orange: difficult conditions possible for cable installation due to potential structure/bedrock, difficult to achieve/maintain cable burial (further investigation required) Red: cable may not be installed/maintained to required depths due to potential bedrock or moraine, armoring may be required.	Light Green: Atlantic is generally soft sediments suitable for cable installation Orange: Western Long Island Sound and East River contain structure, potential presence of shallow bedrock in East River may create difficulties to meet cable burial depth requirements, armoring may be required.
SHORE APPROACH AND LANDING ROUTE SEGMENT	Further Regulatory Constraints (triggering additional state approvals)	Green: no trigger anticipated Light Green: trigger of additional (non-NY) state/federal coastal review unlikely or not burdensome Yellow: trigger of additional state/federal coastal management programs is possible and/or supplemental NY coastal review expected. Orange: trigger of additional state/federal coastal management program(s) expected Red: trigger of multiple additional state/federal permitting (e.g., Section 401 Water Quality Certifications) review will occur	Yellow: Route from Atlantic corridors adjacent to NJ State waters may trigger NJ coastal management program. Routes into New York City (NYC) will also require NYC Local Waterfront Revitilization Program (LWRP) approval Red: Riverside West Narrows and Farragut West Narrows crosses into NJ state waters and all state permit approvals will be necessary. Will also require NYC LWRP approval. May also require NPS submerged land easement approval for routing along west side of Narrows.
SHORE APPROACH AND LANDING ROUTE SEGMENT	Potential Stakeholder Concerns (Fisheries /Marine Vessel Operators)	Green: no concerns anticipated Light Green: some concerns anticipated Yellow: moderate concern anticipated Orange: opposition anticipated Red: high level of opposition anticipated	Yellow: Lower NY Bay, high marine traffic levels on approach to NY Harbor Orange: NY Harbor and LI Sound - high marine traffic levels
SHORE APPROACH AND LANDING ROUTE SEGMENT	Landing Site Complexity (e.g., back-bay crossings, shore structure crossings, dense development)	Green: very low complexity Light Green: low complexity Yellow: moderate complexity- given the presence of coastal structures that must be crossed under and urban location, including existing utility lines Orange: high complexity Red: very high complexity: HDD may not be possible other installation method may be required and or additional concerns given size of area and higher usage	Yellow: Lower New York Bay landing requires HDD under Belt Parkway and working in anchorage area, Gowanus requires HDD under revetment and close to channel, Astoria and Rainey required HDD under coastal structures Red: Riverside is in a highly trafficked public park on the waterfront, 149th limited area for HDD, CSO present at end of road, and close proximity to existing infrastructure. Alternate location on site would be on adjacent privately owned lot, Farragut limited area for HDD makes trenchless technology likely not possible, only feasible for open trench
SHORE APPROACH AND LANDING ROUTE SEGMENT	Navigation Channels, Anchorage Areas, and USACE Coastal Storm Risk Management Projects	Green: no crossings Light Green: lower number of crossings 1 Yellow: moderate number of crossings 2 to 5 Orange: high number of crossings 6 to 9 Red: very high number of crossings +9 or long runs	Light Green: Lower New York Bay ~1, Yellow: Long Island Sound 149th Street ~2, Astoria ~2, LI Sound Rainey ~3 and all run for along distance adjacent to channels and anchorages Orange: Farragut East Narrows ~7, Riverside East Narrows ~7, Gowanus ~6 Red: Riverside West Narrows ~12, Farragut West Narrows ~10, Rainey and 149th Street, given the long length that potentially must run in/adjacent to the channel
SHORE APPROACH AND LANDING ROUTE SEGMENT	Contaminated Sediments	Green: no contamination Light Green: lower levels of contamination likely Yellow: moderate levels of contamination likely Orange: high levels of contamination likely Red: high levels of contamination very likely	Yellow: Lower New York Bay has pockets of elevated (e.g., NYSDEC Class C) contamination and multiple combined sewer overflows passed Orange: longer route through Lower NY Bay and into Upper NY Bay increases likelihood of contamination, multiple shoreline DEC Remediation areas and combined sewer overflows passed Red: longer route through Upper NY Bay and the East River increases likelihood of contamination passes two marine superfund sites, multiple shoreline DEC Remediation areas and combined sewer overflows, Hudson River is a DEC Remediation Area
SHORE APPROACH AND LANDING ROUTE SEGMENT	Cultural Resources and Wrecks/Obstructions	Green: none present Light Green: lower number present Yellow: moderate number present Orange: high number present Red: very high number present	Light Green: Lower New York Bay has some wrecks present, and historical sites on shore where consultations would be required Yellow: Gowanus and Riverside longer route through Lower NY Bay and into Upper NY Bay/East River/Hudson increases likelihood of consultations more wrecks/ historical sites Orange: 149th Street, Farragut and Rainey longer route through Upper NY Bay and the Northern East River significantly increases quantity of consultations as more wrecks and cultural sites passed, also Brooklyn Bridge a Natural Historic Landmark is routed adjacent to Red: Western Long Island Sound and northeast East River have high number of wrecks

PRELIMINARY ROUTE FEASIBILITY SCORING IN NEW YORK CITY - CRITICAL CONSTRAINTS MATRIX

Offshore Route	Atlantic Central Corridor									Atlantic South Corridor									Long Island Sound Corridor		
Shore Approach and Landing Site	Lower New York Bay	Gowanus	Farragut (Narrows East)		Farragut (Narrows West)	Rainey	149th Street	Riverside (Narrows West)	Riverside (Narrows East)	Lower New York Bay	Gowanus	Farragut (Narrows East)		Farragut (Narrows West)	Rainey	149th Street	Riverside (Narrows West)	Riverside (Narrows East)	Rainey	Astoria	149th Street
Point of Interconnection	Farragut	Farragut	Farragut	Rainey	Farragut	Rainey	Mott Haven	West 49th		Farragut	Farragut	Farragut	Rainey	Farragut	Rainey	Mott Haven	West 49th		Rainey	Rainey	Mott Haven
ONSHORE ROUTE SEGMENT: Infrastructure HDDs and/or Bridge Crossings (roadway and waterway)																					
Wetlands, Sensitive Habitats																					
Potential Stakeholder Concerns/Jurisdictions Crossed																					
Contaminated Sites (total area encountered)																					
Cultural Resources																					
Route Distance (miles)																					
Available Land for Converter Stations (> 2.5 acre parcel)																					
Parkway/Highway (Permitting constraint)																					

ONSHORE ROUTE SEGMENT	Scoring explanations (Note that the group of NYC routes are ranked against each other for each consideration. The criteria that defines each rank may not be directly comparable to Long Island routes presented in separate matrix.)	Specific Route Scoring Comments
Infrastructure HDDs and/or Bridge Crossings (roadway and waterway)	Green: No major arterial or waterway crossings Light Green: 1-2 crossings Yellow: 3-4 of crossings Orange: 5-6 crossings Red: 7+ crossings	Green: Farragut to Farragut- 0, Rainey to Rainey- 0 Light Green: 149th to Mott Haven- 2, Riverside to W49th- 1, Rainey Park to Rainey- 1 Yellow: Rainey to Astoria- 4 Red: Lower NY Bay to Farragut- 7, Gowanus to Farragut- 8, Farragut to Rainey- 13
Wetlands, Sensitive Habitats	Green: No sensitive habitats along route Light Green: Small sensitive habitats, which can be avoided Yellow: Sensitive habitat exists in the entire area Orange: Majority of the route passes through sensitive habitat designations or adjacent where additional consultations may be required Red: Route entirety is through or adjacent to sensitive habitats	Green: No wetlands or sensitive habitats were identified along these routes from publicly available data Light Green: Lower NY Bay to Farragut passes along the edge of Prospect Park (Important Bird Area) and within about 200 feet of a DEC Wetland Check Zone for Dyker Beach Park
Potential Stakeholder Concerns/Jurisdictions Crossed	Green: 0 - 0.5 mi of route passes within 0.5 mi of NYC Zoning residential classification and 1 local jurisdiction Light Green: 0.5 - 2 mi of route passes within 0.5 mi of NYC Zoning residential classification and/or 2 local jurisdictions Yellow: 2 - 4 mi of route passes within 0.5 mi of NYC Zoning residential classification and/or 2 - 3 local jurisdictions Orange: 4 - 5 mi of route passes within 0.5 mi of NYC Zoning residential classification and/or 4 local jurisdictions Red: More than 5 mi of route passes within 0.5 mi of NYC Zoning residential classification and/or more than 4 local jurisdictions	Green: Farragut to Farragut 0 mi and 1 jurisdiction, Rainey Park to Rainey 0.13 mi and 1 jurisdiction, 149th to Mott Haven 0.7 mi and 1 jurisdiction, and Riverside to W49th- 0 mi and 1 jurisdiction Yellow: Gowanus to Farragut- 0.42 mi and 1 jurisdiction but passes near Boreum Hill which is known to have concerns about construction , Farragut to Rainey- 1.26 mi and 3 jurisdictions, and Rainey to Astoria 0.77 mi and 1 jurisdiction Red: Lower NY Bay to Farragut 2.06 mi and 1 jurisdiction
Contaminated Sites (total area encountered)	Green: No contaminated sites along route Light Green: Small contaminated sites along route, which may be avoidable Yellow: Crossing small contaminated sites is unavoidable along route Orange: Route passes large contaminated sites, crossing of which can be avoided Red: Large contaminated sites are along route and unavoidable	Green: Farragut to Farragut, 149th to Mott Haven, and Riverside to W 49th have no contaminated sites along the route Light Green: Gowanus to Farragut- passes 4 sites all avoidable, Rainey Park to Rainey- passes 2 sites both avoidable Yellow: Lower NY Bay to Farragut- Passes near Fort Hamilton and Brooklyn Navy Yard two Superfund Sites Orange: Farragut to Rainey- passes Brooklyn Navy Yard and under Newtown Creek, Rainey Park to Mott Haven via Astoria- Astoria is a DEC Remediation site but portions with the most contamination should be avoidable
Cultural Resources	Green: No known cultural resources along route Light Green: Low number and/or avoidable known cultural resources Yellow: Moderate number and/or avoidable known cultural resources Orange: Moderately high number of cultural resources, some of which can not be avoided Red: High number or large area of cultural resources	Green: 149th to Mott Haven, Rainey Park to Rainey, and Rainey to Astoria no known cultural resources along route Light Green: Farragut to Farragut heavily landmarked areas around Farragut (DUMBO Industrial, Brooklyn Navy Yard etc), Riverside to W49th is near but does not pass the Intrepid Orange: Lower NY Bay to Farragut passes through highly religious areas and dense historical areas/districts, Gowanus to Farragut and Brooklyn Bridge Park to Rainey pass through heavily landmarked areas around Farragut (DUMBO Industrial, Brooklyn Navy Yard etc)
Route Distance (miles)	Green: Route is <0.5 mi Light Green: Route is >0.5 mi but <1 mi Yellow: Route is 1-5 mi Orange: Route is 5-10 mi Red: Route is >10 mi	Green: Farragut to Farragut- 0 mi, Rainey Park to Rainey- 0.31 mi, 149th to Mott Haven- 0.75 mi, Riverside to W49th- 0.79 mi Yellow: Gowanus to Farragut- 4.94 mi, Rainey to Astoria- 2.71 mi Orange: Lower NY Bay to Farragut- 8.80 mi, Farragut to Rainey- 7.64 mi
Available Land for Converter Stations (> 2.5 acre parcel)	Green:6+ undeveloped and/or unconstrained 2.5 acre parcels within 1 mi of route or POI (Visual aerial interpretation) Light Green: 4-5 undeveloped and/or unconstrained 2.5 acre parcels within 1 mi of route or POI Yellow: 3 undeveloped and/or unconstrained 2.5 acre parcels within 1 mi of route or POI Orange: Only 2 undeveloped and/or unconstrained 2.5 acre parcels within 1 mi of route or POI Red: Only 1 undeveloped and/or unconstrained 2.5 acre parcel within 1 mi of route or POI Black: No suitable 2.5 acre parcels or only constrained parcels within 1 mi of route - further analysis by real estate planners warranted	Yellow: Gowanus - So. Brooklyn Terminal considered as more than one "parcel" pending Empire Wind, also 640 Columbia St 0.2 mi from route 4 acres but near Red Hook Park and public housing might also now be parking for IKEA; Rainey to Astoria - area at ConEd plant pending CHPE construction & 3-15 26 Avenue 0.5 mi from route 3.1 acres Orange: L NY Bay to Farragut - 595 Dean St. 2.75 vacant acres 0.08 mi from route; Rainey & Rainey to Farragut - 0.7 mi south along east river 42-02 & 44-02 Vernon Blvd totaling 5.2 acres; Mott Haven- old juvenile detention center at 707 Barretto St 0.7 mi from more eastern & favorable landing point Red: Rainey to Farragut - all 4 parcels identified as vacant and over 2 acres did not meet the minimum 80 m wide criteria for converter station
Parkway/Highway (Permitting constraint)	Green: Route does not touch parkway or highway interstate Light Green: Route may touch or cross parkway or highway interstate enough to trigger additional USDOT/FHWA approval Yellow: Moderate amount of route runs along or multiple crossings of parkway or highway interstate Orange: A significant portion of route is along parkway or highway interstate Red: Majority of route is along a parkway or highway interstate	Green: Farragut to Farragut and Rainey Park to Rainey do not touch parkways or highways Light Green: 149th to Mott Haven crosses under Bruckner Expy, Riverside to W49th runs down Hudson Pkwy Yellow: Farragut to Lower NY Bay parallels Principal Arterial Other Fulton Ave, Vanderbilt Ave, Prospect Park W, Prospect Park SW, Coney Island Ave for 3.07 mi and crosses BQE 1x Orange: Rainey to Farragut- parallels McGuinnis Blvd for 1.3 mi (classified as Principal Arterial Other by NYDOT) and crosses BQE 2x, Farragut to Gowanus- parallels Principal Arterial Other Atlantic Ave & 4th Ave 2.78 mi and crosses BQE 2x and Prospect Expressway 1x

Lease Area/Region	Hudson North									Hudson South			New Jersey						Massachusetts		
Offshore Route	Atlantic Central Corridor									Atlantic South Corridor									Long Island Sound Corridor		
Shore Approach and Landing Site	Lower New York Bay	Gowanus	Farragut (Narrows East)		Farragut (Narrows West)	Rainey Park	149th Street	Riverside (Narrows West)	Riverside (Narrows East)	Lower New York Bay	Gowanus	Farragut (Narrows East)		Farragut (Narrows West)	Rainey Park	149th Street	Riverside (Narrows West)	Riverside (Narrows East)	Rainey Park	Astoria	149th Street
Point of Interconnection	Farragut	Farragut	Farragut	Rainey	Farragut	Rainey	Mott Haven	West 49th		Farragut	Farragut	Farragut	Rainey	Farragut	Rainey	Mott Haven	West 49th		Rainey	Rainey	Mott Haven
Count: 1x	0	1	6	1	6	5	5	4	4	0	1	6	1	6	5	5	4	4	6	2	5
2x	7	5	4	3	4	5	5	7	7	5	3	2	1	2	3	3	5	5	3	4	5
3x	11	9	5	6	4	6	5	4	5	12	10	6	7	5	7	6	5	6	6	9	4
4x	3	8	7	11	6	4	4	3	4	4	9	8	12	7	5	5	4	5	6	7	6
5x	2	1	1	3	3	4	5	5	3	2	1	1	3	3	4	5	5	3	3	2	4
100x	1	0	1	0	1	0	0	1	1	1	0	1	0	1	0	0	1	1	0	0	0
Total Points*	169	75	162	84	165	69	71	167	164	172	78	165	87	168	72	74	170	167	69	75	71
Site Ranking**	19	7	12	10	14	1	3	16	13	21	9	14	11	18	5	6	20	16	1	7	3

No constraints present
Low constraints present
Moderate constraints present
Major constraints present
Substantial constraints present
Challenges considered potentially insurmountable

* Note: Lowest points => best option. Weighting factors applied: Light Green x1; Green x2; Yellow x3 Orange x4; Red x5; Black x100.

** Note: Lowest value => best option

Attachment 2-2

PRELIMINARY ROUTE FEASIBILITY SCORING
ON LONG ISLAND, NEW YORK - CRITICAL CONSTRAINTS MATRIX

Color Key (with scoring)

Score	Description
1x	No constraints present
2x	Low constraints present
3x	Moderate constraints present
4x	Major constraints present
5x	Substantial constraints present
100x	Challenges considered potentially insurmountable

Lease Area/Region	Hudson North					Empire Wind					Massachusetts										Massachusetts					
Offshore Route	Atlantic Central Corridor										Atlantic North Corridor										Long Island Sound Corridor					
Shore Approach and Landing Site	Smith Point	Jones Beach						Long Beach			Smith Point	Jones Beach						Long Beach			Northport	Cold Spring Harbor		Bayville		Hempstead Harbor
Point of Interconnection	Brookhaven	Northport (via Syosset)	Newbridge	Syosset	Shore Road	East Garden City	Ruland Road	Newbridge	East Garden City	Shore Road	Brookhaven	Northport (via Syosset)	Newbridge	Syosset	Shore Road	East Garden City	Ruland Road	Newbridge	East Garden City	Shore Road	Northport	Syosset East	Syosset West	Shore Road	Syosset	Shore Road
Considerations																										
LEASE TO POI: Approximate route distance in miles (AC Feasibility: +/- 70 miles) — Empire Wind	51	67	47	54	59	49	52	55	53	61	138	193	173	181	185	175	178	183	181	189	166	182	181	188	189	187
Hudson North	58	85	65	73	77	67	70	74	71	80																

Segment	Considerations	Scoring explanations (Note that the group of Long Island routes are ranked against each other for each consideration. The criteria that defines each rank may not be directly comparable to NYC routes presented in separate matrix.)	Specific Route Scoring Comments
LEASE TO POI	Approximate route distance in miles (AC Feasibility: +/- 70 miles)	Dark Grey: less than 70 miles Light Grey: >70 mi but <75 mi No color: more than 75 miles	
OFFSHORE ROUTE SEGMENT	Infrastructure Crossings (linear utilities)	Green: no crossings Light Green: lower number of crossings > 15 Yellow: moderate number of crossings 15 to 25 Orange: high number of crossings 25 to 35 Red: very high number of crossings 35+	Light Green: Atlantic Central Corridor > 15 crossings varies by route Yellow: Long Island Sound Corridor ~ 17 crossings, Atlantic South Shore ~18 crossings
OFFSHORE ROUTE SEGMENT	Designated Marine Zones (traffic lanes, danger zones)	Green: no navigation features present in area Light Green: route generally avoids navigation features but some in area Yellow: likely must cross a navigation feature Orange: must cross multiple navigation features Red: significant impact to navigation anticipated	Light Green: routing could generally avoid desginated marine zones Yellow: traffic lanes or precautionary area on Atlantic Central Corridor
OFFSHORE ROUTE SEGMENT	Department of Defense Areas	Green: none present Light Green: present in area but can be avoided or no restrictions apply Yellow: must cross a Department of Defense (DoD) area where site specific stipulations apply Orange: must cross a DoD area where site specific stipulations apply and/or multiple other features apply Red: DoD exclusion area present that must be crossed	Orange: in Atlantic and on approach to Long Island (LI) Sound DoD OPAREA, Sub lane, testing range exist
OFFSHORE ROUTE SEGMENT	Sensitive Habitats (presence of sensitive species or habitat exists)	Green: no sensitive habitat present Light Green: some sensitive habitat exists but can be avoided Yellow: sensitive habitat exists in the entire area Orange: increased sensitive habitat designations in area or adjacent Red: high number of sensitive habitats must be crossed	Yellow: entire Atlantic in this area is BIA for NARW Orange: entire Atlantic in this area is BIA for NARW and in LI Sound DEC CIA and NYSDOS SCFWH area must be crossed/routed adjacent to
OFFSHORE ROUTE SEGMENT	Marine Geology and Oceanography (seabed, erosion, bedforms, etc.)	Green: highly suitable conditions for cable installation cable burial very easily achieved/maintained Light Green: generally suitable conditions for cable installation cable burial easily achieved/maintained Yellow: moderately suitable conditions for cable installation potential difficulty to achieve/maintain cable burial Orange: difficult conditions may exist for cable installation do to structure difficult to achieve/ maintain cable burial Red: cable may not be installed/maintained to required depths due to potential bedrock or moraine armoring may be required	Light Green: Atlantic is generally soft sediments go for cable installation Red: Long Island Sound Corridor presence of rock reefs at moraines may make cable burial difficult to achieve, armoring may be required. Strong current also exits in entrance to Long Island Sound.
OFFSHORE ROUTE SEGMENT	Further Regulatory Constraints (triggering additional state approvals)	Green: no trigger possible Light Green: trigger of additional state review is not likely Yellow: trigger of state coastal management programs is possible Orange: trigger of multiple state coastal management program(s) expected Red: trigger of multiple state permitting (i.e. Section 401) review will occur	Orange: RI and CT Coastal Management Programs by entering Long Island Sound, as well as multiple Local Waterfront Revitilization Program reviews.
OFFSHORE ROUTE SEGMENT	Stakeholder Concerns (Fisheries /Marine Vessel Operators)	Green: no concerns anticipated Light Green: some concerns anticipated Yellow: moderate concern anticipated Orange: potential opposition anticipated Red: high level of opposition anticipated	Yellow: Atlantic from commercial fisherman and marine vessel operators possible Orange: Long Island Sound from commercial fisherman, marine vessel operators and CT on impacts on their coastal waters
SHORE APPROACH AND LANDING ROUTE SEGMENT	Infrastructure Crossings (linear utilities)	Green: no crossings Light Green: lower number of crossings > 2 Yellow: moderate number of crossings 2 to 10 Orange: high number of crossings 10 to 15 Red: very high number of crossings 15+ -	Light Green: Northport, Cold Spring Harbor, and Bayville 1 crossing Yellow: Hempstead Harbor ~4 crossings, Smith Point ~8 crossings, Jones Beach ~9 crossings Orange: Long Beach ~ 12 crossings
SHORE APPROACH AND LANDING ROUTE SEGMENT	Sensitive Habitats (presence of sensitive species or habitat exists)	Green: no sensitive habitat present Light Green: some sensitive habitat exists but can be avoided Yellow: sensitive habitat exists in the entire area Orange: increased sensitive habitat designations in area or adjacent Red: high number of sensitive habitats must be crossed	Light Green: Long Beach - no Significant Coastal Fish and Wildlife Habitat (SCFWH) or Critical Environmental Area (CEA) uncertified shellfish waters and low presence of shorebirds Yellow: Northport/Bayville routes pass near sensitive habitats and areas with increased likelihood of nesting shorebird presence Orange: Smith Point, Jones Beach CSH, Hempstead Harbor routes all cross sensitive habitat (i.e. SCFWH, natural heritage areas)
SHORE APPROACH AND LANDING ROUTE SEGMENT	Marine Geology and Oceanography (seabed, erosion, bedforms, etc.)	Green: highly suitable conditions for cable installation cable burial very easily achieved/maintained Light Green: generally suitable conditions for cable installation cable burial easily achieved/maintained Yellow: moderately suitable conditions for cable installation potential difficulty to achieve/maintain cable burial Orange: difficult conditions may exist for cable installation do to structure difficult to achieve/ maintain cable burial- Structure present on approach Red: cable may not be installed/maintained to required depths due to potential bedrock or moraine armoring may be required	Yellow: Atlantic Ocean shoreline is highly dynamic
SHORE APPROACH AND LANDING ROUTE SEGMENT	Further Regulatory Constraints (triggering additional state approvals)	Green: no trigger anticipated Light Green: trigger of additional (non-NY) state/federal coastal review unlikely or not burdensome Yellow: trigger of additional state/federal coastal management programs is possible and/or supplemental NY coastal review expected. Orange: trigger of additional state/federal coastal management program(s) expected Red: trigger of multiple additional state/federal permitting (e.g., Section 401 Water Quality Certifications) review will occur	Light Green: No triggering of other states' permitting requirements for shore approach segments. Trigger of Local Waterfront Revitilization Programs not anticipated based on plans approved as of December 2020. NYSDEC Coastal Erosion Management Permit may be required for Jones Beach/Long Beach, but addressed as part of standard New York State Joint Permit Application. Orange: Approach to Bayville and Cold Spring Harbor would trigger Local Waterfront Revitilization Program review.
SHORE APPROACH AND LANDING ROUTE SEGMENT	Potential Stakeholder Concerns (Fisheries /Marine Vessel Operators)	Green: no concerns anticipated Light Green: some concerns anticipated Yellow: moderate concern anticipated Orange: potential opposition anticipated Red: high level of opposition anticipated	Yellow: Atlantic from commercial fishermen and marine vessel operators possible, Orange: Long Island Sound from commercial fishermen, marine vessel operators and CT on impacts on their coastal waters, Cold Spring Harbor likely to have increased concerns as a result of commercial shell fisherman and proximity to village center, Bayville likely to have increased concerns from local community and adjacent homeowners, Long Beach has vocal local population
SHORE APPROACH AND LANDING ROUTE SEGMENT	Landing Site Complexity (e.g., back-bay crossings, shore structure crossings, dense development)	Green: very low complexity Light Green: low complexity Yellow: moderate complexity Orange: high complexity Red: very high complexity	Light Green: Northport and Hempstead Bay landings do not require backbay crossing and HDD can likely be accomplished Yellow: Smith Point has one backbay crossing, Cold Spring Harbor and Bayville HDD feasibility is lower but open trench can likely be completed Orange: Jones Beach has 3 backbay crossings, Long Beach has 1 backbay crossing and is in developed area
SHORE APPROACH AND LANDING ROUTE SEGMENT	Navigation Channels, Anchorage Areas, and USACE Coastal Storm Risk Management Projects	Green: no crossings Light Green: lower number of crossings 1 Yellow: moderate number of crossings 2 to 3 Orange: high number of crossings 3 to 5 Red: very high number of crossings +5 or long runs	Green: Long Island Sound routes would require no crossing of navigation channels, anchorage areas, or USACE Coastal Storm Risk Management Projects Yellow: Smith Point and Long Beach 2, Orange: Jones Beach 4
SHORE APPROACH AND LANDING ROUTE SEGMENT	Contaminated Sediments	Green: no contamination anticipated Light Green: lower levels of contamination likely Yellow: moderate levels of contamination likely Orange: high levels of contamination likely Red: high levels of contamination very likely	Green: Atlantic Ocean contamination is not expected Light Green: Long Beach backbay area has potential for contamination as adjacent shoreline site is DEC remediation area, LI Sound tributaries and harbors have increased likelihood of contamination Yellow: Hempstead Harbor shore has several DEC remediation sites.
SHORE APPROACH AND LANDING ROUTE SEGMENT	Cultural Resources and Wrecks/Obstructions	Green: none present Light Green: lower number present Yellow: moderate number present Orange: high number present Red: very high number present	Light Green: Atlantic wrecks obstructions but can generally be routed around Yellow: Central Long Island Sound has increased concentration of wrecks/obstructions

PRELIMINARY ROUTE FEASIBILITY SCORING ON LONG ISLAND, NEW YORK - CRITICAL CONSTRAINTS MATRIX

ONSHORE ROUTE SEGMENT	Scoring explanations (Note that the group of Long Island routes are ranked against each other for each consideration. The criteria that defines each rank may not be directly comparable to NYC routes presented in separate matrix.)	Specific Route Scoring Comments
Infrastructure HDDs and/or Bridge Crossings (roadway and waterway)	Green: no major arterial or waterway crossings Light Green: 1-2 crossings Yellow: 3-4 of crossings Orange: 5-6 crossings Red: 7+ crossings	Green: Northport to Northport- 0, Cold Spring Harbor to Syosset East & West- 0, Bayville to Shore Rd and Syosset assumes OH AC along the railroad therefore no HDD needed, Shore Rd to Hempstead Harbor- 0 Light Green: Jones Beach to Newbridge- 1, Long Beach to East Garden City- 1 Yellow: Brookhaven to Smith Point- 3, Jones Beach to East Garden City- 3 Orange: Jones Beach to Shore Rd- 6, Jones Beach to Ruland Rd- 6 Red: Jones Beach to Northport- 10, Jones Beach to Syosset- 10, Long Beach to Shore Rd- 7
Wetlands, Sensitive Habitats	Green: no sensitive habitats along route Light Green: small sensitive habitats, which can be avoided Yellow: sensitive habitat exists in the entire area Orange: majority of the route passes through sensitive habitat designations or adjacent where additional consultations may be required Red: route entirety is through or adjacent to sensitive habitats	Light Green: Routes originating at Long Beach have less overall sensitive habitats due to development. Onshore routes pass near sensitive habitats but not through. Jones Beach to Syosset & Ruland Rd avoids wetlands. Yellow: Jones Beach to Newbridge passes through wetland check zones on Wantagh Pkwy, Cold Spring Harbor to Syosset East passes through wetland check zones along Harbor Rd Orange: Jones Beach to Shore Rd & East Garden City must route up extensive portion of Meadowbrook Pkwy which is surrounded by wetlands for much of the route.
Potential Stakeholder Concerns/ Jurisdictions Crossed	Green: 0 - 1 mi of route passes along low and medium density developed lands, mostly including single family residences and 1 local jurisdiction Light Green: 1 - 4 mi of route passes along low and medium density developed lands, mostly including single family residences and 1 - 3 local jurisdictions Yellow: 4 - 6 mi of route passes along low and medium density developed lands, mostly including single family residences and 3 - 5 local jurisdictions. Orange: 6 - 10 mi of route passes along low and medium density developed lands, mostly including single family residences and 5 - 9 local jurisdictions. Red: More than 10 mi of route passes along low and medium density developed lands, mostly including single family residences and more than 9 local jurisdictions.	Yellow: Bayville to Shore Rd elevated due to crossing 6 local municipalities, but only passes 3.92 mi of low and medium density lands Orange: Brookhaven to Smith Point only passes through 2-3 local jurisdictions Red: Long Beach routes elevated even though routes are under 10 mi through single family residence zones due to previous opposition to cable construction in area and passing through 10 local jurisdictions
Contaminated Sites (total area encountered)	Green: no contaminated sites along route Light Green: small contaminated sites along route, which may be avoidable Yellow: crossing small contaminated sites is unavoidable along route Orange: route passes large contaminated sites, crossing of which can be avoided Red: large contaminated sites are along route and unavoidable	Green: Northport to Northport and Hempstead Harbor to Shore Rd pass no contaminated sites Light Green: Routes pass small sites but are avoidable Yellow: Jones Beach and Long Beach to Shore Rd passes through 1 small site, East Garden City itself is a completed State Superfund Site that has an environmental easement, bumping up the ranking of both routes, Jones Beach and Long Beach, to yellow.
Cultural Resources	Green: no known cultural resources along route Light Green: Low number and/or avoidable known cultural resources Yellow: moderate number and/or avoidable known cultural resources Orange: moderately high number of cultural resources, some of which can not be avoided Red: high number or large area of cultural resources	Light Green: Long Beach to East Garden City and Shore Rd pass and avoid a few small cultural resources Yellow: Jones Beach to Syosset, East Garden City, and Shore Rd pass near but avoid small cultural resources Orange: Jones Beach to Ruland Rd must pass through the large Bethpage State Park and golf course
Route Distance (miles)	Green: Route is <5 mi Light Green: Route is 5-10 mi Yellow: Route is 10-15 mi Orange: Route is 15-20 mi Red: Route is >20 mi	Green: Northport to Northport- 0 mi, Cold Spring Harbor to Syosset East- 3.34 mi, Cold Spring Harbor to Syosset West- 3.58 mi, Hempstead Harbor to Shore Rd- 0.49 mi Yellow: Smith Point to Brookhaven- 10.20 mi, Jones Beach to Newbridge- 11.10 mi, Jones Beach to East Garden City- 12.92 mi, Long Beach to Newbridge- 14.17 mi, Long Beach to East Garden City-11.61 mi, Bayville to Shore Rd- 10.88 mi, Bayville to Syosset-12.30 mi Orange: Jones Beach to Syosset-18.48 mi, Jones Beach to Ruland Rd-16.92 mi Red: Jones Beach to Northport- 30.80 mi, Jones Beach to Shore Rd-24.30 mi, Long Beach to Shore Rd-21.34 mi
Available Land for Converter / Transformer Stations (> 2.5 acre parcel)	Green: 6+ undeveloped and/or unconstrained 2.5 acre parcels within 1 mi of route or POI (Visual aerial interpretation) Light Green: 4-5 undeveloped and/or unconstrained 2.5 acre parcels within 1 mi of route or POI Yellow: 3 undeveloped and/or unconstrained 2.5 acre parcels within 1 mi of route or POI Orange: Only 2 undeveloped and/or unconstrained 2.5 acre parcels within 1 mi of route or POI Red: Only 1 undeveloped and/or unconstrained 2.5 acre parcel within 1 mi of route or POI Black: No suitable 2.5 acre parcels or only constrained parcels within 1 mi of route - further analysis by real estate planners warranted	Yellow: Jones Beach to East Garden City, Jones Beach to Ruland Rd (parcel needed to be 5 acres for DC conversion), Jones Beach to Shore Rd, Long Beach to East Garden City, and Long Beach to Shore Rd all had 3 potential parcels Red: Jones Beach to Syosset only 1 potential parcel on Boundary Ave, Hempstead Harbor to Shore Rd 1 parcel Black: Jones Beach to Newbridge & Syosset no unconstrained 2.5 acre parcels within 1 mi of route, further search warranted
Parkway/Highway (Permitting constraint)	Green: route does not touch parkway or highway interstate Light Green: route may touch or cross parkway or highway interstate enough to trigger additional USDOT/FHWA approval Yellow: moderate amount of route runs along or multiple crossings of parkway or highway interstate Orange: a significant portion of route is along parkway or highway interstate Red: majority of route is along a parkway or highway interstate	Light Green: Long Beach to Shore Rd and East Garden City only cross Sunrise Hwy, Southern State Pkwy, Northern Pkwy, and LIE Orange: Jones Beach to Shore Rd and East Garden City parallels Meadowbrook Pkwy for 11.6 mi, Jones Beach to Ruland Rd parallels Seaford-Oyster Bay Expy for 4.3 mi and Sunrise Hwy for 0.76 mi Red: Jones Beach to Syosset- parallels Watagh Pkwy/Jones Beach Causeway and Seaford-Oyster Bay Expy for 14.3 mi

Lease Area/Region	Hudson North			Empire Wind							Massachusetts										Massachusetts						
Offshore Route	Atlantic Central Corridor										Atlantic North Corridor										Long Island Sound Corridor						
Shore Approach and Landing Site	Smith Point	Jones Beach						Long Beach			Smith Point	Jones Beach						Long Beach			Northport	Cold Spring Harbor		Bayville		Hempstead Harbor	
Point of Interconnection	Brookhaven	Northport (via Syosset)	Newbridge	Syosset	Shore Road	East Garden City	Ruland Road	Newbridge	East Garden City	Shore Road	Brookhaven	Northport (via Syosset)	Newbridge	Syosset	Shore Road	East Garden City	Ruland Road	Newbridge	East Garden City	Shore Road	Northport	Syosset East	Syosset West	Shore Road	Syosset	Shore Road	
Count: 1x	1	1	1	1	1	1	1	0	0	0	1	1	1	1	1	1	1	0	0	0	7	5	4	2	3	7	No constraints present
2x	8	7	7	7	5	5	7	10	11	10	8	7	7	7	5	5	7	10	11	10	6	4	7	7	6	4	Low constraints present
3x	11	7	8	7	9	10	6	7	8	6	11	7	8	7	9	10	6	7	8	6	4	5	4	8	8	5	Moderate constraints present
4x	4	6	6	5	7	8	10	5	5	5	4	6	6	5	7	8	10	5	5	5	6	9	8	6	6	6	Major constraints present
5x	0	3	1	3	2	0	0	2	0	3	0	3	1	3	2	0	0	2	0	3	1	1	1	1	1	2	Substantial constraints present
100x	0	0	1	1	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	Challenges considered potentially insurmountable
Total Points*	66	75	168	171	76	73	73	71	64	73	66	75	168	171	76	73	73	71	66	73	60	69	67	69	68	64	
Site Ranking**	4	19	23	25	21	13	13	11	2	13	4	19	23	25	21	13	13	11	4	13	1	9	7	9	8	2	

* Note: Lowest points => best option. Weighting factors applied: Light Green x1; Green x2; Yellow x3 Orange x4; Red x5; Black x100.

** Note: Lowest value => best option

Annex B - Part 3
Refined Route Feasibility Scoring Matrices

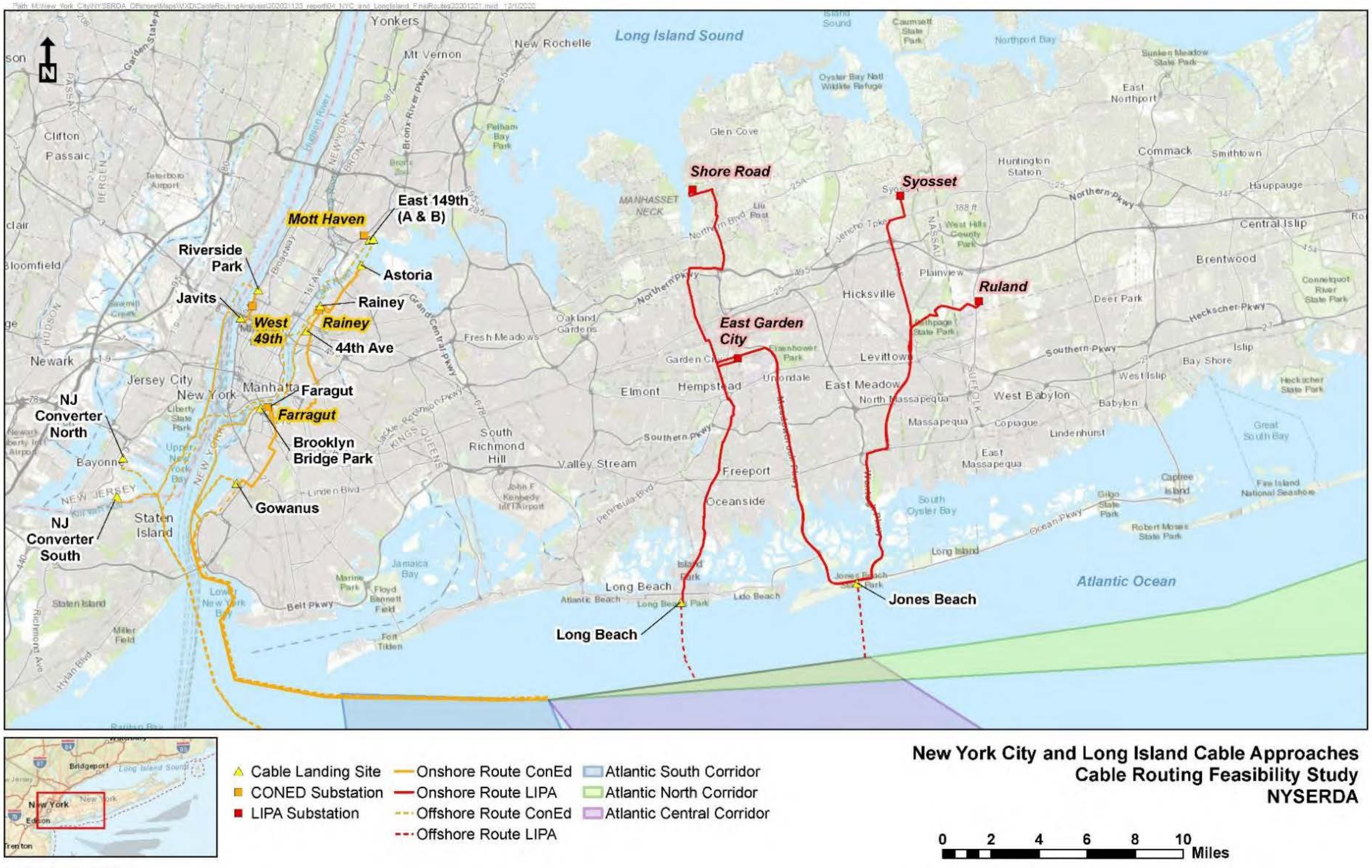
Below is a map (Figure B) showing final representative routes that were subject to a more detailed analysis during the transmission cable routing feasibility assessment (Routing Assessment). Following the map, two matrices – one for New York City points of interconnection (POIs) and one for Long Island POIs – present the results of the preliminary route feasibility scoring for potential critical constraint categories. Each matrix is split across two pages (11” by 17” format). Blue-shaded headers are carried over onto each page for ease of review.

The matrix identifies the preliminary routes split into three segments – (1) offshore, (2) shore approach and landing site, and (3) onshore. The blue-shaded column headers identify the name of each route segment. The scoring for each route segment is presented for each critical constraint category; color coding was applied as a visual aid. The color key at the top-center of each matrix denotes the score value and description of each corresponding color. The total score and relative rank for each representative route can be found at the bottom of the second page of each matrix.

To the right of the color-coded scoring section, in the middle of the page, a column titled “Scoring Explanations” describes the criteria used to assign scores for each constraint category. Farthest to the right, a column titled “Specific Route Scoring Comments” provides a summary of details considered when assigning constraint scores for specific route segments.

Figure B. Refined Shore Approach Routes, Landings, and Onshore Routes to New York City and Long Island

Source: WSP 2020; DNVGL 2020; ESRI 2020. (See Annex B, Part 1 - GIS Data Source List for full list of figure references.)



REFINED ROUTE FEASIBILITY SCORING
IN NEW YORK CITY - CRITICAL CONSTRAINTS MATRIX

Color Key (with scoring)

Score	Description
1x	No constraints present
2x	Low constraints present
3x	Moderate constraints present
4x	Major constraints present
5x	Substantial constraints present
100x	Challenges considered potentially insurmountable

	Lease Area/Region	Hudson North	Hudson South				New Jersey				
	Offshore Route	Atlantic Central Corridor	Atlantic South Corridor								
	Shore Approach and Landing Site	Gowanus (via either pierline segment or Bay Ridge Flats segment)	Brooklyn Bridge Park	44th Ave	149th Street (Narrows West)	Rainey Park & 149th Street via Astoria (Narrows East)	Riverside (Narrows West & NJ Converter-South)	Riverside (Narrows West & NJ Converter-North)	Javits Center Pier Converter	**Scoring Explanations** **(Note that the group of Long Island routes are ranked against each other for each consideration. The criteria that defines each rank may not be directly comparable to NYC routes presented in separate matrix.)**	**Specific Route Scoring Comments**
	Point of Interconnection	Farragut	Rainey	Rainey	Mott Haven	Mott Haven	West 49th	West 49th	West 49th		
Considerations											
LEASE TO POI	Approximate route distance in miles (AC Feasibility: +/- 70 miles)	101	113	111	113	119	126	127	121	Grey: less than 70 miles No color: more than 70 miles	
OFFSHORE ROUTE SEGMENT	Infrastructure Crossings (linear utilities)									Green: no crossings Light Green: lower number of crossings less than 15 Yellow: moderate number of crossings 15 to 25 Orange: high number of crossings 25 to 35 Red: very high number of crossings 35+	Light Green: Atlantic Central Corridor > 15 crossing varies by route Orange: Atlantic South Corridor ~27 crossings (Long Beach Island on Manasquan has multiple infrastructure landings that must be crossed)
	Designated Marine Zones (traffic lanes, danger zones)									Green: no navigation features present in area Light Green: Route generally avoids navigation features but some in area Yellow: Likely must cross a navigation feature Orange: Must cross multiple navigation features Red: Significant impact to navigation anticipated	Yellow: Atlantic Central Corridor traffic lanes or precautionary area on Atlantic Approach to New York (NY) Harbor Orange: Atlantic South Corridor traffic lanes or precautionary area on approach to NY Harbor and Danger Zone (unexploded ordinance) east of Sandy Hook, New Jersey (NJ) and south of Rockaway Beach, NY on NY Harbor approach
	Department of Defense Areas									Green: none present Light Green: present in area but can be avoided or no restrictions apply Yellow: must cross a Department of Defense (DoD) area where site specific stipulations apply Orange: must cross a DoD area where site specific stipulations apply and/or multiple other features apply Red: DoD exclusion area present that must be crossed	Yellow: Atlantic South Corridor - Atlantic City DoD OPAREA exists Orange: Atlantic Central Corridor - Atlantic DoD OPAREA, Submarine transit lane, testing range exist
	Sensitive Habitats (presence of sensitive species or habitat exists)									Green: no sensitive habitat present Light Green: some sensitive habitat exists but can be avoided Yellow: sensitive habitat exists in the entire area Orange: increased sensitive habitat designations in area or adjacent Red: high number of sensitive habitats must be crossed	Yellow: Atlantic in this area is biologically important area for North Atlantic Right Whale
	Marine Geology and Oceanography (seabed, erosion, bedforms, etc.)									Green: highly suitable conditions for cable installation cable burial very easily achieved/maintained Light Green: generally suitable conditions for cable installation cable burial easily achieved/maintained Yellow: moderately suitable conditions for cable installation potential difficulty to achieve/maintain cable burial Orange: difficult conditions may exist for cable installation do to structure difficult to achieve/ maintain cable burial Red: cable may not be installed/maintained to required depths due to potential bedrock or moraine armoring may be required	Light Green: Atlantic is generally soft sediments good for cable installation
	Further Regulatory Constraints (triggering additional state approvals)									Green: no trigger possible Light Green: trigger of additional state review is not likely Yellow: trigger of additional state coastal management programs is possible Orange: trigger of state coastal management program(s) will occur Red: trigger of state permitting (i.e. Section 401) review will occur	Light Green: NYSDOS Coastal Management Program Yellow: NYSDOS Coastal Management Program and NJ Shore can reroute to avoid NJ state waters but crossing offshore of NJ waters may trigger coastal management program if determined to impact state users (i.e. fishermen)
	Potential Stakeholder Concerns (Fisheries /Marine Vessel Operators)									Green: no concerns anticipated Light Green: some concerns anticipated Yellow: moderate concern anticipated Orange: potential opposition anticipated Red: high level of opposition anticipated	Yellow: Atlantic from commercial fisherman and marine vessel operators possible
SHORE APPROACH AND LANDING ROUTE SEGMENT	Infrastructure Crossings (linear utilities and tunnels)									Green: no crossings Light Green: lower number of crossings > 10 Yellow: moderate number of crossings 10 to 20 Orange: high number of crossings 20 to 30 Red: very high number of crossings 30+	Orange: Gowanus ~26 crossings Red: Brooklyn Bridge Park ~30 crossings ,Rainey Park ~37 crossings, 149th Street ~41 crossings, Riverside West Narrows ~34 crossings, additionally all must cross subway/train/road tunnels
	Sensitive Habitats (presence of sensitive species or habitat exists)									Green: no sensitive habitat present Light Green: some sensitive habitat exists but can be avoided Yellow: sensitive habitat exists in the entire area Orange: increased sensitive habitat designations in area or adjacent Red: high number of sensitive habitats must be crossed	Yellow: Several sensitive habitats (e.g., EFH) must be crossed, including winter flounder spawning and anadromous fish migratory areas. Endangered sturgeon species in area (Atlantic and Shortnose) Orange: Hudson River is critical habit for Atlantic Sturgeon
	Marine Geology and Oceanography (seabed, erosion, bedforms, etc.)									Green: highly suitable conditions for cable installation cable burial very easily achieved/maintained Light Green: generally suitable conditions for cable installation cable burial easily achieved/maintained Yellow: moderately suitable conditions for cable installation potential difficulty to achieve/maintain cable burial Orange: difficult conditions possible for cable installation due to structure/bedrock that may be present difficult to achieve/ maintain cable burial (further investigation required) Red: cable may not be installed/maintained to required depths due to potential bedrock or moraine, armoring may be required.	Light Green: Atlantic is generally soft sediments suitable for cable installation Red: East River contains structure, potential presence of shallow bedrock in East River may create difficulties to meet cable burial depth requirements, armoring may be required. Additionally, East River is a tidal channel with strong currents that have high potential for seafloor scouring and could present logistical challenges during cable installation.
	Further Regulatory Constraints (triggering additional state approvals)									Green: no trigger anticipated Light Green: trigger of additional (non-NY) state/federal coastal review unlikely or not burdensome Yellow: trigger of additional state/federal coastal management programs is possible and/or supplemental NY coastal review expected. Orange: trigger of additional state/federal coastal management program(s) expected Red: trigger of multiple additional state/federal permitting (e.g., Section 401 Water Quality Certifications) review will occur	Yellow: Route adjacent to NJ State waters may trigger NJ coastal management program. Will also require New York City (NYC) Local Waterfront Revitilization Program (LWRP) approval Red: Routes along the west side of the Narrows cross into NJ state waters and all relevant NJ state permit approvals will be necessary. Will also require NYC LWRP approval. May also require NPS submerged land easement approval for routing along west side of Narrows.
	Potential Stakeholder Concerns (Fisheries /Marine Vessel Operators)									Green: no concerns anticipated Light Green: some concerns anticipated Yellow: moderate concern anticipated Orange: opposition anticipated Red: high level of opposition anticipated	Orange: NY Harbor high marine traffic levels
	Landing Site Complexity (e.g., back-bay crossings, shore structure crossings, dense development)									Green: very low complexity Light Green: low complexity Yellow: moderate complexity- given the presence of coastal structures that must be crossed under and presence of site in urban area, including existing utility lines Orange: high complexity: HDD potentially feasible but significant constraints exist Red: very high complexity: HDD may not be possible other installation method may be required and or additional concerns given size of area and higher usage	Yellow: Gowanus requires HDD under bulkhead and close to channel but suitable space, Brooklyn Bridge required HDD under coastal structures and is in public park, Javits can likely land in converter without need for HDD Orange: Riverside is in a highly trafficked public park on the waterfront and need to cross under bulkhead, Rainey/44th must cross under coastal structure, bedrock may be present in nearshore, and strong currents in East River may make it difficult for landing. Red: 149th limited area for HDD, CSO present at end of road and close proximity to existing infrastructure. Alternate landing location on adjacent private lot
	Navigation Channels, Anchorage Areas, and USACE Coastal Storm Risk Management Projects									Green: no crossings Light Green: lower number of crossings 1 Yellow: moderate number of crossings 2 to 5 Orange: high number of crossings 6 to 9 Red: very high number of crossings +9 or long runs	Orange: Gowanus 7 Red: Riverside Park 11, Javits 12, Rainey Park 12, 149th Street 13 44th Ave 8 and also long runs adjacent to channel in East River, Brooklyn Bridge Park 8 but must route for long distance adjacent to nav channel
	Contaminated Sediments									Green: no contamination Light Green: lower levels of contamination likely Yellow: moderate levels of contamination likely Orange: high levels of contamination likely Red: high levels of contamination very likely	Orange: longer route through Lower NY Bay and into Upper NY Bay increases likelihood of contamination, multiple shoreline DEC Remediation areas and combined sewer overflows passed
	Cultural Resources and Wrecks/Obstructions									Green: none present Light Green: lower number present Yellow: moderate number present Orange: high number present Red: very high number present	Yellow: For Gowanus Javits and Riverside longer route through Lower NY Bay and into Upper NY Bay/East River/Hudson increases likelihood of consultations more wrecks/ historical sites passed Orange: 149th Street, Brooklyn Bridge, 44th and Rainey longer route through Upper NY Bay and the Northern East River significantly increases quantity of consultations as more wrecks and cultural sites passed, also Brooklyn Bridge a Natural Historic Landmark is routed adjacent to that shore approach

REFINED ROUTE FEASIBILITY SCORING
IN NEW YORK CITY - CRITICAL CONSTRAINTS MATRIX

App. D to Initial Report on Power Grid Study

		Offshore Route	Atlantic Central Corridor	Atlantic South Corridor							Scoring Explanations (Note that the group of Long Island routes are ranked against each other for each consideration. The criteria that defines each rank may not be directly comparable to NYC routes presented in separate matrix.)	Specific Route Scoring Comments
		Shore Approach and Landing Site	Gowanus (via either pierline segment or Bay Ridge Flats segment)	Brooklyn Bridge Park	44th Ave	149th Street (Narrows West)	Rainey Park & 149th Street via Astoria (Narrows East)	Riverside (Narrows West & NJ Converter-South)	Riverside (Narrows West & NJ Converter-North)	Javits Center Pier Converter		
		Point of Interconnection	Farragut	Rainey	Rainey	Mott Haven	Mott Haven	West 49th	West 49th	West 49th		
ONSHORE ROUTE SEGMENT	Infrastructure HDDs and/or Bridge Crossings (roadway and waterway)										Green: No major arterial or waterway crossings Light Green: 1-2 crossings Yellow: 3-4 of crossings Orange: 5-6 crossings Red: 7+ crossings	Light Green: 149th to Mott Haven- 2, Riverside to W49th- 1, Javits to W49th- 1 Yellow: 44th Ave to Rainey- 4 Orange: Rainey Park to Mott Haven via Astoria- 6 Red: Gowanus to Farragut- 8, Brooklyn Bridge Park to Rainey- 13
	Wetlands, Sensitive Habitats										Green: No sensitive habitats along route Light Green: Small sensitive habitats, which can be avoided Yellow: Sensitive habitat exists in the entire area Orange: Majority of the route passes through sensitive habitat designations or adjacent where additional consultations may be required Red: Route entirety is through or adjacent to sensitive habitats	Green: No wetlands or sensitive habitats were identified along these routes from publicly available data
	Potential Stakeholder Concerns/ Jurisdictions Crossed										Green: 0 - 0.5 mi of route passes within 0.5 mi of NYC Zoning residential classification and 1 local jurisdiction Light Green: 0.5 - 2 mi of route passes within 0.5 mi of NYC Zoning residential classification and/or 2 local jurisdictions Yellow: 2 - 4 mi of route passes within 0.5 mi of NYC Zoning residential classification and/or 2 - 3 local jurisdictions Orange: 4 - 5 mi of route passes within 0.5 mi of NYC Zoning residential classification and/or 4 local jurisdictions Red: More than 5 mi of route passes within 0.5 mi of NYC Zoning residential classification and/or more than 4 local jurisdictions	Green: 44th Ave to Rainey 0.33 mi and 1 local jurisdiction, 149th to Mott Haven 0.07 mi and 1 jurisdiction, and Riverside to W49th- 0.03 mi and 1 local jurisdiction Light Green: Rainey Park to Mott Haven via Astoria- 0.92 mi and 2 jurisdictions Yellow: Gowanus to Farragut- 0.75 mi and 1 jurisdiction but passes near Boreum Hill which is known to have concerns about construction , Brooklyn Bridge Park to Rainey- 1.05 mi and 3 jurisdictions, and Javits to W49th- 0.02 mi and 1 jurisdiction but near Lincoln Tunnel.
	Contaminated Sites (total area encountered)										Green: No contaminated sites along route Light Green: Contaminated sites along route, which may be avoidable Yellow: Crossing small contaminated sites is unavoidable along route Orange: Route passes large contaminated sites, crossing of which can be avoided Red: Large contaminated sites are along route and unavoidable	Green: 149th to Mott Haven and Riverside to W 49th have no contaminated sites along the route Light Green: Gowanus to Farragut- passes 4 sites all avoidable, 44th to Rainey- passes 2 sites both avoidable, and Javits to W49th- passes but avoids 5 sites Orange: Brooklyn Bridge Park to Rainey- passes Brooklyn Navy Yard and under Newtown Creek, Rainey Park to Mott Haven via Astoria- Astoria is a DEC Remediation site but portions with the most contamination should be avoidable
	Cultural Resources										Green: No known cultural resources along route Light Green: Low number and/or avoidable known cultural resources Yellow: Moderate number and/or avoidable known cultural resources Orange: Moderately high number of cultural resources, some of which can not be avoided Red: High number or large area of cultural resources	Green: 149th to Mott Haven and Rainey Park to Mott Haven via Astoria no known cultural resources along route Light Green: Riverside to W49th is near but does not pass the Intrepid, 44th to Rainey passes under Queensboro Bridge national register site Yellow: Javits to W49th passes nearer to Intrepid and popular sightseeing areas Orange: Gowanus to Farragut and Brooklyn Bridge Park to Rainey pass through heavily landmarked areas around Farragut (DUMBO Industrial, Brooklyn Navy Yard etc)
	Route Distance (miles)										Green: Route is <0.5 mi Light Green: Route is >0.5 mi but <1 mi Yellow: Route is 1-5 mi Orange: Route is 5-10 mi Red: Route is >10 mi	Light Green: 149th to Mott Haven- 0.75 mi, Riverside to W49th- 0.79 mi Yellow: Gowanus to Farragut- 4.94 mi, 44th to Rainey- 1.32 mi, Rainey Park to Mott Haven via Astoria- 3.65 mi, Javits to W49th- 1.19 mi Orange: Brooklyn Bridge Park to Rainey- 7.91 mi
	Available Land for Converter Stations (> 5 acre parcel) (real estate planning firm analysis)										Green: Multiple potential parcels within 1 mi of route or POI Light Green: Several potential parcels within 1 mi of route or POI Yellow: 3 potential parcels within 1 mi of route or POI Orange: Only 2 potential parcels within 1 mi of route or POI Red: Only 1 potential parcel within 1 mi of route or POI	Green: 44th Ave to Rainey & Brooklyn Bridge Park to Rainey- 5 sites identified Light Green: Farragut to Gowanus- 658 Columbia St, Brooklyn Marine Terminal, 109 25th St;149th to Mott Haven- recycling center & 2 surrounding industrial warehouses Yellow: Riverside to W 49th- likely one parcel available (though 2 ID'd) in NJ and 1 in Manhattan (2 ID'd shown below) Orange: Javits to W 49th- Pier 76 & Pier 90/92 (requires construction to fit converter station dimensions, remain orange)
	Parkway/Highway (Permitting constraint)										Green: Route does not touch parkway or highway interstate Light Green: Route may touch or cross parkway or highway interstate enough to trigger additional USDOT/FHWA approval Yellow: Moderate amount of route runs along or multiple crossings of parkway or highway interstate Orange: A significant portion of route is along parkway or highway interstate Red: Majority of route is along a parkway or highway interstate	Orange: Brooklyn Bridge Park to Rainey- parallels McGuinnis Blvd for 1 mi (classified as Principal Arterial Other by NYDOT) and crosses BQE 2x and exit for Midtown Tunnel, Gowanus to Farragut- parallels Minor Arterial 5th Ave 1.78 mi, crosses Major Arterial Atlantic Ave, and crosses BQE 2x and Prospect Expressway 1x

	Lease Area/Region	Hudson North	Hudson South				New Jersey		
	Offshore Route	Atlantic Central Corridor	Atlantic South Corridor						
	Shore Approach and Landing Site	Gowanus (via either pierline segment or Bay Ridge Flats segment)	Brooklyn Bridge Park	44th Ave	149th Street (Narrows West)	Rainey Park & 149th Street via Astoria (Narrows East)	Riverside (Narrows West & NJ Converter-South)	Riverside (Narrows West & NJ Converter-North)	Javits Center Pier Converter
	Point of Interconnection	Farragut	Rainey	Rainey	Mott Haven	Mott Haven	West 49th	West 49th	West 49th
Count:	1x	1	2	4	4	3	3	3	1
	2x	6	1	3	5	3	6	6	5
	3x	9	8	8	5	7	6	6	9
	4x	7	9	6	5	8	6	6	6
	5x	1	4	3	5	3	3	3	3
	100x	0	0	0	0	0	0	0	0
	Total Points*	58	67	64	68	65	65	65	66

No constraints present
Low constraints present
Moderate constraints present
Major constraints present
Substantial constraints present
Challenges considered potentially insurmountable

* Note: Lowest points => best option. Weighting factors applied: Light Green x1; Green x2; Yellow x3 Orange x4; Red x5; Black x100.

REFINED ROUTE FEASIBILITY SCORING ON LONG ISLAND - CRITICAL CONSTRAINTS MATRIX

Color Key (with scoring)

Score	Description
1x	No constraints present
2x	Low constraints present
3x	Moderate constraints present
4x	Major constraints present
5x	Substantial constraints present
100x	Challenges considered potentially insurmountable

Lease Area/Region	Hudson North		Empire Wind				Massachusetts					
Offshore Route	Atlantic Central Corridor						Atlantic North Corridor					
Shore Approach and Landing Site	Jones Beach				Long Beach		Jones Beach				Long Beach	
Point of Interconnection	Syosset	Shore Road	East Garden City	Ruland Road	East Garden City	Shore Road	Syosset	Shore Road	East Garden City	Ruland Road	East Garden City	Shore Road
Considerations												
LEASE TO POI: Approximate route distance in miles (AC Feasibility: +/- 70 miles) — Empire Wind	54	60	49	53	53	62	181	185	175	179	181	189
LEASE TO POI: Approximate route distance in miles (AC Feasibility: +/- 70 miles) — Hudson North	73	79	67	71	71	81						

Segment	Consideration	Scoring Explanations (Note that the group of Long Island routes are ranked against each other for each consideration. The criteria that defines each rank may not be directly comparable to NYC routes presented in separate matrix.)	Specific Route Scoring Comments
LEASE TO POI	Approximate route distance in miles (AC Feasibility: +/- 70 miles)	Dark Grey: less than 70 miles Light Grey: >70 mi but <75 mi No color: more than 75 miles	
OFFSHORE ROUTE SEGMENT	Infrastructure Crossings (linear utilities)	Green: no crossings Light Green: lower number of crossings less than 15 Yellow: moderate number of crossings 15 to 25 Orange: high number of crossings 25 to 35 Red: very high number of crossings 35+	Light Green: Atlantic Central Corridor > 15 crossings varies by route Yellow: Atlantic North Corridor ~18 crossings (multiple cable landings along south shore of Long Island must be crossed)
OFFSHORE ROUTE SEGMENT	Offshore Feature Crossings (traffic lanes, danger zones)	Green: no navigation features present in area Light Green: route generally avoids navigation features but some in area Yellow: likely must cross a navigation feature Orange: must cross multiple navigation features Red: significant impact to navigation anticipated	Yellow: traffic lanes or precautionary area in Atlantic Central Corridor approach (Nantucket to Ambrose Shipping Lanes)
OFFSHORE ROUTE SEGMENT	Department of Defense Areas	Green: none present Light Green: present in area but can be avoided or no restrictions apply Yellow: must cross a DoD area where site specific stipulations apply Orange: must cross a DoD area where site specific stipulations apply and/or multiple other features apply Red: DoD exclusion area present that must be crossed	Orange: in Atlantic, Narraganset OPAREA, Submarine transit lane, Naval Undersea Warfare Testing Range exist
OFFSHORE ROUTE SEGMENT	Sensitive Habitats (presence of sensitive species or habitat exists)	Green: no sensitive habitat present Light Green: some sensitive habitat exists but can be avoided Yellow: sensitive habitat exists in the entire area Orange: increased sensitive habitat designations in area or adjacent Red: high number of sensitive habitats must be crossed	Yellow: entire Atlantic in this area is Biologically Important Area for North Atlantic Right Whale
OFFSHORE ROUTE SEGMENT	Marine Geology and Oceanography (seabed, erosion, bedforms, etc.)	Green: highly suitable conditions for cable installation cable burial very easily achieved/maintained Light Green: generally suitable conditions for cable installation cable burial easily achieved/maintained Yellow: moderately suitable conditions for cable installation potential difficulty to achieve/maintain cable burial Orange: difficult conditions may exist for cable installation do to structure difficult to achieve/ maintain cable burial Red: cable may not be installed/maintained to required depths due to potential bedrock or moraine armoring may be required	Light Green: Atlantic is generally soft sediments go for cable installation
OFFSHORE ROUTE SEGMENT	Further Regulatory Constraints (triggering additional state approvals)	Green: no trigger possible Light Green: trigger of additional state review is not likely Yellow: trigger of state coastal management programs is possible Orange: trigger of multiple state coastal management program(s) expected Red: trigger of multiple state permitting (i.e. Section 401) review will occur	Light Green: NYSDOS Coastal Management Program
OFFSHORE ROUTE SEGMENT	Potential Stakeholder Concerns (Fisheries /Marine Vessel Operators)	Green: no concerns anticipated Light Green: some concerns anticipated Yellow: moderate concern anticipated Orange: potential opposition anticipated Red: high level of opposition anticipated	Yellow: Atlantic from commercial fisherman and marine vessel operators possible
SHORE APPROACH AND LANDING ROUTE SEGMENT	Infrastructure Crossings (linear utilities)	Green: no crossings Light Green: lower number of crossings > 2 Yellow: moderate number of crossings 2 to 10 Orange: high number of crossings 10 to 15 Red: very high number of crossings 15+	Yellow: Jones Beach ~9 crossings Orange: Long Beach ~ 12 crossings
SHORE APPROACH AND LANDING ROUTE SEGMENT	Sensitive Habitats (presence of sensitive species or habitat exists)	Green: no sensitive habitat present Light Green: some sensitive habitat exists but can be avoided Yellow: sensitive habitat exists in the entire area Orange: increased sensitive habitat designations in area or adjacent Red: high number of sensitive habitats must be crossed	Light Green: Long Beach - Endangered Atlantic sturgeon seasonally present nearshore. However, no Significant Coastal Fish and Wildlife Habitat (SCFWH) or Critical Environmental Area (CEA) uncertified shellfish waters and low presence of shorebirds Orange: Jones Beach - Endangered Atlantic sturgeon seasonally present nearshore. Also routes cross sensitive habitat (i.e. SCFWH, natural heritage areas, endangered nesting shorebird habitat)
SHORE APPROACH AND LANDING ROUTE SEGMENT	Marine Geology and Oceanography (seabed, erosion, bedforms, etc.)	Green: highly suitable conditions for cable installation cable burial very easily achieved/maintained Light Green: generally suitable conditions for cable installation cable burial easily achieved/maintained Yellow: moderately suitable conditions for cable installation potential difficulty to achieve/maintain cable burial Orange: difficult conditions may exist for cable installation do to structure difficult to achieve/ maintain cable burial- Structure present on approach Red: cable may not be installed/maintained to required depths due to potential bedrock or moraine armoring may be required	Yellow: Atlantic Ocean shoreline is highly dynamic with winds, waves, and currents.
SHORE APPROACH AND LANDING ROUTE SEGMENT	Further Regulatory Constraints (triggering additional state approvals)	Green: no trigger anticipated Light Green: trigger of additional (non-NY) state/federal coastal review unlikely or not burdensome Yellow: trigger of additional state/federal coastal management programs is possible and/or supplemental NY coastal review expected. Orange: trigger of additional state/federal coastal management program(s) expected Red: trigger of multiple additional state/federal permitting (e.g., Section 401 Water Quality Certifications) review will occur	Light Green: No triggering of other states' permitting requirements. Trigger of Local Waterfront Revitilization Programs not anticipated based on plans approved as of December 2020. NYSDEC Coastal Erosion Management Permit may be required, but addressed as part of standard New York State Joint Permit Application.
SHORE APPROACH AND LANDING ROUTE SEGMENT	Potential Stakeholder Concerns (Fisheries /Marine Vessel Operators/Coastal Communities)	Green: no concerns anticipated Light Green: some concerns anticipated Yellow: moderate concern anticipated Orange: potential opposition anticipated Red: high level of opposition anticipated	Yellow: Atlantic from commercial fishermen, including back bay commercial shellfishermen, and marine vessel operators possible Orange: Long Beach has history of vocal local population when considering cable routing
SHORE APPROACH AND LANDING ROUTE SEGMENT	Landing Site Complexity (e.g., back-bay crossings, shore structure crossings, dense development)	Green: very low complexity Light Green: low complexity Yellow: moderate complexity Orange: high complexity Red: very high complexity	Orange: Jones Beach has 3 backbay crossings, Long Beach has 2 backbay crossing and is in developed area
SHORE APPROACH AND LANDING ROUTE SEGMENT	Navigation Channels, Anchorage Areas, and USACE Coastal Storm Risk Management Projects	Green: no crossings Light Green: lower number of crossings 1 Yellow: moderate number of crossings 2 to 3 Orange: high number of crossings 3 to 5 Red: very high number of crossings +5 or long runs	Yellow: Long Beach 3 Orange: Jones Beach 4
SHORE APPROACH AND LANDING ROUTE SEGMENT	Contaminated Sediments	Green: no contamination anticipated Light Green: lower levels of contamination likely Yellow: moderate levels of contamination likely Orange: high levels of contamination likely Red: high levels of contamination very likely	Green: Atlantic Ocean contamination is not expected Light Green: Long Beach backbay area has potential for contamination as adjacent shoreline site is DEC remediation area
SHORE APPROACH AND LANDING ROUTE SEGMENT	Cultural Resources and Wrecks/Obstructions	Green: none present Light Green: lower number present Yellow: moderate number present Orange: high number present Red: very high number present	Light Green: Atlantic wrecks/obstructions exist but can generally be routed to avoid

REFINED ROUTE FEASIBILITY SCORING ON LONG ISLAND - CRITICAL CONSTRAINTS MATRIX

Offshore Route	Atlantic Central Corridor						Atlantic North Corridor					
Shore Approach and Landing Site	Jones Beach				Long Beach		Jones Beach				Long Beach	
Point of Interconnection	Syosset	Shore Road	East Garden City	Ruland Road	East Garden City	Shore Road	Syosset	Shore Road	East Garden City	Ruland Road	East Garden City	Shore Road

Scoring Explanations
(Note that the group of Long Island routes are ranked against each other for each consideration. The criteria that defines each rank may not be directly comparable to NYC routes presented in separate matrix.)

ONSHORE ROUTE SEGMENT

Consideration	Scoring Explanations	Specific Route Scoring Comments
Infrastructure HDDs and/or Bridge Crossings (roadway)	Green: no major arterial or waterway crossings Light Green: 1-2 crossings Yellow: 3-4 of crossings Orange: 5-6 crossings Red: 7+ crossings	Light Green: Long Beach to East Garden City- 1 Yellow: Jones Beach to East Garden City- 3 Orange: Jones Beach to Shore Rd- 6, Jones Beach to Ruland Rd- 6 Red: Jones Beach to Syosset- 10, Long Beach to Shore Rd- 7
Wetlands, Sensitive Habitats	Green: no sensitive habitats along route Light Green: small sensitive habitats, which can be avoided Yellow: sensitive habitat exists in the entire area Orange: majority of the route passes through sensitive habitat designations or adjacent where additional consultations may be required Red: route entirety is through or adjacent to sensitive habitats	Light Green: Routes originating at Long Beach have less overall sensitive habitats due to development. Onshore routes pass near sensitive habitats but not through. Jones Beach to Syosset & Ruland Rd avoids wetlands. Orange: Jones Beach to Shore Rd & East Garden City must route up extensive portion of Meadowbrook Pkwy which is surrounded by wetlands for much of the route.
Potential Stakeholder Concerns/ Jurisdictions Crossed	Green: 0 - 1 mi of route passes along low and medium density developed lands, mostly including single family residences and 1 local jurisdiction Light Green: 1 - 4 mi of route passes along low and medium density developed lands, mostly including single family residences and 1 - 3 local jurisdictions Yellow: 4 - 6 mi of route passes along low and medium density developed lands, mostly including single family residences and 3 - 5 local jurisdictions. Orange: 6 - 10 mi of route passes along low and medium density developed lands, mostly including single family residences and 5 - 9 local jurisdictions. Red: More than 10 mi of route passes along low and medium density developed lands, mostly including single family residences and more than 9 local jurisdictions.	Orange: Jones Beach to East Garden City 10.44 mi and 5 jurisdictions, Jones Beach to Ruland Rd 9.84 mi and 6 jurisdictions, Long Beach to East Garden City 4.69 mi and 7 jurisdictions Red: Jones Beach to Syosset 13.33 mi and 8 jurisdictions, Jones Beach to Shore Rd 16.26 mi and 9 jurisdictions, Long Beach to Shore Rd 9.48 mi and 10 local jurisdictions
Contaminated Sites (total area encountered)	Green: no contaminated sites along route Light Green: small contaminated sites along route, which may be avoidable Yellow: crossing small contaminated sites is unavoidable along route Orange: route passes large contaminated sites, crossing of which can be avoided Red: large contaminated sites are along route and unavoidable	Light Green: Routes pass small sites but are avoidable Yellow: Jones Beach and Long Beach to Shore Rd passes through 1 small site, East Garden City itself is a completed State Superfund Site that has an environmental easement, bumping up the ranking of both routes, Jones Beach and Long Beach, to yellow.
Cultural Resources	Green: no known cultural resources along route Light Green: Low number and/or avoidable known cultural resources Yellow: moderate number and/or avoidable known cultural resources Orange: moderately high number of cultural resources, some of which can not be avoided Red: high number or large area of cultural resources	Light Green: Long Beach to East Garden City and Shore Rd pass and avoid a few small cultural resources Yellow: Jones Beach to Syosset, East Garden City, and Shore Rd pass near but avoid small cultural resources Orange: Jones Beach to Ruland Rd must pass through the large Bethpage State Park and golf course
Route Distance (miles)	Green: Route is <5 mi Light Green: Route is 5-10 mi Yellow: Route is 10-15 mi Orange: Route is 15-20 mi Red: Route is >20 mi	Yellow: Jones Beach to East Garden City- 12.92 mi, Long Beach to East Garden City-11.61 mi Orange: Jones Beach to Syosset-18.48 mi, Jones Beach to Ruland Rd-16.92 mi Red: Jones Beach to Shore Rd-24.30 mi, Long Beach to Shore Rd-21.34 mi
Available Land for Converter Stations (> 1.5 acre parcel)	Green: Multiple potential parcels within 0.5 mi of route or POI (Visual aerial interpretation) Light Green: Several potential parcels within 0.5 mi of route or POI Yellow: 3 potential parcels within 0.5 mi of route or POI Orange: Only 2 potential parcels within 0.5 mi of route or POI Red: Only 1 potential parcel within 0.5 mi of route or POI	Light Green: Jones Beach to Shore Rd had several potential parcels within 0.5 mi of the route Yellow: Jones Beach to East Garden City, Jones Beach to Ruland Rd (parcel needed to be 5 acres for DC conversion), Long Beach to East Garden City, and Long Beach to Shore Rd all had 3 potential parcels Red: Jones Beach to Syosset only 1 potential parcel on Boundary Ave
Parkway/Highway (Permitting constraint)	Green: route does not touch parkway or highway interstate Light Green: route may touch or cross parkway or highway interstate enough to trigger additional USDOT/FHWA approval Yellow: moderate amount of route runs along or multiple crossings of parkway or highway interstate Orange: a significant portion of route is along a parkway or highway interstate Red: majority of route is along a parkway or highway interstate	Light Green: Long Beach to Shore Rd and East Garden City only cross Sunrise Hwy, Southern State Pkwy, Northern Pkwy, and LIE Orange: Jones Beach to Shore Rd and East Garden City parallels Meadowbrook Pkwy for 11.6 mi, Jones Beach to Ruland Rd parallels Seaford-Oyster Bay Expy for 4.3 mi and Sunrise Hwy for 0.76 mi Red: Jones Beach to Sysosset- parallels Watagh Pkwy/Jones Beach Causeway and Seaford-Oyster Bay Expy for 14.3 mi

Lease Area/Region	Hudson North			Empire Wind			Massachusetts					
Offshore Route	Atlantic Central Corridor						Atlantic North Corridor					
Shore Approach and Landing Site	Jones Beach				Long Beach		Jones Beach				Long Beach	
Point of Interconnection	Syosset	Shore Road	East Garden City	Ruland Road	East Garden City	Shore Road	Syosset	Shore Road	East Garden City	Ruland Road	East Garden City	Shore Road
Count: 1x	1	1	1	1	0	0	1	1	1	1	0	0
2x	7	6	5	7	11	10	7	6	5	7	11	10
3x	7	8	11	7	8	7	7	8	11	7	8	7
4x	5	7	7	9	5	4	5	7	7	9	5	4
5x	4	2	0	0	0	3	4	2	0	0	0	3
100x	0	0	0	0	0	0	0	0	0	0	0	0
Total Points*	76	75	72	72	66	72	76	75	72	72	66	72

No constraints present
Low constraints present
Moderate constraints present
Major constraints present
Substantial constraints present
Challenges considered potentially insurmountable

* Note: Lowest points => best option. Weighting factors applied: Light Green x1; Green x2; Yellow x3 Orange x4; Red x5; Black x100.

Annex C: OSW Build-Out Scenario Maps

<u>Scenario 1A and 1B Rationale</u>:

A. Light BOEM lease auction activity and thus:
   - 2030 capacity from existing leases only (no call areas available)
   - 2035 capacity from existing leases and primary call areas (no secondary call areas available)

B. 1-nm spacing for MA enforced, but relaxed elsewhere

C. 2035 scenario includes expansions of North projects, instead of South, given expected higher competition for New Jersey capacity)

D. Hudson fairways (smaller areas to the north) are excluded entirely for feasibility reasons

Scenario 1A

Scenario 1B

<u>Scenario 2 Rationale</u>:

A. Aggressive BOEM lease auction activity and thus:

- 2030 capacity from existing leases AND primary call areas
- 2035 capacity from existing leases, primary and secondary call areas

B. 1-nm spacing enforced for all locations (i.e. beyond MA)

C. Hudson fairways (smaller areas to the north) are excluded entirely for feasibility reasons

Scenario 2

<u>Scenario 3A and 3B Rationale</u>:

A. Aggressive BOEM lease auction activity and thus:

- 2030 capacity from existing leases AND primary call areas
- 2035 capacity from existing leases, primary and secondary call areas

B. NY Bight projects will be at disadvantage to win PPAs with other states and thus, NY Bight projects will be highly focused on winning PPAs with NY

C. 1-nm spacing enforced for MA, but relaxed elsewhere

D. Hudson fairways (smaller areas to the north) are excluded entirely for feasibility reasons

Scenario 3A

Scenario 3B

Annex D. Summary Tables for Preliminary OSW Connection Analysis

Scenario 1A

	Dedicated Radials	Split	Mesh	Shared Substations	Backbone
Total Offshore CAPEX vs. Radial Baseline	Baseline	+0.2 B	+1.8 B	+0.6 B	+1.3 B
Performance: lost energy due to elec. losses	2224 GWh/yr	2217 GWh/yr	1970 GWh/yr	1928 GWh/yr	2096 GWh/yr
LTCOE Rank (includes CAPEX, OPEX, and losses)	Lowest	Low	Highest	Moderate	Moderate to High
	LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)		LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)		LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)
Resilience & Redundancy Summary	Weak		Strong	Moderate	Moderate
Definition: transmission integrity, auxiliary system redundancy, and component overload dimensioning	Lower level of redundancy, high loss of generated energy in case of single component outages		Higher level of redundancy (bipolar, alternative transmission path, etc)	Lowest loss of generated energy in case of single component outages, but large cable length increase down time	Higher loss of generated energy in case of single component outages than Shared, but smaller cable length decrease down time
Operational Benefits Summary	Moderate		Strong	Weak	Strong
Definition: standardized spare keeping, interconnector topologies, and technologies	Strong onshore voltage control for DC connections		Strong onshore voltage support and strongest power dispatch control	Weakest onshore voltage control and power dispatch, control instabilities require onshore reinforcement.	Strong onshore voltage support and strong power dispatch control
Phased installation considering uncertainty in OSW project locations	Straightforward given inherently a phased approach		Complex but possible – upfront planning required to ensure individual project substation platforms have capability to accept future mesh connection	Very challenging to plan effectively/economically if OSW project locations and sizes remain highly uncertain	Complex but possible – upfront planning required to ensure individual project substation platforms have capability to accept future backbone connection

Scenario 1B

	Dedicated Radials	Split	Mesh	Shared Substations	Backbone
Total Offshore CAPEX vs. Radial Baseline	Baseline	+0.0 B	+1.7 B	+0.7 B	+1.2 B
Performance: lost energy due to elec. Losses	2211 GWh/yr	2211 GWh/yr	1945 GWh/yr	1928 GWh/yr	2077 GWh/yr
LTCOE Rank (includes CAPEX, OPEX, and losses)	Lowest	Lowest	Highest	Moderate	Moderate to High
	LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)		LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)		LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)
Resilience & Redundancy Summary	Weak		Strong	Moderate	Moderate
Definition: transmission integrity, auxiliary system redundancy, and component overload dimensioning	Lower level of redundancy, high loss of generated energy in case of single component outages		Higher level of redundancy (bipolar, alternative transmission path, etc)	Lowest loss of generated energy in case of single component outages, but large cable length increase down time	Higher loss of generated energy in case of single component outages than Shared, but smaller cable length decrease down time
Operational Benefits Summary	Moderate		Strongest	Weak	Strong
Definition: standardized spare keeping, interconnector topologies, and technologies	Strong onshore voltage control for DC connections		Strong onshore voltage support and strongest power dispatch control	Weakest onshore voltage control and power dispatch, control instabilities require onshore reinforcement.	Strong onshore voltage support and strong power dispatch control
Phased installation considering uncertainty in OSW project locations	Straightforward given inherently a phased approach		Complex but possible – upfront planning required to ensure individual project substation platforms have capability to accept future mesh connection	Very challenging to plan effectively/economically if OSW project locations and sizes remain highly uncertain	Complex but possible – upfront planning required to ensure individual project substation platforms have capability to accept future backbone connection

Scenario 2

	Dedicated Radials	Split	Mesh	Shared Substations	Backbone
Total Offshore CAPEX vs. Radial Baseline	Baseline	+0.3 B	+1.8 B	+0.1 B	+1.9 B
Performance: lost energy due to elec. losses	2179 GWh/yr	2179 GWh/yr	2071 FWh/yr	1890 GWh/yr	2317 GWh/yr
LTCOE Rank (includes CAPEX, OPEX, and losses)	Lowest	Low	High	Low	Highest
	LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)		LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)		LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)
Resilience & Redundancy Summary	Weak		Strong	Moderate	Moderate
Definition: transmission integrity, auxiliary system redundancy, and component overload dimensioning	Lower level of redundancy, high loss of generated energy in case of single component outages		Higher level of redundancy (bipolar, alternative transmission path, etc)	Lowest loss of generated energy in case of single component outages, but large cable length increase down time	Higher loss of generated energy in case of single component outages than Shared, but smaller cable length decrease down time
Operational Benefits Summary	Moderate		Strongest	Weak	Strong
Definition: standardized spare keeping, interconnector topologies, and technologies	Strong onshore voltage control for DC connections		Strong onshore voltage support and strongest power dispatch control	Weakest onshore voltage control and power dispatch ,control instabilities require onshore reinforcement.	Strong onshore voltage support and strong power dispatch control
Phased installation considering uncertainty in OSW project locations	Straightforward given inherently a phased approach		Complex but possible – upfront planning required to ensure individual project substation platforms have capability to accept future mesh connection	Very challenging to plan effectively/economically if OSW project locations and sizes remain highly uncertain	Complex but possible – upfront planning required to ensure individual project substation platforms have capability to accept future backbone connection

Scenario 3A

	Dedicated Radials	Split	Mesh	Shared Substations	Backbone
Total Offshore CAPEX vs. Radial Baseline	Baseline	+0.0 B	+1.4 B	+0.4 B	+1.5 B
Performance: lost energy due to elec. losses	2179 GWh/yr	2255 GWh/yr	1989 GWh/yr	1909 GWh/yr	2109 GWh/yr
LTCOE Rank (includes CAPEX, OPEX, and losses)	Lowest	Lowest	High	Moderate	Highest
	LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)		LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)		LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)
Resilience & Redundancy Summary	Weak		Strong	Moderate	Moderate
Definition: transmission integrity, auxiliary system redundancy, and component overload dimensioning	Lower level of redundancy, high loss of generated energy in case of single component outages		Higher level of redundancy (bipolar, alternative transmission path, etc)	Lowest loss of generated energy in case of single component outages, but large cable length increase down time	Higher loss of generated energy in case of single component outages than Shared, but smaller cable length decrease down time
Operational Benefits Summary	Moderate		Strongest	Weak	Strong
Definition: standardized spare keeping, interconnector topologies, and technologies	Strong onshore voltage control for DC connections		Strong onshore voltage support and strongest power dispatch control	Weakest onshore voltage control and power dispatch, control instabilities require onshore reinforcement.	Strong onshore voltage support and strong power dispatch control
Phased installation considering uncertainty in OSW project locations	Straightforward given inherently a phased approach		Complex but possible – upfront planning required to ensure individual project substation platforms have capability to accept future mesh connection	Very challenging to plan effectively/economically if OSW project locations and sizes remain highly uncertain	Complex but possible – upfront planning required to ensure individual project substation platforms have capability to accept future backbone connection

Scenario 3B

	Dedicated Radials	Split	Mesh	Shared Substations	Backbone
Total Offshore CAPEX vs. Radial Baseline	Baseline	+0.0 B	+1.6 B	+0.2 B	+1.2 B
Performance: lost energy due to elec. losses	2022 MWh/yr	2173 GWh/yr	1945 GWh/yr	1865 GWh/yr	2077 GWh/yr
LTCOE Rank (includes CAPEX, OPEX, and losses)	Lowest	Lowest	Highest	Low	Moderate
	LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)		LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)		LTCOE estimates subsequently updated with higher detail conceptual design (See Section 8)
Resilience & Redundancy Summary	Weak		Strong	Moderate	Moderate
Definition: transmission integrity, auxiliary system redundancy, and component overload dimensioning	Lower level of redundancy, high loss of generated energy in case of single component outages		Higher level of redundancy (bipolar, alternative transmission path, etc)	Lowest loss of generated energy in case of single component outages, but large cable length increase down time	Higher loss of generated energy in case of single component outages than Shared, but smaller cable length decrease down time
Operational Benefits Summary	Moderate		Strongest	Weak	Strong
Definition: standardized spare keeping, interconnector topologies, and technologies	Strong onshore voltage control for DC connections		Strong onshore voltage support and strongest power dispatch control	Weakest onshore voltage control and power dispatch, control instabilities require onshore reinforcement.	Strong onshore voltage support and strong power dispatch control
Phased installation considering uncertainty in OSW project locations	Straightforward given inherently a phased approach		Complex but possible – upfront planning required to ensure individual project substation platforms have capability to accept future mesh connection	Very challenging to plan effectively/economically if OSW project locations and sizes remain highly uncertain	Complex but possible – upfront planning required to ensure individual project substation platforms have capability to accept future backbone connection

Appendix E

(to Initial Report on New York Power Grid Study)

Zero-Emissions Electric Grid in New York by 2040 Study

Zero-Emissions Electric Grid in New York by 2040

Final Report

Prepared for: NYSERDA

New York State Energy Research and Development Authority

Albany, NY

New York State Department of Public Service

Albany, NY

Prepared by Siemens Power Technologies, Inc. (Siemens PTI)

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Notice

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Acronyms and Abbreviations

AC	Alternating Current
APC	Adjusted Production Costs
B/C	Benefit to Cost Ratio
BTM	Behind The Meter
CALISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine (also CC)
CLCPA	Climate Leadership and Community Protection Act
DC	Direct Current
DER	Distributed Energy Resources
EE	Energy Efficiency
EFORd	Equivalent Forced Outage Rate on demand
ELCC	Effective Load Carrying Capability
ft	Feet
HVDC	High Voltage Direct Current
IRM	Installed Reserve Margin
ISO-NE	New England Independent System Operator
kv	Kilovolts
kWh	Kilowatt hours
LBW	Land Based Wind
LOLE	Loss of Load Expectation
LTCE	Long-Term Capacity Expansion
m/s	Meters Per Second
MISO	Midcontinent Independent System Operators
MTTR	Mean Time To Repair
MW	Megawatts
NYC	New York City
NYC Tx	New York City Transmission
NYS	New York State
NYCA	New York Control Area (same footprint as NYISO)
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
PV	Photovoltaic
BES	Battery Energy Storage
PJM	An independent system operator, covers New Jersey, Pennsylvania, Maryland, among other states
pu	Per Unit
SCCT	Simple Cycle Combustion Turbine
SCED	Security Constrained Economic Dispatch
W	Watts

1 Executive Summary

1.1 Introduction

In July 2019, Governor Cuomo signed the Climate Leadership and Community Protection Act (CLCPA), which adopted the most ambitious and comprehensive climate and clean energy legislation in the United States. The CLCPA requires New York State to achieve a zero-emission electricity system by 2040 and reduce greenhouse gas emissions 85% below 1990 levels by 2050 (mid-century). The CLCPA sets a new standard for states and the nation to expedite the transition to a clean energy economy. As part of this push to decarbonize the grid, the legislation codifies Governor Cuomo's nation-leading sustainability goals outlined in his Green New Deal, including a mandate for at least 70% of New York State's electricity to come from renewable energy sources such as wind and solar by 2030.

This globally unprecedented ramp up of renewable energy would include at least the following:

- Quadrupling New York State's offshore wind target (OSW) to 9,000 megawatts by 2035, up from 2,400 megawatts by 2030
- Doubling distributed solar deployment to 6,000 megawatts by 2025, up from 3,000 megawatts by 2023
- Deploying 3,000 megawatts of energy storage by 2030, with an interim target of 1,500 megawatts by 2025

The achievement of these goals is likely to require investments in New York State's electric transmission system. The scope and nature of these investments are expected to vary depending upon the location, type of energy storage, and zero-emission generation resources that are added to the system to meet the overall goal. While New York does not have a vertically integrated electricity market or structure, conducting transmission, generation, and energy storage resource planning would be useful in identifying potential strategies and needs to support the fulfillment of the State's clean energy goals.

In this context, NYSERDA and the Department of Public Service (DPS), collectively referred to as "the State team," developed a resource planning study to analyze a transmission, generation, and storage options for meeting New York State's goals of zero-emission electricity by 2040 and achieving interim targets of 70% renewable generation by 2030. The study seeks to identify reliable and cost-efficient system outcomes based on the assumptions used for each scenario that was analyzed.

This report presents the results of the study and addresses the following research questions:

- What level of land-based, zero-emission resources can be added to the system without the need for bulk transmission upgrades?
- What levels of fast response resources are required as renewable generation levels rise?

- What bulk transmission (and/or energy storage) investments are needed to avoid having upstate zero-emission generation "bottled" by systemic congestion and unable to serve New York load?

The results illustrate two potential scenarios for how New York State can meet the CLCPA's objectives economically based on a set of given assumptions. The study is centered on assessing transmission impact and needs at the Bulk Power System (BPS), 230 kV and above. Additional insights related local transmission may be found in the NYISO Congestion Assessment and Resource Integration Study (CARIS) and the Utility Transmission & Distribution Investment Working Group Report.

The study analyzed two scenarios: the Initial Scenario and the High Demand Scenario. The Initial Scenario demand forecast reflects the assumptions used on the High Technology Availability Pathway section of the Pathways to Deep Decarbonization in New York State[1] study, while the high demand load forecast is based on the Limited Non-Energy Pathway developed as part of the same study. The high demand load forecast was refined to include 2030 statewide demand and peak levels that are comparable to those in the NYISO CARIS 70 x 30 Base Load case while maintaining the 2040 outcomes of the pathways case.

Both scenarios result in resource portfolios that keep New York State on a trajectory to meet the interim goal of 70% renewable energy by 2030 and zero-emission generation by 2040. The main difference between the scenarios is that the High Demand Scenario electricity demand forecast has a greater growth trajectory for net energy for load and peak load forecast. In addition, the High Demand Scenario shows that the State could become a winter peaking system by 2040.

1.2 Meeting New York State's Goals

To achieve New York State's interim goal of 70% renewable generation by 2030 and a zero-emission electricity system by 2040, a substantial amount of renewable capacity will need to be developed across the State. Based on the study's assumptions, New York State can economically achieve its goals by adding a diversified combination of renewable capacity to the power generation supply mix, substantially increasing the deployment of energy storage, and making investments in bulk power system transmission (230 kV and above) over the 2030 to 2040 period. In the short term, local transmission investments to support interconnection of renewable generation are expected to be added to the system.

[1] Visit https://climate.ny.gov/Climate-Resources for The study Pathways to Deep Decarbonization in New York State.

1.2.1 Initial Scenario

Table 1-1 shows the diversified installed capacity mix resulting from the assumptions on the Initial Scenario. Table 1-2 summarizes the renewable generation produced to meet electricity demand in 2030 and 2040. This supply mix provides sufficient power generation to meet future electricity demand while maintaining system reliability based on current market structures and reliability requirements. The supply mix reflects a substantial increase in the amount of energy storage, which will support the integration of zero-emission resources while providing reserves.

Table 1-1. 2030 and 2040 Initial Scenario Installed Renewable Capacity in New York State

In megawatts.

	2030	2040
DG Solar (AC) [2]	5,323	6,443
Grid Solar	3,808	16,759
Land-based Wind	6,230	12,804
Offshore Wind	6,000	9,837
NYC Tx	1,250	1,250
Energy Storage	3,000	15,515

Table 1-2. 2030 and 2040 Initial Scenario Renewable and Zero-Emission Generation in New York State

In gigawatt hours.

	2030	2040
Energy Demand	151,605	207,477
Total RE Generation	106,124	180,584
RE Gen % of Demand	70.0%	87.0%
NYC Tx	9,930	9,340
Legacy Can. Hydro	10,009	10,069
DG Solar	7,994	9,697
Grid Solar	5,571	31,902
Land-based Wind	18,888	43,950
Offshore Wind	24,062	45,478
NY Hydro	28,039	28,684
Other Renewables*	1,640	1,532

"Other Renewables" Generation Discounted 40%

[2] New York State features 6,000 MW (DC) of distributed solar in 2025 and 6,601 MW (DC) in 2030 and therefore exceeds the State goal of having 6,000 MW (DC) in 2025.

The Other Renewables row in the table above includes generation using biomass and landfill gas. Due to uncertainty in eligibility for certain resources, the contribution of Other Renewables was discounted by 40%. The NYC Tx (New York City Transmission) row refers to a new 1,250 MW HVDC transmission line capable of delivering 10,000 gigawatt hours (GWh) of dispatchable renewable energy directly into New York City. This is a proxy project under the recently approved Tier 4 Clean Energy Standard (CES) that seeks to increase renewable energy into New York City (NYISO Zone J).

This supply mix was found to have adequate levels of flexible operating capacity to ensure system reliability under the Initial Scenario. Table 1-3 provides an estimate of the capacity required to achieve this objective.

Table 1-3. Initial Scenario Fast Ramping Capacity Needed to Provide 10-Minute Reserves

In megawatts.

	NYCA (Zone A-K)	East (Zone F-K)	SENY (Zone G-K)	NYC (Zone J)	Long Island (Zone K)
2030	2,981	1,947	1,647	901	557
2040	5,877	3,557	2,596	1,268	964

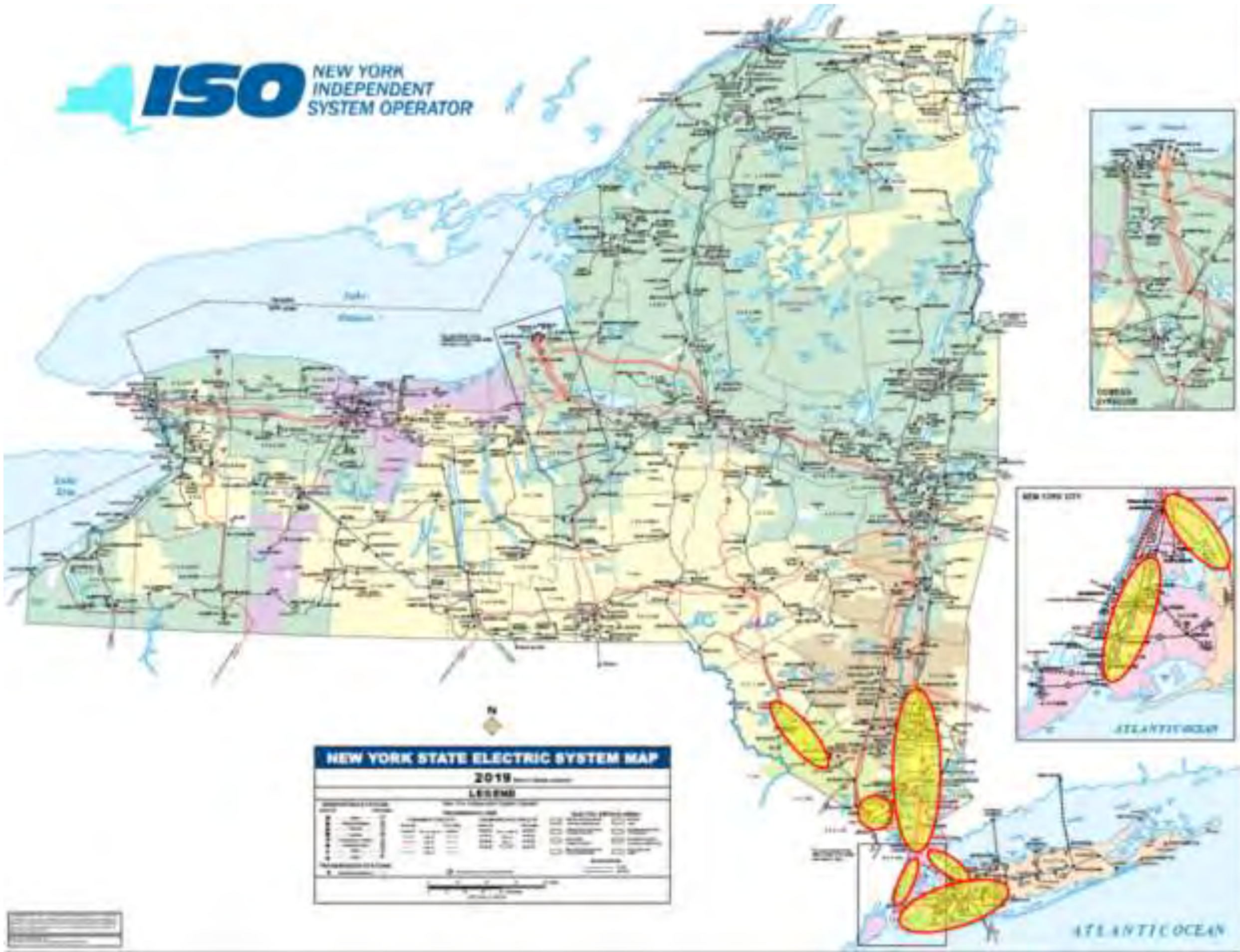
With the Initial Scenario capacity buildout through 2030, New York State achieves the CLCPA's renewable generation and emission targets without transmission upgrades at the bulk power system (BPS), beyond those already committed by public policy and expected under Tier 4. Upgrades include the Western 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 the expected 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). This finding assumes that any upgrades necessary at the local transmission and sub-transmission levels for the interconnection of renewable generation as well as delivery to the local loads are in place.

The CLCPA's zero-emission targets are met by 2040 without the need for major upgrades to the BPS transmission. The low levels of renewable generation curtailment observed did not hamper achievement of the CLCPA's goals. Again, this finding assumes that any necessary local transmission and sub-transmission level investments are in place.

However, even though zero-emissions targets are met, without any additional BPS transmission upgrades by 2040, system congestion and, to a lesser extent, curtailment (1.5% statewide) will occur during high levels of renewable energy production. By 2040 without BPS transmission upgrades, system congestion and curtailment result in higher production costs. This finding is more pronounced under the High Demand Scenario since the higher demand fosters much higher levels of congestion, as presented later in this summary. The study identified indicative bulk system upgrades that may be able to economically alleviate substantial levels of congestion. Additional information can be found in sections 6 and 7.

Figure 1-1 shows a general overview of the location of the major constraints by 2040 when the New York State power supply will achieve the zero-emissions goal. As can be observed in the figure, these transmission constraints are largely concentrated in the system connecting renewable resources in Upstate New York with New York City and Long Island. The locations of these constraints are the same under both the Initial and the High Demand scenarios, differing only on the level of congestion and dimension of the upgrades necessary to address the issue.

Figure 1-1. Major Congestion Areas Identified (2040) Initial and High Demand Scenario



* *Highlighted area on the map indicate major constraints.*

The indicative upgrade projects identified are summarized in Table 1-4. These projects were found to relieve both congestion and curtailment, and the economic benefits of these projects exceed their costs. However, further research is needed given the dependence of this outcome on uncertainties on the renewable buildout, load growth, the actual cost of the projects and their constructability, which may result in material modifications. As no action is immediately needed, there is time to conduct this research. The transmission upgrades were not identified to be needed until after 2030, and further research should solidify uncertainty factors, identify the best alternatives to be built, and address the expected congestion.

Table 1-4. Initial Scenario Indicative Transmission Upgrades

Zone	Indicative Transmission Upgrade
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 cables 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

1.2.2 High Demand Scenario

The High Demand Scenario identified an economic supply mix to meet the interim goal of 70% renewable energy by 2030 and zero-emission generation by 2040. The High Demand Scenario assumes net energy load increases on average 2.0%/yr. from 2020 to 2040 and peak load increases on average 1.5%/year from 2020 to 2040 and New York transitions to a winter peak. By 2040, net energy load is 12.5% greater and peak load is 10.2% greater than the Initial Scenario as shown in Table 1-5.

Table 1-5. Initial Scenario and High Demand Scenario Demand

	INITIAL SCENARIO		HIGH DEMAND		Change (%)	
ELECTRICTY DEMAND	2030	2040	2030	2040	2030	2040
Net Energy for Load (GWh)	151,678	207,506	162,188	233,481	6.9%	12.5%
Peak Load (MW)	30.3	38.1	34.4	42.0	13.5%	10.2%

Table 1-6 shows the economic mix to realize the zero-emission goal by 2040 for the Initial Scenario and for the High Demand Scenario. Under the High Demand Scenario, the New York State electricity system would require substantially more renewable capacity. The increase is concentrated in grid solar generation (35% more) and offshore wind generation (38% more). Storage and onshore wind reduced slightly.

Table 1-6. Initial Scenario and High Demand Scenario 2040 Renewable Capacity Mix and Storage

RENEWABLE CAPACITY (MW)	INITIAL SCENARIO	HIGH DEMAND	Change (MW)
DG Solar (MW-AC) by 2040	6,443	6,443	0
Grid Solar by 2040	16,759	22,577	5,818
Onshore Wind by 2040	12,804	12,690	(114)
Offshore Wind by 2040	9,837	13,597	3,760
Energy Storage by 2040	15,515	14,891	(624)
NY Tx by 2040	1,250	1,250	0

The construction of the New York Public Policy transmission projects described in the Initial Scenario text support the achievement of the 70% renewable goal by 2030 with low levels of renewable curtailment and bulk system congestion. As such, no additional bulk transmission projects (230 kV and above) were identified by 2030 under the High Demand Scenario. However, transmission upgrades are likely necessary at the local transmission level.

By 2040, high levels of uneconomic congestion and some curtailment are expected with the generation additions identified to achieve the goal of a zero-emission electric system. Overall, the congestion and curtailment considerations are similar under the Initial and High Demand Scenarios, but they are more pronounced in the High Demand Scenario. Indicative bulk transmission upgrades, shown in Table 1-7 were found to relieve both congestion and curtailment with the economic benefits of these upgrades exceed their costs. However, further research is needed to assess the various forms of uncertainty including: the generation buildout and its location, the level of load growth, and the best potential designs and costs for these potential projects. As the transmission upgrades were not needed until after 2030, there is ample time to conduct this further research.

Table 1-7. Initial Scenario and High Demand Scenario 2040 Indicative Transmission Upgrades

In mega volt amperes (MVA).

Zone	UPGRADE	INITIAL SCENARIO	HIGH DEMAND	Change
H/I/J	Millwood South Interface	13,000	17,000	4,000
	Dunwoodie South Interface	6,000	6,000	0
I/K	Dunwoodie—Shore Rd. LTE Rating	3,000	4,000	1,000
E/G	Coopers Corner—Middleton—Rock Tavern—Dolson Ave 345 kV LTE	3,000	3,000	0
G	Ladentown—Ramapo 345kV LTE	2,500	2,500	0

1.3 Overarching Observations of the Study

The analysis carried out in the study indicates that New York State can achieve its 70 x 30 and zero-emission generation by 2040 goals with a mix of distributed energy, energy efficiency measures, energy storage, planned transmission projects, utility-scale renewables, and zero-emission resources.

Energy storage would be used to store excess solar and wind energy so that this energy may be utilized during peak hours. This additional storage will contribute to the maintenance of locational planning reserve margins.

The construction of the New York Public Policy transmission projects described previously supports the achievement of the 70% renewable goal by 2030 with low levels of bulk system curtailment and congestion. As such, no additional bulk transmission projects (230 kV and above) were identified by 2030 under either the Initial Scenario or the High Demand Scenario. However, transmission upgrades may be necessary at the local transmission level and additional needs may be found based on a more detailed analysis of New York's offshore wind goal.

By 2040, high levels of uneconomic congestion and some curtailment are expected with the generation additions identified to achieve the goal of a zero-emission electric system. Overall, the congestion and curtailment considerations are similar under both scenarios, but they are more pronounced in the High Demand Scenario. Indicative bulk transmission upgrades, described in more detail in sections 6 and 7, were found to relieve both congestion and curtailment with the economic benefits of these upgrades exceeding their costs. However, further research is needed to assess the various forms of uncertainty, including the generation buildout and its location, the level of load growth, and the best potential designs and costs for these potential projects. As the transmission upgrades were not needed until after 2030, there is ample time to conduct further research.

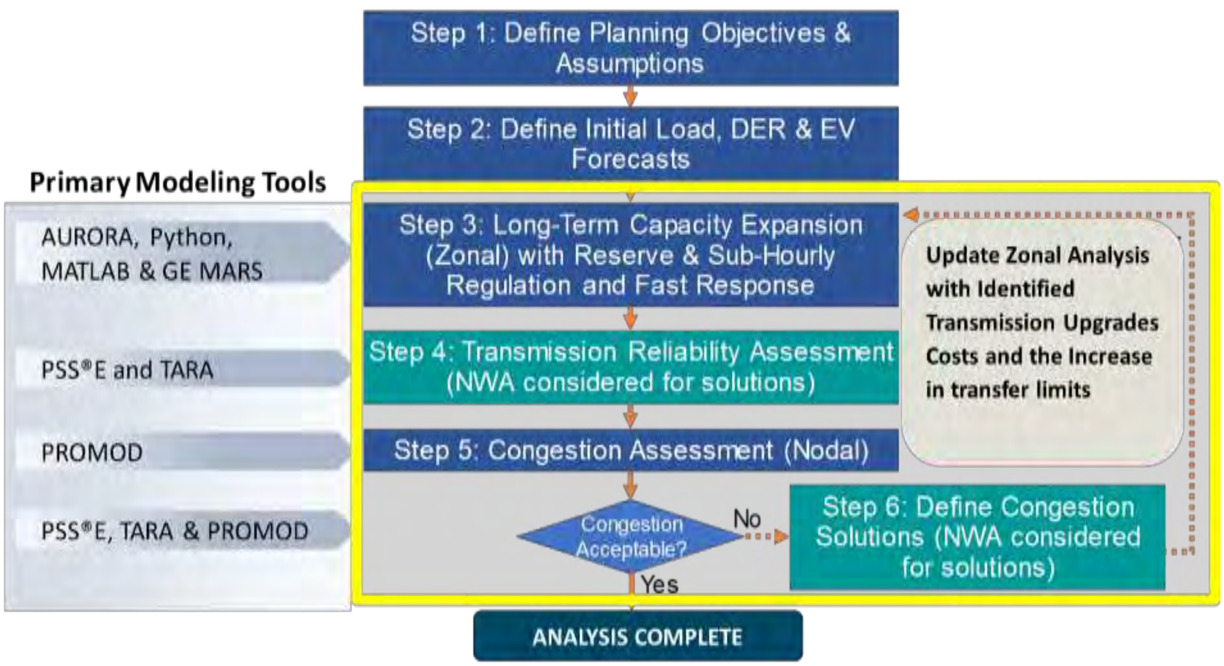
2 Methodology

2.1 Study Plan Development

The electric power industry is undergoing a paradigm shift characterized by a changing supply matrix with a shift towards renewable generation and storage, developments in both local and utility scale, and large retirements of the existing conventional thermal generation. These developments have demanded, more than ever, a planning process that more fully integrates generation resources with transmission capabilities.

Improved integration is achieved in this analytical process via the creation of an iteration case that is triggered if the Long-Term Capacity Expansion plan or LTCE (step 3) results in significant congestion and/or renewable curtailment (steps 4 and 5), thus prompting transmission investments (step 6). This iteration allows for the revision of the LTCE to account for both the added cost of transmission for the renewable asset and the increase in transmission limits. This results in a capacity expansion plan that is more closely coordinated with the changes in transmission. The planning approach used in the study is depicted in the figure below.

Figure 2-1. Integrated Generation and Transmission Planning Approach



* The figure highlights the tools and approach for this project.

2.1.1 Step 1: Define Planning Objectives and Assumptions

The primary objective considered in the study is the achievement of zero-emission supply by 2040 with an intermediate goal in 2030 of 70% of the energy supply coming from renewable resources. In interpreting the State goal of a zero-emission electricity grid by 2040, the study solves for a system in which all supply resources located in the State are zero-emission resources by 2040. For the purposes of the study, "zero-emission resources" constitute resources that are zero emission via their fundamental generation technology (e.g., wind and solar) or that use fuels deemed to be zero emissions (e.g., renewable natural gas [RNG]). Consistent with the definition of renewable energy systems in the CLCPA, hydro imports contributed to the achievement of the renewable energy goals excluding these renewable imports, New York State was found to have zero net imports in 2040. A comprehensive list of the assumptions used in the study is provided in section 3.

2.1.2 Step 2: Define Load and Distributed Energy Resources Forecasts

Distributed Energy Resources (DER) and loads are modeled in an aggregated fashion.

Analyzing the growth of various behind-the-meter resources was beyond the scope of this project, such as demand response (flex load), commercial battery energy storage, and other behind-the-meter generation resources. The only DER technology analyzed was behind-the-meter (BTM) PV. The study assumes timely achievement of 6 GW BTM solar target by 2025, and then applies an average annual growth rate of 1.9% for the years 2026–2040. The average annual rate is calculated as the average of year-on-year growth rate for years 2026–2040 from 2020 NYISO Goldbook.

Regarding battery energy storage, the study analyzed the economic development of utility-scale energy storage using wholesale energy revenues and ICAP payments as criteria.

Two scenarios were formulated with respect of the load forecast. The Initial Scenario's load forecast reflects the assumptions used on the High Technology Availability Pathway section of the Pathways to Deep Decarbonization in New York State[3] study, while the high demand load forecast is based on the Limited Non-Energy Pathway developed as part of the same study. The high demand load forecast was refined to include 2030 statewide demand and peak levels that are comparable to those in the NYISO CARIS 70 x 30

[3] Visit https://climate.ny.gov/Climate-Resources for The study Pathways to Deep Decarbonization in New York State.

Base Load case while maintaining the 2040 outcomes of the pathways case. Electric vehicle and electric heating penetration are included in these pathways forecasts.

2.1.3 Step 3: Long-Term Capacity Expansion

Once the planning objectives were defined, the project team developed assumptions common to the Initial Scenario and the High Demand Scenario. The study also incorporated forecasts for a variety of inputs including fuel prices, emission prices, technology (particularly renewable generation and storage) costs, and performance.

Both scenarios reflect all operating and other requirements, such as reserve margins, interim renewable targets, and transmission constraints. When running multiple models for generation and transmission planning, this methodology ensures that the forecasts are consistently applied across models.

The AURORA long-term capacity expansion (LTCE) model was used for both scenarios.

The AURORA model determines the most economic mix of generation and energy storage resources that achieve the State renewable requirements for each scenario as well as maintain all operational reliability requirements. The objective function seeks to maximize the value of generation and energy storage, considering revenues and costs in an efficient market.

The AURORA model was run in zonal mode with each NYISO zone represented by its portfolio of supply and load as well as transfer limits to adjacent zones.

Verifying Resource Adequacy

As part of the LTCE analysis, New York State's 2020 Installed Reserve Margin (IRM) and locational capacity requirements were met annually. In addition, the State's Installed Capacity Market (ICAP) was simulated by adopting the 2020 ICAP demand curves along with ICAP/UCAP (Unforced Capacity Market) translation factors. By adhering to the IRM, locational capacity requirements, and the ICAP market, the capacity expansion plan is able to meet the 1-in-10 LOLE criteria. This method is dependent on estimating and assigning to renewable resources and storage devices a proper Effective Load Carrying Capability (ELCC) used to contribute to the IRM and locational capacity requirements. Thus, as presented later in this report, the ELCC of solar, onshore wind, and offshore wind generation was determined dynamically to account for increased penetration. Additionally, the storage contribution was made a function of the energy content (two, four, or six hours).

The modeling methodology incorporated several verification steps that guarantee that the 1-in-10 LOLE criteria was met. In addition to the IRM, AURORA's internal LTCE optimization ascribes a high cost and, hence, low value to a proxy energy source to capture the cost of energy not served (ENS) and avoids proxy energy sources in meeting the load. As such, the model's cost minimization logic results in new peaking or storage resources added to the system for reserves and avoidance of ENS.

To determine if a select portfolio will meet the 1-in-10 LOLE standard, Siemens PTI employed AURORA's risk outage functionality and demand uncertainty features. The process also incorporates 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 producing a different internally generated net (demand minus supply) outage pattern for resources.

The study also benchmarked the results of AURORA LOLE analysis against a comparable analysis using the GE MARS analysis 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. GE MARS produced results that were substantially the same as AURORA LOLE for the Initial Scenario. (see section 4.5.1), thus the High Demand Scenario was only assessed with AURORA.

Ramping Adequacy and Flexibility Ramping Adequacy

Ramping reserves are used in each of the ISO markets to address the actual variability of load including deviations of resource scheduling and dispatch instructions, import schedules, and any other non-contingency variable factors. Ramping reserves address inter-scheduling period deviations required to follow load and compensate for scheduling uncertainties. The study 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).

Flexibility reserve (Flex) is a relatively new type of ancillary service product that has been implemented in CAISO (California) and MISO energy markets to address the increasing need for resources that can rapidly ramp up or down to respond to the changes in the intra-hour production of renewable resources. The study estimated the Flex adequacy requirements in supply portfolios based on the estimated sub-hourly variation in renewable energy production and load.

The study used a program developed by Siemens PTI in Python scripting language for assessing the adequacy of Flex serving resources in the portfolio. The program uses the industry-standard Monte Carlo approach of simulating multiple state-space possibilities of sub-hourly system performance. The 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. A normal distribution was used to generate the probabilistic distribution of sub-hourly generation and load forecasts.

For Flex adequacy calculations, the program generated randomly selected values for sub-hourly site level renewable energy production and load data. The program generated sub-hourly net load (load to serve minus 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 Flex serving assets or not. This process was repeated 1,000 times to capture extreme behavior. Once the amount of ramping and Flex resources were defined, they were then added as AURORA constraints for AURORA to select the least cost resources to meet the ramping and Flex adequacy requirements.

2.1.4 Step 4: Transmission Reliability Assessment

The LTCE identified in the AURORA analysis from step 3 was an input to the steady-state assessments for each scenario. However, the assessment does not include a network bus allocation for the generation resources added as it is based on zonal information. To address this, interconnection points were determined first for those AURORA-selected projects that could be aligned with the NYS queue. For resources for which there was no queue, the new generation on the capacity expansion was mapped to substations as follows:

- Land based wind (LBW) and solar photovoltaic (PV) projects were assigned to substations near the identified latitude and longitudinal locations of the renewable generation.
- Battery Energy Storage (BES) was modeled at substations that contain similarly sized PV/LBW resources. Storage is dispatched by the optimization process (AURORA and PROMOD) based off the net load curve (i.e. gross energy demand minus renewable generation), resulting in energy storage charging when net load is the lowest (when renewable generation is high) and discharges when net load is high (when renewable generation is low). The net load curve also provides a good representation for when energy prices are at a daily high for storage discharge and for when energy prices are daily low for charging.
- Additional Thermal Generation was modeled as a potential repowering at sites of retired conventional units. For example, Brownfield sites are likely to have the pipelines already in place and could be good sites for the renewable natural gas (RNG) resources.
- Behind the meter rooftop solar (DG Solar) was placed at load buses of similar size.

The focus of the analysis was on the bulk transmission system 230 kV and above, although lower voltages were also monitored. The analysis was carried out for 2030 and 2040 to identify potentially needed expansions. The analysis was performed only for certain snapshots that resulted in heavy utilization of the transmission system based on the dispatch of the zonal runs (summer peak high solar and high wind, low load). In determining any needed expansions, reassignment of resources between the substations and additional energy storage were considered as alternatives to traditional transmission reinforcements. This portion of the study identified transmission upgrades required, for example, to deliver renewable generation to NYC (Zone I) and Long Island (Zone K) and that were later confirmed under Step 5: Congestion Assessment.

2.1.5 Step 5: Congestion Assessment

In the next step, a nodal analysis was performed using the PROMOD analysis tool to identify congestion and/or curtailment issues not determined in the above power flow analysis with a view across the 8,760 hours of the year. PROMOD uses a security-constrained nodal analysis in a power flow model and considers all variable costs of the generators to dispatch generation economically while preventing security violations. The nodal analysis identified the need for potential additional transmission enhancements to mitigate congestion and/or curtailment and allow for the lowest operational cost of the system.

2.1.6 Step 6: Define Transmission Solutions for Congestion

It was expected that the analysis in steps 5 and 6 would result in notable levels of congestion and possibly renewable curtailment. As such, in step 6 indicative transmission expansions to address these issues were identified and effectiveness assessed in terms of benefit to cost (B/C) ratios. These ratios measure the reduction in operating costs in terms of the Adjusted Production Costs (APC). APC accounts for energy sales and purchases with neighbors made possible by the indicative transmission projects and then divides sales and purchases by carrying costs to evaluate return on capital, amortization, and O&M. The increase in transmission limits (along with associated costs) is allocated back to the generation that would benefit from the transmission upgrades. The cost associated with the upgrades is identified through shift factors or the percentage of their flow over the reinforced facility. The findings were then passed back to the AURORA LTCE assessment (step 3) to potentially create a revised generation and storage resource mix.

3 Assumptions and Analytical Tools

3.1 Assumptions

The study utilizes a broad set of power market assumptions across a 20-year period (2020 to 2040). Inputs to the modeling process such as load forecasts, fuel and technology price curves, and other factors are derived from multiple sources including third-party providers such as: S&P Global Platts and IHS and other independent sources such as the Energy Information Administration (EIA); American Wind Energy Association (AWEA); National Renewable Energy Laboratory (NREL); and the Environmental Protection Agency (EPA). These inputs reflect only one view of the data and modeling results evolve as technology costs and load forecasts change.

Implementing current and widely accepted market input data is the initial step of the study's development process. Data inputs such as load forecast, energy efficiency and demand side management projections, fuel prices, projected CO_2 prices, individual plant operating and cost information, and future resource information were updated with the most current data as of December 2019.

A detailed discussion of each of these data elements has been presented throughout this document. Data points are examined in more detail in the annexes.

- Load forecast for customer demand, inclusive of energy efficiency (EE), and demand response.
- Environmental legislation and regulations.
- Renewable resources and cost projections.
- Fuel costs forecasts.
- Technology costs and operating characteristics.

Table 3-1 provides a high-level summary of key assumptions applied to the study. A more detailed review of each of the major assumptions and their sources can be found in the annexes.

Table 3-1. Key Assumptions in the Study

INPUT	INITIAL SCENARIO		HIGH DEMAND SCENARIO	
Load Forecast[4]	2020-30' Energy: -0.43%/yr. 2030 Energy: 152 TWh 2030 Winter Peak: 23 GW 2030 Summer Peak: 30 GW	2030-40' Energy: 3.2%/yr. 2040 Energy: 208 TWh 2040 Winter Peak: 34 GW 2040 Summer Peak: 38 GW	2020-30' Energy: 0.33%/yr. 2030 Energy: 162 TWh 2030 Winter Peak: 27 GW 2030 Summer Peak: 34 GW	2030-40' Energy Rate: 1.8%/yr. 2040 Energy: 234 TWh 2040 Winter Peak: 42 GW 2040 Summer Peak: 42 GW
CLCPA Targets	70% Renewable Generation by 2030 Zero-emission Generation by 2040			
Installed Reserve Margin & Locational Capacity Requirements	NYCA: 118.9% Zone J: 88.6% Zone K: 103.4% Zone G-J: 90%			
Installed Capacity Market	ICAP Summer 2020 Demand Curves; 2020/2021 ICAP/UCAP Translation Factors[5]			
DG Solar	6,601 MW-DC (5,323 MW-AC) by 2030 7,989 MW-DC (6,443 MW-AC) by 2040			
NYC HVDC	DC transmission line delivering 10,000 GWh of dispatchable renewable energy into NYC (1,250 MW)			
Offshore Wind	9,000 MW by 2035 (6,000 MW allocated to Zone J and 3,000 to Zone K)			
Battery Energy Storage	3,000 MW by 2030 distributed in a manner consistent with the New York State Energy Storage Roadmap[6]; allowed model to economically build BES based on duration (2-hr, 4-hr, 6-hr)			
Natural Gas Prices	Henry Hub reaches $4/mmBtu by 2039; RNG in 2040 $23/mmBtu and limited to 32 Tbtu/yr			
Emission Prices	RGGI: NYISO CARIS prices through 2028; Increases 7%/yr thereafter reaching $22/$CO_2$-ton by 2040			
Nuclear	80-yr useful life (EPA v6 Base Case Documentation) Except for announced retirements			
Zonal Transfer Limits	2020 NYISO Reliability Needs Assessment (RNA) topology study years 2024–2030			

Load Forecast: The Initial Scenario load forecast is from the High Technology Availability Pathway section of the Pathways to Deep Decarbonization in New York State[7] study while the High Demand

[4] Load forecast does not net out behind-the-meter solar

[5] Visit https://www.nyiso.com/documents/20142/11477343/ICAP-Translation-of-Demand-Curve-Summer-2020-FINAL.pdf/63166d63-50c4-e2fb-cfcc-38a17274997b for ICAP/UCAP Translation of Demand Curve 2020.

[6] Energy storage price curves are from NY's Energy Storage Roadmap are included in the Annex.

[7] Visit https://climate.ny.gov/-/media/CLCPA/Files/2020-06-24-NYS-Decarbonization-Pathways-Report.pdf for the Decarbonization Pathways Report.

Scenario load forecast is based on the Limited Non-Energy Pathway of the same study. The high demand load forecast was refined to include 2030 statewide demand and peak levels that are comparable to those in the NYISO CARIS 70 x 30 Base Load case while maintaining the 2040 outcomes of the pathways case.

70% Renewable Generation by 2030: For the 2030 interim target, renewable generation from the following sources are applicable: distributed solar, grid solar, onshore wind, offshore wind, hydroelectricity, Legacy Canadian hydro imports, the proxy Tier 4 NYC Tx, and 40% of landfill gas and biomass generation. (Note: Due to uncertainty in eligibility for certain resources, the contribution of bioenergy resources was discounted by 40%).

Zero-emission Generation by 2040: For the 2040 zero-emission generation target, generation from the following sources can contribute: distributed solar, grid solar, onshore wind, offshore wind, hydroelectricity, Legacy Canadian hydro imports, the proxy Tier 4 NYC Tx project, nuclear, and thermal generators consuming biomass, landfill gas, or renewable natural gas.

Starting in 2040, New York cannot be an aggregate net importer from these adjacent power markets (PJM, ISO-NE and Ontario).

Capacity Market: Capacity market prices were determined using a proprietary excel model that estimates prices based on Summer 2020 ICAP demand curves and ICAP/UCAP translation factors. The 2020 demand curves and translation factors were used throughout the study. Essentially, the UCAP requirements as a percentage of peak are maintained throughout the study. Also, contribution to the peak for different resource types was determined by a dynamic effective load carrying capacity (ELCC) calculation within the capacity expansion model.

Distributed Solar Forecast: The distributed solar forecast meets the New York State goal of having 6,000 MW DC in 2025 and then increases 1.9% per year through 2040. The proportion of distributed solar in each zone is based on the proportions of distributed solar in each zone from the 2019 Goldbook.[8]

New York Offshore Wind: The CLCPA's goal is to achieve 9,000 MW of offshore wind by 2035. As a proxy, it was assumed that 6,000 MW would be interconnected to Zone J and 3,000 MW interconnected to Zone K.

[8] NYSERDA Gold Book 2019 can be found at https://www.nyiso.com/documents/20142/2226333/2019-Gold-Book-Final-Public.pdf/ online.

Battery Energy Storage: Battery Storage followed the trends as published in the New York State Energy Storage Roadmap[9] and allowed dispatch model to economically build battery energy storage using three duration options (two, four, and six hours). The overnight capital cost forecasts for each energy storage duration type are summarized in the annexes.

PJM and ISO-NE Renewable Energy Targets: For neighboring regions (PJM and ISO-NE), the renewable energy standards (RES) applied to the analysis were based on the announced initiatives as of November 2019. The specific offshore wind targets and RES applied can be found in the annexes.

Firm Builds and Retirements: Short-term firm builds and retirements are sourced from EIA-860, 2019 NYISO Goldbook and S&P Global Market Intelligence. In addition, a list of recently procured renewables were included in the analysis based on a NYSERDA program that secures Tier 1 renewable energy credits (RECs).

NOx Peaker Rule: The study adopted the compliance plan for each gas turbine affected by New York State's NOx Peak rule, which requires all applicable simple cycle combustion turbines (SCCTs) to emit less than 15% oxygen on a parts per million dry volume basis (ppmvd) by May 1, 2023. The limit is 25 ppmvd for gaseous fuels and 42 ppmvd for distillate oil or other liquid fuel by May 1, 2025.[10] To avoid generation deficiencies noted in the NYISO 2019 Comprehensive Reliability Plan (CRP) study, base models for all three study years included a 420 MW non-renewable compensatory unit at Greenwood 138 KV substation. The unit was considered available for dispatch in its entire range in all analyses.

Nuclear: Nuclear generators have an 80-year lifespan except for Indian Point. It was announced that Indian Point 2 would retire in April 2020 and Indian Point 3 would in April 2021. This assumption was adopted from EPA's Power Sector Modeling Platform v6.[11]

[9]Visit https://www.nyserda.ny.gov/All-Programs/Programs/Energy-Storage for NYSERDA Energy Storage Programs.

[10] Adopted Subpart 227-3, Ozone Season Oxides of Nitrogen (NOx) Emission Limits for Simple Cycle and Regenerative Combustion Turbines can be found at https://www.dec.ny.gov/regulations/116131.html online.

[11] Documentation of EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model can be found online at https://www.epa.gov/sites/production/files/2019-03/documents/epa_platform_v6_november_2018_reference_case.pdf

3.2 Tools Utilized

3.2.1 AURORA by Energy Exemplar

AURORA is a mixed integer, chronological dispatch model of the electric sector, developed by Energy Exemplar. It is used to simulate the hourly operations of U.S. electric power markets.

AURORA's functionality includes Long-Term Capacity Expansion (LTCE) logic, which allows AURORA to estimate the magnitude and timing of capacity resources needed to meet operational, reliability, and regulatory retirements economically. The LTCE logic also analyzes the economic retirements of existing capacity resources.

For the study, the project team utilized AURORA's "Max Value" option which analyzes new build and retirement decisions based on unit profitability. For example, for economically viable new capacity entry, a developer would expect to recover all cost, including build costs and a normal rate of return. Aurora uses net present value (NPV) related metrics to evaluate resources in a LTCE study. The NPV will be derived from annual resource net revenue, or reported Value ($000):

Annual Value = Energy Revenue +Capacity Revenue – (Fixed Cost + VOM + Fuel Cost + Emission Cost +Startup Cost)

Where, Capacity Revenue = Capacity Price x Capacity x Peak Credit (ELCC)

3.2.2 PowerGEM's TARA

Siemens PTI used PowerGEM's TARA version 1902_2 to conduct the thermal and voltage analysis for pre-contingency, local, and design criteria contingency conditions, focusing on the impact in the study area. TARA performs a 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 provides an initial view on curtailment.

3.2.3 PROMOD IV and Database

Siemens PTI used Hitachi ABB PROMOD®IV version 11.2 to conduct the nodal production cost analysis focusing on congestion and curtailment. The production cost model started with the Hitachi ABB PROMOD®IV Nodal 2021 F19 Eastern Interconnection Powerbase model (Release Fall 2019) which provides updates to the Simulation Ready Data NERC database release through March 2020.

PROMOD®IV (or "PROMOD" in this document) is an Hourly Monte Carlo tool that performs a security constrained unit commitment and a security constrained economic dispatch (SCED) in a way that closely aligns with how power systems are operated. It contains a detailed model of the network and produces a secure dispatch considering all the monitored constraints (monitored elements/contingencies) provided for the analysis. In the study, PROMOD monitored all elements 230 kV and above in New York Control Area (NYCA), interfaces to neighboring systems, and transformation to lower voltages.

3.2.4 Power Analytics Software and Adjusted Production Costs Reporter

Siemens PTI used the Power Analytics Software (PAS) APC Reporter Tool Version 1.15.3.0 to report some of the results from the nodal production cost analysis as well as calculate the Adjusted Production Costs (APC).

4 Long-Term Capacity Expansion—Initial Scenario

The objective of the long-term capacity expansion (LTCE) analysis is to determine the magnitude and timing of needed resources and the type of resources that should be added to meet operational, reliability and regulatory requirements economically. The LTCE also analyzes which power generators should be economically retired based on market dynamics. This section summarizes the results of the LTCE analysis and discusses the reasoning behind the zonal capacity buildout. The results described in this section are results of the final LTCE, after considering the transmission upgrades and costs from section 6 of this report. The Original LTCE that was used to determine the transmission upgrades is included in Annex A.

4.1 Long-Term Capacity Expansion—Initial Scenario

4.1.1 Capacity Expansion—70% Renewable Generation by 2030

At the beginning of the study in 2020, New York State features roughly 10.3 GW of steam units, 11.9 GW of gas combined cycles, 6.1 GW of gas turbines, 5 GW of nuclear, 4.6 GW of in-state hydro, 1.4 GW of pumped storage, 2.4 GW of wind, 500 MW of utility-scale solar, 40 MW of energy storage, and 2.2 GW (2.8 GW DC) of behind-the-meter solar.

Through 2025, several notable events occur that change the capacity resource mix of the State:

- The Department of Environmental Conservation's NOx Peaker Rule, Subpart 227-3, becomes enforced, which establishes more stringent thresholds for emissions of nitrogen oxides (NOx) for power plants. 1 GW of oil and gas fired turbines retire in accordance with their NOx compliance plan filing by 2025.
- Indian Point 2 and Indian Point 3 both retire, removing 2 GW of nuclear capacity from the market.
- New York State reaches its mandate of deploying 1,500 MW total energy storage in the system by 2025.
- A Tier 4 renewable transmission project that provides 1,250 MW of firm capacity and offers up to 10,000 GWh of dispatchable zero-emission energy directly into New York City (NYC Tx).
- New York State installs renewable capacity based from pre-2020 Clean Energy Standard procurements.
- New York State adds 1.8 GW of offshore wind capacity, including 130 MW from South Fork LIPA Contract, and 1,696 MW from Sunrise and Empire Wind NYSERDA contracts.
- New York State achieves its 6 GW (DC) goal of behind-the-meter solar installed.

By 2030, New York achieves its interim target of 70% renewable generation (70 x 30). New York State achieves 70 x 30 with a total capacity supply of 6.2 GW of land-based wind, 6 GW of offshore wind, 3.8 GW of utility-scale solar, 4.7 GW of in-state hydro, 1.25 GW of Tier 4 NYC Tx, and 6.6 GW (DC) of behind-the-meter solar. Additionally, the State meets its 2030 mandated 3 GW of energy storage in the system.

With the addition of 14,000 MW of renewable capacity to New York State's capacity supply from 2020 through 2030, renewable generation displaces marginal gas-fired generation and capacity prices decline with the net increase in unforced capacity. The combination of these two factors results in the economic retirement of gas-fired capacity. From 2020 to 2030, 5,200 MW of thermal capacity retires.

4.1.2 Capacity Expansion—Zero Emissions by 2040

As energy demand escalates at an average rate of 3.2% per year from 2030 to 2040, New York State needs to continue to add renewable capacity to its supply mix to maintain its 70% renewable energy mandate. From 2030 to 2035, roughly 6,700 MW of additional renewable capacity is added to the system (500 MW of onshore wind, 3,000 MW of offshore wind, 2,600 solar, 533 MW of DG solar).

In addition to building renewable capacity to meet the State's 70% annual renewable generation mandate, starting in 2036, additional renewable capacity needs to be added to the market in the transition to 100% zero-emission generation by 2040 (100 x 40). To simulate real-world development limitations and construction timelines, the following annual renewable build limits were assumed in the LTCE modeling: 2,000 MW/yr onshore wind, 3,000 MW offshore wind, 2,500 MW grid solar (increasing incrementally to 3,000 MW in 2040), and 2,500 MW/yr energy storage.

To achieve a zero-emission power sector by 2040, a diverse mix of renewable capacity is added to the power grid. From 2036 to 2040, 17,800 MW of renewable capacity is added: 6,000 MW of onshore wind, 800 MW of offshore wind, 10,300 MW of utility solar, and 580 MW (AC) of DG solar. To simulate real-world development limitations and construction timelines, annual build limits for renewable technologies were assumed in the LTCE modeling, which are summarized in the annexes. The resulting capacity supply mix of the Initial Scenario is presented in Table 4-1.

Table 4-1. New York Annual Installed Capacity Supply Mix

In megawatts.

	2025	2030	2035	2040
Thermal	24,447	23,458	24,113	17,269
Nuclear	3,381	3,381	3,381	3,381
Hydro	4,663	4,663	4,663	4,663
Onshore Wind	3,932	6,230	6,736	12,804
Offshore Wind	1,826	6,000	9,000	9,837
Grid Solar	3,099	3,808	6,426	16,759
Energy Storage	1,542	3,000	5,154	15,515
Other Renew	416	416	416	416
NYC Tx	1,250	1,250	1,250	1,250
BTM Solar (AC)	4,839	5,323	5,856	6,443

As New York State adds zero-emission resources post-2030 with close to zero variable dispatch cost, thermal generation is displaced. Therefore, energy revenues for thermal plants decline. However, capacity market prices increase to a level that covers the fixed operating costs of thermal capacity to maintain market reliability. Dispatchable capacity is needed by the market to maintain locational reserve margin requirements as electricity demand escalates and the effective load carrying capability of renewables declines.

From 2036–2040, roughly 6,800 MW of thermal capacity economically retires from the market. In 2040, 17,200 MW of thermal capacity economically persists in the market even though they have low-capacity factors. The essential driver for their persistence in this analysis is that the study assumes current capacity market structures persist through 2040. Capacity markets and prices certainly may change to meet the needs of a different system 20 years from now. Therefore, it is hard to anticipate whether this level of thermal capacity will truly remain in 2040 if the units are operating at low-capacity factors.

Energy Storage

As New York State adds a significant amount of renewable capacity to meet its 2040 zero-emission goal, renewable generation will exceed electricity demand at times. During these hours of excess renewable generation, energy storage is added to the system to store energy for peak demand hours when renewable energy is not available.

In this study, starting in 2030, peak demand shifts to evening hours (after 6 p.m.) when solar energy is not available. Therefore, energy storage can be dispatched as grid solar and DG solar production declines and electricity demand reaches its peak demand in the early evening. Energy storage will also be needed in the market to provide reliable capacity to meet locational reserve margin requirements and the effective load carry capability of renewable capacity declines, especially solar capacity.

4.2 Energy Outlook—Initial Scenario

New York State's energy usage stems from demand for electricity, generation capacity supply mix, and the dispatch price of the power generation fleet. The goal of the CLCPA is to achieve a zero-emission wholesale power generation by 2040, including an interim 2030 renewable energy target. The following section summarizes how the State's energy production will shift based on the study's market assumptions and the capacity buildout analyzed in the previous section.

4.2.1 Energy Outlook—70% Renewable Generation by 2030

The study assumed generation from onshore wind, offshore wind, grid solar, DG solar, in-state hydroelectricity, and Canadian hydroelectric imports[12] may contribute towards the 2030 interim goal. Due to the uncertainty of whether biomass and landfill gas would be considered renewable energy, the study assumed only 40% of biomass and landfill gas can contribute to the 2030 interim goal. In recent years, New York State has been entering into contracts with developers to secure the renewable energy necessary to achieve the State's clean energy goals, and plans to continue these efforts into the future. The renewable energy certificates (RECs) created through the procurement contracts will be tracked using the New York Generation Attribute Tracking System (NYGATS) to ensure that RECs used to meet State goals are not double counted in neighboring regions. As a result, this analysis treats in-state renewable attribute purchases as not being a component of any exported energy and subtracts this energy from the residual mix that is exported.

To estimate the potential changes in energy consumption due to the CLCPA, actual 2019 generation and end-use energy demand will be used as base year data for comparison purposes (Table 4-2). In 2019, New York State's total in-state generation included 24% renewable generation. Of this amount, in-state hydroelectricity accounts for 81% of total renewable generation and wind energy accounts for 12%. The State had 23,128 GWh in net imports in 2019 and roughly 10,000 GWh of total net imports is sourced from Canadian hydroelectricity.

[12] Legacy Canadian hydroelectricity is assumed to provide 10,000 GWh/yr of renewable energy to New York. This is consistent with the recent Clean Energy Standard white paper.

Using CLCPA's guidelines, in 2019 roughly 30% of end-use energy demand was supplied from renewable resources, while thermal generation accounted for 33% of total net energy load.

Table 4-2. Actual 2019 New York ISO Generation by Technology and Energy Demand

Technology Type	Generation (GWh)	% of End-Use Demand
End-Use Energy Demand[13]	157,664	
EE Savings & BTM Gen[14]	(1,832)	
Baseline Energy Demand[15]	155,832	
Thermal	51,871	32.9%
Grid Solar	52	0.0%
Onshore Wind	4,454	2.8%
Nuclear	44,788	28.4%
Hydro	30,141	19.1%
Pumped Storage	583	0.4%
Other Renewable	2,648	1.7%
Total NYCA Generation[16]	134,536	85.3%
Net Imports[17]	23,128	14.7%

Through 2030, several key factors are associated with New York State achieving 70% renewable generation:

- Energy demand decreases on average 0.33% from 156.8 TWh to 151.7 TWh.
- Indian Point 2 and 3 nuclear generators retire in 2020 and 2021, respectively, reducing nuclear generation by about 9 TWh/yr.
- A Tier 4 proxy renewable transmission project (NYC Tx) provides 1,250 MW of firm capacity and offers up to 10,000 GWh/yr of dispatchable zero-emission energy directly into New York City. 100% of this energy is renewable and helps NY achieve its 2030 interim goal.
- New York installs renewable capacity from pre-2020 Clean Energy Standard procurements.

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[13] Estimated by summing NYCA net generation and net imports.

[14] Estimated by subtracting End-Use Demand and Baseline Energy Demand.

[15] 2020 NYISO Goldbook Table I-1a.

[16] 2020 NYISO Goldbook Table III-3c.

[17] 2020 NYISO Goldbook Table III-3d.

- 1.8 GW of offshore wind goes online in 2025 and by 2030 NY achieves 6 GW of offshore wind capacity by 2030 on the way to achieving its 9 GW 2035 OSW mandate.
- New York State achieves its 6 GW (DC) mandate of behind-the-meter solar in 2025 and adds another 0.6 GW through 2030.
- New York State complies with its NOx Peaker Rule, which reduces thermal generation from units that have high NO_X emission rates.

Based on 2030 net energy load assumptions, roughly 106 TWh of renewable generation is needed in 2030 to achieve the State's interim target of 70% renewable generation. Based on the key market changes described above and the additional renewable capacity added to the market as described in section 4, New York achieves the 70% renewable generation goal. Table 4-3 summarizes annual generation from 2025 to 2040 in five-year increments, while Table 4-4 summarizes the breakdown of renewable generation resources that make up the 2030 interim goal.

Table 4-3. 2025–2040 Annual Generation by Technology

In gigawatt hours.

	2025	2030	2035	2040
Thermal	40,093	18,063	14,300	1,146
Nuclear	28,875	27,042	28,875	27,127
Hydro	28,570	28,039	28,621	28,684
Onshore Wind	10,462	18,888	20,918	43,950
Offshore Wind	5,863	24,062	38,794	45,478
Solar	4,098	5,571	11,051	31,902
Other Renew	2,744	2,716	2,632	2,538
NYC TX	10,000	9,930	9,853	9,340
Legacy Hydro Imports	10,008	10,009	10,012	10,069
DG Solar (AC)	7,266	7,994	8,795	9,697
Non-Hydro Net Imports	(166)	(280)	3,082	(359)

Table 4-4. 2030 Renewable Generation Breakdown by Technology/Source

In gigawatt hours.

		% of Net Energy for Load
Energy Demand	151,605	
Total RE Generation	106,133	
RE Gen % of Demand	70%	
NYC Tx	9,930	7%
Legacy Can. Hydro	10,009	7%
DG Solar	7,994	5%
Grid Solar	5,571	4%
Onshore Wind	18,888	12%
Offshore Wind	24,062	16%
NY Hydro	28,039	18%
Other Renew[18]	1,640	1%

4.2.2 Energy Outlook—Zero-Emission Generation by 2040

From 2030 to 2040, net energy load increases on average 3.2% per year. To maintain the 70% renewable generation mandate, renewable energy available to the market must grow at the same rate of total demand. By 2040, the minimum amount of renewable energy needed in the market must be at least 145 TWh. However, to achieve zero-emission generation by 2040, it is estimated that under this scenario renewable generation will account for 87% of total energy demand. Table 4-5 summarizes the breakdown of renewable generation estimated to meet 2040 demand.

Table 4-5. 2040 Renewable Generable Generation Breakdown

		% of Net Energy for Load
Energy Demand	207,477	
Total RE Generation	180,653	
RE Gen % of Demand	87.1%	
NY Tx	9,340	5%
Legacy Can. Hydro	10,069	5%
DG Solar	9,697	5%
Grid Solar	31,902	15%
Onshore Wind	43,950	21%
Offshore Wind	45,478	22%
NY Hydro	28,684	14%
Other Renew	1,532	1%

[18] Due to uncertainty in eligibility for certain resources, the contribution of 'Other Renewables' was discounted by 40%

4.3 Energy Prices

Average wholesale power prices in the study are determined on a zonal basis by calculating the dispatch cost of the marginal generation resource used to serve electricity demand at any given hour. As such, electricity demand and the factors that affect dispatch costs (e.g., fuel prices, emission prices, and variable costs) will impact power prices over time.

Historically, New York State's wholesale power prices settle at different levels in each zone. To illustrate power price dynamics in the State, Table 4-6 summarizes actual 2019 day-ahead wholesale power prices by zone.

Table 4-6. 2019 NYISO Around-the-Clock Day-Ahead Prices [19]

Zone	$/MWh
West–A	25.34
Genesee–B	20.57
Central–C	21.80
North–D	18.03
Mohawk Valley–E	21.82
Capital–F	27.95
Hudson Valley–G	26.87
Millwood–H	27.31
Dunwoodie–I	27.45
N.Y.C.–J	28.94
Long Island–K	32.89

4.3.1 Energy Prices—70% Renewable Generation by 2030

As New York State's capacity supply mix transitions to meet the 70% renewable energy interim target by 2030, there are several market dynamics that apply upward and downward pressure on wholesale energy prices.

Upward power price pressure is found in the following factors from 2020–2030:

- Henry Hub natural gas prices escalate from $2.32/MMBTU in 2020 to $3.15/MMBTU in 2030 (all values in $2018).

[19] Source, Energy Market and Operational Data. Visit https://www.nyiso.com/energy-market-operational-data to access the data.

- Regional Greenhouse Gas Initiative (RGGI) Carbon Dioxide prices increase from $4.90/short ton in 2020 to $11.59/short ton in 2030. (All values in 2018 dollars.)

Downward power price pressure is found in the following factors from 2020–2030:

- Electricity demand declines at an average rate of 0.33%/yr. from 2020 to 2030.
- New York State builds utility-scale solar, land-based wind, offshore wind, and the NYC Tx project, all have a near zero dispatch cost.

On average, 2030 power prices remain flat compared to actual 2019 day-ahead power prices based on the upward and downward power price factors. The increased fuel and emission prices of marginal gas-fired energy is offset by the reduction in demand and addition of zero-dispatch-cost renewable resources. Figure 4-1 summarizes the average day-ahead energy prices for Zone A and Zone J from 2025 to 2040.

4.3.2 Energy Prices—Zero-Emission Generation by 2040

As the State transitions to zero-emission generation from 2030 to 2040, the study's market dynamics shift through 2040 resulting in an increase in power prices. The upward and downward power price factors are as follows:

Upward power price pressure is found in the following factors from 2020–2040:

- Electricity demand increases at an average rate of 3.2%/yr from 2030 to 2040 and peak demand increases on average 2.1%/yr from 2030 to 2040.
- Henry Hub natural gas prices increase to $4/MMBtu in 2039 (all values in $2018).
- RGGI carbon prices reach $21.50/$CO_2$ ton (all values in $2018).
- In 2040, all gas generators can only consume renewable natural gas that was modeled with a fuel price of $23/MMBtu; the dispatch cost of a gas turbine is estimated to be $220/MWh in 2040 (assuming 9,000 btu/kWh heat rate). (All values in 2018 dollars.)

Downward power price pressure is found in the following factors from 2020–2040:

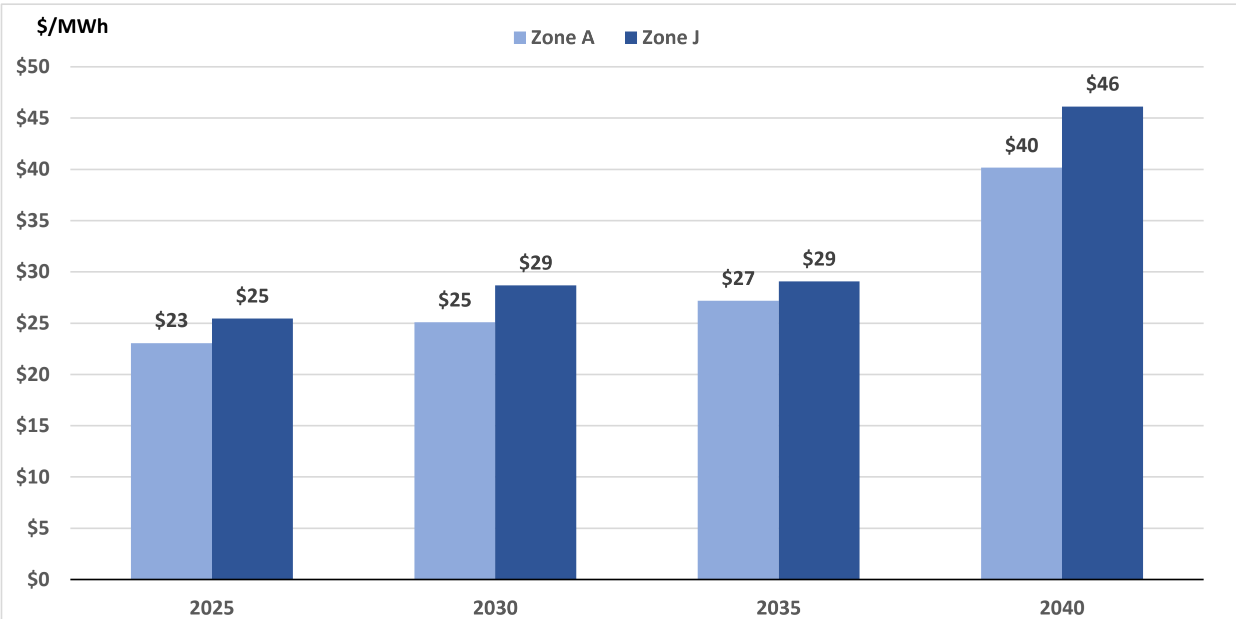
- New York State supply mix is heavily weighted with renewable capacity and by 2040 renewable generation accounts for at least 80% of total net energy load.

Even though more than 80% of the State's net energy to meet demand is sourced from zero dispatch cost renewable resources in 2040, on average power prices increase roughly $15/MWh from 2030. This increase in power prices occurs because the cost of thermal generation using renewable natural gas (RNG) was modeled to be roughly $220/MWh and thermal generation is setting power prices during peak demand hours, when there are reductions in renewable energy availability. However, it is important to note that there are significant uncertainties on what the price of renewable natural gas will be in the long term (2040) and the cost of other competing technologies to provide dispatchable generation with zero emissions.

On a monthly basis, prices are relatively low in the winter and shoulder months when energy demand is relatively low and wind generation is relatively high, but the use of expensive fuel in the summer months to help meet peak summer demand lifts prices. Figure 4-1 summarizes the average day-ahead energy prices for Zone A and Zone J from 2025 to 2040.

Figure 4-1. Zone A and Zone J Average Wholesale Energy Price Forecast

$2018/MWh



4.4 Emissions

The CLCPA's overall goal is to achieve a zero-emissions electric sector by 2040. Roughly a third of New York State's current generation mix is sourced from gas-fired resources and New York emitted 24.9 million tons of CO_2[20] in 2019 from the power sector. To achieve this goal, the State will need to incrementally reduce its emissions over the next 20 years.

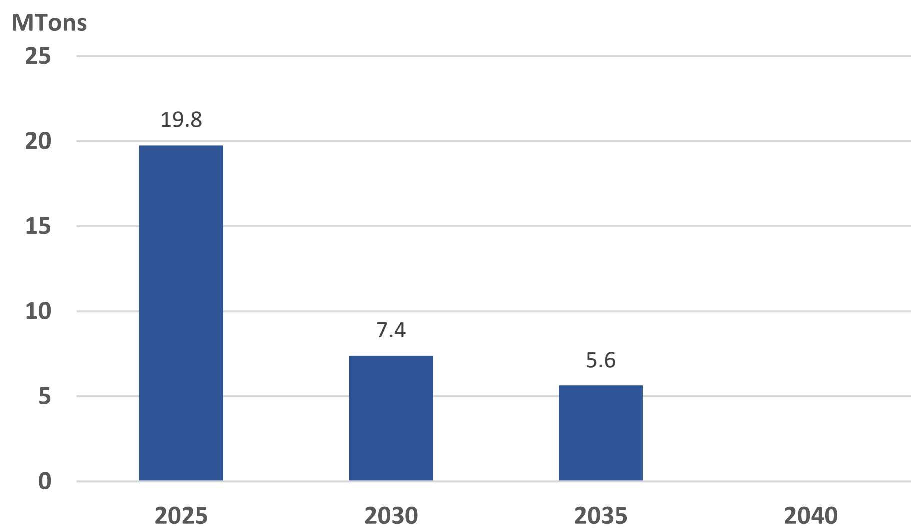
By 2030, when New York State meets its 70% renewable energy goal, the state has enough renewable resources (solar, wind, offshore wind, NYC Transmission), that carbon emissions fall 70% compared to actual 2019 levels. By 2030, the State still relies on gas-fired generation to help meet peak demand, but the

[20] Visit https://ampd.epa.gov/ampd/ for EPA Continuous Emission Monitoring Systems.

significantly reduced gas-fired generation levels lead to lower emission levels. Additionally, by 2030 some of the less-efficient thermal generators have exited the market.

By 2040, the State achieves a net zero electricity system with zero internal carbon emissions. New York still operates thermal capacity to meet electricity demand, but it is using renewable natural gas. The State imports power from its neighbors to help meet peak demand in the summer. Although power is imported during certain hours, net-imports excluding Canadian hydro resources in 2040 are effectively zero. Figure 7-1 displays annual New York State emissions in short tons from 2025 to 2040

Figure 4-2. Annual NYISO Carbon Emissions (Million Short Tons) Forecast



4.5 System Reliability

The study included two separate analyses to ensure the resulting capacity expansion plan through 2040 was operationally reliable enough to meet demand in case of sudden losses of renewable production, sudden increases in demand, or major unplanned power generator outages. The two reliability analyses performed were the following:

- Loss of Load Expectation (LOLE), which measures the security of capacity supply. The study applied New York State's requirement of having no more than 1-day of loss of load events in a 10-year period.
- Flexible Resource Adequacy, which estimates the amount of fast ramping capacity needed by the market to cover variability in load and renewable generation in the 1 to 10-minute horizon.

4.5.1 LOLE Analysis

A resource adequacy analysis using AURORA evaluated if there was sufficient capacity in the PowerGEM State's wholesale power market to meet electricity demand in the event of numerous, unforced generator outages and unexpected increases to the base energy demand forecast.

The goal of the resource adequacy plan is to ensure that Loss of Load Expectations (LOLE) occur less often than 0.1 days/year.

To perform the analysis, the Equivalent Forced Outage Rate demand (EFORd) and Mean Time to Repair (MTTR) was estimated for each generating technology. EFORd is the probability a power unit will not be available due to an unforced outage when there is a demand for the unit to generate. MTTR is the average amount of time a generator will not be available during a forced outage event. Additionally, unexpected variations in energy demand were simulated by applying zonal monthly standard deviations and monthly correlations to the demand forecast based off 8-years of New York State historical data. Table 4-7 summarizes the EFORd and MTTR assumptions used for the resource adequacy analysis.

Table 4-7. Equivalent Forced Outage Rate Demand (EFORD) and Mean Time to Repair (MTTR)

Technology	EFORd (%)	MTTR (hrs.)
Internal Combustion	21%	227
Steam-Oil	10%	534
Steam-Gas	9%	505
Gas Turbine	9%	92
Gas CC	4%	60
Nuclear	3%	149
Hydro	9%	48
Pump Storage	3%	29
Wind	10%	96
Offshore Wind	3%	499
Solar	1%	1560
Energy Storage	3%	15

One hundred randomized modeling iterations were performed to simulate hourly market operations in 2035 and 2040. Each iteration applies random forced outage events and durations to generators based on their EFORd and MTTR, as well as unexpected changes to energy demand based off the probabilities of zonal demand standard deviations. A LOLE event is identified when there is a one-hour period where there is no available capacity to meet electricity demand.

The analysis did not observe any loss of load events in the iterations examined. Therefore, it was determined that New York State met the 0.1 days/year LOLE requirement.

To benchmark the results in AURORA, GE MARS was also used to perform a resource adequacy analysis. The resource adequacy (RA) analysis methodology between AURORA and GE MARS is comparable. Both models sensitize fluctuations in electricity demand and the unforced outages of generation resources. However, the energy demand and resource outages in surrounding regions (PJM, ISONE, Canada) were not sensitized in the AURORA analysis but were varied in the GE MARS analysis. The GE MARS model resulted in a similar result as AURORA, reflecting that the 1-in-10 LOLE requirement was met.

4.5.2 Flexible Resource Adequacy

The study forecasted the Long-Term Capacity Expansion by simulating power market operations on an hourly basis. However, with a high-renewable capacity supply, there should be sufficient fast ramping capacity to cycle up/down within the 1- to 10-minute horizon to offset sudden losses or production of renewable generation.

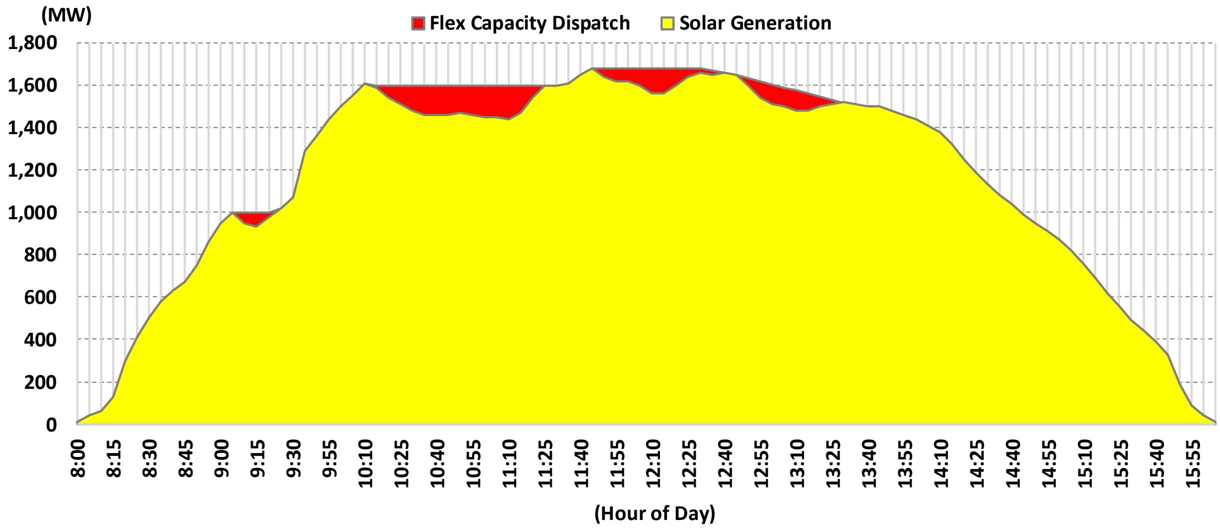
The flexible resource adequacy analysis estimates how much capacity is needed to offset any sudden increases/decreases in renewable availability and electricity demand. This flexible service can be provided by energy storage or controllable generation such as gas turbines, which could participate in the fast (10 minute) non-spin and spin reserve market.

The flex capacity analysis includes the following steps:

- Analyze historical sub-hourly land-based-wind generation, offshore wind generation, solar generation, and electricity demand to estimate historical capacity factor volatility.
- Estimate with 99% confidence, what the historical 10-minute capacity factor volatility is of each variable generation resource and electricity demand.
- Using the hourly average renewable generation and load forecast and the volatility with 99% confidence, find the amount of flexible capacity required in each year and zone to maintain dispatch reliability.

The Figure 4-3 illustrates a potential solar production scenario with flex capacity utilization. In the graph, the red represents sub-hourly intervals when a typical solar generator may not produce as much as expected on average at an hourly basis. When those events occurred, fast ramping resources were needed to meet energy demand.

Figure 4-3. Five-Minute Solar Production and Flex Capacity Utilization



As New York State relies more on intermittent capacity toward 2040, more reliable capacity is required to support quick shifts in solar and wind availability.

Applying the zonal groups that the State uses for operating reserve requirements, New York has sufficient flexible capacity to offset sudden changes in renewable generation and electricity demand based on a 99.9% confidence interval.

Table 4-8. Estimated Sub-hourly Flexible Reserves—Required versus Available

In megawatts.

		NYCA (Zone A-K)	East (Zone F-K)	SENY (Zone G-K)	NYC (Zone J)	Long Island (Zone K)
2030	Flex Cap. Required	2,981	1,947	1,647	901	557
	Flex Cap. Available	7,372	6,486	6,342	2,775	3,122
2040	Flex Cap. Required	5,877	3,557	2,596	1,268	964
	Flex Cap. Available	19,595	16,038	13,394	6,063	4,461

In 2040, 17.2 GW of thermal capacity economically persists in the market even though thermal generators have low-capacity factors. The essential driver for their persistence is that the study assumes current capacity market structures remain in place through 2040. Capacity market guidelines and rules may change to meet the needs of a different system 20 years from now, so it is hard to anticipate whether this level of thermal capacity will remain to meet resource management targets in 2040.

5 Transmission Load-Flow Contingency Analysis—Initial Scenario

The transmission load-flow analysis aims to evaluate potential transmission needs for meeting New York State's zero-emission goal by 2040. Contingency steady-state analyses (single and multiple) were completed with the overarching objectives to (a) identify possible transmission system upgrades needed to support the load growth and the renewable generation additions and (b) identify critical contingencies to confirm their inclusion in congestion analysis. The latter piece of information provides PROMOD (the congestion analysis tool) with the constraints (contingencies and monitored elements) to use during the formulation of the security-constrained economic dispatch.

5.1 Case Selection

The study assessed load and generation conditions that exert the most stress on the entire State bulk transmission system. The 2040 year was selected for study as it is expected to represent the most stressful condition on the Bulk Power System (BPS) transmission.

The modeled generation was dispatched to represent points of high stress to the transmission system. Each dispatch scenario contains high transfers across the BPS with high-renewable dispatches of either solar or wind. These dispatches should reflect the needs of the system appropriately.

The selected dispatches consist of a summer peak case and a low-load case. The summer peak case represents high usage of solar photovoltaic (PV) generation as this generation type is dispatched at high levels during summer conditions. The low-load case represents high usage of wind generation when this generation type is dispatched at higher levels during times when the sun sets earlier, and load is lower. The actual date and hour load conditions to be modeled were selected considering the hourly transfers between NYISO zones from the AURORA zonal LTCE results. The Table 5-1 provides the date, hour, and load conditions for both dispatches. The summer peak condition represents 93% of the actual 2040 system peak and the low-load dispatch is 57% of the peak.

Table 5-1. 2040 Load for Two Dispatches Assessed for Initial Scenario

Zone	Dispatch High Wind Low Load	Dispatch High Solar Summer Peak
	(April 20 hour 15)	(July 16 hour 19)
A	2,352	3,535
B	1,583	2,378
C	2,476	3,720
D	740	1,112
E	1,205	1,811
F	1,955	2,938
G	1,266	2,436
H	367	706
I	714	1,374
J	6,549	12,607
K	2,866	5,516
NYISO load	**22,073**	**38,133**

5.2 Case Development

5.2.1 2040 Long-Term Capacity Expansion Model and Dispatches

The transmission load-flow cases were developed starting from the NYISO FERC 715 2018 Series ERAG/MMWG package as provided by New York State. This case was modified to reflect the 2040 AURORA Long-Term Capacity Expansion (LTCE) plan. This plan is based on zonal information and it does not include a network bus allocation for the generation resources added. To address this, interconnection points were derived, considering the project information in the NYISO queue first. For those resources with no queue, the new generation on the LTCE was mapped to substations as follows:

- Land-based wind (LBW) and PV. These were assigned to substations near the identified latitude and longitudinal locations of the renewable generation.
- Battery Energy Storage (BES) was modeled at substations that contain similarly sized PV/LBW resources. Battery Energy Storage (BES) was modeled at substations that contain similarly sized PV/LBW resources. Storage is dispatched by the optimization process (AURORA and PROMOD) based off the net load curve (i.e. gross energy demand minus renewable generation), resulting in energy storage charging when net load is the lowest (when renewable generation is high) and discharges when net load is high (when renewable generation is low). The net load curve also provides a good representation for when energy prices are at a daily high for storage discharge and for when energy

prices are daily low for charging. This dispatch strategy was taken into consideration in the creation of the snapshots for load flow assessment.

- Additional thermal generation was modeled as a potential repowering at sites of retired conventional units. For example, Brownfield sites are likely to have the pipelines, etc. already in place and could be good sites for the RNG resources.
- Behind the meter rooftop solar (DG Solar) was placed at load buses of similar size.

To stress the transmission network, the generation was dispatched as shown in the table below, instead of using the reduced dispatch from the AURORA simulations. The generator models for the resources were assumed to have a 0.95 power factor and a scheduled voltage of 1.03 at major buses.

Table 5-2. Load-Flow Assessment

	Summer Peak	**Light Load**
Fuel Type Under Study	**Dispatched as % of**	**Dispatched as % of**
Hydro	100%	100%
Nuclear	100%	100%
Waste Heat	100%	100%
Wind	15.6%	85%
Offshore Wind	15.6%	90%
Solar	90%	10%
Battery	0%	0%

5.2.2 Base Case Transmission Modeled

The base cases were modeled with all New York Public Policy transmission projects in place. This includes the Western NY Empire State line 345 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 the expected upgrades reinforcing the connection between Porter to Edic substations at 345 kV. Additionally, as a Tier 4 proxy project, a new 1,250 MW HVDC transmission line into New York City was modeled (the NYC Tx Project). This line allows for the delivery of dispatchable renewable generation directly into NYC.

5.2.3 Contingency and Monitoring Elements

In assessing the impact of the LTCE within the study area under normal N-0, N-1, and N-1-1 contingency conditions, the study monitored for possible thermal (branch overloads) or voltage violations on the bulk power system, as well as the local 115 kV networks. The tested contingencies included outages of single lines and transformers, generator outages, tower contingencies and stuck breaker contingencies from the New York State study cases and modified as necessary to reflect the generation added to the system.

Transmission Security Auxiliary files associated with the NYISO FERC 715 2018 Series ERAG/MMWG package were used throughout the load-flow analysis. This includes the Monitored Element file (TS2019-Monitored_Elements_Yr2029_v1), the subsystem file (TS2019-SCD-2029_v1), the Exclude file (TS2019-Exclude-Sum_rev1, TS2019-Exclude-Win_rev1 and the Contingency package (TS2019_Yr_2029S) that includes the singles and multiples as studied by New York State. The input files were updated to include 100 kV and above branches as needed.

5.3 Planning Criteria

Thermal limits were assessed using normal ratings for pre-contingency conditions and Long-Term Emergency (LTE) ratings for post-contingency conditions except for some 138kV lines in Zones J and K which were compared on their Short-Term Emergency (STE) ratings. A thermal impact was considered potentially significant if the pre-contingency or post-contingency loading of a branch increased by more than 1% of the facility's Normal or LTE rating, respectively.

Voltage limits were assessed, pre- and post-contingency, per the criteria reflected in the Table 5-3. Voltage impact was considered potentially significant if the pre-contingency or post-contingency voltage changes by more than 0.5% of the nominal voltage.

Table 5-3. Voltage Limits Pre- and Post- Contingency

TO	Pre-Contingency (N-0)		Post-Contingency (N-1) & Extreme	
	Low	High	Low	High
CH	0.95	1.05	0.9	1.05
Con Edison	0.95	1.05	0.95	1.05
LIPA	0.95	1.05	0.90[1]/0.95[2]	1.05[2]/1.1[1]
NG	0.95[3]/0.98[4]	1.05	0.90[3]/0.95[4]	1.05
NYSEG/RG&E	0.90[5]/0.95[6]	1.05	0.90[5]/0.95[6]	1.05
O&R	0.95	1.05		1.05
NYPA	*	*	*	*
* according to OP1 limit				
1–applicable below 69 kV				
2–applicable to 69 kV and above				
3–applicable to 115 kV and below				
4–applicable to 230 kV and above				
5–applicable to regulated (TO control) buses				
6–applicable to non-regulated buses (distribution)				

5.4 Initial Scenario Load-Flow Analysis Results

5.4.1 System Intact and Voltage Violations Observed

Base case reinforcements (upgrades) were required throughout New York State's bulk power system to address reliability violations with the Initial Scenario 2040 capacity expansion plan, before any contingency. The upgrades created a secure case by addressing overloads resulting from the significant change made from the original base case and prepare it for the Single and Multiple contingency analysis.

Most of the violations identified were located at the 115 kV and 138 kV transmission network. There were no voltage violations on the system. After the cases were secured, the steady-state analysis was run to determine if there were any N-0, N-1, and N-1-1 violations.

5.4.2 Single-Contingency Analysis

The single-contingency analysis found criteria violations on the BPS and 115 kV and 138 kV network, with most of the violations on the local 115 kV and 138 kV network. As the congestion analysis is focused on the BPS (230 kV and above), local violations, while noted, did not result in any contingencies to be considered in the PROMOD analysis as events files

The overloads identified on the BPS were in the NYSEG Area 3, NG Area 4 and 5, NYC Area 10. The BPS overloads in Western New York were along the Clay 345 kV and the Meyer 230 kV paths that allow power to flow from West to East within the State. The constraints near the center of the State resulted from high power flows North to South. The constraints noted in the NYC area are due to the large amount of flow coming into the City from the balance of state (BOS) to feed the load.

As before, most of the violations identified by the study were located on the 115kv and 138kV network. The overloads were largely in NYSEG Area 1 and Area 3, NG Area 4, NYC Area 10, and Long Island Area 11. The annexes provide a complete list of results.

5.4.3 Multiple Contingency Analysis

Similar to the single (N-1) contingency analysis, the multiple contingency analysis (N-1-1) identified overload on both the existing New York BPS and local 115 and 138 kV system.

Like the N-1 analysis, the overloads identified on the BPS were located in the NYSEG Area 3, NG Area 4 and 5, NYC Area 10. The BPS overloads in Western New York were along the Clay 345kV and the Meyer 230 kV paths that allow power to flow from west to east within the State. The constraints near the center of the State resulted from high-power flows north to south. The constraints noted in the NYC area are due to the large amount of flow coming into the city from the balance of state (BOS) to feed the load. Again, most of the violations identified by the study were located on the 115 kV and 138 kV network and the overloads were largely located in NYSEG Area 1 and Area 3, NG Area 4, NYC Area 10, and Long Island Area 11.

5.5 Load-Flow Analysis Findings

The transmission analysis identified that most of the reliability violations are located at the local 115 kV and 138 kV networks, confirming the important beneficial impact of the New York Public Policy transmission projects listed above for the bulk system.

Additional important contingency overloads were identified in the following areas:

- Downstream of Coopers Corner into Zone GHI
- Dunwoodie-Shore Rd cable
- NYC and West Long Island area

Also, the analysis identified overloads in the system connecting Edic to Porter, but these are expected to be addressed under the North New York project.

Information on the identified constraints including the contingencies/monitored elements and candidate reinforcements were provided to and considered in the production costing (PROMOD) analysis. The annexes contain the list of contingencies and monitored elements provided to PROMOD for congestion analysis as well as the information on facilities to be reinforced. PROMOD analysis confirmed that these contingent elements did appear as binding constraints driving congestion and renewable curtailment, particularly in 2040, as presented in the next section.

6 Congestion Analysis—Initial Scenario

6.1 Study Overview and Objectives

The objective of the Transmission Congestion and Curtailment Analysis is to assess the performance of the generation mix selected by the AURORA's LTCE process to achieve New York State's zero-emission goal by 2040 as well as the interim 70% renewable generation goal by 2030, under security-constrained unit commitment and economic dispatch (SCUC/SCED).

This analysis was carried out with PROMOD®IV on nodal SCUD/SCED mode which reflects transmission congestion issues, renewable generation curtailment, system production cost, and identifies indicative transmission reinforcement to support the achievement of the 100 x 40 goal in a least costly manner.

AURORA's LTCE analysis (generation retirements and additions of both thermal and renewable resources along with energy storage) was carried out on a zonal basis; thus, it has a limited view on transmission impacts. The analysis presented in this section complements the LTCE analysis by examining two critical years: 2030 with the 70% renewable goal and 2040 with the zero-emission goal.

The transmission congestion and curtailment analysis uses the results of the load-flow analysis presented in section 5 that provided an initial view on the transmission issues and the critical constraints (contingencies/monitored elements) to be included in this part of the study.

6.2 Initial Scenario Case Development

The Initial Scenario analysis was carried out by developing and evaluating the cases below for 2030 and 2040:

- Initial buildout with no transmission upgrades (base case), this is the initial AURORA LTCE result without any new transmission in the system, beyond that in the NY Transmission Public Policy
- Initial buildout with transmission upgrades, (upgrade case), same case as above but now with indicative new transmission projects in place.
- Iteration buildout with no transmission upgrades (iteration base case), this is the LTCE resulting from the iteration LCTE run where AURORA considered the estimated cost of transmission upgrades and the increased transfer limits, but without the new indicative transmission in place.
- Iteration buildout with transmission upgrades, (iteration upgrade case), same case as above but with the new transmission upgrades in place.

6.3 Initial Scenario Results Summary

To facilitate the review of the congestion analysis results, key findings of the Initial Scenario for all cases analyzed are summarized below. The comparison focuses on year 2040 because there was low congestion and curtailment in 2030.

The table shows for each case whether it used the Original LTCE or the Iteration LTCE (produced after transmission cost and increased transfer limits were factored in) and whether transmission upgrades were considered or not.

Based on the results found:

- Congestion and curtailment are both reduced from the Original to the Iteration LTCE and include the effects of new transmission (upgrade), indicating the effectiveness of the study process.
- The New York State system is found to be an exporter in all cases but the amount of energy exported reduces as the LTCE improves and new transmission is added (upgrade).
- RNG consumption also reduces as less congestion exists in the system.
- The overall Adjusted Production Costs (APC) is trending down with sizable APC savings between the Transmission Original and upgrade cases, showing the impact of transmission in addressing congestion.

Table 6-1. Initial Scenario—Results Summary

2040 PROMOD Case	Generation Buildout	Transmission Buildout	Zonal Congestion Cost $B	Statewide RE Curtail %	RNG Generation (GWh)	APC ($M)
Base Case	Original LTCE	Original	4.3	1.5	4,617	1,507
Upgrade Case	Original LTCE	Upgrade	2.4	0.1	2,668	878
Iteration Base Case	Iteration LTCE	Original	2.9	1.3	4,242	1,156
Iteration Upgrade Case	Iteration LTCE	Upgrade	1.9	0.4	2,977	862

More detailed results will be discussed in the following sections for each of the individual cases analyzed.

6.3.1 Model Overview and Forecast Overview 2030 and 2040

The production cost model started with the Hitachi ABB PROMOD®IV Nodal 2021 Eastern Interconnection F19 Powerbase model (Release Fall 2019) which provides updates to the Simulation Ready Data NERC database release through March 2020. The database was updated according to the assumptions and results from the LTCE for 2030 and 2040. This includes various updates of the demand forecast, fuel forecasts, applicable cost of carbon, transmission topology, generation retirements, and new generation.

Demand Forecast, Fuel Forecast, and Emission Costs

The PROMOD demand forecast was modeled using the forecast from the AURORA LTCE model, reflecting the same 8,760-hour hourly demand profile for 2030 or 2040.

The fuel forecast was also updated to reflect the same forecast from the LTCE model for natural gas in the region. Coal prices and oil prices were not modified since there is no coal generation in New York State and oil is not used for any significant levels of generation in the State, so it was left as in the original database. Nuclear fuel prices were also maintained as in the base database. A new natural gas fuel ID was created to represent RNG that will be burned at thermal generation (non-nuclear) in 2040 as part of the goal of zero-emission production.

The costs for carbon allowances/emissions were set according to NYISO CARIS pricing and matching the pricing modeled in the LTCE. The cost of other emissions was left as in the base database.

Regional Interconnection Models

The interconnections from New York State to other regions were modeled accounting for a "hurdle rate" or transmission tariffs as specified by the PROMOD model and adjusted as necessary to match those in the LTCE model. In general, these tariffs reflect the cost of transmission delivery services and do not add any additional hurdle to the interchanges.

Generation Modeling

The detailed resource retirements and additions as provided by the AURORA LTCE runs were incorporated into the PROMOD model. The resources remain unchanged within the simulation yea (i.e., all additions are modeled as available by January 1 of the year). Renewable resources were all modeled with nominal curtailment bid pricing ($ 0.1/MWh), so that all the units are bidding into the market model on the same conditions. The only exception is the NYC Tx project that is considered dispatchable and bids at a slightly higher price than $0.1/MWh.

Hydroelectric resources were modeled in PROMOD®IV to match the AURORA model as closely as possible. Standard hydro modeling in PROMOD®IV does not allow the ability to represent curtailment on those units. Thus, key hydro facilities were modeled as transactions to allow for the reporting of potential curtailment. The hydro facilities at Niagara and St. Lawrence along with the Legacy HQ hydroelectric generation were modeled as transactions. In addition, the new generation to be delivered by the NYC Tx project was modeled as a transaction to reflect the dispatchability of this last resource.

Battery storage is modeled in PROMOD®IV with charging and discharging to minimize the potential curtailment of renewable facilities. As such, the program logic matches the charging/discharging to the net load, which is the difference between the actual load and renewable resources. Battery storage was modeled with 87% efficiency in 2-hour, 4-hour, and 6-hour capacity as provided in the LTCE.

Solar behind-the-meter demand generation (BTM DG) was modeled explicitly as a resource as opposed to modeling the DG with the demand.

Transmission Nodal Modeling

The AURORA LTCE plan is zonal and does not have a network bus allocation. The nodal transmission model in the production cost model was updated considering the resource bus allocation on the load-flow model (see section 5.2.1). The load-flow model also provides identified candidate upgrades.

The transmission model also included New York Public Policy projects including the Western NY Empire State 345 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 (including upgrades on Porter to Edic). Additionally, the new 1,250 MW HVDC Tier 4 proxy transmission line to New York City was modeled. All the analyses include critical contingencies determined by the transmission power flow analysis and contingencies from the NYISO Summer 2019 Operating Study, which are in the form of event files used by PROMOD®IV.

6.3.2 Monitoring Elements, Interfaces, Flowgates

This analysis mainly focuses on the BPS interzonal interfaces/flowgates and the BPS transmission (230 kV and above). Facilities rated 138 kV and below were not monitored as it is assumed that any 138 kV and lower voltage facility violations resulting from the addition of new resources would be addressed by the local transmission owners, New York State planning process, and the generation interconnection processes.

6.4 2030 Base Case Results—Initial Scenario

The Initial Scenario—2030 Base Case results show some congestion, albeit low compared to the 2040 cases. The binding constraints in the analysis have a corresponding congestion cost (shadow price[21] times flow) that indicates the severity of the constraint. The existence of congestion costs increases energy costs

[21] A shadow price is equal to the value the optimization objective would change by relieving the constraint by one unit. In our case it is the change in production cost resulting from the increase of the capacity of the limiting constraint (transmission facility) by one unit. As this results in a reduction of the operating cost the shadow prices and the associated congestion cost are negative and the more negative the greater the impact.

and the resulting overall system production cost. The presence of congestion signals the opportunity to relieve transmission bottlenecks to move power from zones with cheaper energy to zones with higher prices.

New York State is found to be a net exporter of energy for the 2030 Base. The purchases/sales are driven by the economics of the production cost model where the State's system is allowed to purchase from or sell energy to neighboring systems based on economics.

The curtailment observed was low at 0.1%. Land-based wind experienced the most curtailment at 0.3% among all curtailable resources. Whenever "curtailment" is referred to in this analysis, it reflects the results of the planning model used (PROMOD). Actual curtailment in day-ahead and real-time operations can fluctuate higher due to factors such as maintenance activities or forced outages, which are not captured in the long-term planning production cost models.

One key focus in the production cost analysis is the binding constraints congestion in the production costs analysis because it impacts overall system costs. For the 2030 Base, the following top congested elements were observed.

Table 6-2. Initial Scenario—2030 Base Constraints

Constraints	Congestion Cost (k$)	Congested Hours
DUNWOODIE to SHORE RD FLO BASE CASE	(22,491)	1,889
I:NY_NYC-LI FLO BASE CASE	(17,951)	904
FRASR345 to FRASR115 FLO BASE CASE	(16,561)	1,273
I:NY INTERFACE NY-ON FLO BASE CASE	(8,578)	1,581
I:NERC7002 WEST CENTR FLO BASE CASE	(8,388)	385
NORTH WAV115 to EAST SAYRE FLO BASE CASE	(7,564)	1,881
LADENTOWN to RAMAPO FLO BASE CASE	(7,339)	133
I:NERC7005 TOTAL EAST FLO BASE CASE	(6,883)	140
RAMAPO to HOPATCONG FLO BASE CASE	(6,332)	3,162
E13ST to FARRAGUT WES FLO BASE CASE	(5,028)	712
COOPERS CORNERS to MDTN TAP FLO ROCK TAV to DOLSON AVE	(3,947)	213

The total observed zonal congestion costs for New York State were $159 million in 2030. The level of congestion does not warrant upgrades in light of the cost of those upgrades.

By 2030, there are New York Public Policy transmission upgrades that support the 70% renewable goal with low levels of renewable curtailment (0.1%) and congestion.

Local transmission upgrades (138 kV and below) will likely be associated with the addition of new resources and the need to move energy from those resources to the rest of the grid. The addition of 6 GW of offshore wind in downstate New York is being analyzed on a separate study to make sure those facilities do not adversely impact the lower voltage grid and are able to utilize the higher voltage effectively.

The integration of storage is becoming more important to reduce the amount of curtailment associated with renewable resources. Storage may also become important in working toward the zero-emission goal to not only enable lower curtailment levels but also to provide energy during peaks normally supplied by conventional thermal units, especially peaking units.

6.5 2040 Base Case Results—Initial Scenario

The 2040 Base Case was evaluated to test the results from the LTCE with and without additional transmission. The PROMOD models consider inputs from transmission power flow analysis as well as the model parameters and buildout from the LTCE.

New York is found to be a net exporter of energy in the 2040 Base Case. The annual gross net external sale is 6.8 TWh, which is driven by economics of the production cost simulation.

6.5.1 2040 Base Case Congestion and Curtailment

The total curtailment was about 1.5% in 2040, slightly higher than 2030. The most curtailed resource was land-based wind at about 4.5%, particularly in Central New York (about 8.7%).

The 2040 Base Case does show significant congestion. The greatest impact on congestion is noted on the Millwood South interface and the Dunwoodie-Shore Road cable, which accounts for a large portion of the congestion identified.

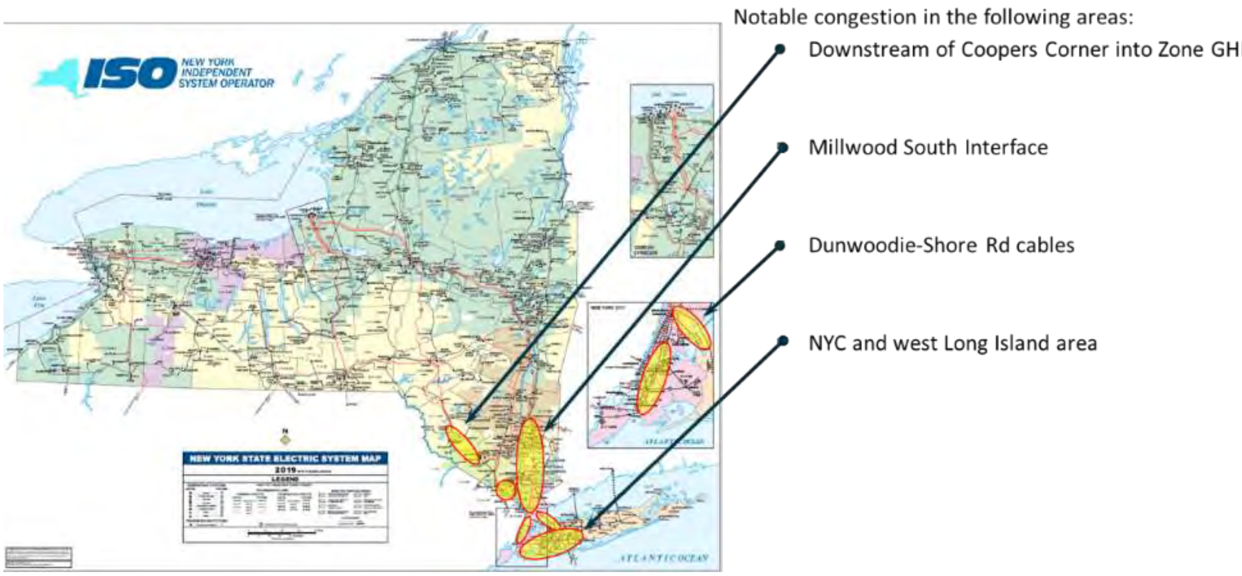
Table 6-3. Initial Scenario—2040 Base Constraints

Constraints	Congestion Cost (k$)	Congested Hours
I:NY_MILLWOOD-SOUTH FLO BASE CASE	(724,064)	582
DUNWOODIE to SHORE RD FLO SPRAINBROOK CABLE	(410,287)	2,798
RAINEY8W to VERNON-W FLO BASE CASE	(352,335)	4,960
N.SCOT99 to N.SCOT1 1 FLO BASE CASE	(219,921)	760
E13ST to FARRAGUT WES FLO BASE CASE	(127,426)	1,990
COOPERS CORNERS to MDTN TAP FLO ROCK TAV to DOLSON AVE	(90,282)	1,145
VERNON-E to GRENWOOD S FLO BASE CASE	(89,869)	823
ANNTRHIGH to ASTOR FLO BASE CASE	(86,480)	5,436
FRASR345 to FRASR115 FLO BASE CASE	(83,428)	4,063
I:NY INTERFACE NY-ON FLO BASE CASE	(78,621)	2,935
ASTE-ERG to HELLGATE FLO BASE CASE	(74,231)	750
DUNWOODIE to SHORE RD FLO BASE CASE	(70,419)	2,150
HUDAVE E to JAMAICA FLO BASE CASE	(69,301)	650
COOPC345 to COOPC115 FLO BASE CASE	(63,429)	2,332
NORTH WAV115 to EAST SAYRE FLO BASE CASE	(41,679)	1,484
I:NY_PJM EAST-NY G FLO BASE CASE	(34,656)	1,780
LADENTWN to RAMAPO FLO BASE CASE	(10,354)	85

The Millwood South Interface recorded $724 million and the Dunwoodie cable (combined) recorded $480 million in congestion costs. As a whole, New York State experienced zonal congestion costs of about $4.3 billion in the 2040 Base Case.

Figure 6-1 shows the general location of the congested areas.

Figure 6-1. Initial Scenario—2040 Base System Congestion



The congestion costs signal the opportunity for system upgrades to relieve the transmission bottlenecks and move power to the large load pockets (especially downstate). It should be noted that any constraint resolutions are, at this time, indicative and further analysis is needed to fully vet any of these potential transmission improvements.

A preliminary list of the upgrades to address the identified binding constraints is provided in the table below. Note that not all identified constraints were proposed to be upgraded as the study only focuses on interzonal interfaces and BPS elements within NYCA. The benefits, costs, and economics of these upgrades are addressed in subsequent sections.

Table 6-4. Initial Scenario—2040 Base Indicative 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

6.6 2040 Upgrade Results—Initial Scenario

The 2040 Upgrade Case evaluates the impact in the PROMOD model with the upgrades indicated for the 2040 Base Case (Table 6-4). As previously stated, the 2030 Base Case did not require transmission upgrades. However, some of the same congestion (at a much-reduced level) exists in the 2030 Base Case and was also observed in the 2040 Base Case.

Net exports were found to be effectively zero with a small level of net energy exports (as in the 2040 Base).

6.6.1 2040 Upgrade Curtailment and Congestion

Curtailment in the 2040 Upgrade Case was reduced because of the transmission upgrades implemented in the model. The total system curtailment was reduced to 0.1% (down from the 2040 Base at 1.5%). LBW is curtailment is reduced to 0.2%. Following the reduction in curtailment, a reduction in congestion can also be noted. Focusing on the elements that were upgraded, it is possible to compare the congestion costs before and after upgrades. Table 6-5 shows the impact of these projects in relieving congestion. The top congested interface, Millwood-South, is reduced 97% with the preliminary upgrades, while the Dunwoodie to Shore Rd interface also showed significant congestion reduction.

Table 6-5. Initial Scenario—2040 Base, 2040 Upgrade and % Reduction

Constraints	Base Congestion Cost (k$)	Upgrade Congestion Cost (k$)	Congested Hours	% Reduction
I:NY_MILLWOOD-SOUTH FLO BASE CASE*	(724,064)	(19,305)	28	97%
DUNWOODIE to SHORE RD FLO SPRAINBROOK CABLE*	(410,287)	(158,144)	3,568	61%
COOPERS CORNERS to MDTN TAP FLO ROCK TAV to DOLSON AVE*	(90,282)	-	-	100%
DUNWOODIE to SHORE RD FLO BASE CASE*	(70,419)	-	-	100%
COOPC345 to COOPC115 FLO BASE CASE*	(63,429)	-	-	100%
LADENTWN to RAMAPO FLO BASE CASE*	(10,354)	-	-	100%

*These constraints are associated with the transmission upgrades applied.

The overall zonal congestion costs for New York State were $2.4 billion, reduced from $4.3 billion in the 2040 Base Case.

6.6.2 Transmission Upgrade Costs

The total estimated capital cost of the indicative upgrades ranges is about $2.6 billion (2040) as detailed in Table 6-6. This estimate corresponds to the value calculated using planning level unit costs plus a 50% contingency considering the uncertainty surrounding future development of the projects.

The total estimated operations and maintenance (O&M) cost of the upgrades, assuming 2.5% of the capital cost, is $64 million. In light of these indicative transmission upgrades, it is important to note the following:

- The transmission upgrades and cost estimates are indicative of the need to move energy across the congested interfaces and BPS transmission facilities in the State. The evaluation of the upgrades needs to be further researched to verify need and define the most effective way to achieve the transmission capacity increase and costs.

- Additional factors such as right-of-way, real estate costs, environmental permitting, and constructability are not a part of this assessment and could affect the feasibility and cost estimates of these indicative upgrades. Additional research is needed for the range of uncertainties.
- Alternative designs to the indicative upgrades (e.g., HVDC) should be pursued to address the transmission limitations not factored at this stage.

Table 6-6. Indicative Upgrades and Costs

Zone	Indicative Transmission Upgrades in 2040 Upgrade Case	$M
H/I/J	Increase Millwood South Interface transfer capability to 13000 MVA, and increase Dunwoodie South Interface transfer capability to 6000 MVA	1,350
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)	750
E/G	Increase Coopers Corner—Middletown—Rock Tavern—Dolson Ave 345 kV line sections LTE rating to ~3000 MVA	400
G	Increase Ladentown—Ramapo 345 kV line LTE rating to ~2500 MVA	55
	Estimated Total Base Costs with Contingency	**2,555**

The transmission upgrades in Table 6-6 do not include any potentially necessary local transmission investments, as the screening levels performed in the PROMOD analysis focused on congestion in the bulk transmission system (230 kV and above) and interzonal interfaces.

6.6.3 Adjusted Production Costs and Benefit to Cost Ratio

An indicative factor in assessing whether a transmission improvement is economically justifiable is to look at the Adjusted Production Costs (APC) savings and the Benefit to Cost ratio (B/C). The equation below shows APC savings between the base and upgrade cases in 2040.

The APC is the Total Production Cost plus the Cost of External Purchases less the Revenues from External Sales. With the upgrades, the APC decreases from $1,507 million to $878 million, resulting in a savings of $629 million. Assuming a Cost Recovery Factor of 8%, and a 2.5% O&M cost adder to annualize the total transmission costs, the indicative B/C Ratio is about 3.0.

Equation 1. Adjusted Production Costs Benefit to Cost Ratio

$$\frac{Benefit(One - Year\ APC\ Saving)}{Cost\ (Annualized\ Cost)} = \frac{\$629}{\$2{,}555 \times\ 8\% \ \times\ 102.5\%} = \ 3.0$$

It should be noted that the one-year APC and B/C analysis is intended for screening purposes and indicates that the preliminary upgrades are cost effective. A more detailed 10-year net present value analysis would require at least three future year PROMOD runs (e.g., 2035, 2040 and 2045) to estimate the full APC savings. This additional analysis was not in scope for this study.

6.7 Iteration Buildout Results—Initial Scenario

As part of the overall analysis, the LTCE was reassessed with AURORA to determine the changes that the new transmission transfer capability and cost would introduce in the generation buildout.

The resultant iteration buildout had a slight reduction of the total renewable capacity by 2040 (2.8%), mainly in solar (865 MW or 4.9%) and offshore wind (469 MW or 4.6%). There was a small increase in land-based wind generation (184 MW or 1.5%). The energy storage increased by 2,538 MW (or 12.8%) and helps reduce curtailment, allows better use of the renewable to supply load at times of reduced renewable energy output, and, in general, provides for better management of congestion.

6.7.1 2040 Iteration Base Results

The 2040 LTCE iteration buildout was added to the PROMOD program without new transmission creating the 2040 Iteration Base Case. Similar as the original LTCE, energy exports are found to be essentially net neutral with a very small level of net energy exports. as driven by the economics of the model. The curtailment in the case was observed at 1.3%. As in the 2040 Base Case, the most curtailment is related to LBW at 3.4%.

Regarding constraints and congestion, based on a review of both the 2040 Initial and the 2040 Iteration buildouts, there is a reduction in congestion (see Table 6-7 versus Table 6-3) but not enough to eliminate the need for all of the identified reinforcements. They are still necessary, and the buildout changes did not alter or avoid any indicative upgrades. No new reinforcements are found to be required. The constraints in the Table 6-7 focus on those elements that are upgraded in the 2040 Initial Buildout Upgrade Case.

Table 6-7. Initial Scenario—2040 Iteration Base Constraints

Constraints	Congestion Cost (k$)	Congestion Hours
I:NY_MILLWOOD-SOUTH FLO BASE CASE*	(447,392)	439
DUNWOODIE to SHORE RD FLO SPRAINBROOK CABLE*	(185,102)	2733
COOPERS CORNERS to MDTN TAP FLO ROCK TAV to DOLSON AVE*	(89,241)	845
DUNWOODIE to SHORE RD FLO BASE CASE*	(35,388)	2280
COOPC345 to COOPC115 FLO BASE CASE*	(28,816)	1215
LADENTWN to RAMAPO FLO BASE CASE*	(13,833)	70

* Indicates constraints are associated with the reinforcements in the system.

The total zonal congestion costs are at $2.9 billion in the iteration base case.

6.7.2 2040 Iteration Upgrade Results

The 2040 Iteration Upgrade Case results follow with the addition of the transmission upgrades to the model. Energy exchanges with neighboring systems indicate that State is essentially net neutral, which is in line with the 2040 Upgrade result.

Curtailment is reduced from 1.3% to 0.4%, as compared to the iteration base case. As with the 2040 Upgrade Case, the curtailment shifted away from LBW being the leading contributor of curtailment.

The table shows the impact of the transmission upgrades in the congestion on this iteration upgrade case. Congestion reductions were observed from the constraints in the iteration upgrade case and iteration base case. Overall congestion is significantly reduced, and the preliminary transmission upgrades effectively address the targeted, congested elements.

Table 6-8. Initial Scenario—2040 Iteration Constraints Base, Upgrade and % Reduction

Constraints	Base Congestion Cost (k$)	Upgrade Congestion Cost (k$)	Congestion Hours	% Reduction
I:NY_MILLWOOD-SOUTH FLO BASE CASE*	(447,392)	(1,437)	139	100%
DUNWOODIE to SHORE RD FLO SPRAINBROOK CABLE*	(185,102)	(105,531)	3,248	43%
COOPC345 to COOPC115 FLO BASE CASE*	(28,816)	-	-	100%
COOPERS CORNERS to MDTN TAP FLO ROCK TAV to DOLSON AVE*	(89,241)	-	-	100%
DUNWOODIE to SHORE RD FLO BASE CASE*	(35,388)	-	-	100%
LADENTWN to RAMAPO FLO BASE CASE*	(13,833)	-	-	100%

* Indicates constraints are associated with the reinforcements in the system.

The total zonal congestion costs, as compared to the iteration base case, are also reduced from $2.9 billion to $1.9 billion, and lower than the $2.4 billion in 2040 Initial Buildout Base Case. It was also observed that the total RNG consumption reduced from 4,617 GWh in the 2040 Base Case to 2,978 GWh in the 2040 Iteration Upgrade Case.

6.7.3 Adjusted Production Costs and Benefit to Cost Ratio

A comparison of the APC for the iteration base cases shows there is a savings from the iteration upgrade cases.

With the upgrades in place, the APC decreases from $1,156 million to $862 million in 2040, resulting in a savings of $294 million. Assuming a Cost Recovery Factor of 8%, and a 2.5% O&M cost adder to annualize the total transmission costs, the indicative B/C Ratio is about 1.4.

Equation 2. Iteration Case Adjusted Production Costs Benefit to Cost Ratio

$$\frac{Benefit(One - Year\ APC\ Saving)}{Cost\ (Annualized\ Cost)} = \frac{\$294}{\$2{,}555 \times\ 8\%\ \times\ 102.5\%} =\ 1.4$$

In this case, as the Iteration Buildout partially addressed the congestion with a better selection and location of the resources, transmission somewhat reduced impact resulting in smaller APC reduction and lower B/C ratios (1.4 vs. 3.0). Further, as will be shown in the High Demand Scenario, increases in load significantly affect the APC savings and the B/C ratios are much higher in that Scenario.

6.8 Summary of Comparisons of the Initial Scenario

Based on the extent of changes in the buildout and the increases in battery storage along with the overall congestion and curtailment reductions, the Iteration case buildout provides a better option for the Initial Scenario, hence it is considered the final LTCE.

As the power grid adds a significant amount of renewable capacity to the market post 2035, the identified transmission reinforcements offer a potential opportunity to relieve congestion in an economic fashion, while supporting the achievement CLCPA's zero-emission generation goal by 2040.

Indicative transmission reinforcements were identified and were found to be effective in addressing congestion and curtailment. The economic benefits of these upgrades appear to exceed their costs. However, further research is needed to address the uncertainties on the generation buildout and its location, load growth uncertainty, and optimize the design and cost of these projects. This research can be completed at a later date as no action is immediately indicated. The research should be targeted to reduce uncertainty and identify the best projects to address the expected congestion.

Transmission reinforcement investments should be evaluated in context of the 2040 Iteration Base Case, which shows significant transmission constraints, similar to those in the 2040 Base Case.

The analysis showed that in the short term, by 2030, the addition of the Western New York (Empire State line), AC Transmission PPTN, Northern NY project, and NYC Tx projects supports achievement of the 70% renewable goal with low levels of bulk system curtailment (0.1%) and congestion. No additional BPS (230 kV and above) investments appear to be necessary.

7 High Demand Scenario

7.1 Assumptions—High Demand Load Forecast

The High Demand Scenario incorporates the same assumptions as the Initial Scenario but increases the projection of net energy load and peak load. The energy demand forecast for the High Demand Scenario was based on the Limited Non-Energy Pathway of the Pathways to Deep Decarbonization in New York State[22] study. The forecast was refined to include 2030 statewide demand and peak levels that are comparable to those in the NYISO CARIS 70 x 30 Base Load case while maintaining the 2040 outcomes of the pathways case. Table 7-1 and Table 7-2 summarize the High Demand Scenario and Initial Scenario net energy for load and peak demand forecast.

Table 7-1. Net Energy for Load—Initial Scenario and High Demand Scenario

	Energy (GWh)	
	Initial Scenario	High Demand Scenario
2020	156,799	156,959
2025	147,602	150,855
2030	151,678	162,188
2035	176,171	195,874
2040	207,506	233,481

Table 7-2. Summer and Winter Peak Load—Initial Scenario and High Demand Scenario

	Winter Peak (GW)		Summer Peak (GW)	
	Initial Scenario	High Demand Scenario	Initial Scenario	High Demand Scenario
2020	22	23	32	31
2025	22	23	30	30
2030	23	27	30	34
2035	28	35	34	38
2040	34	42	38	42

[22] Visit https://climate.ny.gov/Climate-Resources for the study Pathways to Deep Decarbonization in New York State.

Additionally, the High Demand Scenario's hourly demand shaping was modified in 5-year increments, which transitions New York State to a winter peaking system. By 2040, the State will become winter peaking. Figure 7-1 summarizes the monthly peak demand for the High Demand Scenario and the Initial Scenario. The hourly demand shapes are such that peak demand occurs in the early evening (6 p.m.), which reduces the amount of reliable peak capacity solar can provide to the market. The hourly demand shape for 2030 and 2040 peak days are illustrated in Figures 7-2, 7-3, and 7-4.

Figure 7-1. Monthly Peak Demand—Initial Scenario and High Demand Scenario

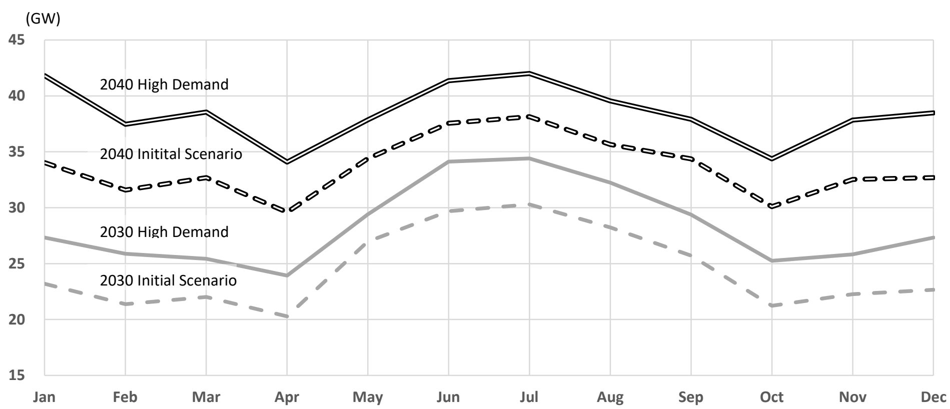


Figure 7-2. 2030 Hourly Peak Day Demand—Winter and Summer—High Demand Scenario

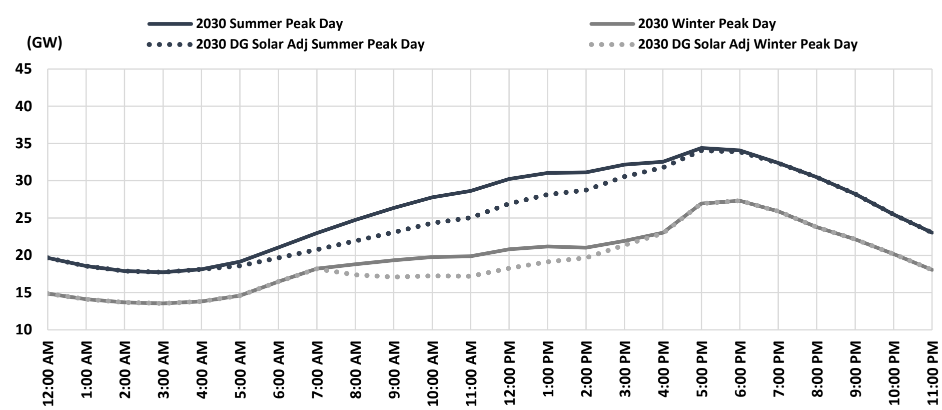


Figure 7-3. 2040 Hourly Winter Peak Day Demand—High Demand Scenario

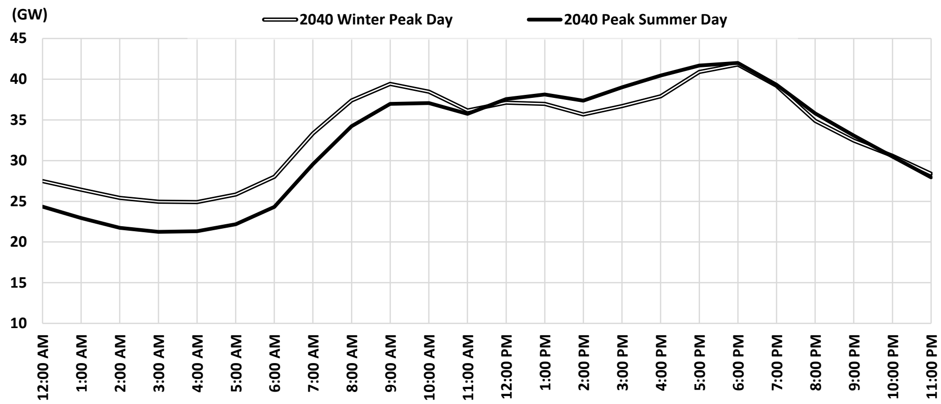
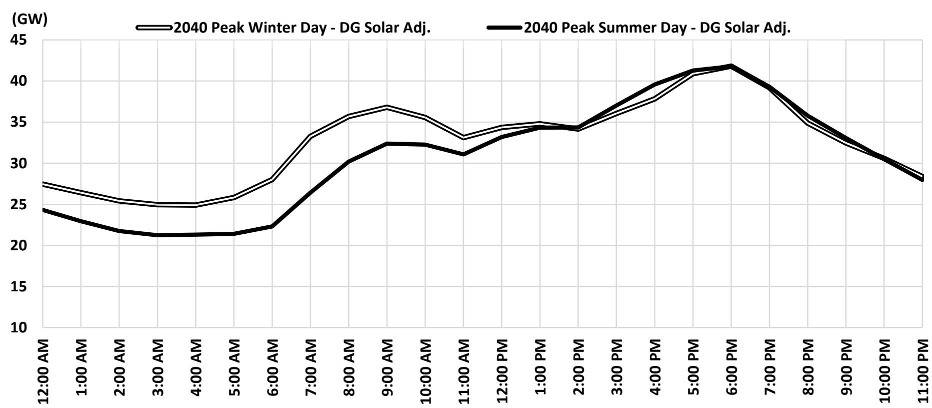


Figure 7-4. 2040 Hourly Summer Peak Day Demand—High Demand Scenario



7.2 Long-Term Capacity Expansion—High Demand Scenario

7.2.1 Long-Term Capacity Buildout

The goal of the long-term capacity expansion (LTCE) analysis is to determine the most economical mix of resources to be added or removed in the market to meet operational, reliability, and regulatory requirements. Key factors resulting in a different build mix in the High Demand Scenario are the 12% greater net energy for load and the 13% greater peak demand by 2040. Also, the scenario includes a more pronounced winter peak, and peak hours occurring later in the day. The results described in this section are results of the final LTCE, after considering the transmission upgrades and costs from section 7.4 of this report. The Original LTCE that was used to determine the transmission upgrades is included in Annex A.

To achieve CLCPA's interim 70% renewable generation goal by 2030 and zero-emission generation by 2040 under the High Demand Scenario, a significant amount of additional renewable capacity is added to the market compared to the Initial Scenario. Also, to maintain locational reserve margins under the High

Demand Scenario, the market will require additional reliable capacity. Because the effective load carrying capability of renewables declines throughout the study with higher penetration (especially solar), New York State's supply mix will include more gas-fired capacity compared to the Initial Scenario. This is because thermal capacity's peak, effective load, carrying capability is close to 100%. A summary of the State's capacity supply mix from the High Demand Scenario is summarized in Table 7-3.

Table 7-3. 2020-2040 New York Installed Capacity Supply Mix—High Demand Scenario

In megawatts.

	2025	2030	2035	2040
Thermal	25,730	28,231	28,758	22,954
Nuclear	3,381	3,381	3,381	3,381
Hydro	4,663	4,663	4,663	4,663
Wind	4,027	7,357	9,194	12,690
Offshore Wind	1,826	6,000	9,000	13,597
Solar	3,099	5,707	11,577	22,577
Energy Storage	1,542	3,000	4,213	14,891
Other Renew	450	472	472	472
NY Tx	1,250	1,250	1,250	1,250
BTM Solar (MW-AC)	4,839	5,323	5,856	6,443

7.2.2 Energy Outlook

Under the High Demand Scenario, roughly 113 TWh of renewable generation is required in 2030 to achieve New York State's interim target of 70% renewable generation. By 2040, the State needs 233 TWh of zero-emission generation to meet CLCPA's overall target. The modeling results include 88% of renewable generation in achieving the overall 2040 outcome. A summary of the generation outlook based on the capacity expansion for the High Demand Scenario is provided in Tables 7-4 and 7-5.

Table 7-4. 2025-2040 Annual Generation by Technology—High Demand Scenario

In gigawatt hours.

	2025	2030	2035	2040
Thermal	41,342	22,906	19,232	2,150
Nuclear	28,875	27,042	28,875	27,127
Hydro	28,643	28,547	28,622	28,390
Onshore Wind	10,780	22,770	29,231	42,118
Offshore Wind	5,863	24,078	38,308	64,467
Solar	4,094	9,547	21,658	40,758
Other Renew	2,761	2,739	2,630	2,239
NYC Tx	10,000	9,973	9,383	8,479
Legacy Hydro Imports	10,008	10,010	10,010	10,066
DG Solar (AC)	7,266	7,994	8,795	9,697
Non-Hydro Net Imports	1,421	(2,877)	(24)	592

Table 7-5. 2030 and 2040 Renewable Generation Breakdown by Technology/Source

In gigawatt hours.

	2030	2040
Energy Demand	162,116	233,475
Total RE Generation	114,563	205,318
RE Gen % of Demand	71%	88%
NYC Tx	9,973	8,479
Legacy Can. Hydro	10,010	10,066
DG Solar	7,994	9,697
Grid Solar	9,547	40,758
Land-based Wind	22,770	42,118
Offshore Wind	24,078	64,467
NY Hydro	28,547	28,390
Other Renewables[23]	1,643	1,343

7.2.3 Energy Prices

Power prices in the High Demand Scenario remain relatively flat over time as zero variable cost renewable energy is added to New York State's capacity supply, which offsets the high-electricity demand growth.

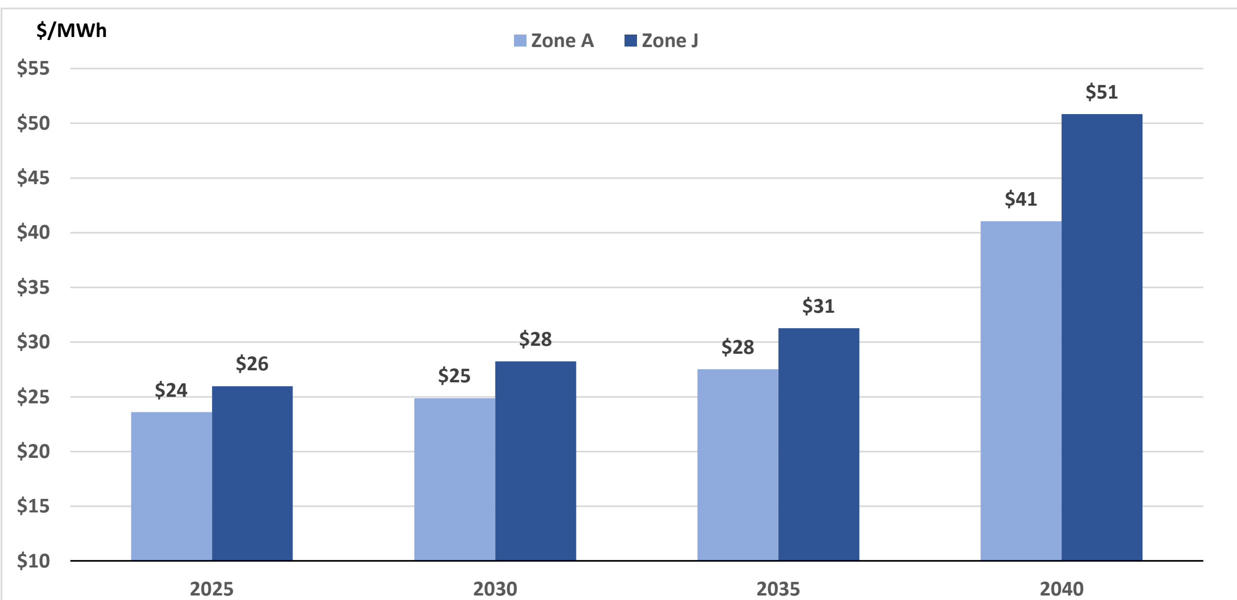
[23] Due to uncertainty in eligibility for certain resources, the contribution of "Other Renewables" was discounted by 40%.

Electricity demand escalates throughout the forecast, but the amount of renewable energy needs to go up in a proportionate manner to ensure that the 70% renewables requirement is achieved in 2030.

The slight increase in power prices that occurs prior to 2040 is the result of increased natural gas prices and RGGI carbon prices. In 2040, the New York State still needs fast ramping thermal generation to provide energy during peak demand hours. Additionally, the State's thermal generation fleet was modeled with only the option to consume renewable natural gas (RNG) starting in 2040, which was assumed to cost $23/MMBtu. The dispatch cost for a gas turbine with a 9,000 btu/kwh heat rate that consumes RNG would be $220/MWh in 2040. However, it is important to note that there are significant uncertainties on what the price of renewable natural gas will be in the long term (2040) and the cost of other competing technologies to provide dispatchable generation with zero emissions

A representation of upstate and downstate power prices in the State is summarized in Table 7-6.

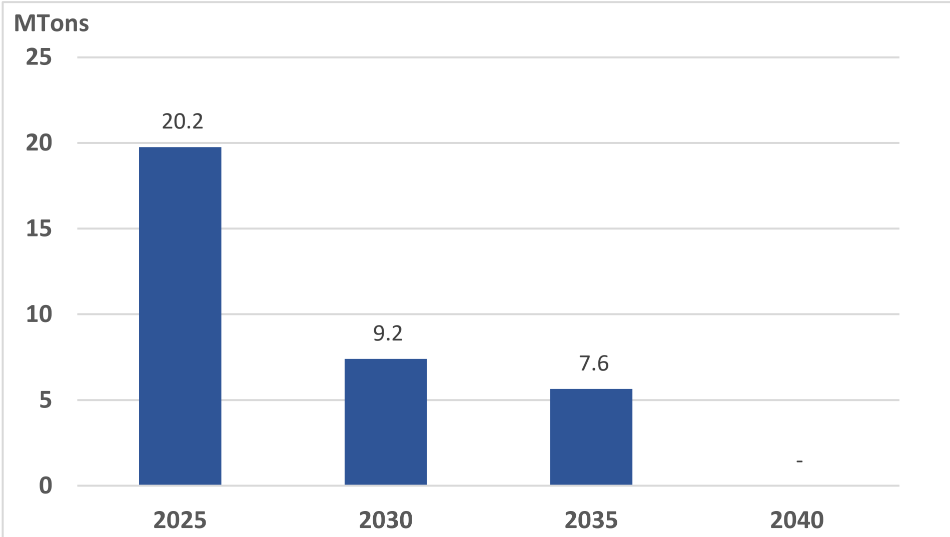
Figure 7-5. Zone A and Zone J Average Wholesale Energy Price Forecast ($2018/MWH)



7.2.4 Emissions

Similar to the Initial Scenario, as New York State strives to meet its 70% renewable energy goal by 2030 and to realize a zero-emission power system by 2040, the system will reduce its emissions over time. In the High Demand Scenario, high energy demand leads to more gas-fired generation over the study's time horizon. More generation from thermal units leads to a slight increase in emissions throughout the forecast compared to the Initial Scenario, except for 2040, when carbon emissions drop to zero.

Figure 7-6. Annual NYISO Carbon Emissions (Million Short Tons) Forecast



7.2.5 System Reliability

For the High Demand Scenario, the study conducted a loss of load expectation (LOLE) analysis within AURORA and a flexible capacity analysis using the same methodologies as the Initial Scenario reliability analyses.

Unlike the Initial Scenario, the LOLE analysis in the High Demand Scenario did uncover instances of loss of load. After simulating 100 iterations in 2040, there were 193 hours with unserved load, resulting in an LOLE of 0.8 days/10 years. However, the system's reliability metrics met the current NYISO criteria of 1 day/10 years (1-in-10) without adding any additional capacity.

The flexible capacity analysis in the High Demand Scenario was similar to the Initial Scenario, but higher demand and more intermittent resources required a higher amount of fast ramping capacity (energy storage or gas turbines). However, similar to the Initial Scenario, the capacity buildout for the High Demand Scenario met flexible capacity requirements without adding additional capacity.

Table 7-6. Estimated Sub-Hourly Flexible Reserves—Required versus Available

In megawatts.

		NYCA (Zone A-K)	East (Zone F-K)	SENY (Zone G-K)	NYC (Zone J)	Long Island (Zone K)
2030	Flex Cap. Required	3,356	2,316	1,824	939	584
	Flex Cap. Available	9,182	8,604	8,543	3,690	3,809
2040	Flex Cap. Required	6,779	4,227	3,311	1,658	1,270
	Flex Cap. Available	24,468	18,242	17,681	8,809	5,452

In 2040, 23 GW of thermal capacity economically persists in the market even though thermal generators have low-capacity factors. The essential driver for their persistence is that the study assumes current capacity market structures remain in place through 2040. Capacity market guidelines and rules may change to meet the needs of a different system 20 years from now, so it is hard to anticipate whether this level of thermal capacity will remain in 2040.

7.3 Transmission Reliability Analysis—High Demand Scenario

As in the case of the Initial Scenario, the transmission load-flow analysis aims to evaluate transmission needs for New York State's zero-emission by 2040 goal. The analysis has the overarching objectives to (a) identify possible transmission system upgrades needed to support the load growth and the renewable generation additions and (b) identify critical contingencies to confirm their inclusion in congestion analysis. In general, this analysis identified similar constraints as in the Initial Scenario but with deeper levels of overloads.

7.3.1 Case Selection and Modeling

As in the Initial Scenario analysis, Siemens selected dispatches to represent points of high stress to the transmission system including a 2040 summer peak case with high levels of solar photovoltaic generation and a 2040 low-load, high-wind generation dispatch. The table below shows the loads at the times selected for both dispatches. The summer peak condition represents 96% of the actual 2040 system peak and the low-load dispatch is 64% of the peak.

Table 7-7. 2040 Load for Two Dispatches Assessed for High Demand Scenario

Zone	Dispatch High Wind Low Load (MW) (March 11 15 hour)	Dispatch High Solar Summer Peak (MW) (July 17 16 hour)
A	2,876	3,863
B	1,935	2,599
C	3,027	4,065
D	905	1,216
E	1,473	1,979
F	2,391	3,211
G	1,540	2,529
H	446	733
I	869	1,427
J	7,970	13,090
K	3,487	5,727
NYISO Load	**26,919**	**40,439**

The initial load-flow cases and the modeling and dispatch of new generation was performed using the same cases and guidelines as in the Initial Scenario (see sections 5.2.1) and these cases were modified to include the same 345 kV NY State Public Policy Transmission projects (section 5.2.2). Contingency analysis was carried out using the contingencies in section 5.2.3 and applying the planning criteria in section 5.3.

7.3.2 Load-Flow Analysis Results

System Intact and Voltage Violations Observed

There were base case reinforcements (upgrades) indicated throughout the New York State bulk power system to address reliability violations with the High Demand 2040 capacity expansion plan, before any contingency. The upgrades were similar to those in the Initial Scenario.

Most of the violations identified were located at the 115 kV and 138 kV (in particular NYSEG Area 3) which experienced important base-case overloads. There were no voltage violations on the system.

Single and Multiple Contingency Analysis

The single contingency analysis identified criteria violations on the BPS and 115 kV and 138 kV network, with most of the violations on the 115 kV and 138 kV network—as was also observed in the Initial Scenario.

The overloads identified on the BPS were located in the NYSEG Areas 2 and 3, NG Area 4 and 5, CHGE Area 6 and NYC Area 10. The BPS overloads in Western New York were along the Pannell, Clay 345kV, and the Meyer 230 kV paths that allow power to flow from west to east within the State. The constraints near the center of the State were, as before, the consequence of higher power flows from north to south. These were along the Porter, Valley, and the Leeds, New Scotland's areas. The constraints noted in the NYC/Long Island area are due to the large amount of flow coming into the City from the balance of State (BOS) to feed the load.

7.3.3 Load-Flow Analysis Findings

The High Demand results largely parallel those of the Initial Scenario, although the level of overloads observed were higher. The heaviest impacts were found at the local 115 kV and 138 kV system but, as before, BPS impacts by 2040 were located in the following areas:

- Downstream of Coopers Corner into Zone GHI
- Dunwoodie-Shore Rd cable
- NYC and West Long Island area

Information on the identified constraints including the contingencies/monitored elements and candidate reinforcements were provided to and considered in the production costing (PROMOD) analysis.

7.4 Transmission Congestion Analysis—High Demand Scenario

7.4.1 Study Overview and Objectives

As in the Initial Scenario, the High Demand Scenario's LTCE performance was assessed under security-constrained unit commitment and economic dispatch (SCUC/SCED) using PROMOD®IV.

The results of the High Demand Scenario are similar to those in the Initial Scenario, but with much higher levels of congestion and resulting in the need for larger scope upgrades.

As before, the analysis presented in this section complements the LTCE analysis by examining two critical years: 2030 with the 70% renewable goal and 2040 with the zero-emission goal.

7.4.2 High Demand Scenario Development

The High Demand Scenario was carried out by developing and evaluating the same cases as in the Initial Scenario for 2030 and 2040:

- Initial buildout with no new transmission (base case)
- Initial buildout with new transmission (upgrade case)
- Iteration buildout with no new transmission (iteration base case)

- Iteration buildout with new transmission (iteration upgrade case)

The High Demand PROMOD model used the same assumptions and procedures as in the Initial Scenario (see sections 6.3.1 and 6.3.2), with the exception of the higher demand forecast and the corresponding LTCE.

7.4.3 High Demand Scenario Results Summary

As in the Initial Scenario, the study compares key metric results on a system-wide basis from the production cost analysis on the High Demand Scenario. The comparison focuses on year 2040 as there was low congestion and curtailment observed from the 2030 analysis.

As can be seen in the Table 7-8, starting from the original LTCE buildout to the Iteration LTCE buildout, as well as from the cases without transmission upgrade, cases compared to the cases with transmission upgrade cases, note the following:

- Congestion and curtailment are both reduced from the Original to the Iteration LTCE and include the effects of new transmission (upgrade). The congestion and the benefits of transmission are much larger than in the Initial Scenario (refer to Table 6-1).
- The NYCA system energy exchange is found to be almost net neutral in all cases with very small of energy being exported except for the iteration upgrade case where the system is almost in equilibrium. Note that the amount of energy being exported reduces for each subsequent case and finally reaches near equilibrium on the last case.
- The RNG consumptions are found to be generally higher than the Initial Scenario cases. However, with most of the congestion resolved, RNG is also reduced to below 3,000 GWh level.
- The overall APC trends down as transmission is added and/or the iteration LTCE is considered, similar to the Initial Scenario, and there is more APC savings potential in the High Demand Scenario than the Initial Scenario. This is due to higher levels of congestion addressed by new transmission in the upgrade cases.

Table 7-8. High Demand Scenario—2040 Results Summary

2040 PROMOD Case	Generation Buildout	Transmission Buildout	Zonal Congestion Cost ($B)	Statewide RE Curtail (%)	RNG Generation (GWh)	APC ($M)
Base Case	Original LTCE	Original	23.0	3.4	13,943	5,343
Upgrade Case	Original LTCE	Upgrade	1.1	0.6	4,960	1,477
Iteration Base Case	Iteration LTCE	Original	13.8	2.5	8,788	3,495
Iteration Upgrade Case	Iteration LTCE	Upgrade	1.5	0.8	2,645	967

More detailed results will be discussed in the sections below for each of the individual cases analyzed.

7.5 2030 Base Results—High Demand Scenario

The 2030 Base Case for the High Demand Scenario mirrored the results observed for the Initial Scenario. The 2030 High Demand Base Case showed low congestion and, as before, the congestion in 2030 is not enough to warrant upgrades beyond those already established in New York Public Policy.

7.5.1 2030 Base Congestion and Curtailment

Curtailment on renewable resources is low (0.1%) and the maximum values were observed for land-based wind (LBW) at 0.1%. It should be emphasized that this low curtailment assumes that the public policy transmission projects and any necessary local transmission upgrades are in place. Further, curtailment in day-ahead and real-time operations is likely to be higher due to aspects not captured by the model, such as operations with facilities out of service due to maintenance or forced outages.

The table below shows the 2030 Base Case congestion where the top congested element is an interface with New England.

Table 7-9. High Demand Scenario—2030 Base Constraints

Constraints	Congestion Cost (k$)	Congested Hours
I:NY_NYC-LI FLO BASE CASE	(35,806)	2119
EAST GARDEN CITY to PAR FLO BASE CASE	(35,104)	2093
DUNWOODIE to SHORE RD FLO BASE CASE	(22,023)	1522
I:NY INTERFACE NY-ON FLO BASE CASE	(15,140)	1926
LADENTOWN to RAMAPO FLO BASE CASE	(13,475)	330
NORTH WAV115 to EAST SAYRE FLO BASE CASE	(12,233)	2229
DUNWOODIE to SHORE RD Dunwoodie-Shore Road 2	(11,682)	1377
COOPERS CORNERS to MDTN TAP FLO ROCK TAV to DOLSON AVE	(10,202)	540
I:NERC7005 TOTAL EAST FLO BASE CASE	(6,275)	115
RAMAPO to HOPATCONG FLO BASE CASE	(4,812)	2893
I:NY_PJM EAST-NY G FLO BASE CASE	(4,249)	472

Total zonal congestion costs for New York State were relatively low at $142 million.

7.6 2040 Base Results—High Demand Scenario

The 2040 Base Case was evaluated to test the results from the LTCE with and without additional transmission upgrades. The PROMOD models consider inputs from transmission power flow analysis as well as the model parameters and buildout from the LTCE.

Energy prices for New York State show an increase in prices from the 2030 run. This change indicates significant congestion as a result of the increase in load and renewable resources.

7.6.1 2040 Base Congestion and Curtailment

Curtailment of renewable resources in the 2040 Base Case is higher than observed in the 2030 Base Case. The system curtailment was 3.4% of all renewable energy. The most significant curtailment statewide is observed for LBW at 8.7% and particularly in Central New York (20.9%).

The 2040 Base Case shows significant congestion. The greatest impact on congestion is noted for the Dunwoodie-Shore Road interface and the Millwood South interface. This was also observed in the Initial Scenario but at much higher levels (see Table 7-10 versus Table 6-3).

Table 7-10. High Demand Scenario—2040 Base Constraints

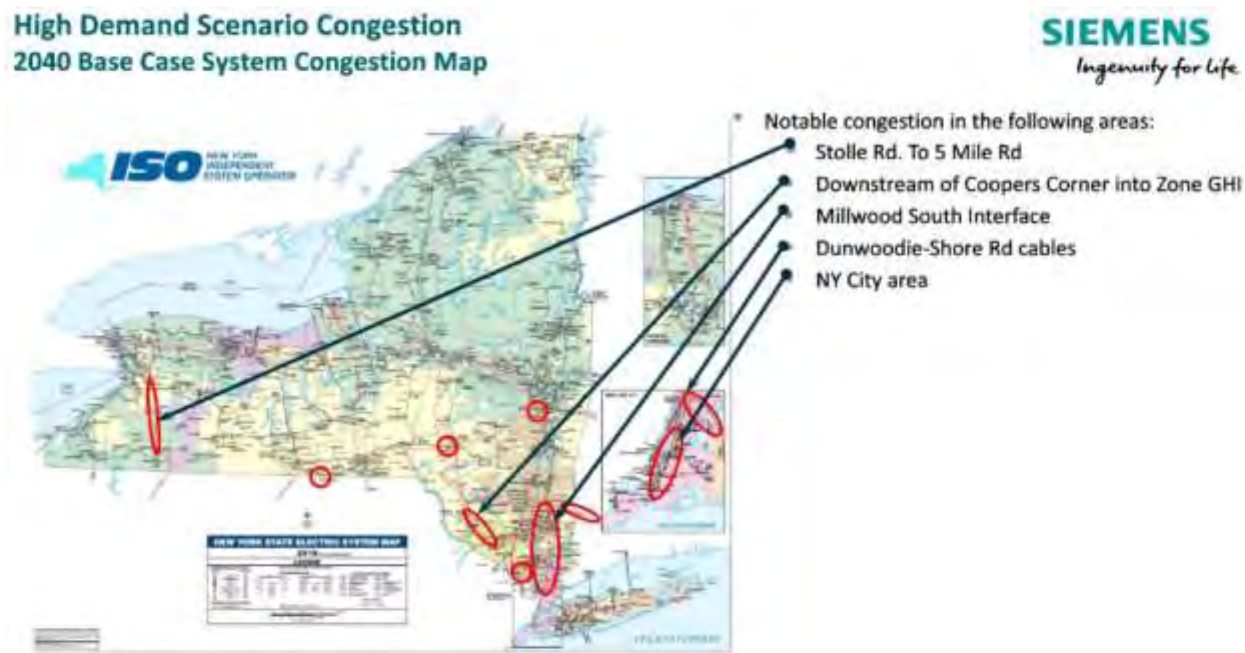
Constraints	Congestion Cost (K$)	Congestion Hours
DUNWOODIE to SHORE RD FLO SPRIANBROOK CABLE*	(13,595,595)	3354
DUNWOODIE to SHORE RD FLO BASE CASE*	(4,760,818)	3404
I:NY_MILLWOOD-SOUTH FLO BASE CASE*	(3,867,551)	2162
EAST GARDEN CITY to PAR FLO BASE CASE	(1,583,484)	3688
FRASER 345/138KV TRANSFORMER FLO BASE CASE*	(1,457,019)	2243
I:NY_NYC-LI FLO BASE CASE	(370,796)	4122
I:NERC7002 WEST CENTR FLO BASE CASE	(244,271)	1839
I:NY INTERFACE NY-ON FLO BASE CASE	(206,338)	4207
COOPER CORNER to MIDDLETOWN TAP 345KV FLO Coopers Corners-Middleton TAP (CCRT34) 345KV*	(204,350)	1308
N.WAV115 to E.SAYRE 1 FLO BASE CASE	(150,275)	3233
New Scotland 345/115 kV Transformer FLO BASE CASE	(149,921)	259
E13ST 46 to FARRAGUT WES1 FLO BASE CASE	(129,098)	2571
I:NY_PJM EAST-NY G FLO BASE CASE	(113,957)	2706
SPRAINBROOK to ACADEMY 1 FLO BASE CASE	(113,868)	2664
ESTSTO to 5MILE 345kV 1 FLO BASE CASE	(102,044)	2703
SPRAINBROOK to DUN NO S6 6 FLO BASE CASE	(83,566)	3571
Cooper Corner 345/115 kV Transformer FLO BASE CASE*	(65,836)	2057
LOVETT345 ST to E13ST 46 1 FLO BASE CASE	(60,180)	159
B: SPRAINBROOK to TREMONT 1 FLO BASE CASE	(45,811)	3094
I:NERC7005 TOTAL EAST FLO BASE CASE	(40,489)	150
RAMAPO 5 to HOPATCONG 1 FLO BASE CASE	(38,187)	2544
LADENTWN to RAMAPO 1 FLO BASE CASE*	(34,648)	258

*These binding constraints are directly related to the proposed transmission reinforcements.

The top three constraints are responsible for more than $22 billion in congestion costs. The total zonal congestion costs for New York State are at $23 billion, much higher than in the Initial Scenario ($4.3 billion).

The Figure 7-7 shows the general locations of the congestion noted in Table 7-10.

Figure 7-7. High Demand Scenario—2040 Base Congestion



As with the Initial Scenario, evaluation of the constraints has generated a list of indicative transmission upgrades to address the congestion issues noted in the 2040 Base Case. The list is very similar to the transmission upgrades from the Initial Scenario except that the illustrative upgrades require much higher transmission capacities. Note that, as in the Initial Scenario, not all identified constraints were proposed to be upgraded as the study only focuses on interzonal interfaces and BPS elements within NYCA. The benefits, costs, and economics of these illustrative upgrades are addressed in the sections below.

Table 7-11. High Demand Scenario—2040 Base Indicative Transmission Upgrades

Zone	Indicative Transmission Upgrades
H/I/J	Increase Millwood South Interface transfer capability to 17000 MVA, and increase Dunwoodie South Interface transfer capability to 6000 MVA
I/K	Increase Dunwoodie—Shore Rd path LTE rating to ~4000 MVA. (assumed three new 345 kV cables in parallel and three new 345/138kV transformers at Shore Rd)
E/G	Increase Coopers Corner—Middletown—Rock Tavern—Dolson Ave 345 kV sections path LTE rating to ~3000 MVA and fix Coopers Corner 345/115 kV transformer thermal overload
G	Increase Ladentown—Ramapo 345 kV path LTE rating to ~2500 MVA

7.7 2040 Upgrade Results—High Demand Scenario

The upgrade case for 2040 evaluates the impact of the illustrative upgrades previously indicated for the 2040 Base Case. As previously stated, the 2030 Base did not require upgrades. However, some of the same congestion (at a much-reduced level) exists in 2030 and was also observed in the 2040 Base Case.

In the 2040 Upgrade, New York State is found to be effectively in balance with respect to net imports and exports of energy.

7.7.1 2040 Upgrade Congestion and Curtailment

The 2040 Upgrade transmission improvements significantly reduce the curtailment of the renewable facilities. The overall curtailment is reduced from 3.4% to 0.8%, and the LBW curtails about 0.8%.

Congestion is still present but greatly reduced with the transmission reinforcements in place. The leading constraint is the Millwood South interface, although the congestion is down from $13.6 billion in the base case to $1.1 billion in the upgrade case as seen in Table 7-12. In general, the top congested constraints are relieved between 73% to 100%.

Table 7-12. High Demand Scenario—2040 Base, Upgrade Congestion, and % Reduction

Constraints	Base Congestion Cost (k$)	Upgrade Congestion Cost (k$)	Congestion Hours	% Reduction
I:NY_MILLWOOD-SOUTH FLO BASE CASE*	(3,867,551)	(1,057,589)	697	73%
DUNWOODIE to SHORE RD FLO SPRIANBROOK CABLE*	(13,595,595)	-	-	100%
DUNWOODIE to SHORE RD FLO BASE CASE*	(4,760,818)	-	-	100%
COOPER CORNER to MIDDLETOWN TAP 345KV FLO Coopers Corners-Middleton TAP (CCRT34) 345KV*	(204,350)	-	-	100%
Cooper Corner 345/115 kV Transformer FLO BASE CASE*	(65,836)	-	-	100%

*These lines are a part of the transmission reinforcements

The total congestion for New York State was $1.4 billion which is greatly down from $23.1 billion in the base case.

The Table 7-13 shows the cost of the preliminary transmission upgrades which, due to the needed higher capacity, are higher than they were in the Initial buildout.

Table 7-13. High Demand Scenario—Indicative Upgrades by Zone with Costs

Zone	Indicative Transmission Upgrades in 2040 Upgrade Case	$M
H/I/J	Increase Millwood South Interface transfer capability to 17000 MVA, and increase Dunwoodie South Interface transfer capability to 6000 MVA	2,737.5
I/K	Increase Dunwoodie—Shore Rd path LTE rating to ~4000 MVA. (assumed three new 345 kV cables in parallel and three new 345/138kV transformers at Shore Rd)	1,125
E/G	Increase Coopers Corner—Middletown—Rock Tavern—Dolson Ave 345 kV sections path LTE rating to ~3000 MVA and fix Coopers Corner 345/115 kV transformer thermal overload	475
G	Increase Ladentown—Ramapo 345 kV path LTE rating to ~2500 MVA	62.5
	Estimated Total Base Costs with Contingency	**4,400**

The upgrades do not include the potential need for local transmission investments.

The total estimated capital cost of the indicative upgrades is $4.4 billion (in 2040 dollars). As before, this cost estimate includes 50% contingency to account for the high uncertainty on future development of the projects. The total estimated operations and maintenance (O&M) cost of the upgrades, assuming 2.5% of the capital cost, is $110 million.

These indicative upgrades are subject to the same caveats indicated in section 6.6.2 and the summary is as follows:

- The transmission upgrades and cost estimates are indicative of the need to move energy across the congested interfaces and BPS transmission facilities in the State and need to further researched to verify need and define the most effective way to achieve the transmission capacity increase and costs.
- Additional factors such as right-of-way, real estate costs, environmental permitting, and constructability are not a part of this assessment and could affect the feasibility and cost estimates. Additional research is needed.
- Alternative designs to the indicative upgrades should be pursued to address the transmission limitations not factored at this stage.

7.7.2 Adjusted Production Costs and Benefit to Cost Ratio

As for the Initial Scenario, benefit to cost (B/C) shows the economic viability of the indicative upgrade projects. With the upgrades, APC decreases from $5,343 million to $1,477 million in 2040, resulting in a savings of \$3,866 million. Assuming a Cost Recovery Factor of 8%, and a 2.5% O&M cost adder to annualize the total transmission costs, the indicative B/C Ratio is 10.7, much higher than the corresponding values of 3.0 in the Initial Scenario Base Case.

Equation 3. High Demand Scenario Adjusted Production Costs Benefit Cost Ratio

$$\frac{Benefit(One - Year\ APC\ Saving)}{Cost\ (Annualized\ Cost)} = \frac{\$3{,}866}{\$4{,}400 \times\ 8\%\ \times\ 102.5\%} =\ 10.7$$

As with the Initial Scenario, the one-year APC and B/C analysis is intended for screening purposes and indicates that the upgrades are economically justifiable.

7.8 2040 Iteration Buildout Results—High Demand Scenario

The LTCE was updated with new transfer capability and transmission cost information to determine if the LTCE program would significantly change the buildout because of the transmission updates based on the Initial Buildout (the Iteration LTCE). The analysis results are provided to confirm that all the transmission upgrades recommended and modeled are still applicable.

The resulting iteration buildout had a slight reduction of the total renewable capacity by 2040 (2.7%), mainly in solar (1,886 MW or 7.7%). There was an increase in land-based wind generation by 591 MW (4.9%), while offshore wind remained largely unchanged (51 MW or 0.4%). Energy storage decreased for 1,721 MW (10.4%). The overall total curtailment went down by about 1% as a result of the capacity changes.

7.8.1 2040 Iteration Base Results

As with the Initial Scenario, the 2040 LTCE Iteration Buildout was modeled in the PROMOD program without new transmission creating the iteration base case.

For the 2040 Iteration Base, the State is found to be effectively in balance with respect of imports / exports of energy.

7.8.2 2040 Iteration Base Congestion and Curtailment

Curtailment compared to the 2040 Iteration Base shows a drop from 3.4% to 2.5%. Similar to the initial buildout analyses, land-based wind leads curtailment at 5%.

The major congested elements are provided in the Table 7-14. It should be noted that the congested elements are the same as in the 2040 Base Case, albeit with lower congestion costs (see Table 7-10).

Table 7-14. High Demand Scenario—2040 Iteration Base Constraints and Costs

Constraints	Congestion Cost (k$)	Congested Hours
DUNWOODIE to SHORE RD FLO SPRIANBROOK CABLE*	(7,662,762)	3189
I:NY_MILLWOOD-SOUTH FLO BASE CASE*	(3,528,996)	1920
DUNWOODIE to SHORE RD FLO BASE CASE*	(3,070,917)	2558
Fraser 345/115 kV Transformer FLO BASE CASE	(347,542)	1711
I:NY_NYC-LI FLO BASE CASE	(293,172)	4155
Cooper Corner to Middletown Tap 345 kV FLO Rock Tavern to Dolson Ave 345KV*	(275,761)	1580
New Scotland 345/115 kV Transformer FLO BASE CASE	(196,983)	533
E13ST 46 to FARRAGUT WES1 FLO BASE CASE	(187,579)	2905
I:NY INTERFACE NY-ON FLO BASE CASE	(183,151)	4332
GOTHLS to GOTHLS R 1 FLO BASE CASE	(113,146)	4059
LOVETT345 ST to E13ST 46 1 FLO BASE CASE	(98,132)	197
N.WAV115 to E.SAYRE 1 FLO BASE CASE	(97,362)	2795
LADENTWN to RAMAPO 1 FLO BASE CASE*	(92,067)	421
I:NY_PJM EAST-NY G FLO BASE CASE	(83,482)	2685
SPRAINBROOK to DUN NO S6 6 FLO BASE CASE	(77,086)	3697
I:NERC7002 WEST CENTR FLO BASE CASE	(76,183)	1291
SPRAINBROOK to ACADEMY 1 FLO BASE CASE	(72,369)	2447
ESTSTO to 5MILE 345kV 1 FLO BASE CASE	(61,176)	2652
RAMAPO 5 to HOPATCONG 1 FLO BASE CASE	(44,563)	2584
SPRAINBROOK to TREMONT 1 FLO BASE CASE	(43,356)	3234
PACKARD2 to NIAGAR2W 2 FLO NIAGARA PA	(39,006)	432
I:NERC7005 TOTAL EAST FLO BASE CASE	(26,218)	101
Cooper Corner 345/115 kV Transformer FLO BASE CASE*	(24,132)	1079

*Transmission Reinforcements connection

The total zonal congestion costs for New York State are $13.8 billion, which is a reduction from the total congestion costs in the 2040 Initial Buildout Base Case ($23.1 billion).

7.9 2040 Iteration Upgrade Results—High Demand Scenario

The implementation of the upgrades resulted in lower curtailment (2.5% in the base case versus 0.8% in the upgrade case). LBW is curtailed about 0.9%. The largest beneficial impact of the transmission reinforcements can be appreciated in the congestion levels. The Table 7-15 shows the most congested interfaces experience a large reduction.

Table 7-15. High Demand Scenario—2040 Iteration Base, Upgrade, and % Reduction

Constraints	Base Congestion Cost (k$)	Upgrade Congestion Cost (k$)	Congested Hours	% Reduction
I:NY_MILLWOOD-SOUTH FLO BASE CASE*	(3,528,996)	(721,195)	401	80%
ESTSTO to 5MILE 345kV 1 FLO BASE CASE	(61,176)	(30,949)	1,838	49%
I:NY_NYC-LI FLO BASE CASE	(293,172)	(4,110)	3,269	99%
SPRAINBROOK to DUN NO S6 6 FLO BASE CASE	(77,086)	(2,519)	1,417	97%
SPRAINBROOK to ACADEMY 1 FLO BASE CASE	(72,369)	(1,443)	1,415	98%
SPRAINBROOK to TREMONT 1 FLO BASE CASE	(43,356)	(1,414)	1,432	97%
PACKARD2 to NIAGAR2W 2 FLO NIAGARA PA	(39,006)	(1,012)	40	97%
DUNWOODIE to SHORE RD FLO SPRIANBROOK CABLE*	(7,662,762)	-	-	100%
DUNWOODIE to SHORE RD FLO BASE CASE*	(3,070,917)	-	-	100%
Cooper Corner to Middletown Tap 345 kV FLO Rock Tavern to Dolson Ave 345KV*	(275,761)	-	-	100%
LADENTWN to RAMAPO 1 FLO BASE CASE*	(92,067)	-	-	100%
Cooper Corner 345/115 kV Transformer FLO BASE CASE*	(24,132)	-	-	100%

*These transmission elements are associated with transmission reinforcements

The total zonal congestion costs for New York State were $1.48 billion, which is a significant reduction from the iteration base ($13.8 billion).

7.9.1 Adjusted Production Costs Savings and Benefit to Cost Ratio

With the upgrades, the APC decreases from $3,495 million to $967 million in 2040, resulting in a savings of $2,528 million. Assuming a Cost Recovery Factor of 8%, and a 2.5% O&M cost adder to annualize the total transmission costs, the indicative B/C Ratio is 7.0, which confirms that the indicative upgrades are cost-effective.

Equation 4. Adjusted Production Costs Benefit to Cost Ratio

$$\frac{Benefit(One - Year\ APC\ Saving)}{Cost\ (Annualized\ Cost)} = \frac{\$2{,}528}{\$4{,}400 \times\ 8\% \ \times\ 102.5\%} =\ 7.0$$

As was noted with the Initial Scenario, the iteration buildout partially addresses congestion by the selection and location of the new resources and relies less on transmission. This results in a lower B/C ratio than in the initial buildout case; however, the indicative B/C ratios are well over one pointing to the economic desirability of the indicative projects.

7.10 Findings and Observations—High Demand Scenario

Based on the analysis performed in the initial and iteration cases for the High Demand Scenario, the indicative transmission upgrades make a substantial contribution to the economics of the system. In general, the iteration buildout shows better results and is thus considered the final LTCE.

As in the Initial Scenario, the identified transmission reinforcements yield benefits after 2030 and are included in the 2040 results as they were observed to be effective in addressing congestion and curtailment. The economic benefits of these upgrades appear to exceed their costs under all conditions assessed. Additional research should address uncertainties on the generation buildout and its location, load growth uncertainty, and optimization of the design and cost of these projects. There is time to conduct this research as no action is immediately necessary.

In the iterative modeling process, the transmission reinforcements identified potentiated improvement in congestion and curtailment. All identified reinforcements were preserved in the course of the iterative modeling process for this reason.

In the short term, by 2030, the addition of the Western NY (Empire State line), AC Transmission PPTN, Northern NY project and NYC Tx projects support achievement of the 70% renewable goal with low levels of bulk system curtailment (0.01%) and congestion. No additional BPS (230 kV and above) investments appear to be necessary.

Significant additional upgrades are likely necessary at the local 115 kV and 138 kV levels both by 2030 and 2040. The interconnection of offshore wind development must be assessed, which would be carried out on a parallel project.

The total RNG consumption reduced from 13,943 GWh in the 2040 Base Case to 4,961 GWh in the 2040 iteration upgrade case of the High Demand Scenario.

8 Electric Grid Analysis—Findings

Based on the analysis carried out in the study, New York State should be able to achieve its 70 x 30 and zero-emission generation by 2040 goals under both the Initial Scenario and the High Demand Scenario using a mix of distributed energy, energy efficiency measures, energy storage, planned transmission projects, utility-scale renewables, and zero-emission resources. The most significant difference in these scenarios was the amount of renewable generation added and the scope (transmission capacity increases) of the transmission projects required to manage congestion and reduce costs.

Additional energy storage would store excess solar and wind energy so that this energy may be utilized during peak hours. Additional energy storage will contribute to the maintenance of locational planning reserve margins.

The construction of the New York Public Policy transmission projects supports achievement of the 70% renewable goal by 2030 with low levels of bulk system curtailment and congestion. Thus, no additional bulk transmission projects (230 kV and above) were identified by 2030 under either of the scenarios considered. However, more detailed analysis of offshore wind integration into the downstate grid is required, and significant transmission upgrades are expected at the local transmission and sub-transmission level.

By 2040, high levels of uneconomic congestion and some curtailment are expected with generation additions supporting the goal of zero emissions. For the Initial Scenario, the models forecasted that there should be a modest level of statewide curtailment (1.5%) with land-based wind experiencing the highest levels of curtailment (4.5%), particularly in Central New York (8.7%). The High Demand Scenario had more than double the curtailment (3.4%) with land-based wind experiencing almost double (8.7%) and, again, in particular in Central New York (20.9%).

The uneconomic congestion and curtailment can be addressed by indicative BPS projects located downstream of Coopers Corner into Zone GHI, at the Millwood South Interface, at the Dunwoodie to Shore Rd cables, and in NYC and the West Long Island area. These indicative projects were found to be effective in relieving curtailment and their economic benefits appear to exceed their costs. However, further research is needed to assess the various forms of uncertainty including the generation buildout and its location, the level of load growth, and the best potential designs and costs for these potential projects. There is time, however, to conduct this research as no action is immediately necessary; the transmission upgrades were not identified to be needed until after 2030.

Annex A. Assumption Details

Load Forecast

The Initial Scenario load forecast was based on High Technology Availability Pathway taken from the report Pathways to Deep Decarbonization in New York State published by Energy + Environmental Economics (E3) Consulting. This forecast was also used for the Clean Energy Standard Cost Study. The High Demand Scenario load forecast was based on the forecast from the Limited Non-Energy Scenario from the report Pathways to Deep Decarbonization in New York State.

Figure A- 1. 2030 Hourly Peak Day Demand—Winter and Summer—Initial Scenario

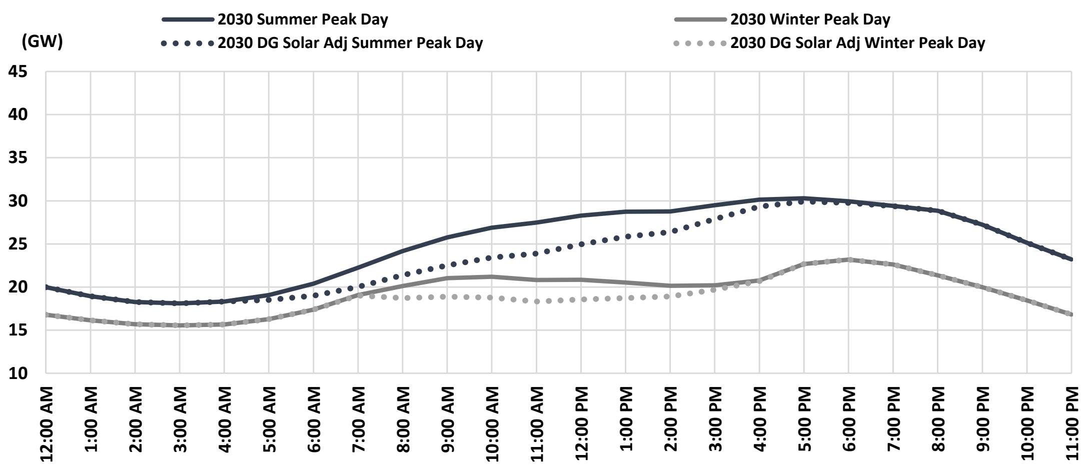


Figure A- 2. 2040 Hourly Winter Peak Day Demand—Initial Scenario

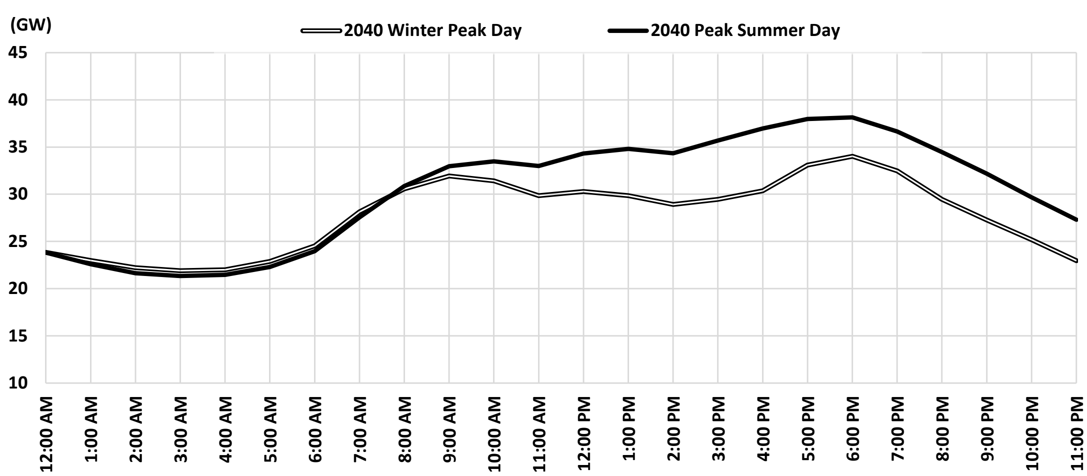
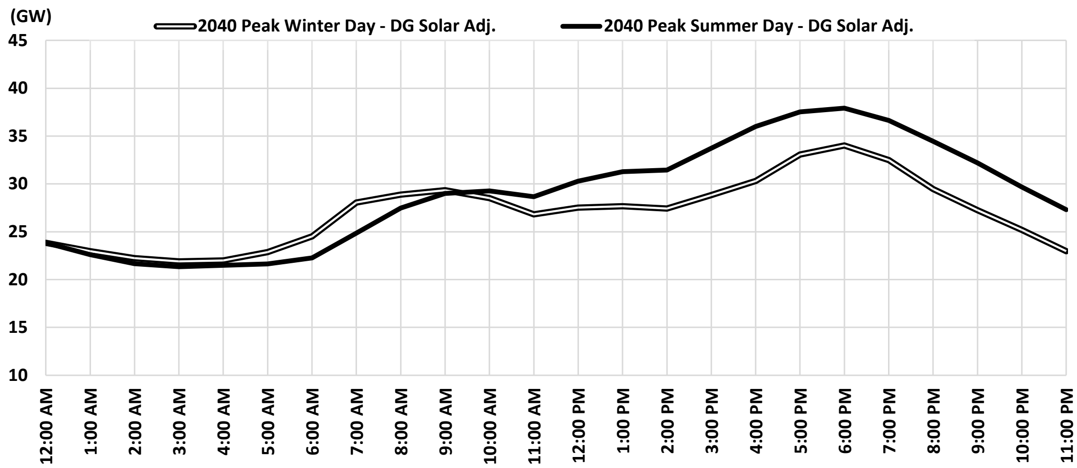


Figure A- 3. 2040 Hourly Summer Peak Day Demand—Initial Scenario



CLCPA Milestone Targets

Seventy Percent Renewable Generation by 2030

To achieve 70% renewable generation by 2030, it was assumed that a diverse set of renewable energy could meet the interim target. The resources that could contribute to the interim target were distributed solar, grid solar, land-based wind, offshore wind, and hydroelectricity (Canadian and New York). This study also assumed 40% of landfill gas and biomass generation could help achieve the 70% renewable generation target, and zero-emission generation by 2040.

To achieve zero-emission generation by 2040, it was assumed that a diverse set of zero-emission technologies could meet the 2040 target. The power generation technologies that were considered zero-emission were distributed solar, grid solar, on shore wind, offshore wind, and hydroelectricity (Canadian and New York), nuclear, thermal generators consuming biomass, landfill gas, and renewable natural gas.

2020-2023 Supply Mix and Announced Builds and Retirements

The existing capacity mix and near-term build and retirement assumptions were sourced from several public resources that included NYISO Goldbook, NYISO Interconnection Queue, NYSERDA Clean Energy Standard Tier 1 Procurement Program, EIA-860 data, market announcements. It was assumed that these resources provided reliable new build and retirement information through 2023, after which, the study relied on using the Long-Term Capacity Expansion logic contained in the power dispatch model.

Distributed Generation Solar

The distributed generation solar forecast was derived from the 2019 Goldbook estimate of DG solar by NY Zone. First, total 2019 DG solar for NY was escalated to 6,000 MW (DC) in 2025 and then increased 1.9% per year through 2040. Each year's zonal DG solar estimates were based on the 2019 weights of the total DG solar estimate. The forecast was derived in DC megawatts and then estimated in AC megawatts for modeling purposes.

The hourly dispatch of DG Solar is based on 2017 production curves adopted from NYSERDA's Distributed Energy Resources Performance Data.[24]

Legacy Hydro Generation

Legacy Canadian hydroelectricity is dispatched using monthly production shapes that are based on the average 2017–2019 historical electricity export sales data from Quebec and Ontario to New York State. Source is the export sales data from Canada's Energy Regulator.[25]

NYC Tx

NYC Tx is a 1,250 MW one-way line that connects Quebec to NYC and it is assumed to transfer 10,000 GWh per year, which equates to 91.3% capacity factor. NYC Tx is dispatched at a constant capacity factor of 91.3% throughout the study.

When there is excess energy generated from NYC Tx and offshore wind that can be used to meet energy demand, NYC Tx will back down before offshore wind.

Natural Gas, Renewable Natural Gas, and Carbon Sequestration

Internal forecast of delivered natural gas prices uses ICE Futures for Henry Hub and gas basis through 2024 and then blends AEO High Gas Resource Case with monthly ICE futures applied 2030 and beyond. This approach creates more monthly variation to delivered prices.

In 2040, the only gas available to gas-fired resources is renewable natural gas (RNG), which is limited to 32TBtu and costs $23/MMBTU (in 2018 dollars).

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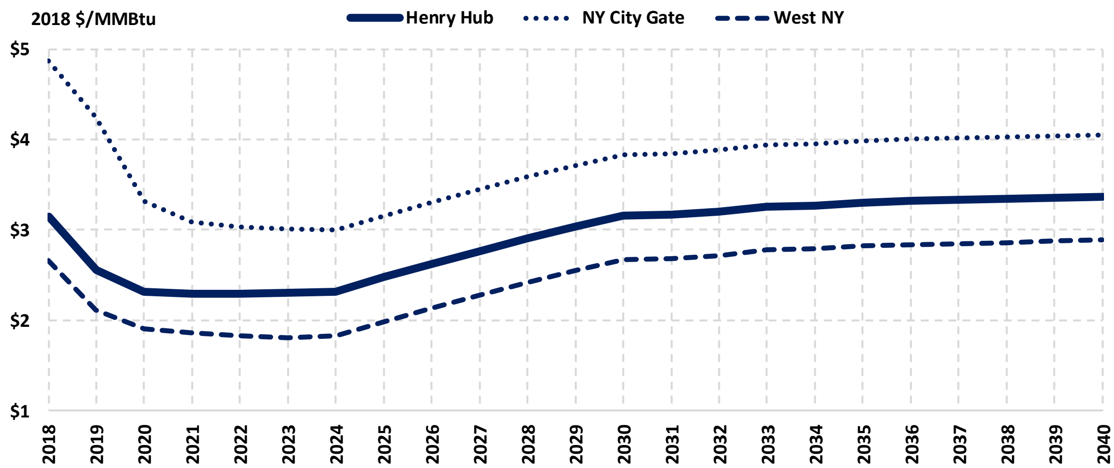
[24] Visit https://der.nyserda.ny.gov/ for NYSERDA Distributed Energy Resources guide.

[25] Canada Energy Regulator Commodity Statistics tool can be accessed at https://apps.cer-rec.gc.ca/CommodityStatistics/Statistics.aspx?language=english on their site.

Figure A- 4. Natural Gas Price Forecast

In metric million British thermal units and 2018 dollars.



For carbon capture and sequestration, it has not been determined under the CLCPA if it will be considered a zero-emission option, so to be conservative, this analysis did not include that technology option.

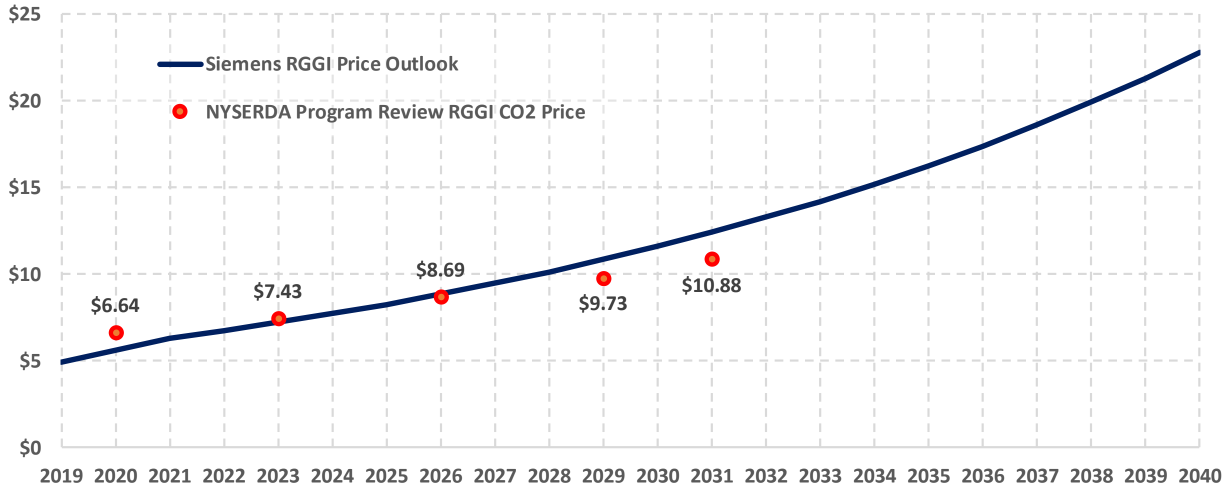
Emission Prices—RGGI

RGGI CO_2 price outlook increases gradually reaching $10/ton CO_2 by 2028 and increasing 7% annually thereafter. 2040 RGGI prices are projected at ~$22/$CO_2$-ton ($2018).

Siemens uses NYISO CARIS through 2028, and then increases by 7% annually thereafter reflecting the growth rate in the CARIS forecast. An emissions cap was not modeled.

Figure A- 5. RGGI CO2 Allowance Trajectory

In 2018 dollars per short ton.



Locational Planning Reserve Margins

The installed reserve margin assumptions are sourced from NYISO's Locational Minimum Installed Capacity Requirement Study for the 2020–2021 Capability Year.[26]

Reserve margins and locational capacity requirements were assumed constant throughout the study period.

Based on the NYSRC IRM base case for the 2020–2021 capability year and the changes identified above, the NYISO's calculations result in a New York City LCR of 86.6%, a Long Island LCR of 103.4%, and a G-J Locality LCR of 90.0%.

Table A- 1. NYISO Locational Capacity Requirement by Location

The following table shows the breakdown of capacity requirements by location.

IRM	J LCR	K LCR	G-J LCR
18.9%	86.6%	103.4%	90.0%

[26] Locational Minimum Installed Capaciyt Requirements Study NYISO can be found at https://www.nyiso.com/documents/20142/8583126/LCR2020-Report.pdf/4c9309b2-b13e-9b99-606a-7af426d93a47 online.

These assumptions were used throughout the study since future installed reserve margin (IRM) and installed capacity (ICAP) and unforced capacity (UCAP) conversion ratings are challenging to predict for the future.

In addition, the summer 2020 ICAP/UCAP translation factors were adopted throughout the study.

Effective Load Carrying Capability (ELCC)

The Effective Load Carrying Capability (ELCC) for utility solar, land-based wind, and offshore wind are calculated using AURORA's Dynamic Peak Credit feature. AURORA calculates the average contribution of a resource to the net peak load. Net peak load is defined as when the energy demand is highest after netting out generation from distributed solar, solar, wind, and offshore wind.

Net load = Baseline Demand – DG solar – Solar – Wind

For this study, AURORA used the 50 highest net peak load hours per year to analyze average contributions to peak demand. Net peak load will shift as New York State adds more renewables. Therefore, the ELCC of renewable capacity changes over time. Solar's ELCC decreases rapidly as the net peak shifts to the evening when solar production is low.

Net peak load will shift as the State adds more renewables. Therefore, the ELCC of renewable capacity changes over time. Solar's ELCC decreases rapidly as the net peak shifts to the evening when solar production is low. To reduce volatility in energy storage ELCC over study horizon, the study applied NYISO's current peak capacity credit factors through 2040 (2-hr 37.5%; 4-hr 75%; 6-hr 90%)

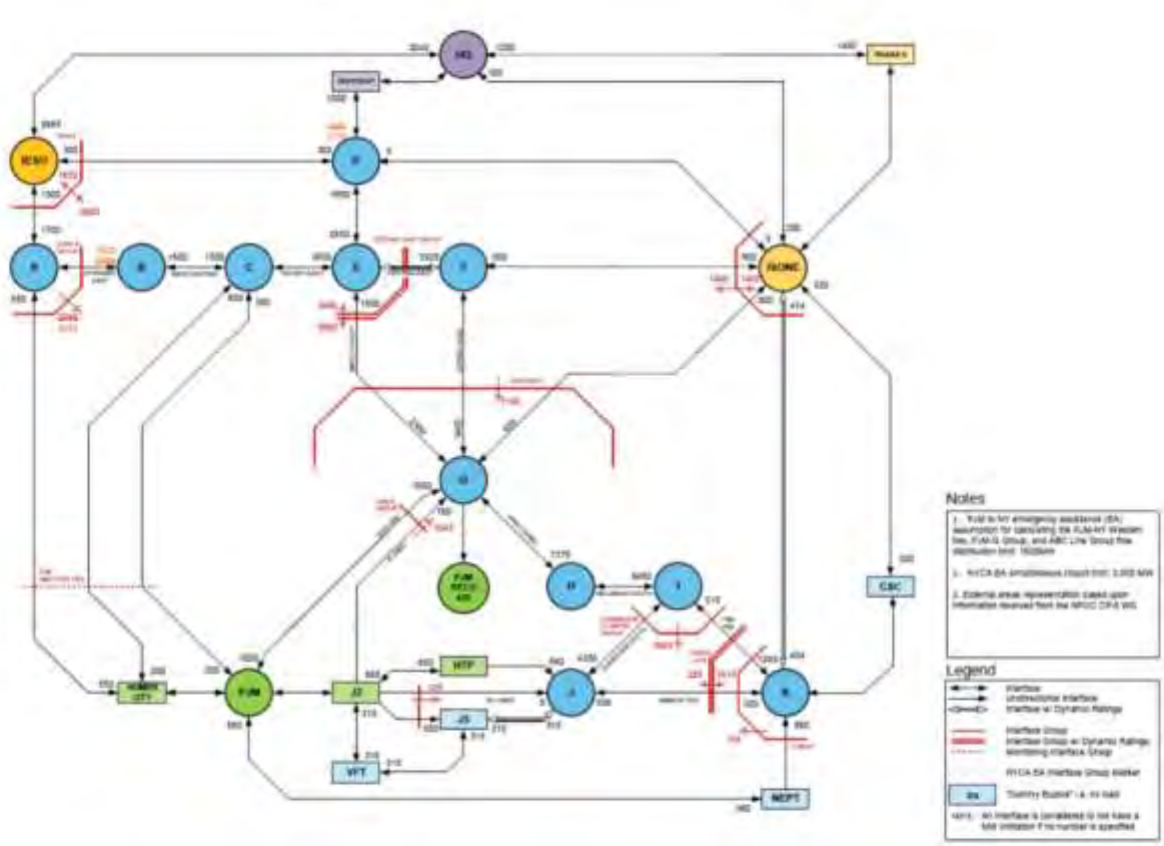
Figure A- 6. ICAP Supplier Payment Structure

This graphic shows the NYISO proposed capacity values.[27]

27 Visit https://www.nyiso.com/documents/20142/5375692/Expanding%20Capacity%20Eligibility%20030719.pdf/19c4ea0d-4827-2e7e-3c32-cf7e36e6e34a to access NYISO Expanding Capacity Eligibility.

Energy Transfer Limits

Figure A- 7. Topology for 2020 Reliability Needs Assessment: Study Years 2024 to 2030



Our assumptions focused on 230 kV and above kV levels. These levels are complemented with limited 115 kV lines that perform a similar long-distance transmission function in the study. Load-flow analysis and PROMOD congestion studies were centered on the identification of constraints affecting the evacuation of power from production areas and delivery to load centers (hence, the facilities considered and voltage levels). Local constraints associated with the interconnection of the generations were not addressed as this is heavily dependent on the actual location of the resources and their timing. This would be addressed by the local planning process.

Renewable Build Costs and Production Profiles

Renewable generation build costs were sourced from the Clean Energy Standard cost study. There are annual statewide limits on the amount of clean energy that can be built by technology. The limitations are as follows:

- Grid solar: 2,000 MW through 2030 and increases 100 MW annually, reaching a max limit of 3,000 MW in 2040.
- Land-based wind: 2,000 MW per year.
- Energy storage: 2,500 MW per year.

The goal of the modeling exercise is to achieve 100% zero-emission generation by 2040. Technically, it is possible for the model to build/retire all the necessary capacity in 2039 to meet the 100 x 40 target. To achieve a realistic buildout and retirement plan, annual build limitations were adopted to mimic real-world construction capabilities.

Location specific land-based wind, offshore wind, and solar resource data were developed from the NREL Wind Toolkit and National Solar Radiance database for a 2009 meteorological year and adjusted for a mean capacity factor (found from analyzing 2007–2013 data). The State team deemed 2009 as a representative year. NYISO also selected to use 2009 profiles from NREL for its 70 x 30 CARIS analysis.

For storage, two-hour, four-hour and six-hour battery storage capacities were considered with the costs indicated in the table below.

Table A- 2. Energy Storage Overnight Capital Costs

Shown in kilowatts and 2018 dollars.

Year	2 Hr.	4 Hr.	6 Hr.
2020	972	1,426	2,020
2021	875	1,269	1,798
2022	795	1,144	1,620
2023	729	1,042	1,477
2024	676	960	1,360
2025	632	894	1,266
2026	596	841	1,191
2027	568	799	1,132
2028	546	767	1,087
2029	529	744	1,054
2030	514	722	1,022
2031	503	707	1,002
2032	493	693	982
2033	483	679	962
2034	474	666	943
2035	464	652	924
2036	455	639	906
2037	446	627	888
2038	437	614	870

Year	2 Hr.	4 Hr.	6 Hr.
2039	428	602	852
2040	424	596	844

A 1.25x cost multiplier was applied to new energy storage resources in NYC Zone J and a 1.10 X cost multiplier was applied to new energy storage resources in Long Island Zone K. The storage overnight capital costs were based on the costs used for the New York State Storage Roadmap.[28]

Neighboring Renewable Energy Standards and Offshore Wind Targets

The RES and offshore wind targets for neighboring regions are based off initiations as of November 2019.

The RES targets for surrounding areas are as follows:

Vermont: 75% by 2032
New Hampshire: 24.8% by 2025
Maine: 100% by 2050
Massachusetts: 35% by 2030
Rhode Island: 38.5% 2035
Connecticut: 48% 2030
New Jersey: 50% by 2030
Pennsylvania: 18% 2021
Delaware: 25% 2026
Maryland: 50% by 2030
District of Colombia: 100% 2032
Virginia:15% 2025
West Virginia: 25% 2025
North Carolina: 12.5% 2021
Ohio: 12.5% 2026

Offshore wind capacity development initiatives for surrounding regions:

Connecticut: 2,000 MW by 2030
Maryland: 1,200 MW by 2030
Massachusetts: 1,600 MW by 2027 and 3,200 by 2035
New Jersey: 3,500 MW by 2030 and 7,500 MW by 2035
Virginia: 2,500 MW by 2026 and 5,200 MW by 2034

[28] Visit https://www.nyserda.ny.gov/All-Programs/Programs/Energy-Storage to learn more about NYSERDA Energy Storage Programs.

Initial Scenario Supplementary Tables

The table below shows the Initial Scenario Original LTCE, that was provided to PROMOD for the assessment of transmission needs. That is the buildout before transmission costs and increased transmission capacity were taken into consideration.

Table A- 3. Original Long-Term Capacity Expansion Buildout—Initial Scenario

Shown in megawatts.

	2025	2030	2035	2040
Thermal	25,030	24,690	24,877	19,777
Nuclear	3,381	3,381	3,381	3,381
Hydro	4,663	4,663	4,663	4,663
Onshore Wind	3,932	6,437	7,101	12,620
Offshore Wind	1,826	6,000	9,000	10,307
Solar	3,099	4,133	6,753	17,624
Energy Storage	1,542	3,000	3,263	13,479
Biomass	80	80	80	24
Other Renew	392	392	392	392
NYC Tx	1,250	1,250	1,250	1,250
DG Solar (AC)	4,839	5,323	5,856	6,443

Table 4-1 provided the Initial Scenario Final LTCE at the state level, to complement this information the table below provides this information by NYISO Zone.

Table A- 4. Final Zonal Long-Term Capacity Expansion Buildout—Initial Scenario

		2025	2030	2035	2040	2040 Non Thermal Sub-Total
NYISO	Solar	3,099	3,808	6,426	16,759	54,915
	Wind	3,932	6,230	6,736	12,804	
	Offshore Wind	1,826	6,000	9,000	9,837	
	Energy Storage	1,542	3,000	5,154	15,515	
	Thermal	24,447	23,458	24,113	17,269	
Zone A	Solar	649	649	649	796	3,817
	Wind	1,094	1,094	1,094	2,690	
	Offshore Wind	-	-	-	-	
	Energy Storage	31	331	331	331	
Zone B	Solar	41	41	41	202	460
	Wind	21	121	121	226	
	Offshore Wind	-	-	-	-	
	Energy Storage	31	31	31	31	
Zone C	Solar	831	909	1,082	2,341	3,903
	Wind	1,278	1,384	1,384	1,521	
	Offshore Wind	-	-	-	-	
	Energy Storage	41	41	41	41	
Zone D	Solar	26	26	246	675	1,564
	Wind	678	678	678	810	
	Offshore Wind	-	-	-	-	
	Energy Storage	31	79	79	79	
Zone E	Solar	618	1,104	2,191	5,640	11,288
	Wind	757	1,765	2,271	3,321	
	Offshore Wind	-	-	-	-	
	Energy Storage	41	341	341	2,326	
Zone F	Solar	540	685	1,429	5,135	9,967
	Wind	96	1,178	1,178	2,188	
	Offshore Wind	-	-	-	-	
	Energy Storage	61	144	1,644	2,644	
Zone GHI	Solar	257	257	652	1,355	6,173
	Wind	10	10	10	2,048	
	Offshore Wind	-	-	-	-	
	Energy Storage	257	344	344	2,769	
Zone J	Solar	25	25	25	32	10,198
	Wind	-	-	-	-	
	Offshore Wind	978	3,952	6,000	6,000	
	Energy Storage	879	879	1,183	4,167	
Zone K	Solar	112	112	112	582	7,546
	Wind	-	-	-	-	
	Offshore Wind	848	2,048	3,000	3,837	
	Energy Storage	170	810	1,160	3,127	

High Demand Scenario Supplementary Tables

The table below shows the High Demand Scenario Original LTCE that was provided to PROMOD for the assessment of transmission needs. As before, this is the buildout before transmission costs and increased transmission capacity were taken into consideration.

Table A- 5. Original Long-Term Capacity Expansion Buildout—High Demand Scenario

Shown in megawatts.

	2025	2030	2035	2040
Thermal	25,641	27,576	29,047	23,052
Nuclear	3,381	3,381	3,381	3,381
Hydro	4,663	4,663	4,663	4,663
Onshore Wind	3,932	6,437	7,101	12,620
Offshore Wind	1,826	6,000	9,000	10,307
Solar	3,099	4,133	6,753	17,624
Energy Storage	1,542	3,000	3,263	13,479
Biomass	80	80	80	24
Other Renew	392	392	392	392
NYC Tx	1,250	1,250	1,250	1,250
DG Solar (AC)	4,839	5,323	5,856	6,443

Table 7-3 provided the High Demand Scenario Final LTCE at the State level. To complement this information, the table below provides this information by NYISO Zone.

Table A- 6. Final Zonal Long-Term Capacity Expansion Buildout—High Demand Scenario

		2025	2030	2035	2040	2040 Non Thermal Sub-Total
NYISO	Solar	3,099	5,707	11,577	22,577	63,755
	Wind	4,027	7,357	9,194	12,690	
	Offshore Wind	1,826	6,000	9,000	13,597	
	Energy Storage	1,542	3,000	4,213	14,891	
	Thermal	25,730	28,231	28,758	22,954	
Zone A	Solar	649	649	649	1,546	5,297
	Wind	1,188	1,188	1,243	2,925	
	Offshore Wind	-	-	-	-	
	Energy Storage	31	31	36	825	
Zone B	Solar	41	41	50	748	799
	Wind	21	21	21	21	
	Offshore Wind	-	-	-	-	
	Energy Storage	31	31	31	31	
Zone C	Solar	831	1,004	2,370	4,432	6,316
	Wind	1,278	1,278	1,278	1,278	
	Offshore Wind	-	-	-	-	
	Energy Storage	41	81	606	606	
Zone D	Solar	26	26	26	1,219	2,719
	Wind	678	678	678	1,020	
	Offshore Wind	-	-	-	-	
	Energy Storage	31	31	31	480	
Zone E	Solar	618	1,884	4,855	7,060	9,995
	Wind	757	1,495	2,043	2,594	
	Offshore Wind	-	-	-	-	
	Energy Storage	41	341	341	341	
Zone F	Solar	540	1,185	2,435	5,603	8,512
	Wind	96	2,118	2,687	2,804	
	Offshore Wind	-	-	-	-	
	Energy Storage	61	61	104	104	
Zone GHI	Solar	257	781	1,056	1,355	6,036
	Wind	10	579	1,245	2,048	
	Offshore Wind	-	-	-	-	
	Energy Storage	257	257	257	2,633	
Zone J	Solar	25	25	25	32	14,210
	Wind	-	-	-	-	
	Offshore Wind	978	3,952	6,000	8,120	
	Energy Storage	879	879	1,269	6,059	
Zone K	Solar	112	112	112	582	9,871
	Wind	-	-	-	-	
	Offshore Wind	848	2,048	3,000	5,478	
	Energy Storage	170	1,288	1,538	3,812	

E. (end of appendix)