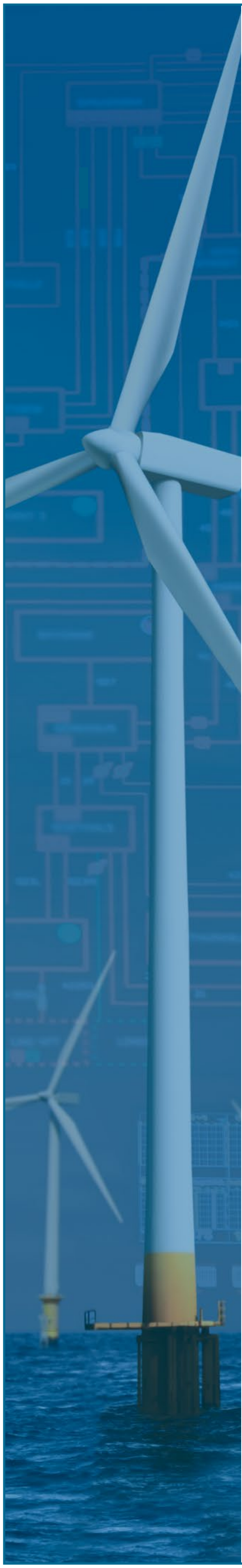

New York ISO
Independent System Operator

Long Island Offshore Wind Export Public Policy Transmission Need Evaluation

A Report from the New York Independent System Operator

DRAFT April 3, 2023 ESPWG/TPAS

DRAFT – FOR DISCUSSION PURPOSES ONLY

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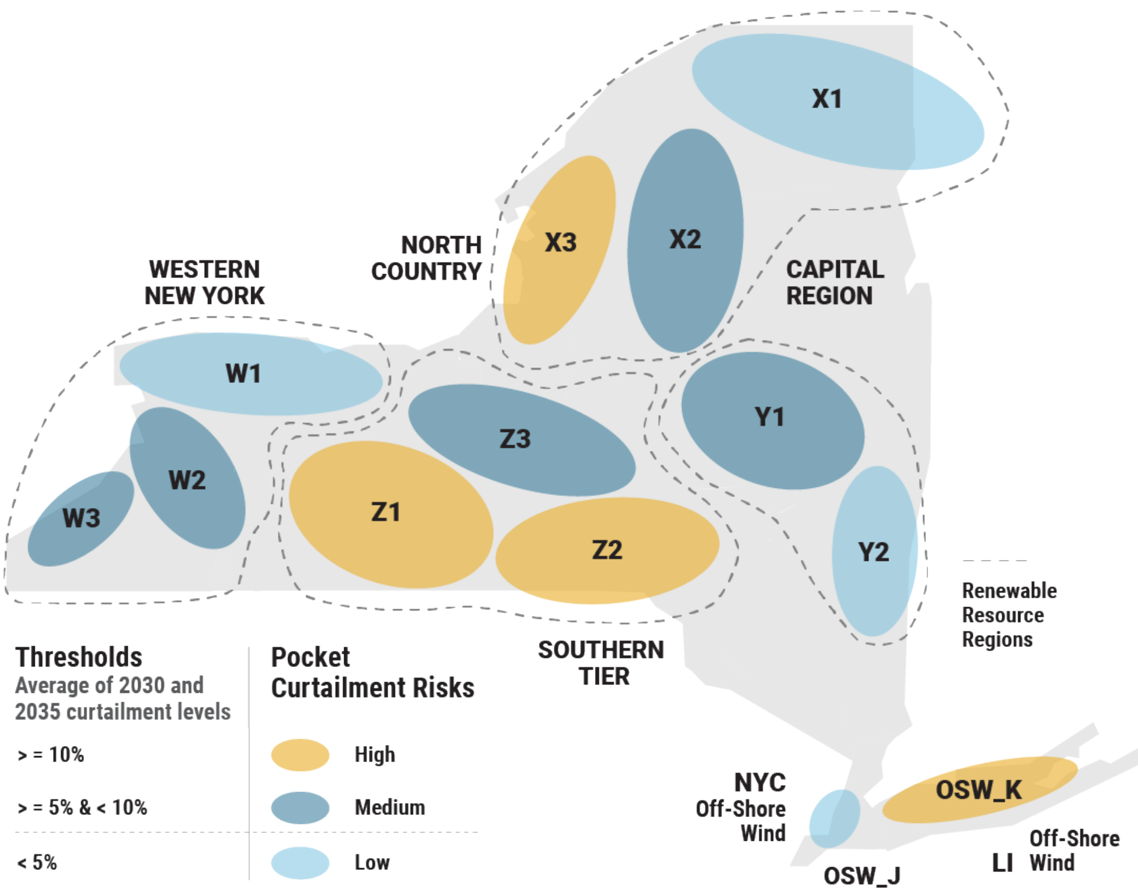
Executive Summary

This section will be filled out in a future version of the report.

1. Long Island Offshore Wind Export Public Policy Transmission Need

The Climate Leadership and Community Protection Act (CLCPA) mandates that the New York State procure 9,000 MW of offshore wind power by 2035. The coast along Long Island is an excellent location for the installation of offshore wind resources and has the advantage of its proximity to major load centers in New York City and Long Island. The offshore wind injection in Long Island will not only help to supply the demand within Zone K but could also be exported to supply Southeast New York. However, the transmission system's current export capability from Long Island is very limited. That lack of transmission capability from Long Island to the rest of New York would result in periods of wind energy curtailment.

The potential curtailment of wind energy on Long Island is consistent with results from several studies, including the NYISO's *2021-2040 System & Resource Outlook* (The Outlook) and the 2019 Congestion Assessment and Resource Integration Study. In the Outlook, the NYISO evaluation the transmission system based on renewable generation pockets, which are detailed in the figure below. The shaded areas summarize the findings by identifying the pockets as having a "low," "medium," or "high" risk of curtailment. The pockets with a "high" risk were determined to have both persistent and significant renewable generation curtailment within the pocket.



Offshore wind generation connected to Long Island (Zone K) is identified as "high" risk and would be curtailed. Transmission expansion that increases the transfer capability from Long Island to the rest of New York is expected to significantly reduce the potential for offshore wind curtailment.

On August 3, 2020, the 2020-2021 cycle of the Public Policy Transmission Planning Process commenced with a request to interested parties to submit proposed transmission needs driven by Public Policy Requirements. Responses were received from 15 entities—nine of which highlighted the need for transmission associated with the delivery of offshore wind energy across New York State. On October 9, 2020, the NYISO filed the proposed transmission needs with the New York Public Service Commission (PSC) and the proposed transmission needs that will result in physical modifications to the Long Island Transmission District with the Long Island Power Authority (LIPA). On February 3, 2021, LIPA filed with the PSC its determination that a transmission need driven by a Public Policy Requirement exists in the Long Island Transmission District and its recommendation that specific upgrades be pursued.

On March 19, 2021, the PSC issued an Order[1] identifying the Long Island Offshore Wind Export Public Policy Transmission Need ("Long Island PPTN") and referred that need to the NYISO for solicitation and evaluation under its Public Policy Transmission Planning Process ("Public Policy Process"). The Order declared that the CLCPA constitutes a Public Policy Requirement driving the need for transmission to increase the export capability from Long Island to the rest of New York State to ensure full output of offshore wind interconnected to Long Island. The Order defined the need as:

1) Adding at least one bulk transmission intertie cable to increase the export capability of the LIPA-Con Edison interface, that connects NYISO's Zone K to Zones I and J to ensure the full output from at least 3,000 MW of offshore wind is deliverable from Long Island to the rest of the State; and

2) Upgrading associated local transmission facilities to accompany the expansion of the proposed offshore export capability.[2]

[1] Case No. 20-E-0497, *In the Matter of New York Independent System Operator, Inc.'s Proposed Public Policy Transmission Needs for Consideration for 2020*, Order Addressing Public Policy Requirements for Transmission Planning Purposes (March 19, 2021), *available at* https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={8C8F3D7A-4FEB-4B18-88F5-82CF587895C9}

[2] *Id.* at p 23.

2. Proposed Solutions

2.1 Solicitation for Solutions

After the PSC issued the Long Island PPTN Order, the NYISO staff promptly began working to address the Long Island PPTN in its Public Policy Process. Baseline analysis identified the constraints on the existing system's capability to integrate at least 3,000 MW of Long Island offshore wind and shared the results with stakeholders and developers. Anticipating that higher amounts of offshore wind above 3,000 MW may seek to be interconnected in Long Island, the NYISO also studied an alternate scenario to integrate 6,000 MW. The NYISO provided the baseline and alternate scenario results to prospective developers.

Prior to the solicitation for solutions, the NYISO discussed the Long Island PPTN and baseline and alternate scenario results with stakeholders and interested parties at numerous meetings through the shared governance process. A Technical Conference[3] was held on July 8, 2021 with prospective developers to discuss the solicitation process, sufficiency criteria, evaluation methodology and criteria, and to address developers' questions. More than 100 external participants joined the day-long Technical Conference. Furthermore, the NYISO issued three Frequently Asked Questions (FAQ) documents[4] and posted them on the NYISO website so that all interested developers and parties had access to the information.

The NYISO began the 60-day solicitation window on August 12, 2021. Proposals were due on October 11, 2021. The solicitation letter and viability & sufficiency criteria are included in Appendix placeholder. In response to NYISO's solicitation,19 proposals were submitted by a total of four developers: one proposal from LS Power Grid Corporation I ("LS Power"), ten proposals from NextEra Energy Transmission New York, Inc. ("NextEra"), one proposal from Anbaric Development Partners, LLC ("Anbaric"), and seven proposals from Propel NY (a partnership between the New York Power Authority and New York Transco, LLC).[5]

2.2 Viability and Sufficiency Assessment

The Viability & Sufficiency Assessment is a pass/fail test to screen whether each of the 19 proposed projects is capable of satisfying the minimum criteria of the Long Island PPTN. The Viability & Sufficiency

3 https://www.nyiso.com/documents/20142/22968753/LI-PPTN-TechConference.pdf/

4 https://www.nyiso.com/documents/20142/22968753/LIPPTN-FAQ-08112021-rev09202021.pdf/

5 All of the developers that submitted proposed solutions to the Long Island PPTN were qualified transmission developers in accordance with the Attachment Y of the OATT. *See* https://www.nyiso.com/documents/20142/1395552/List-of-Qualified-Developers-2022-11-02-Final.pdf/0bfd049b-e386-dc01-780f-7ccc928fd138

Assessment found two projects that did not meet the sufficiency criteria—T046 Anbaric Downstate Clean Powerlink and T050 Propel Base Solution 4. The NYISO also determined that one project, T045 NextEra Plus 3, which was found to be viable and sufficient, was not eligible for evaluation and selection because it contained non-transmission facilities and, therefore, was an "Other Public Policy Project." The NYISO presented the Viability & Sufficiency Assessment Report to stakeholders and filed it with the PSC on April 4, 2022. The report is included in Appendix placeholder.

2.3 Characterization of New and Upgrade Facilities

In October 2021, the NYISO filed tariff revisions with FERC, pursuant to Section 206 of Federal Power Act, to establish new procedures in the Public Policy Process to implement the right of Transmission Owners to build, own, and recover the cost of upgrades to their existing transmission facilities. The new procedures went into effect on October 12, 2021. In accordance with the new procedures, the NYISO identified Public Policy Transmission Upgrades[6] in the proposed projects by posting to its website an initial characterization of project facilities as new or Public Policy Transmission Upgrades. Disputes to the characterization of specific facilities were raised by several parties. After discussing with the disputing parties, the NYISO posted a final list of facility characterizations[7] to its website on June 10, 2022, and is included in Appendix placeholder.

2.4 Project Descriptions

The developers of all 16 viable and sufficient Public Policy Transmission Projects elected for the NYISO to evaluate the projects for purposes of selection as the more efficient or cost-effective solution to the Long Island PPTN. Below is a brief description of the major facilities of these projects. Appendix placeholder contains a more detailed description and map of each project.

<u>T035 LS Power Atlantic Gateway</u>

- 3 x Barrett – Ruland Rd 345 kV PAR-controlled lines
- 3 x Ruland Rd-Millwood HVDC lines

<u>T036 NextEra Core 1</u>

- East Garden City – Dunwoodie 345 kV PAR-controlled line
- East Garden City – Sprain Brook 345 kV PAR-controlled line

[6] Public Policy Transmission Upgrades a portion of a Public Policy Transmission Project that satisfy the definition of upgrade set forth in Section 31.6.4 of Attachment Y and are eligible for the applicable Transmission Owner to exercise the right to build, own, and recover the costs.

[7] https://www.nyiso.com/documents/20142/31279228/LI_OSW_Export_ESPWG_06-08-2022.pdf/

- Ruland Road – Sprain Brook 345 kV line
- East Garden City – Jamaica 138 kV PAR-controlled line

T037 NextEra Core 2

- East Garden City – Dunwoodie 345 kV line
- East Garden City – Sprain Brook 345 kV line
- Ruland Road – Sprain Brook 345 kV PAR-controlled line
- East Garden City – Jamaica 138 kV PAR-controlled line
- East Garden City – Farragut 345 kV PAR-controlled line

T038 NextEra Core 3

- Northport – Dunwoodie 345 kV line
- East Garden City – Sprain Brook 345 kV PAR-controlled line
- Ruland Road – Sprain Brook 345 kV PAR-controlled line
- East Garden City – Jamaica 138 kV PAR-controlled line
- East Garden City – Farragut 345 kV PAR-controlled line
- Pilgrim – Northport 138kV line

T039 NextEra Core 4

- Northport – Dunwoodie 345 kV line
- East Garden City – Sprain Brook 345 kV PAR-controlled line
- Ruland Road – Sprain Brook 345 kV line
- East Garden City – Jamaica 138 kV PAR-controlled line
- Sprain Brook – Farragut 345 kV line
- Pilgrim – Northport 138kV line

T040 NextEra Core 5

- Northport – Dunwoodie 345 kV line
- East Garden City – Sprain Brook 345 kV PAR-controlled line

- Ruland Road – Sprain Brook 345 kV line
- East Garden City – Jamaica 138 kV PAR-controlled line

T041 NextEra Core 6

- Northport – Sprain Brook HVDC line
- East Garden City –Dunwoodie 345 kV PAR-controlled line
- Ruland Road – Sprain Brook 345 kV line
- East Garden City – Jamaica 138 kV PAR-controlled line
- Pilgrim – Northport 138kV line

T042 NextEra Core 7

- Northport – Sprain Brook HVDC line
- East Garden City –Dunwoodie 345 kV PAR-controlled line
- Ruland Road – Sprain Brook 345 kV line
- East Garden City – Jamaica 138 kV PAR-controlled line
- 2 x HVDC connectors between the NY Bight and Buchanan
- Pilgrim– Northport 138kV line

T043 NextEra Enhanced 1

- Northport – Sprain Brook HVDC line
- East Garden City – Sprain Brook 345 kV PAR-controlled line
- East Garden City – Dunwoodie 345kV line
- Ruland Road – Sprain Brook 345 kV PAR-controlled line
- East Garden City – Jamaica 138 kV PAR-controlled line
- Sprain Brook – Farragut – East Garden City 345 kV line (PAR controlled at East Garden City towards Farragut)
- Barrett – Buchanan HVDC line
- Pilgrim – Northport 138kV line

T044 NextEra Enhanced 2

- Northport – Sprain Brook HVDC line
- East Garden City – Sprain Brook 345 kV PAR-controlled line
- East Garden City – Dunwoodie 345kV line
- Ruland Road – Sprain Brook 345 kV PAR-controlled line
- East Garden City – Jamaica 138 kV PAR-controlled line
- Sprain Brook – Farragut – East Garden City 345 kV line(PAR controlled at East Garden City towards Farragut)
- 2 x HVDC connectors between the NY Bight and Buchanan
- Buchanan – Ramapo 345 kV line
- Jamaica – Corona 138 kV line
- Pilgrim – Holbrook 138kV line
- Pilgrim – Northport 138kV line

<u>T047 Propel Base Solution 1</u>

- East Garden City – Tremont 345 kV PAR-controlled line
- Shore Rd – Sprain Brook 345 kV PAR-controlled line
- Barrett – East Garden City 345 kV PAR-controlled line
- Ruland Rd – Shore Rd 345 kV line
- Ruland Rd – East Garden City 345 kV PAR-controlled line
- Shore Rd – East Garden City 345 kV line

<u>T048 Propel Base Solution 2</u>

- Barrett – Tremont 345 kV PAR-controlled line
- Ruland Rd – Sprain Brook Rd 345 kV PAR-controlled line
- Syosset – Shore Road 138 kV PAR-controlled line

<u>T049 Propel Base Solution 3</u>

- East Garden City – Tremont 345 kV PAR-controlled line
- Shore Rd – Sprain Brook 345 kV PAR-controlled line

- 2 x Barrett – East Garden City 345 kV PAR-controlled lines
- Ruland Rd – Shore Rd 345 kV line
- Ruland Rd – East Garden City 345 kV PAR-controlled line
- Shore Rd – East Garden City 345 kV line
- Shore Rd – East Garden City 138 kV line

T051 Propel Alternate Solution 5

- East Garden City – Tremont 345 kV PAR-controlled line
- 2 x Shore Rd – Sprain Brook 345 kV PAR-controlled lines
- Barrett – East Garden City 345 kV PAR-controlled line
- Ruland Rd – Shore Rd 345 kV line
- Ruland Rd – East Garden City 345 kV PAR-controlled line
- Shore Rd – East Garden City 345 kV line
- Syosset – Shore Road 138 kV PAR-controlled line

T052 Propel Alternate Solution 6

- Eastern Queens – Dunwoodie 345 kV PAR-controlled line
- East Garden City – Tremont 345 kV PAR-controlled line
- 2 x Shore Rd – Sprain Brook 345 kV PAR-controlled lines
- 2 x East Garden City – Eastern Queens 345 kV line
- Barrett – East Garden City 345 kV PAR-controlled line
- Ruland Rd – Shore Rd 345 kV line
- Ruland Rd – East Garden City 345 kV PAR-controlled line
- Shore Rd – East Garden City 345 kV line
- Syosset – Shore Road 138 kV PAR-controlled line

T053 Propel Alternate Solution 7

- Eastern Queens – Dunwoodie 345 kV PAR-controlled line

- Eastern Queens – Tremont 345 kV line
- Ruland Rd – Sprain Brook 345 kV PAR controlled-line
- Northport – Sprain Brook HVDC line
- 3 x Barrett – Eastern Queens 345 kV lines (one is PAR-controlled)
- Syosset – Shore Road 138 kV PAR controlled-line

3. Project Evaluations

The process for the evaluation of proposed solutions is described in the NYISO Public Policy Transmission Planning Process Manual and is based on the metrics set forth in the NYISO's tariff and, to the extent feasible, the criteria prescribed by the PSC. The NYISO's evaluation of Public Policy Transmission Projects differs from its evaluation of projects in its other planning processes because it can give varying levels of considerations to the baseline and the chosen scenarios based upon the nature of the proposed Public Policy Transmission Projects. In other words, certain projects may perform differently under normal operating conditions and other potential operating conditions. Based upon the particulars of the Public Policy Transmission Need, the more efficient or cost-effective solution may be chosen based upon a scenario or a combination of scenarios.

For the purposes of the evaluation and selection of the more efficient or cost-effective Public Policy Transmission Project(s) to address the Long Island PPTN, the following criteria and metrics were applied as defined in Section 31.4.8 of Attachment Y to the NYISO Open Access Transmission Tariff (OATT). The criteria prescribed in the PSC Order for the Long Island PPTN have been addressed throughout the metrics, as detailed below.

Metric	Tariff-Based Metric	Specific Metric in PSC Order	Analysis Performed
Capital Costs Estimates, including quantitative assessment of Cost Caps	X		SECO estimated equipment, construction, and permitting costs. SECO's estimate is compared to Developer's Cost Cap.
Qualitative Evaluation of Cost Caps	X		NYISO consideration of Cost Cap effectiveness in protecting ratepayers
Cost per MW Ratio	X		Compare project cost to various transfer capability increases
Expandability	X		Electrical (additional offshore wind beyond 3000 MW) and Physical Expandability (new points of interconnection)
Operability (*e.g.*, additional flexibility in operating the system and costs of operating the systems)	X		Power flow analysis of flexibility to operate the system under outage conditions
Performance (*i.e.*, interface flows, percent loading of facilities)	X		Transmission utilization through Long Island interfaces, unbottled offshore wind generation
Property rights and routing	X		SECO review of project proposals
Potential of delays in constructing the project, including obtaining permits and certifications	X		SECO review of project proposals
Reliability of the System	X*	X	
➢ **Transmission Security (thermal, voltage, and stability) under**	X	X	Transmission security analysis is included in all interconnection studies, which are performed in parallel with the Public Policy Process.

normal and emergency operating conditions			
Other Metrics Identified through Stakeholder Process	X		
➢ Changes in Locational-Based Marginal Prices	X	X	LBMPs are a product of production cost simulations. LBMPs provide directional understanding of the system behavior, but are less informative than other economic metrics for this PPTN.
➢ Changes in Transmission Losses	X	X	Losses are a product of production cost simulations. Impacts to transmission losses are not significant.
➢ Changes in Installed Capacity costs	X	X	Capacity Benefit analysis
➢ Changes in Transmission Congestion Contract Revenues	X	X	Congestion is a product of production cost simulations. TCC impacts are less informative than other economic metrics for this PPTN.
➢ Changes in Production Costs	X	X	Production Cost Simulations
➢ Changes in Emissions	X	X	Emissions are a product of production cost simulations. For a future with little to no fossil generation, the impact to emissions is not significant.
➢ Changes in Transmission Congestion	X	X	Congestion is a product of production cost simulations.
➢ Impacts on Transfer Limits	X	X	Transfer limit analysis is also incorporated into Cost per MW and Operability
➢ Changes in Resource Deliverability	X	X	Energy production of offshore wind is a product of production cost simulations.

* Reliability of the transmission system is also evaluated under the Viability & Sufficiency Assessment as prescribed by Section 31.4.5 of the Attachment Y to the OATT.

3.1 Evaluation Scenarios

For the purpose of the Long Island PPTN, the NYISO established three scenarios to evaluate the proposed solutions:

- **Baseline Scenario**: evaluates the system condition with 9,000 MW total of offshore wind generation (6,000 MW in New York City and 3,000 MW in Long Island), moderate buildout of upstate renewables, and expected generation retirements. This scenario assumes transmission upgrades on the Barrett – Valley Stream 138kV paths to alleviate congestion.
- **Policy Scenario**: evaluates the system condition with 12,000 MW total of offshore wind generation (6,000 MW in New York City and 6,000 MW in Long Island), upstate renewable buildout, and fossil generation retirements and to meet CLCPA policy mandates. This scenario assumes transmission upgrades on the Barrett – Valley Stream 138 kV paths to alleviate congestion.
- **Policy + Barrett – Valley Stream Scenario** (Policy + B-VS Scenario): evaluates the system condition built upon the Policy Scenario and excludes the assumed upgrades on the Barrett – Valley Stream

138kV paths. The Barrett-Valley Stream path could be one of the most congested paths in the New York Control Area when interconnecting offshore wind projects, such as Empire Wind II, without applicable transmission upgrades. Empire Wind II is proposed to interconnect to Barrett – Valley Stream 138 kV line and causes congestion on the 138 kV lines in the vicinity, including Barrett-Valley Stream, Barrett-Freeport and East Garden City Valley Stream - East Garden City Valley Stream. In the first quarter of 2023, Empire wind II accepted cost allocation for local System Upgrade Facilities but rejected System Deliverability Upgrades in Class Year 2021. The limited upgrades Empire Wind II accepted in the Interconnection Process left the nearby transmission constraints unresolved. The NYISO, therefore, established the Policy + B-VS Scenario to assess the impact that the proposed projects may have on the system.

The evaluation of the proposed solutions utilized tools such as power flow, resource adequacy, and production cost simulations. The NYISO is performing additional sensitivities to the above-identified scenarios to further distinguish between the proposed solutions. The details of the databases are described in Appendix placeholder.

3.2 Capital Cost Estimates and Cost Cap

Evaluation Metric: Capital Cost Estimates and Cost Cap

Purpose: Considers the project cost estimates and the Developer's voluntary Cost Cap

Evaluation: SECO independent cost estimate and qualitative assessment of Cost Caps

Considerations:

- The total cost estimate takes into consideration the independent cost estimate relative to the cost containment structure proposed by each developer.
- Further qualitative evaluation considers the effectiveness of the Cost Caps and their impact on project constructability.

Capital Cost Estimates

In its proposal, a Developer is required to submit credible capital cost estimates for the project. The capital cost estimates must include costs for (1) the proposed project (separately identifying new transmission facilities and Public Policy Transmission Upgrades) and (2) Network Upgrade Facilities, System Upgrade Facilities, System Deliverability Upgrades, Network Upgrades, and Distribution Upgrades, as applicable. A number of the selection metrics evaluate or are impacted by the proposed project's estimated cost. These metrics include the capital costs estimates for the project that take into account: the accuracy of the proposed estimate, the cost per MW ratio of the proposed project; additional metrics that may be proposed by the PSC, and other metrics that the NYISO may consider in consultation with its stakeholders (*e.g.*, changes in production costs).

In performing the evaluation of the capital cost estimates, the NYISO engaged independent consultants to review the project information submitted by a Developer, including its project cost estimate, and relied on the independent consultants' analyses and estimates in evaluating projects' performance under each metric.

Developer Cost Containment Proposals

A Developer may voluntarily submit a Cost Cap with its proposed project that covers its Included Capital Costs, but not its Excluded Capital Costs.

Under the tariff, a Cost Cap is a Developer's binding commitment to contain certain categories of capital costs — defined as "Included Capital Costs" — for a proposed Public Policy Transmission Project.

Included Capital Costs contain all of the capital costs necessary to design, construct, and place a facility into service with the exception of Excluded Capital Costs. The categories of Included Capital Cost include: contract work, labor, materials and supplies, transportation, special machine services, shop services, protection, injuries and damages, privileges and permits, engineering services, the cost of conducting an environmental site assessment or investigation, as well as reasonably foreseeable environmental site remediation and environmental mitigation costs, general administration services, legal services, real estate and land rights, rents, studies, training, asset retirement, and taxes. In addition, a Developer may choose to include, as Included Capital Costs, real estate costs for existing rights-of-way that are a part of the proposed project but are not owned by the Developer.

Excluded Capital Costs include:

1. Capital costs of Public Policy Transmission Upgrades,
2. Capital costs of upgrade facilities determined by the NYISO in one of its transmission expansion or interconnection processes,
3. debt costs, allowance for funds used during construction and other representations of the cost of financing the transmission project during the construction timeframe. That may be included

as part of the capital cost of the project when it enters into services or as otherwise determined by the Commission[8],

4. Unforeseeable environmental remediation and environmental mitigation costs, and
5. Real estate costs for existing rights-of-way that are part of the proposed Public Policy Transmission Project but are not owned by the Developer, that the Developer chooses not to include as Included Capital Costs in its proposal.

These Excluded Capital Costs are types of costs that cannot reasonably be estimated or foreseen by Developers within the 60-day project proposal window with sufficient certainty to subject the costs to the Cost Cap. The NYISO uses independent cost estimates developed by its consultants for the Excluded Capital Costs in its evaluation.

A Developer may submit a Cost Cap either in the form of a hard Cost Cap or a soft Cost Cap. The tariff characterizes the Cost Caps as follows:

Hard Cost Cap is a dollar amount for those costs above which the Developer will not be eligible to recover from ratepayers its actual costs for the Included Capital Costs that exceed the capped amount.

Soft Cost Cap is a dollar amount for those costs above which the Included Capital Costs are shared between the Developer and ratepayers, based on a Developer-proposed percentage. The share of costs above the cap borne by the Developer must be greater than or equal to 20% (leaving 80% of costs in excess of the cap to consumers.)

A Developer's voluntary Cost Cap plays directly into the NYISO's calculation of the total cost estimates for each project and its subsequent quantitative evaluation thereof. The calculation of the total cost estimate depends on whether a Developer submits a Cost Cap and the nature of a submitted Cost Cap. For instance, if a Developer elected not to submit a voluntary Cost Cap, the NYISO would rely only on the estimate of its independent consultant to calculate the Included Capital Costs for that project. However, if a Developer submits a Cost Cap, the tariff defines the treatment of the Cost Cap based on whether it is a hard or soft Cost Cap.

The calculation of Included Capital Costs for a hard Cost Cap requires the NYISO to take the submitted Cost Cap "as is" and use the capped amount as the amount for Included Capital Costs.

The calculation of Included Capital Costs for a Soft Cost Cap proposal depends on whether the capped amount is above or below the independent cost estimate prepared by the NYISO's consultants:

1. Developer's Soft Cost Cap is above the Independent Cost Estimate

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[8] As a part of the evaluation, the NYISO did not estimate or evaluate a developer's return on equity, financing costs, or incentives such as construction work in progress (CWIP) payments.

In this case, the NYISO's tariff prescribes the use of the soft Cost Cap as the amount for the Included Capital Costs. In such case, it is reasonable to use the Developer's own cost estimate because, as a matter of policy design, Developers should have an incentive to beat the independent cost estimate by bidding below what they expect will be the independent estimate for its project. If a Developer that bids above the independent estimate were to benefit from the lower independent estimate in project evaluation, then that would provide the wrong incentive to Developers as they develop their submissions. In the event that a Developer does bid above the independent estimate, it is either because there is an aspect of its project that is unusual and the Developer knows best what its costs will be, or because the Developer elects not to accept much cost risk with its project.

2. Developer's Soft Cost Cap is below the Independent Cost Estimate.

As a soft Cost Cap exposes ratepayers to some percentage of costs in excess of the Cost Cap, the NYISO does not simply use the proposed Cost Cap as the anticipated value of Included Capital Costs. Instead, the NYISO calculates an adjusted value of the Included Capital Cost that is based upon the level of ratepayer exposure to cost overruns. Specifically, the NYISO will (1) multiply the difference between (a) the independent consultant's cost estimate for Included Capital Costs and (b) the Developer's Included Capital Costs, by (c) the risk percentage assumed by ratepayers; and (2) add that amount to the Developer's Included Capital Costs.

All Developers submitted voluntary Cost Caps in their proposals for the Long Island PPTN. LS Power submitted a hard Cost Cap for T035, while NextEra and Propel NY submitted a range of different soft Cost Caps for their respective projects. Figure 1 below summarizes the independent estimate of the capital cost, which includes the Included Capital Costs and Excluded Capital Costs. The "Total Cost Estimate" shown in the figure and used throughout the report takes the Developer's Cost Cap into consideration, as detailed above.

Figure 1: Independent Estimate and Voluntary Cost Cap

Project	Cost Cap	Developer Cost Cap ($M)	Independent Estimate of Included Capital Costs ($M)	Independent Estimate of Excluded Capital Costs ($M)	Total Cost Estimates ($M)
T035 – LS Power	Hard Cap	$3,074	$5,920	$78	$3,152
T036 - NextEra Core 1	50/50 Soft	$5,882	$3,230	$1,137	$7,019
T037 - NextEra Core 2	50/50 Soft	$6,867	$3,627	$1,259	$8,126

T038 - NextEra Core 3	50/50 Soft	$7,444	$4,252	$1,209	$8,653
T039 - NextEra Core 4	50/50 Soft	$7,211	$4,457	$1,272	$8,483
T040 - NextEra Core 5	50/50 Soft	$5,898	$3,610	$1,086	$6,984
T041 - NextEra Core 6	50/50 Soft	$6,774	$4,448	$1,138	$7,912
T042 - NextEra Core 7	50/50 Soft	$10,373	$13,750	$1,131	$13,193
T043 - NextEra Enh 1	50/50 Soft	$11,471	$8,753	$1,298	$12,769
T044 - NextEra Enh 2	50/50 Soft	$14,991	$16,128	$1,338	$16,898
T047 - Propel Base 1	20/80 Soft	$1,877	$2,269	$289	$2,480
T048 - Propel Base 2	20/80 Soft	$1,687	$1,966	$211	$2,121
T049 - Propel Base 3	20/80 Soft	$2,131	$2,642	$295	$2,835
T051 - Propel Alt 5	20/80 Soft	$2,554	$2,902	$430	$3,262
T052 - Propel Alt 6	20/80 Soft	$3,953	$4,071	$658	$4,705
T053 - Propel Alt 7	20/80 Soft	$5,118	$5,113	$458	$5,576

[qualitative cost cap evaluation discussion will be completed in a future version of the report]

Key Findings

- ✓ **The project cost estimates range from $2.1B to $16.9 B**. This wide-ranging total cost estimates result from the combination of project designs and cost caps.
- ✓ **[Key findings on qualitative cost cap evaluation will be filled out in a future version of the report]**

3.3 Transfer Capability & Cost Per MW Ratios

Evaluation Metric: Transfer Capability & Cost Per MW Ratios

Purpose: Determines the cost per MW ratio by dividing the Total Cost Estimate by the MW value of increased transfer capability

Evaluation: Compare the electrical benefits due to the projects, such as increased transfer limits, flexibility during outage conditions, and expandability, to the total cost estimates.

Considerations:

- Lower cost per MW is better when comparing projects' benefit/cost ratios. Note that there are no established thresholds for this metric.

The NYISO calculates the cost per MW ratio metric by dividing each project's Total Cost Estimate[9] by the following three different MW values to help inform how efficiently each project meets the PPTN:

- Increase in normal transfer limit of the Long Island export interface. See Appendix placeholder for more details.
- Increase in offshore wind (OSW) energy integration under light load N-1-1 system conditions. See the Expandability metric for more details.
- Double outage operability range. See the Operability & Resiliency metric for more details.

The results are shown in Figure 2 and Figure 3, with highest performing projects having low $/MW across all transfer, expandability, and operating range values.

Figure 2: Transfer Capability & Cost Per MW Ratios

Project	LI Export Increase (MW)	$M/MW	OSW Expandability (MW)	$M/MW	Second Outage Operating Range (MW)	$M/MW
T035 - LS Power	2,825	$1.12	4,350	$0.72	3,405	$0.93
T036 - NextEra Core 1	1,700	$4.13	4,450	$1.58	3,630	$1.93
T037 - NextEra Core 2	2,400	$3.39	4,150	$1.96	3,870	$2.10
T038 - NextEra Core 3	2,225	$3.89	4,600	$1.88	4,650	$1.86
T039 - NextEra Core 4	2,150	$3.95	4,400	$1.93	4,245	$2.00
T040 - NextEra Core 5	2,150	$3.25	4,375	$1.60	4,250	$1.64
T041 - NextEra Core 6	2,500	$3.16	4,475	$1.77	4,530	$1.75
T042 - NextEra Core 7	2,500	$5.28	4,500	$2.93	4,540	$2.91
T043 - NextEra Enh 1	2,250	$5.68	5,400	$2.36	5,180	$2.47
T044 - NextEra Enh 2	2,275	$7.43	4,900	$3.45	5,220	$3.24
T047 - Propel Base 1	1,500	$1.65	3,750	$0.66	2,250	$1.10
T048 - Propel Base 2	1,525	$1.39	3,725	$0.57	1,945	$1.09
T049 - Propel Base 3	1,500	$1.89	3,750	$0.76	2,245	$1.26
T051 - Propel Alt 5	2,225	$1.47	4,300	$0.76	3,495	$0.93
T052 - Propel Alt 6	2,600	$1.81	5,075	$0.93	4,695	$1.00
T053 - Propel Alt 7	2,550	$2.19	4,350	$1.28	3,670	$1.52

9 The cost per MW metric uses the Total Cost Estimate described in 4.1, as opposed to SECO's independent cost estimate. Consideration of the difference between the Developer's Cost Cap and SECO's independent cost estimate of Included Costs is considered in the cost containment metric.

Figure 3: Cost Per MW Ratios

Key Findings

- ✓ **The transfer capability of each proposal was evaluated using three different methods to offer a more holistic view.** In general, proposals with fewer facilities that expand the system, such as T047 Propel Base 1 and T048 Propel Base 2, offer less transfer capability.
- ✓ **T035 LS Power, T048 Propel Base 2, T049 Propel Base 3, and T051 Propel Alt 5 were among the lowest cost per MW across all three values.**

3.4 Expandability

Evaluation Metric: Expandability

Purpose: Considers the impact of the proposed project on future system expansion

Evaluation: Substation layout review, power flow analysis

Considerations:

- Physical expandability – more new points of interconnection (POIs) proposed by the developers
- Electrical expandability – greater ability to accommodate future generation

The expandability metric assesses each project's ability to accommodate future offshore wind and consists of two separate, but related, assessments—physical expandability and electrical expandability.

Physical expandability evaluates the number of potential POIs for future offshore wind facilities proposed by a project once the project is complete or in the future based on additional modifications to the transmission facilities. Open breaker positions with major equipment included in the proposal (e.g., breaker and buswork) are considered to be "Proposed POI". Open positions that may be created by the installation of breakers in the future (*e.g.*, breakers indicated as future builds in the proposal) are considered to be "Expandable POIs." Figure 4 summarizes the POIs proposed by each project.

The electrical expandability analysis assesses the ability of each project to integrate more than the minimum 3,000 MW of offshore wind interconnected to Long Island. The assessment performs N-0, N-1, and N-1-1 analysis for the Policy Scenario based on the assumption that up to 6,000 MW of offshore wind may be interconnected to Long Island. Figure 7 shows the maximum amount of offshore wind interconnected to Long Island (up to 6,000 MW) that can be accommodated by each project without curtailment under N-1-1 conditions.

Furthermore, the analysis finds that projects marked with an asterisk (*) could deliver more offshore wind capacity than shown in the Figure 5 by redistributing offshore wind interconnections to different POIs. Appendices [x] and [x] detail the physical and electrical expandability, respectively.

Figure 4: Physical Expandability

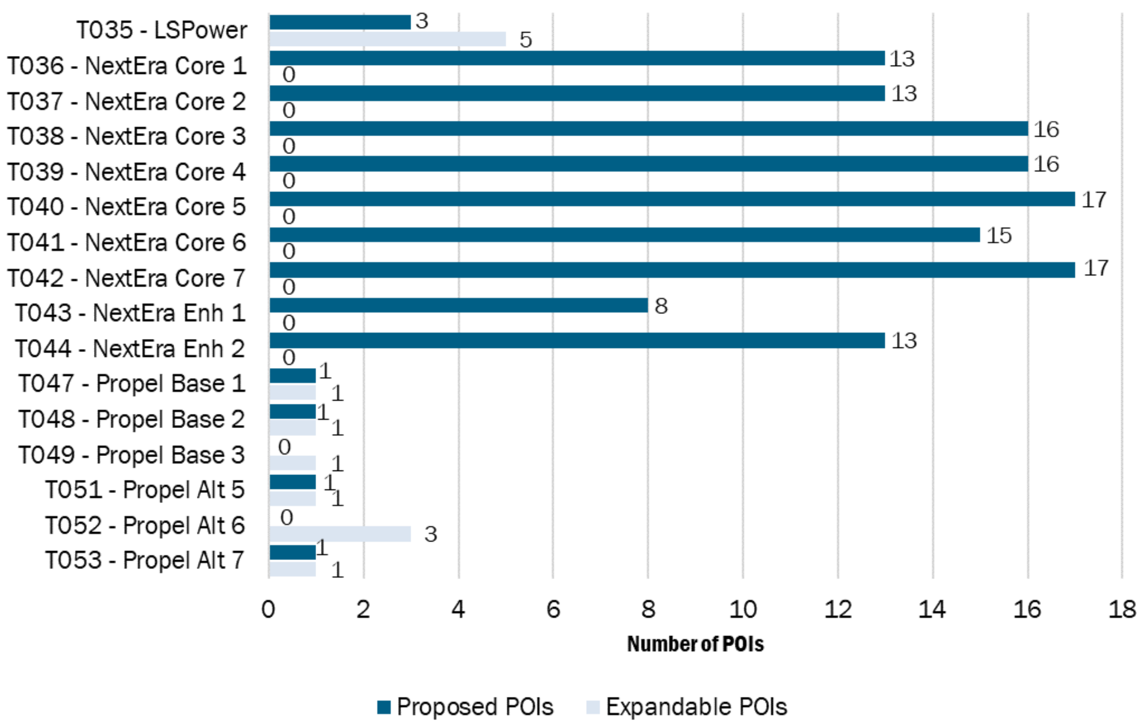
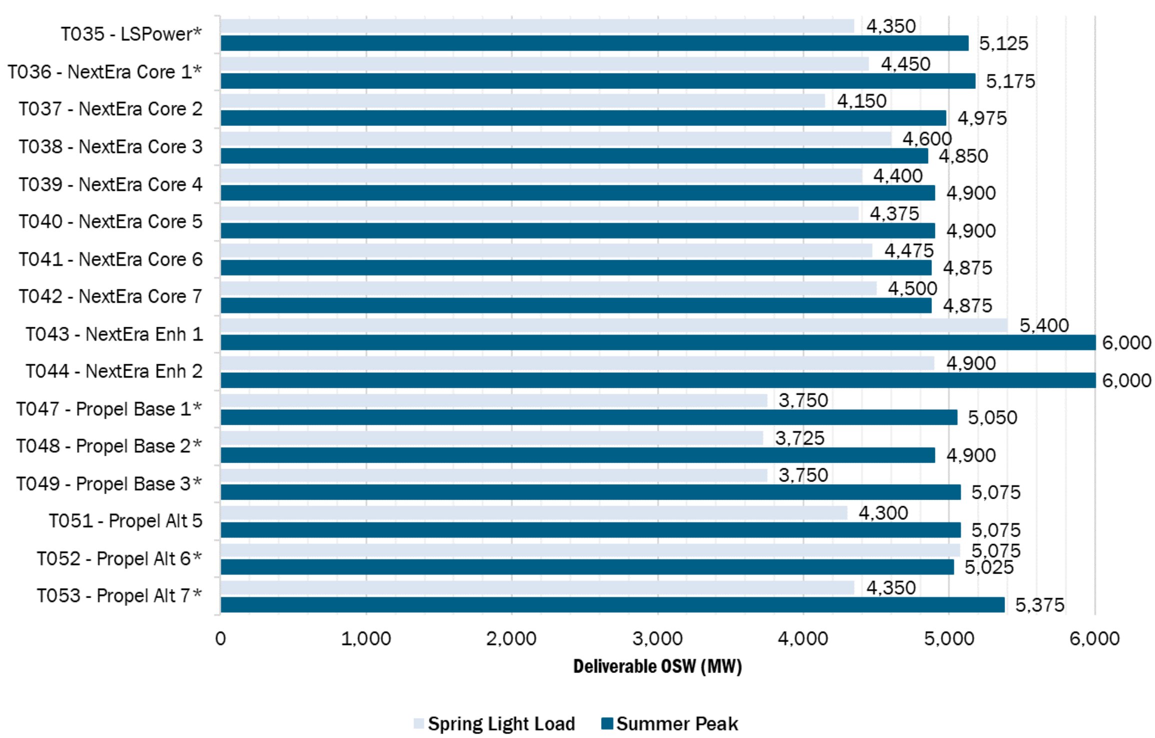


Figure 5: Electrical Expandability



Key Findings

- ✓ **The NextEra projects propose the greatest number of new POIs for future offshore wind facility connections at a diverse set of substation locations.** T042 and T044 provide an additional benefit by building two 122-mile 1200 MW HVDC connections from offshore platforms in the Hudson South Lease area up the Hudson River to the proposed Buchanan substation.

- ✓ **All projects can reliability connect more than 3,000 MW of offshore wind generation to Long Island, with T043 NextEra Enhanced 1 and T052 Propel NY Alternate 6 accommodating the most offshore wind generation under light load conditions.**

3.5 Operability & Resiliency

Evaluation Metric: Operability & Resiliency

Purpose: Considers how the proposed projects would provide additional transfer capability and operating flexibility or the studied future grid conditions

Evaluation: Transfer capability analysis under outage conditions, physical substation layout resiliency review, short circuit analysis to determine electrical system strength, and operating flexibility with expected high levels of offshore wind resources

Considerations:

- Wider range of transfer capability under outage conditions, ability to respond to offshore wind resource output variability, less disruption due to extreme weather, higher grid strength

The NYISO evaluates the operability and resiliency of the proposed projects based on some key metrics that consider how each of the projects compare when integrated into the network. The metrics consider – flexibility under facility outage conditions and physical substation resiliency. In addition, the metrics look at some potential likely conditions of a future grid including electrical system strength and operating flexibility with high levels of offshore wind resources connected to Long Island.

3.5.1 Flexibility Under Transmission Facility Outage Conditions

Transmission facility outages occur in normal operating conditions. This operability analysis focuses on the transfer limits under transmission facility outage conditions to evaluate the flexibility of each project. These maintenance condition transfer limits were determined using optimal transfers to represent the NYISO's energy market scheduling systems used by NYISO Operations.

The Policy and Policy +B-VS scenarios were analyzed with the same methodology. The analysis assumed that the Barrett-Valley Stream constraint would only affect Export Transfers. Therefore, the Import Transfers were not run for the Policy + B-VS Scenario.

When reviewing these transfer limits, a larger range of transfer Import and Export limits is preferable as this gives the NYISO more operational flexibility under transmission outage conditions.

Figure 6: Policy Scenario: Single & Double Outage Import & Export Limits

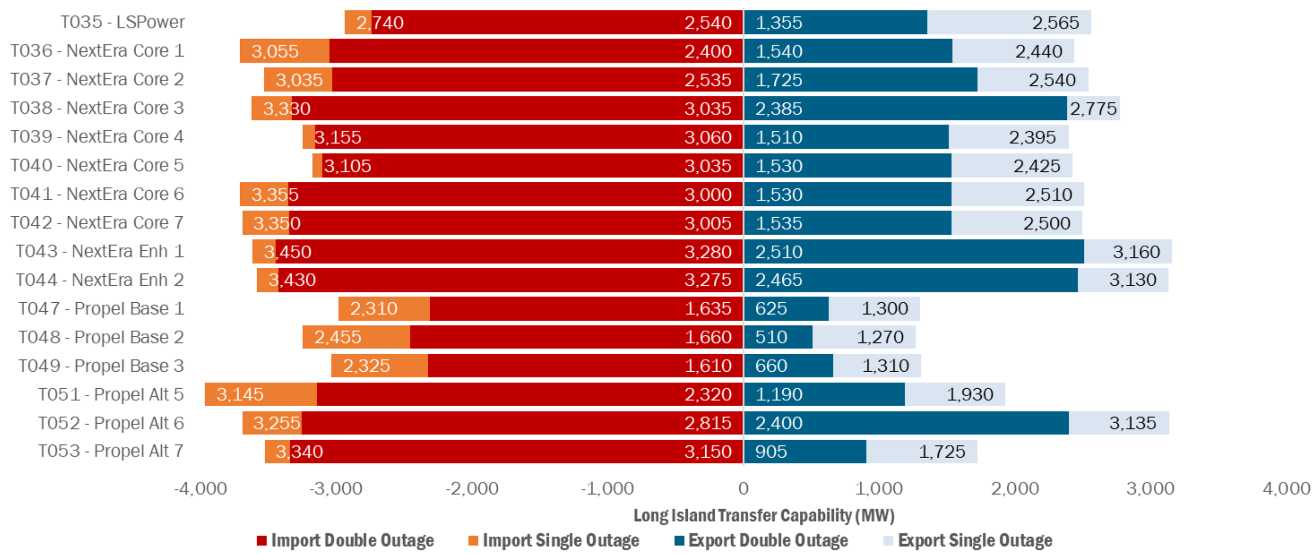
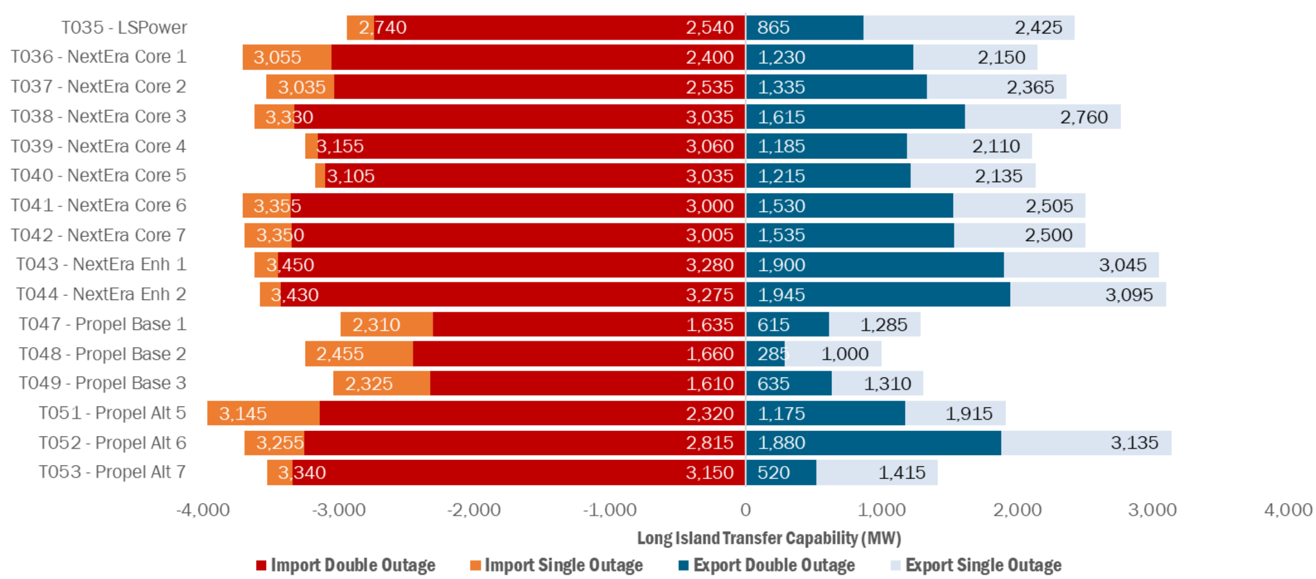


Figure 7: Policy + Barrett–Valley Stream Scenario: Single & Double Outage Import & Export Limits



3.5.2 System Strength

System Strength refers to the grid's voltage stiffness and ability of system components, especially inverter-based resources (IBRs), to respond "as expected" to system perturbations. Weighted short circuit ratio (WSCR) is a common screening method to obtain a high-level understanding of the system strength with multiple IBRs in close proximity. While the North American Reliability Corporation (NERC) does not have a minimum WSCR criterion, a higher WSCR generally indicates a stronger system. The WSCR results are shown in Figure 10 and more details on the analysis can be found in Appendix placeholder. Projects employing a greater number of 345 kV HVAC facilities generally have a higher level of WSCR values, which would help to facilitate the integration of future IBRs.

Figure 8: Weighted Short Circuit Ratio (WSCR)

Project	WSCR			
	N-0	N-1	N-2	N-3
Pre-Project	1.94	1.83	1.61	/
T035 - LS Power	0.82	0.78	0.7	/
T036 - NextEra Core 1	2.49	2.46	2.39	2.12
T037 - NextEra Core 2	2.65	2.63	2.59	2.47
T038 - NextEra Core 3	2.5	2.45	2.38	2.26
T039 - NextEra Core 4	2.55	2.49	2.4	2.17
T040 - NextEra Core 5	2.54	2.48	2.4	2.16
T041 - NextEra Core 6	1.79	1.75	1.68	1.45
T042 - NextEra Core 7	1.79	1.75	1.68	1.45
T043 - NextEra Enh 1	1.47	1.47	1.44	1.39
T044 - NextEra Enh 2	1.91	1.9	1.87	1.78
T047 - Propel Base 1	2.26	2.23	2.11	1.95
T048 - Propel Base 2	2.21	2.15	2.02	1.78
T049 - Propel Base 3	2.24	2.2	2.06	1.87
T051 - Propel Alt 5	2.29	2.26	2.17	2.09
T052 - Propel Alt 6	2.59	2.55	2.42	2.32
T053 - Propel Alt 7	1.34	1.31	1.21	1.07

3.5.3 Physical Substation Resiliency

Resiliency of the proposed projects' associated substations was assessed based on three categories—substation bus type, flood risk, and hurricane risk. Each projects' substations were ranked based on its performance in each category. Total resiliency score for each project was calculated by summing the three category rankings. The lower the score, the better the projects' associated substations perform in context of this metric.

Figure 9: Total Resiliency Score

Project	Total Resiliency Score
T035 - LS Power	13.5
T036 - NextEra Core 1	33.5
T037 - NextEra Core 2	41.5
T038 - NextEra Core 3	57
T039 - NextEra Core 4	58
T040 - NextEra Core 5	48
T041 - NextEra Core 6	52
T042 - NextEra Core 7	52
T043 - NextEra Enh 1	78
T044 - NextEra Enh 2	70
T047 - Propel Base 1	34
T048 - Propel Base 2	34.5
T049 - Propel Base 3	34
T051 - Propel Alt 5	34
T052 - Propel Alt 6	31
T053 - Propel Alt 7	43

3.5.4 Local Network Operability

Benefit or detriment to the TO's local operability, if any, will be evaluated in this section.

3.5.5 Transmission Operations Under High Offshore Wind Scenarios

In the NYISO's 2019 Report on "Reliability and Market Considerations for a Grid in Transition,"[10] the NYISO identified a reliability concern that it may be challenged to meet NERC Transmission Operations requirements when operating under high levels of intermittent generation with system and locational demand requirements that may be difficult to forecast in real-time operations.

Consistent with existing practices in its energy markets, the NYISO would expect to address future transmission operating reliability issues by employing a certain level of reliability margin for the transmission constraints being secured in real-time grid operations. Such reliability margins are used to address resource and/or load variability or other forecasting uncertainties that are not addressed by NYISO's real-time energy market systems so as to avoid overloading transmission constraints. Constraint reliability margin values used today typically range from 10 MW to 50 MW for Long Island area

[10] https://www.nyiso.com/documents/20142/2224547/Reliability-and-Market-Considerations-for-a-Grid-in-Transition-20191220%20Final.pdf

transmission elements. However, the NYISO anticipates that future reliability margins for Long Island transmission elements will need to significantly increase to account for the future high levels of offshore wind resource variability and other wind and net-load forecasting uncertainties.

Certain projects are comprised of both AC and HVDC transmission elements and only the projects' AC transmission elements would require increased values of constraint reliability margins. This requirement is because projects' AC transmission elements are expected to respond naturally to offshore wind variability and other forecasting uncertainties, whereas for those projects with HVDC elements, the HVDC is expected to be scheduled to hold a certain fixed power schedule within the five-minute real-time scheduling horizon. For such projects with HVDC elements, the HVDC schedules would presumably be communicated from the NYISO control center operators or directly from the NYISO energy scheduling systems.

Given this expected operation of a projects' HVDC elements, it is recognized that all of the offshore wind variability and forecasting uncertainties will be realized on only those AC transmission elements that are in parallel with the HVDC elements. As a result, for those projects with fewer number of AC interconnections connecting Long Island to the rest of the state, it is expected that a higher value of constraint reliability margin on those AC interconnections will be required than for those projects that have a greater number of AC interconnections.

The main features and challenges of controlling a proposed HVDC transmission project manually through operator direction or even automatically via the NYISO's real-time energy markets using a telemetry communication path are: (1) more complex grid operating paradigm based on need to actively control the HVDC transmission in order to facilitate changes in off-island power transfers based on forecasted load and supply resource output changes as compared to an Integrated AC system in which power transfers respond naturally to changes in load and supply resource output changes, (2) the need to derate the parallel AC grid by use of a larger transmission margin for the parallel AC grid in recognition of the HVDC transmission not responding to unscheduled changes or variability in load or power supplier output changes as compared to an integrated AC system, and (3) a backup mode needs to be designed in case of NYISO real-time energy market system failure or telecommunications failure with the HVDC operator. The backup mode would be expected to employ less frequent manual direction from the NYISO operator to address reliability criteria in real-time operation.

3.5.6 Summary of Operability Assessment

Key Findings

- ✓ **Both import and export capabilities are important for Long Island.** Projects, such as T043 NextEra Enhanced 1 and T052 Propel Alt 6, offer a wide range of flexibility, while projects like T047 Propel Base 1, T048 Propel Base 2, and T049 Propel Base 3 offer a narrower range in their ability to both import to and export from Long Island.

- ✓ **When reviewing these transfer limits, larger transfer import and export limits are preferable**. The increase of transfer limits under outage conditions is the key finding under the operability metric, with larger transfer limits giving the NYISO more operational flexibility. The electrical grid is rarely operated with all facilities in service, and projects that can maintain large transfer limits under outage conditions bolster reliability and are more favorable.

- ✓ **While there is currently no applicable reliability criteria for system strength, this analysis helps to understand how the system might behave with the different proposals.** Projects T035 LS Power and T053 Propel Alt 7 do not increase the short circuit strength and further investigation may be required prior to integration of nearby inverter-based resources.

- ✓ **Projects with stronger AC tie lines integrating Long Island with the rest of the system provide higher system strength.** Projects with VSC HVDC line(s) may help system performance by coordinating with nearby inverter-based resources without increasing the weighted short circuit ratio.

- ✓ **The projects that perform higher in the resiliency evaluation tend to have gas-insulated substation designs and more inland interconnection points on the system that are less susceptible to extreme weather events.**

3.6 Production Cost Benefits & Performance

Evaluation Metric: Production Cost Benefits

Purpose: Assess the economic benefits of the proposed projects by reducing generation production costs in the New York Control Area

Evaluation: Hourly resolution production cost simulations for 2030, 2035, 2040, and 2045 under several future scenarios

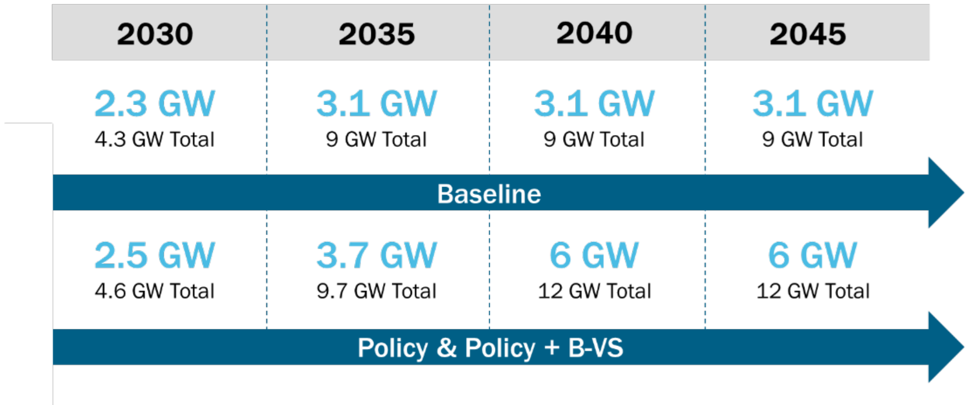
Considerations:

- Projects to unbottle offshore wind energy production
- Projects able to reduce or eliminate offshore wind curtailment will create the greatest production cost savings
- Larger production cost savings reduces the societal cost of producing electricity to meet New York demand

Production cost simulations can gauge the effectiveness of a proposed transmission project in reducing NYCA-wide production cost. A pre-project simulation is first performed without a project in place to establish a baseline for comparison with all assumptions included for the model. A post-project simulation with the transmission project added to the underlying transmission model is performed and the result are compared. Production cost savings for a project are calculated as the difference between the pre-project and post-project results over the duration of a project's study period, starting at the estimated in-service date and extending 20 years.

Assumptions related to generation and load are kept consistent across both simulations, excluding assumed offshore wind installed capacity. Details on the production cost simulation assumptions are further described in Appendix placeholder. The offshore wind capacity varies between the Baseline and Policy Scenarios as shown in the figure below.

Figure 10: Long Island Offshore Wind Addition Timelines



The Long Island PPTN project simulations all show improvements in the export capability of Long Island by adding tie lines between Long Island and the lower Hudson Valley. This added transfer capacity and upgrades to the internal Long Island system reduce the amount of curtailment from offshore wind resources. The energy produced through reduced curtailment of offshore wind resources can then be used to offset more expensive generation to meet New York's energy demand and, therefore, produce a production cost savings. Production cost savings are also created by offsetting high-cost energy imports from neighboring regions with lower cost New York-based generation that was previously inaccessible due to transmission congestion.

In general, all of the proposed projects produce savings by unbottling offshore wind resources in Long Island and reducing the amount of imports from neighboring regions. The figures below show the estimated production cost savings for each project over a 20-year period in 2022 real million dollars.

Figure 11: Estimated 20-year Production Cost Savings (2022 $M)

Estimated Total 20-Year Savings (2022 $M)			
Project	Baseline	Policy	Policy + B-VS
T035 - LS Power	104	340	906
T036 - NextEra Core 1	108	303	291
T037 - NextEra Core 2	108	364	378
T038 - NextEra Core 3	109	380	402
T039 - NextEra Core 4	39	305	307
T040 - NextEra Core 5	107	339	332
T041 - NextEra Core 6	110	291	308
T042 - NextEra Core 7	110	291	308
T043 - NextEra Enh 1	87	458	745
T044 - NextEra Enh 2	81	441	582
T047 - Propel Base 1	109	337	568
T048 - Propel Base 2	99	313	513
T049 - Propel Base 3	102	344	902
T051 - Propel Alt 5	104	341	609
T052 - Propel Alt 6	96	352	618
T053 - Propel Alt 7	108	360	622

Figure 12: Production Cost Savings Over 20 Years (2022 $M)

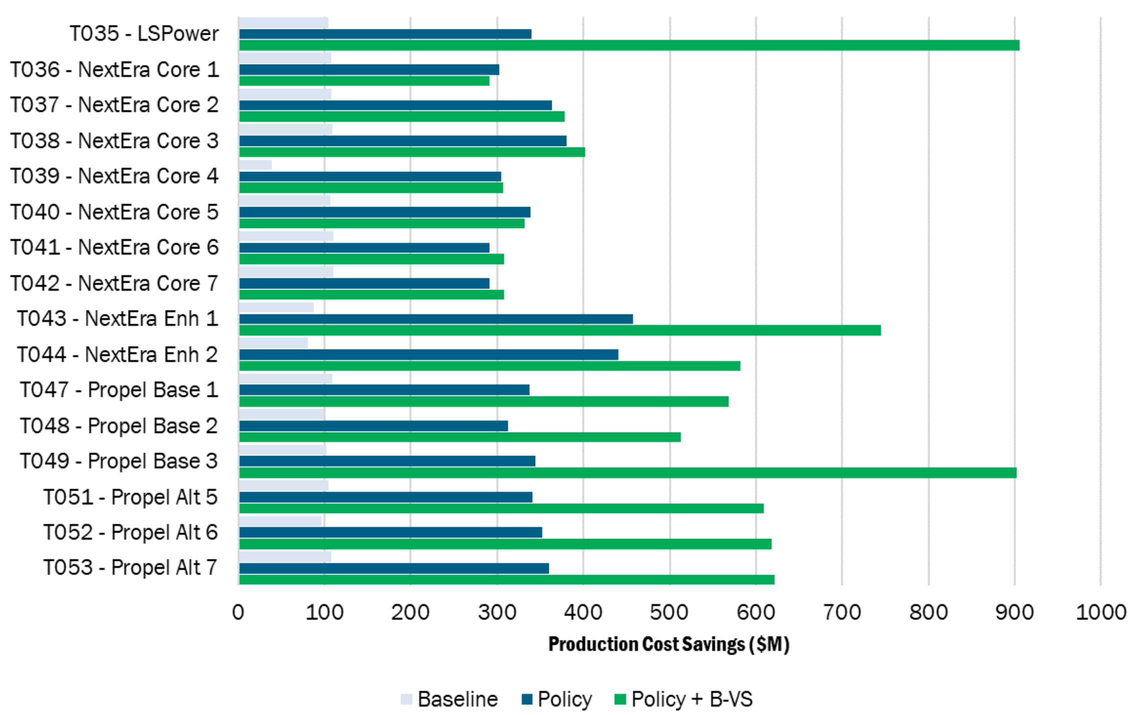
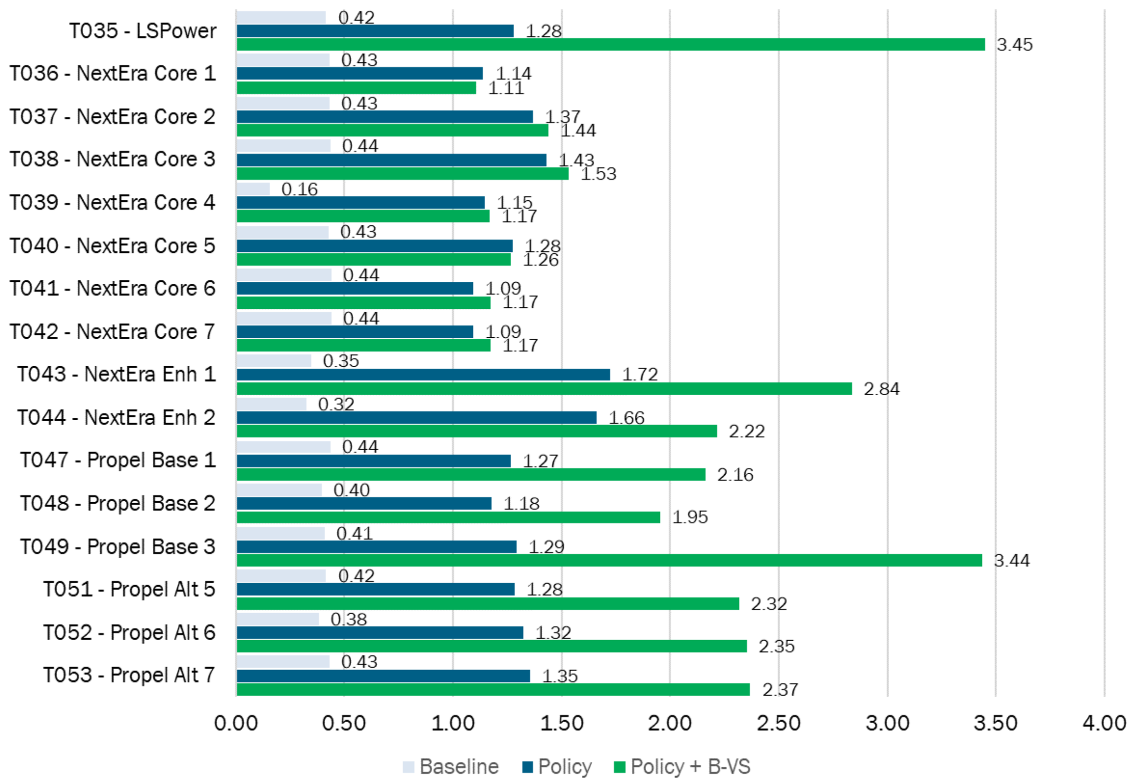


Figure 13: Savings As Percentage of Total NY Production Cost



In general, the production cost savings in the Baseline Scenario are relatively low as this scenario does not include the full achievement of CLCPA policies and has a reduced level of offshore wind capacity as compared to other scenarios. Offshore wind curtailment in the Baseline Scenario is less than 5% prior to transmission projects and presents less opportunity for projects to produce economic benefit.

Production cost savings are higher in the Policy and Policy + B-VS Scenarios due to higher offshore wind curtailment levels in the pre-project simulations. Full achievement of the CLCPA increases offshore wind curtailment in both scenarios, while the inclusion of the existing Barrett-Valley Stream transmission constraints in the Policy + B-VS scenario causes additional curtailment. The proposed projects all unbottle various levels of offshore wind generation in Long Island and reduce the net import for the New York Control Area (NYCA) system.

This analysis, however, shows more production cost savings from the proposed projects that relieve the network constraints on the 138 kV paths. With the Barrett-Valley Stream path secured, Empire Wind II curtailment accounts for almost 60% or total offshore wind curtailment in Long Island in 2040. As a result, the projects that upgrade the lines near Barrett 138 kV or include alternate paths out of the Barrett 138 kV substation for power to flow (*i.e.*, relieving existing transmission constraints) have higher production cost savings due to unbottling of additional offshore wind generation.

Key Findings

- ✓ **Production cost savings are not a material distinguishing factor among projects in the Baseline and Policy scenarios.** Pre-project offshore wind generation curtailment rates are ~10% and post-project displaced energy is often from other renewables. As a result, they produce minimal savings by swapping low-cost energy. Additionally, the model only considers conditions with all lines in service and with no maintenance or random transmission outages. Therefore, curtailments presented in this study are conservative estimates and might not fully capture any additional curtailments due to transmission outages.

- ✓ **Production cost savings in the Barrett-Valley Stream Scenario show that T035, T043, and T049 provide substantial production cost benefit.** Under the Policy + B-VS Scenario, which includes the existing Barrett–Valley Stream transmission constraints, most projects show greater production cost benefits than in the evaluation without the constraint. The most effective projects have two to three times the production cost savings when evaluated under the Policy + B-VS Scenario compared to the Policy scenario without the Barrett-Valley Stream transmission constraint.

3.6.1 Performance Evaluation

Evaluation Metric: Performance

Purpose: Considers how the proposed project may affect the utilization of the system, deliverability of offshore wind energy, and reduction in carbon dioxide emissions

Evaluation: Long Island energy transfers, offshore wind generated energy, fossil fuel related carbon dioxide emissions

Considerations:

- Higher Long Island import/export energy
- Higher offshore wind generation (*i.e.*, lower offshore wind curtailment)
- Reduction in regional carbon dioxide emissions

For the Long Island PPTN, the performance metric focuses on the ability of a project to efficiently utilize the grid to increase energy transfers between Long Island and the rest of New York. Unlike the transfer capability metric, which identifies the maximum instantaneous transfer limit (MW) of an interface, transmission utilization metric identifies the total annual energy transfer (MWh) of an interface.

The results help determine the effectiveness of a transmission project to export offshore wind energy off Long Island and to import energy when needed.

This performance analysis also includes an evaluation of the impact of proposed transmission projects on the energy deliverability of offshore wind projects on Long Island, the import and export of energy with neighboring regions, and the dispatch of fossil generating plants and resulting CO_2 emissions.

3.6.1.1 Transmission Utilization

For the purposes of this analysis, transmission utilization is measured as the total annual energy transacted across existing and proposed project inter-zonal transmission paths that interconnect to the Long Island (Zone K). This also includes transmission paths that connect to other areas within the NYCA and external to the NYCA.

Transmission utilization is split into imported and exported energy, netted on an hourly basis, then summed over each year to delineate the directional flow impact of each project. The figures below present the 20-year utilization results for each proposed project under the Baseline and Policy Scenarios.

Figure 14: Baseline Scenario 20-Year Transmission Utilization

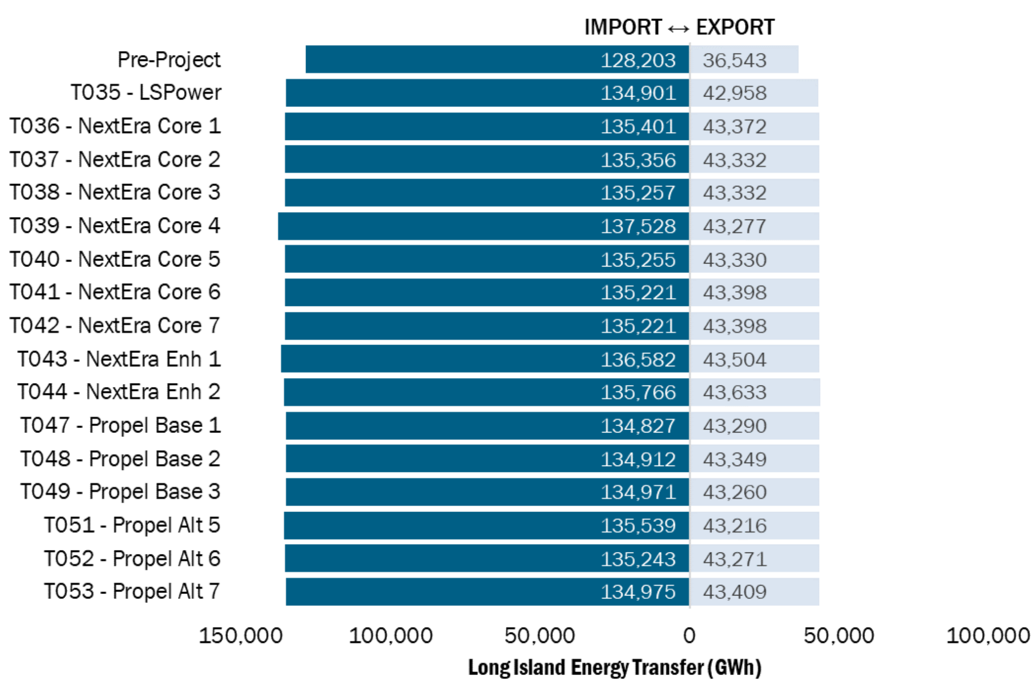


Figure 15: Policy Scenario Transmission Utilization

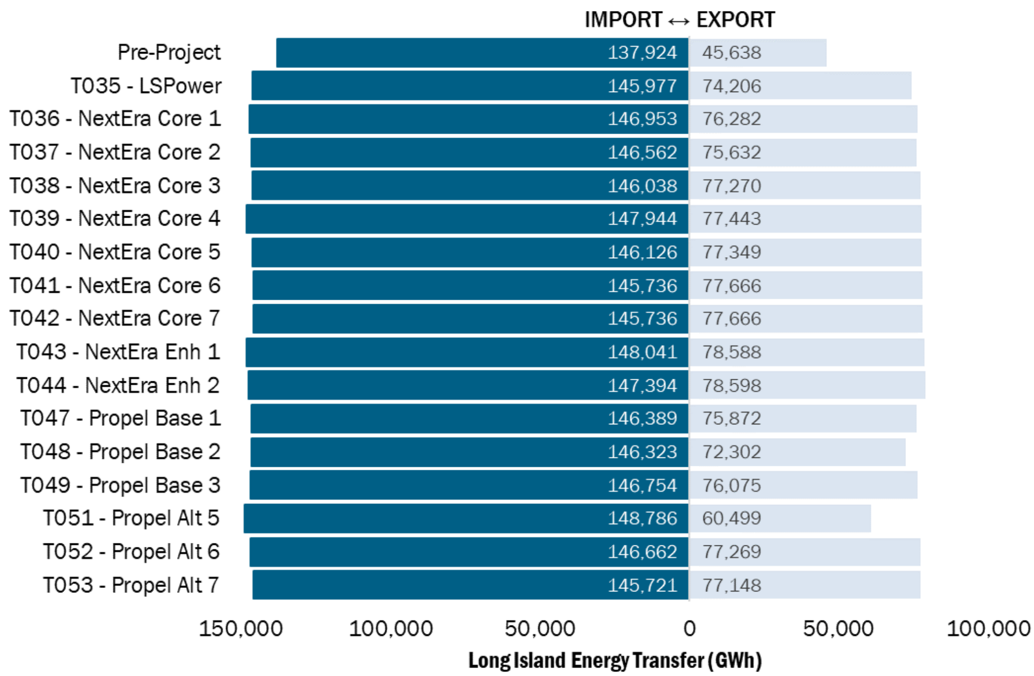
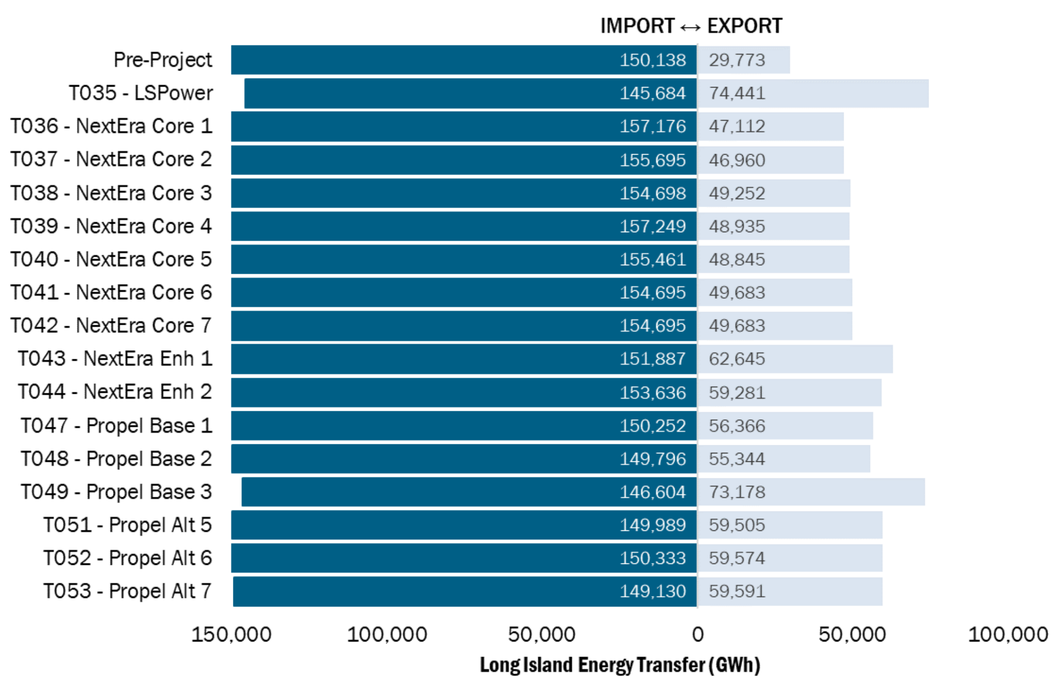


Figure 16: Policy + Barrett–Valley Stream Scenario Transmission Utilization



3.6.1.2 Long Island Offshore Wind Energy Deliverability

A key driver behind the system performance and economic benefits presented is the ability of a proposed transmission project to increase offshore wind energy production through curtailment reductions. The NYISO leverages an energy deliverability measure to gauge the effectiveness of a project in reducing curtailment, which is defined below.

$$Energy\ Deliverability\ (\%) = \frac{Annual\ Energy\ Production\ (GWh)}{Potential\ Annual\ Energy\ Production\ (GWh)}$$

$$Energy\ Deliverability\ (\%) = 100\% - Curtailment\ (\%)$$

Energy deliverability represents the ability of renewable generation (*e.g.*, wind, solar, and hydro) to inject energy into the grid to serve end-use consumers without curtailment. It is expressed as the ratio of energy generated to total potential energy for those resources. Generally, energy deliverability is reduced as more renewable capacity is added to the system due to the transmission constraints in the system. The greater the renewable generation curtailment in a specific location, the greater the opportunity for transmission investment.

In Long Island, transmission constraints exist today and could become more severe within the Zone K and at the ties connecting Zone K to other zones. With the anticipated increase in the injection of offshore wind energy into Long Island, both types of constraints affect the energy deliverability of offshore wind production. To enable the effective export of energy from Long Island, proposed projects may need to address both inter-zonal and intra-zonal transmission constraints. Projects with high offshore wind energy deliverability values (100%) will have to effectively address transmission constraints that limit offshore wind energy delivery and export.

The figures below show the percent of energy deliverability by the proposed projects for the Baseline and Policy Scenarios for each year simulated.

Figure 17: Baseline Scenario Long Island Offshore Wind Energy Deliverability

Project	2030	2035	2040	2045
Baseline Case	99.4%	95.7%	97.2%	98.8%
T035 - LS Power	100.0%	100.0%	100.0%	100.0%
T036 - NextEra Core 1	100.0%	100.0%	100.0%	100.0%
T037 - NextEra Core 2	100.0%	100.0%	100.0%	100.0%
T038 - NextEra Core 3	100.0%	100.0%	100.0%	100.0%
T039 - NextEra Core 4	100.0%	100.0%	100.0%	100.0%
T040 - NextEra Core 5	100.0%	100.0%	100.0%	100.0%
T041 - NextEra Core 6	100.0%	100.0%	100.0%	100.0%
T042 - NextEra Core 7	100.0%	100.0%	100.0%	100.0%
T043 - NextEra Enh 1	100.0%	100.0%	100.0%	100.0%
T044 - NextEra Enh 2	100.0%	100.0%	100.0%	100.0%
T047 - Propel Base 1	100.0%	100.0%	100.0%	100.0%
T048 - Propel Base 2	100.0%	100.0%	100.0%	100.0%
T049 - Propel Base 3	100.0%	100.0%	100.0%	100.0%
T051 - Propel Alt 5	100.0%	100.0%	100.0%	100.0%
T052 - Propel Alt 6	100.0%	100.0%	100.0%	100.0%
T053 - Propel Alt 7	100.0%	100.0%	100.0%	100.0%

Figure 18: Policy Scenario Long Island Offshore Wind Energy Deliverability

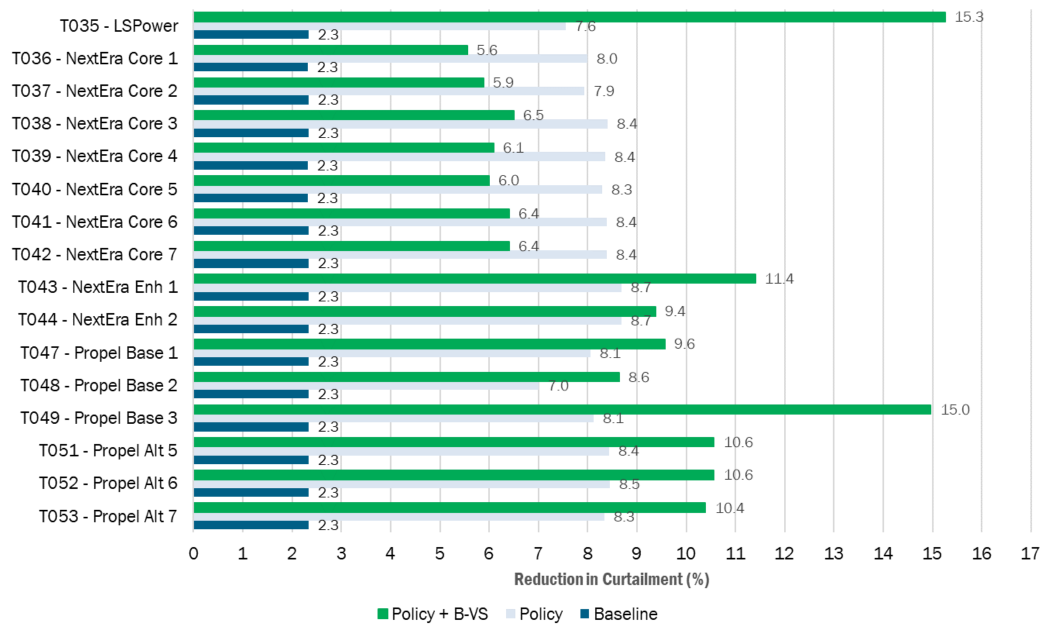
Project	2030	2035	2040	2045
Policy Case	98.3%	96.3%	87.0%	89.7%
T035 - LS Power	99.5%	99.9%	98.4%	98.4%
T036 - NextEra Core 1	99.0%	99.9%	99.1%	99.3%
T037 - NextEra Core 2	99.0%	99.9%	99.1%	99.1%
T038 - NextEra Core 3	99.0%	99.9%	99.8%	99.8%
T039 - NextEra Core 4	99.0%	99.8%	99.6%	99.8%
T040 - NextEra Core 5	99.0%	99.9%	99.6%	99.6%
T041 - NextEra Core 6	99.1%	99.9%	99.8%	99.8%
T042 - NextEra Core 7	99.1%	99.9%	99.8%	99.8%
T043 - NextEra Enh 1	100.0%	100.0%	100.0%	100.0%
T044 - NextEra Enh 2	100.0%	100.0%	100.0%	100.0%
T047 - Propel Base 1	99.1%	99.9%	99.1%	99.4%
T048 - Propel Base 2	99.0%	99.9%	97.3%	98.0%
T049 - Propel Base 3	99.0%	99.9%	99.1%	99.6%
T051 - Propel Alt 5	99.2%	99.9%	99.8%	99.8%
T052 - Propel Alt 6	99.2%	99.9%	99.8%	99.9%
T053 - Propel Alt 7	99.1%	99.9%	99.7%	99.7%

Figure 19: Policy + Barrett–Valley Stream Scenario Long Island Offshore Wind Energy Deliverability

Project	2030	2035	2040	2045
Policy Case + B-VS	75.5%	83.9%	84.1%	86.3%
T035 - LS Power	99.5%	99.9%	98.4%	98.4%
T036 - NextEra Core 1	79.4%	86.9%	91.7%	92.1%
T037 - NextEra Core 2	79.9%	87.3%	92.0%	92.3%
T038 - NextEra Core 3	80.5%	87.8%	92.7%	92.9%
T039 - NextEra Core 4	79.6%	87.3%	92.4%	92.7%
T040 - NextEra Core 5	79.6%	87.3%	92.3%	92.5%
T041 - NextEra Core 6	79.9%	87.3%	92.8%	93.1%
T042 - NextEra Core 7	79.9%	87.3%	92.8%	93.1%
T043 - NextEra Enh 1	89.6%	93.5%	96.5%	96.7%
T044 - NextEra Enh 2	81.8%	88.3%	93.5%	100.0%
T047 - Propel Base 1	87.6%	92.4%	94.2%	94.9%
T048 - Propel Base 2	86.1%	91.4%	93.6%	93.9%
T049 - Propel Base 3	99.0%	99.8%	97.7%	98.5%
T051 - Propel Alt 5	88.6%	93.1%	95.5%	95.8%
T052 - Propel Alt 6	87.5%	92.5%	95.8%	96.3%
T053 - Propel Alt 7	87.8%	92.6%	95.6%	95.8%

In the Baseline Scenario, all projects are effective in fully eliminating offshore wind curtailment on Long Island (2.3% over the 20-year study period) and enabling 100% energy deliverability. Projects differed in their ability to reduce curtailment in the Policy and Policy + B-VS Scenarios with only two projects eliminating all of the offshore wind energy curtailment in the Policy Scenario and one in the Policy + B-VS Scenario. Energy deliverability of offshore wind energy on Long Island ranges between 98.3% and 100% in the Policy Scenario and between 75.5% and 100% in the Policy + B-VS for the proposed projects. Prior to projects being modelled, offshore wind energy deliverability in the Baseline, Policy, and Policy + B-VS Scenarios averaged 97.8%, 92.8%, and 82.5%, respectively. The figure below shows the reduction in offshore wind energy curtailed for each project in each of the scenarios.

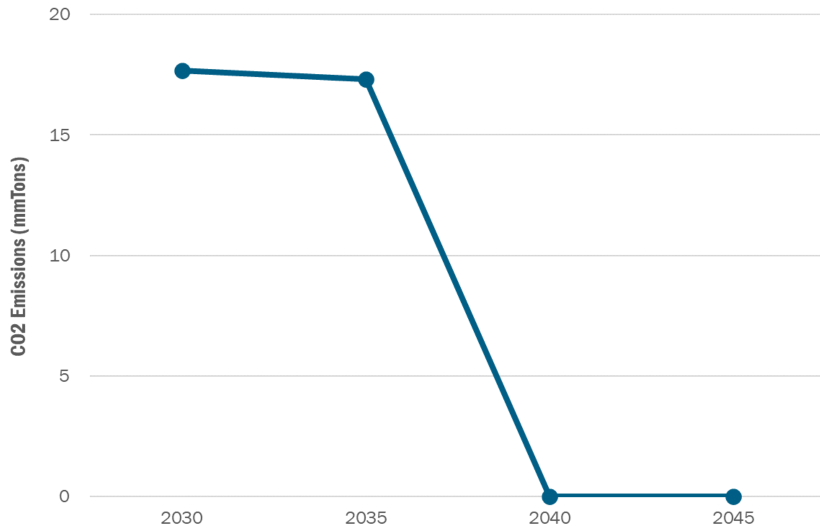
Figure 20: Unbottled Offshore Wind Production



3.6.1.3 CO_2 Emissions

Each scenario model includes thermal generation capacity that burn fossil fuel to generate energy and, through that process, emit carbon dioxide (CO_2). The Baseline Scenario includes announced retirements of fossil fuel generation but does not force the retirement of these plants due to compliance with policy. The Policy and Policy + B-VS Scenario model the full achievement of CLCPA goals and, therefore, include the retirement of all existing fossil-fuel generating units by 2040. The figure below shows the annual NYCA CO_2 emissions in the Policy Scenario (without the addition of the proposed projects) and highlights the elimination of CO_2 emissions beyond 2040.

Figure 21: Annual NYCA CO_2 Emissions in Policy Scenario



The figures below show that the estimated 20-year CO_2 emissions for the Baseline, Policy, and Policy +B-VS Scenarios and the change in emissions associated with each proposed project. A positive value indicates an increase in emissions, while a negative value indicates a decrease in emissions.

Figure 22: Baseline Scenario CO_2 Emissions

20-Year Estimated CO_2 Emissions (Million Tons)				
Case	LI	NYC	NYCA	Regional
Baseline Scenario	53	194	450	8,248
T035 - LS Power	49	197	451	8,246
T036 - NextEra Core 1	49	197	451	8,246
T037 - NextEra Core 2	49	196	451	8,245
T038 - NextEra Core 3	49	196	451	8,246
T039 - NextEra Core 4	48	201	452	8,246
T040 - NextEra Core 5	49	197	451	8,246
T041 - NextEra Core 6	49	197	451	8,246
T042 - NextEra Core 7	49	197	451	8,246
T043 - NextEra Enh 1	48	198	451	8,247
T044 - NextEra Enh 2	49	199	453	8,245
T047 - Propel Base 1	49	197	451	8,244
T048 - Propel Base 2	49	197	451	8,245
T049 - Propel Base 3	49	197	453	8,244
T051 - Propel Alt 5	49	197	451	8,245
T052 - Propel Alt 6	49	197	451	8,245
T053 - Propel Alt 7	49	197	451	8,245

Figure 23: Policy Scenario CO_2 Emissions

20-Year Estimated CO2 Emissions (Million Tons)				
Case	**LI**	**NYC**	**NYCA**	**Regional**
Policy Scenario	24	70	175	8,060
T035 - LS Power	22	72	176	8,056
T036 - NextEra Core 1	22	71	175	8,057
T037 - NextEra Core 2	22	72	176	8,056
T038 - NextEra Core 3	22	72	176	8,057
T039 - NextEra Core 4	22	72	177	8,054
T040 - NextEra Core 5	22	72	176	8,057
T041 - NextEra Core 6	22	71	175	8,058
T042 - NextEra Core 7	22	71	175	8,058
T043 - NextEra Enh 1	22	71	177	8,053
T044 - NextEra Enh 2	22	72	177	8,052
T047 - Propel Base 1	22	72	176	8,051
T048 - Propel Base 2	22	72	176	8,056
T049 - Propel Base 3	22	72	176	8,052
T051 - Propel Alt 5	22	72	176	8,056
T052 - Propel Alt 6	22	72	176	8,056
T053 - Propel Alt 7	22	72	176	8,056

Figure 24: Policy + Barrett–Valley Stream Scenario CO_2 Emissions

20-Year Estimated CO2 Emissions (Million Tons)				
Case	**LI**	**NYC**	**NYCA**	**Regional**
Policy + B-VS Scenario	24	72	179	8,072
T035 - LS Power	22	72	176	8,056
T036 - NextEra Core 1	21	72	179	8,071
T037 - NextEra Core 2	21	73	180	8,069
T038 - NextEra Core 3	21	73	179	8,069
T039 - NextEra Core 4	21	73	179	8,066
T040 - NextEra Core 5	21	73	179	8,070
T041 - NextEra Core 6	21	72	178	8,070
T042 - NextEra Core 7	21	72	178	8,070
T043 - NextEra Enh 1	22	72	178	8,061
T044 - NextEra Enh 2	22	73	181	8,062
T047 - Propel Base 1	22	72	178	8,058
T048 - Propel Base 2	22	72	178	8,063
T049 - Propel Base 3	22	72	176	8,052
T051 - Propel Alt 5	22	72	178	8,063
T052 - Propel Alt 6	22	72	178	8,063
T053 - Propel Alt 7	22	72	178	8,063

CO_2 emissions only occur within the first 10-years of the study as the model includes full achievement of the CLCPA mandate for 100% carbon-free generation by 2040. In both the Baseline and Policy Scenarios, the addition of the proposed projects results in a reduction in the CO_2 emissions on a regional level (*i.e.*, NYISO, ISO-NE, PJM, and IESO). Because energy is economically exchanged between the NYISO and neighboring systems, the addition of the proposed projects can increase CO_2 emissions from local generation dispatch but reduce the total regional CO_2 emissions from generation dispatch outside of New York. In each scenario, the proposed projects result in an increase in CO_2 emissions due to increased fossil dispatch in the Capital and New York City areas. This offsets imported energy from fossil generators in other neighboring systems (primarily ISO-NE and PJM) and results in a net regional CO_2 emission reduction.

A number of states in the region participate in the Regional Greenhouse Gas Initiative (RGGI) Cap and Trade Program. This program caps emissions across the multi-state region and sets a consistent emission allowance price. The caps ensure that there is a consistent disincentive to emit CO_2 across the RGGI region in recognition of the interregional nature of air pollutants.

Key Findings

- ✓ **All projects improve the transmission utilization of paths connecting to Long Island, but such improvements do not serve as a differentiating factor.** Projects increase Long Island energy imports by range between of 1% to 6% and energy exports by 19% to 89%.
- ✓ **All projects show reductions in regional CO2 emission, but the reductions are not significant and are not a distinguishing factor among the projects.** Policy and Policy + B-VS Scenarios already assume the achievement of CLCPA policies and inherently eliminated CO_2 emissions by 2040. Consequently, the amount of CO_2 emission that can be offset by offshore wind generation is limited.

3.7 Capacity Benefits

Evaluation Metric: Capacity Benefit

Purpose: Evaluates the incremental capacity benefits of each proposed project

Evaluation: Compare the pre- and post-project system resource adequacy to identify the reduction in the NYCA Loss of Load Expectation (LOLE)

Considerations:

- Greater reduction in the NYCA LOLE compared to the pre-project case

The New York Installed Capacity (ICAP) market provides a market-based mechanism for maintaining reliability of the bulk power system, by procuring sufficient generation capacity to meet the NYCA forecast peak demand plus an Installed Reserve Margin (IRM). Due to limitations on the export and import capabilities of the NYCA bulk power system, particularly in the downstate area, a certain amount of generation capacity must be procured downstate where it is more expensive to procure. The proposed projects to address the Long Island PPTN bring additional import and export capabilities to the downstate area, particularly Long Island. The additional capabilities would allow some capacity procurement to shift upstate where generation capacity is cheaper, resulting in capacity benefits.

The NYISO evaluated the capacity benefits of the proposed projects by assessing their reliability benefits—*i.e.*, their impact on reducing the NYCA Loss of Load Expectation (LOLE) which was set at the New York State Reliability Council criterion of 0.1 event-day/year (or one load loss event every 10 years) in the pre-project cases. Consequently, a reduction in LOLE implies that the capacity procurement requirement for the NYCA can be shifted from the downstate area, particularly Long Island, to the upstate area. This shift will yield a potential for capacity saving in the ICAP market. Finally, the economic value of the capacity benefit of each project was quantified by applying a Cost of Reliability Improvement (CRI) to the project's LOLE reduction. The CRI reflects the market value of providing reliable capacity beyond the minimum resource adequacy requirements. It is calculated based on the compensation that a generator would receive in the capacity market for providing such reliability. More details can be found in the *2021 State of the Market Report*.[11] For the Long Island PPTN, the CRI was calculated to be $800,000 per 0.001 reduction in LOLE (based on nominal 2022 dollars).

The NYISO developed capacity benefit estimates using the Baseline Scenario and the Policy Scenario. Figure 22 summarizes the reliability benefit (*i.e.*, LOLE reduction) of the proposed projects when

[11] https://www.nyiso.com/documents/20142/2223763/NYISO-2021-SOM-Full-Report-5-11-2022-final.pdf/

compared to the pre-project Baseline and Policy Scenarios at LOLE criterion. See Appendix placeholder for further detail on the capacity benefit evaluation.

Figure 25: Policy Scenario Delta NYCA LOLE (event day/year) on Study Year 2030

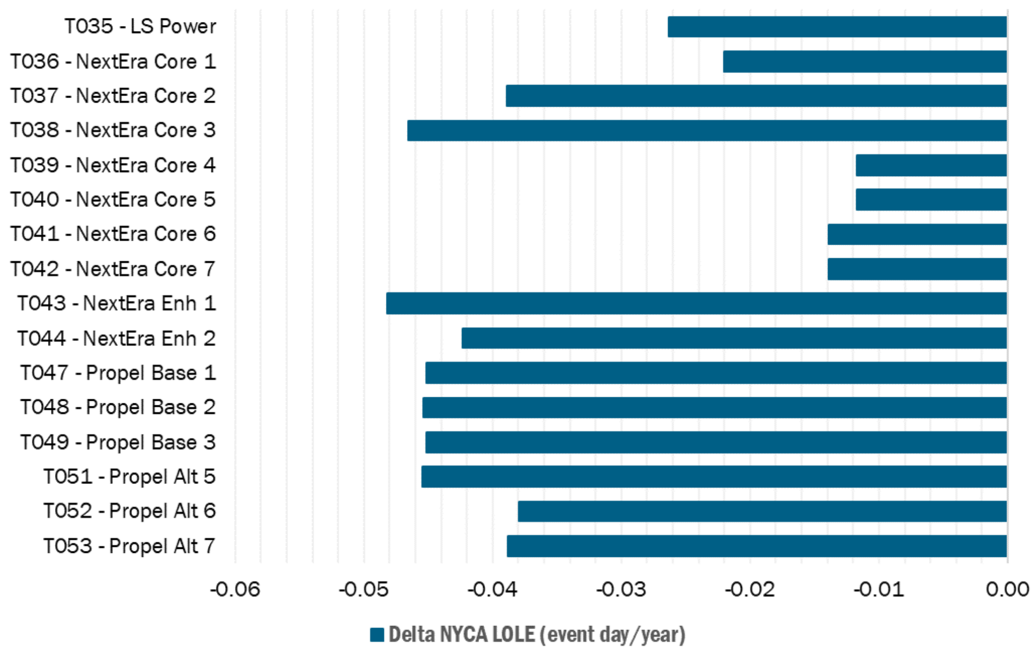
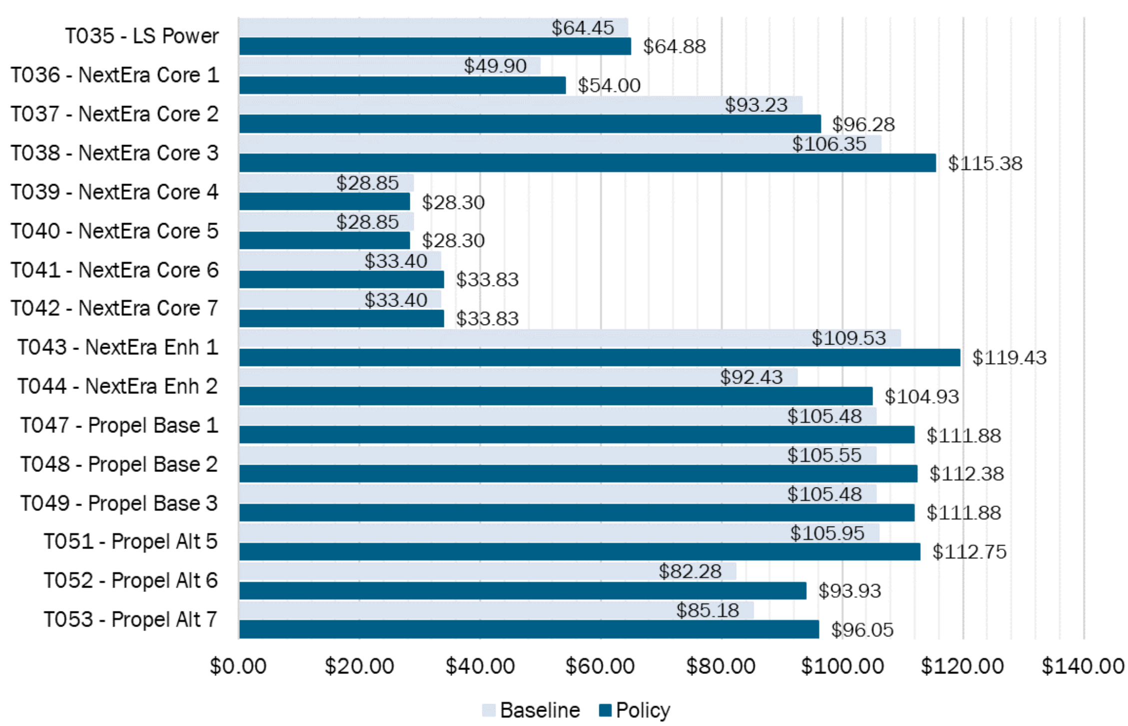


Figure 26: Annual Capacity Benefit (2022 $M)



3.7.1 Avoided Capacity Costs

[TO BE ADDED IN A FUTURE DRAFT]

Key Findings

- ✓ **All proposed projects show reliability improvements that would translate to reduced downstate capacity requirements.** However, the uncertainty of the future resources mix and market conditions makes it difficult to predict the monetary impact that a transmission project will have on the Capacity Market.
- ✓ **Projects with strong tie lines between Long Island and New York City yielded the largest potential capacity savings.**
- ✓ **[AVOIDED CAPACITY COST FINDINGS TO BE ADDED]**

3.8 Property Rights, Routing, Permitting, Construction and Design Review

Evaluation Metric: Property Rights & Risks to Project Completion

Purpose: Assesses potential issues associated with delay in constructing the proposed project and identifies major risks to project schedule and obtaining permits

Evaluation: SECO terrestrial and submarine cable analysis, substation and transmission line design verification, and the risk registry

Considerations:

- Lower cost and lower probability of occurrence if mitigation is required for an identified risk

The NYISO retained Substation Engineering Company (SECO) to review each proposed project's design, constructability, schedule, property rights and land requirements, and resiliency of the proposed substations to, among other things, identify risks. SECO was also tasked with identifying risks associated with potential environmental issues and associated delays in obtaining permits for construction and identifying potential construction delays due to design and permitting requirements.

SECO reviewed the development schedules for each proposed project submitted by the Developers. SECO's review focused on the proposed duration of the tasks in the Developer's project schedules instead of specific dates. SECO performed its evaluation by developing independent estimates of time for each project schedule and comparing it to the Developer's proposed duration of each task. The main drivers to the project schedule durations considered are:

- Article VII licensing effort,
- Procurement of major equipment,
- Real estate requirements, and
- Construction requirements.

SECO also estimated a "minimum duration" using the anticipated time for Article VII application preparation, the anticipated time for the Article VII approval process, and the anticipated time to construct for each project. The minimum durations for each proposed project assume that preparation of the Article VII application will begin following the NYISO's selection of the more efficient or cost-effective solution and that any preliminary work required has already been completed by the Developer prior to that date. SECO also assumed that work to file the first environmental management and construction plan (EM&CP) segment will be completed prior to receipt of certificate of environmental compatibility and need pursuant to Article VII.

Figure 27 below shows the estimated minimum duration for each proposed project. Based on SECO's independent evaluation, the overall construction schedule for each project appears adequate.

Figure 27: Estimate Minimum Duration for Project Development

Projects	Developer Proposed Total Duration	Estimated Minimum Duration
T035 – LS Power	70 Months	71 Months
T036 - NextEra Core1	74 Months	74 Months
T037 - NextEra Core 2	88 Months	89 Months
T038 - NextEra Core 3	88 Months	89 Months
T039 - NextEra Core 4	88 Months	105 Months
T040 - NextEra Core 5	74 Months	74 Months
T041 - NextEra Core 6	74 Months	74 Months
T042 - NextEra Core 7	93 Months	109 Months
T043 - NextEra Enh 1	88 Months	105 Months
T044 - NextEra Enh 2	93 Months	109 Months
T047 - Propel Base 1	72 Months	77 Months
T048 - Propel Base 2	72 Months	77 Months
T049 - Propel Base 3	72 Months	77 Months
T051 - Propel Alt 5	72 Months	77 Months
T052 - Propel Alt 6	72 Months	77 Months
T053 - Propel Alt 7	96 Months	101 Months

In assessing the potential risks for each proposed project, SECO's evaluation also included site review and "walk down" of proposed sites and routes and reviewing feasibility and completeness of the proposed project schedules and sequencing plans. Environmental and permitting requirements for the proposed projects, as proposed by the Developers, were identified predominately using "desktop" analysis. SECO's evaluation does not represent an exhaustive list of all potential issues with each proposed project. The evaluation is intended to identify significant, foreseeable risks based on upon a reasonable evaluation of the proposed projects and is not intended to identify unforeseeable conditions that can only be discovered through detailed engineering, subsurface investigation, and construction.

SECO's evaluation identified both common risks among some or all of the projects and project-specific risks. The risks have been broadly classified into four categories: (1) Property, Routes and Siting Concerns, (2) Construction and Operational Concerns, (3) Environmental and Permitting Concerns, and (4) Design Concerns.

In assessing the availability of real property rights for each proposed project, the NYISO relied on SECO, along with the factual information provided by the Transmission Owners in the applicable Transmission Districts. The NYISO and SECO also reviewed transmission routing studies provided by Developers that identified potential routing alternatives and land-use or environmentally sensitive areas, such as wetlands, agriculture, and residential areas. The evaluation assesses, identifies, and ranks the risks for each of the above-listed categories. The relative scores for each project are then plotted on a heat map with the total probability score plotted against the total schedule plus cost scores. The heat map provides a comparative view of the risks among projects.

Figure 28: Cost and Schedule Risk

Probability Risk Will Occur					
	Very High (VH)				T044 T043
	High (H)		T037 T038 T041	T039 T042	
	Medium (M)		T036 T040 T053		
	Low (L)	T035 T047 T048 T049 T051	T052		
Relative Score		Low (L)	Medium (M)	High (H)	Very High (VH)
		Cost or Schedule Risk			

The most significant risks are summarized below.

4.9.1 Property Rights, Routes and Siting

SECO reviewed the proposed routing of the transmission lines and siting of substations to evaluate the risks associated with each Developer's property acquisition plans and to identify site concerns and land requirements.

4.9.1.1 Property Rights and Siting

All Developers propose to site substations (including substation expansions) on either privately owned land parcels or on utility-owned property. All Developers have documented plans to obtain site control. However, if negotiations with the incumbent Transmission Owners or the private landowners are unsuccessful, all Developers have asserted that they have or would obtain authority to condemn property under New York State law following the PSC's certification of their proposed routes.

A summary of the key risks identified for each Developer is listed below:

<u>LS Power</u>

Proposal T035 – Atlantic Gateway

- Ruland Road Substation: the Transmission Owner that owns the real property that LS Power proposes to construct a substation noted its plans to use a portion of the available property at the site to accommodate an operational-related facility. LS Power will need to coordinate with the Transmission Owner for the precise location of the proposed substation and potentially modify their layout, if needed.

<u>NextEra</u>

Proposals T036, T037, T038, T039, T040, T041, T042, T043, T044 – Core 1-7 and Enhanced 1 & 2

- East Garden City Substation: NextEra proposes to purchase a land parcel that requires acquisition and demolition of a large six floor office/commercial building on Stewart Avenue. The plot plan indicates that the rear access for two adjacent commercial buildings may also be impacted.

<u>Propel NY</u>

Proposals T047, T048, T049, T051, T052, T053 – Base Solutions 1-3 and Alternate Solutions 5-7

- Eastern Queens Substation: Sufficient land may not be available at the proposed site for the construction of the proposed substation.

4.9.1.2 Routing

All Developers have completed preliminary routing of their proposed lines. The NYISO's field review of proposed transmission line routes was limited to routes located in public thoroughfares.

<u>NextEra</u>

Proposals T036, T037, T038, T039, T040, T041, T042, T043, T044 – Core 1-7 and Enhanced 1&2

- East Garden City Substation: The underground lines exiting the East Garden City substation are being routed to Stewart Avenue, which is a busy road and congested with other existing underground utilities. Obtaining sufficient available space within the public easement may be difficult as there may not be sufficient space to install all the lines.

4.9.2 Environmental and Permitting

SECO performed a comprehensive review of the proposed transmission routes, substation land parcels, and the design of each project to identify potential concerns/issues for foreseeable environmental and permitting requirements.

A summary of the key risks identified is listed below:

NextEra

Proposals T036, T037, T038, T039, T040, T041, T042, T043, T044 – Core 1-7 and Enhanced 1 & 2

- Sprain Brook Substation: The proposed 345 kV air-insulated bay addition will require a very large and complex retaining wall to accommodate the 60'-90' drop-off. Obtaining permits is expected to be difficult.
- Cable Transition Substations: The proposed locations where the submarine cables are coming ashore are in sensitive areas, such as parks and beaches. Construction of transition substations in these areas will have significant visual impact and are expected to be subject to public opposition that could require relocation of the proposed site away from those sensitive areas.

Proposals T039, T042, T043, T044 – Core 4, 7 and Enhanced 1 & 2

- Hudson River Routing:
    a. There are a large number of existing pipelines/cables (*i.e.*, Lower New York Bay Lateral Pipeline, multiple Narrows Cables/Pipeline Areas, Neptune Transmission, Bayonne Energy Center, 3 Cross Hudson Pipelines, and a large number of telecom cables) that must be crossed. Owner's approval to cross these may be required. Failure to get owner approval could result in the proposed route being feasible.
    b. The seafloor sediments in the areas surrounding Long Island and New York City contain known areas of contamination. This area is considered a Federal and New York State Superfund Site due to as a result of PCB contamination. Agencies are expected to avoid and reroute projects around areas of high contamination to avoid disturbance.
    c. Hudson River tunnels, including the Lincoln, Holland/NJ Transit and multiple PATH tunnels, will need to be crossed. MTA, Port Authority of NY/NJ, and potential other owners are likely to require permission to cross this infrastructure. There does not appear to be much of a precedent for crossing these tunnels with linear infrastructure.
- Farragut Substation: Desktop analysis concluded that the proposed expansion of the existing

Farragut substation into the East River could be prohibited based on NYC's construction standard. Development of a pier in this area will likely require a variance from the Board of Standards and Appeals.

- East River Routing: Routes cross five subway tunnels and the Battery Tunnel. MTA, Port Authority of NY/NJ, and potential other owners are likely to require permission to cross these pieces of infrastructure. There does not appear to be much of a precedent for crossing these tunnels with linear infrastructure. This routing may not be feasible if owners do not allow permission to cross. In addition, the East River has potential shallow bedrock and the tunnels — some of which are very old and shallow. This could add further complications to crossing these tunnels. If proper burial depths cannot be reached while crossing, armoring of the lines could be logistically challenging given some of the tunnels' ages.

Propel NY

Proposals T047, T048, T049, T051, T052, T053 – Base Solution 1-3 and Alternate Solution 5-7

- River Routing: This area has either known contamination or suspected contamination. Agencies are likely to require avoidance and rerouting around areas of high contamination. Propel NY is proposing to cross the river using horizontal directional drilling (HDD). There is small chance that contaminated sediment will be impacted. However, the use of HDD across the is about a 1.5 mile long. This is approaching the limit of the HDD capability. The successful use this technique will be dependent on the geological conditions and equipment.

Proposal T053 Alternate Solution 7

- Northport: The Developer proposes to locate the new HVDC converter station at Northport on land that houses a large above-ground fuel storage tank. Subsurface contamination would be very likely here. The need to address the contamination could impact cost and schedule.

4.9.3 Design Concern

NextEra

Proposals T036, T037, T038, T039, T040, T041, T042, T043, T044 – Core 1-7 and Enhanced 1&2

- Jamaica Substation: The proposed design does not comply with Con Edison's design principle and engineering specifications.
- Farragut Substation: The proposed design does not comply with Con Edison's design principle and engineering specifications.
- Dunwoodie Substation: The proposed location for the new 345 kV GIS substation is in the right-of-way for three 345 kV transmission lines. NextEra's proposed design does not provide a means to relocate the existing lines to accommodate the GIS building or a means to re-route the existing lines into the new substation.

4.9.4 Construction

SECO reviewed the substation design and transmission routes provided by the Developers to identify potential concerns associated with construction of the proposed projects.

A summary of the key risks identified is listed below:

LS Power

Proposal T035 – Atlantic Gateway

- Subsurface Condition: Approximately 50% of the proposed site for the Northgate substation could encounter rock during excavation, and the site might require extensive slope protection.
- Long Lead Time: Due to high demand and equipment complexities, manufacturers are quoting lead times up to 4 years for onshore HVDC equipment.

NextEra

Proposals T036, T037, T038, T039, T040, T041, T042, T043, T044 – Core 1-7 and Enhanced 1 & 2

- Installing underground cables in existing substations: Installing new underground cables into the existing substations could require additional or concurrent outages, complex construction sequences, and/or more expensive construction methods. Proposals include at least two to six underground cables that are being installed in or routed through the existing substations where the project is connecting.

Propel NY

Proposals T047, T048, T049, T051, T052, T053 – Base Solution 1-3 and Alternate Solution 5-7

- Subsurface Condition: Approximately 90% of the proposed site for the Sprain Brook substation could encounter rock during excavation and the site might require extensive slope protection.

Proposals T053 – Alternate Solutions 7

- Long Lead Time: Due to high demand and equipment complexities, manufacturers are quoting lead times up to 4-years for onshore HVDC equipment.

Key Findings

✓ **There are significant permitting and constructability risks for the NextEra projects that connect to the Farragut substation or have submarine cables routed through New York Harbor and the Hudson River.**

✓ **Connections to the Sprain Brook substation will require significant site work, especially for the NextEra projects that propose to expand to the east side of the substation.** Additional substation risks have been identified for outages required for the NextEra projects to connect to the existing Dunwoodie substation and the Propel NY projects to connect to the existing Tremont substation.

- ✓ **Specific risks identified for terrestrial cable routes will be addressed during the detailed design and permitting process.** Submarine landing and transition substation locations are a higher risk.
- ✓ **HVDC facilities have additional risks due to the long procurement times and large footprints of the converter stations near Northport, Ruland Road, and Millwood.**
- ✓ **Additional Network Upgrade Facilities (NUFs) will be identified through the Transmission Interconnection Procedures.**
- ✓ **Given the complexity of the proposed projects, detailed design and permitting processes may identify additional risks and issues impacting cost and schedule of the projects.**

3.9 Interconnection Studies

In addition to the specific analysis conducted to evaluate the various metrics, the Public Policy Process will give due consideration to the status and results of any available NYISO-conducted interconnection studies in evaluating and selecting the more efficient or cost-effective solution. All of the proposed projects that the NYISO found to be viable and sufficient to satisfy the Long Island PPTN are currently under evaluation in their respective System Impact Studies in the NYISO's Transmission Interconnection Procedures. Figure 29 shows the interconnection queue numbers for all the proposed projects.

Figure 29: Project Interconnection Queue Numbers

Project	Interconnection Queue #
T035 - LSPower	Q1271
T036 - NextEra Core1	Q1278
T037 - NextEra Core 2	Q1279
T038 - NextEra Core 3	Q1280
T039 - NextEra Core 4	Q1281
T040 - NextEra Core 5	Q1282
T041 - NextEra Core 6	Q1283
T042 - NextEra Core 7	Q1284
T043 - NextEra Enh 1	Q1285
T044 - NextEra Enh 2	Q1286
T047 - Propel Base 1	Q1276
T048 - Propel Base 2	Q1274
T049 - Propel Base 3	Q1277
T051 - Propel Alt 5	Q1289
T052 - Propel Alt 6	Q1290
T053 - Propel Alt 7	Q1291

The independent cost estimates include all the preliminary costs for the NUFs identified by the NYISO. The cost estimate for the NUFs will be updated, as necessary, from the ongoing System Impact Studies. The detailed design and cost estimates for the NUFs will be finalized in the Facilities Studies for the selected project. Physical feasibility and design concerns of the point of interconnection for a proposed project, as identified in the ongoing SIS, have been included in the Property Rights, Routing, Permitting, Construction and Design review. Details of project specific risks and concerns can be found in the risk register.

3.10 Consequences for Other Regions

In addition to its evaluation to identify the more efficient or cost-effective solution to the Long Island PPTN, the NYISO also coordinates with neighboring regions to identify the consequences, if any, of the proposed transmission solutions on the neighboring regions using the respective planning criteria of such regions.

Through the NYISO's Transmission Interconnection Procedures and the associated System Impact Studies currently in progress, the NYISO is consulting with PJM and ISO-NE concerning any potential impacts due to the proposed projects. Preliminary results from the System Impact Studies have not identified any system upgrades that may be required in neighboring systems. The NYISO also discussed the proposed projects and any anticipated regional impacts with PJM and ISO-NE through the Joint ISO/RTO Planning Committee.

3.11 Impact on Wholesale Electricity Markets

The NYISO evaluates the impact of proposed viable and sufficient Public Policy Transmission Projects on its wholesale electricity markets, using economic metrics including change in production cost, congestion, and load payments.[12] Based on the transfer and production cost analysis results described in Sections 3.2 and 3.5, the proposed transmission projects increase Long Island import and export capability and reduce congestion. Therefore, the NYISO staff has determined that the viable and sufficient Public Policy Transmission Projects proposed to address the Long Island PPTN will have no adverse impact on the competitiveness of the New York wholesale electricity markets. Rather, the transmission projects all tend to improve the competitiveness of the NYISO's markets by increasing system transfer capability and allowing more resources and suppliers to compete to serve loads. The review from the NYISO's Market Monitoring Unit is included in Appendix C [TO BE ADDED LATER].[13]

3.12 Evaluation of Interaction with Local Transmission Owner Plans

In its Public Policy Transmission Planning Process, the NYISO is required to review the Local Transmission Owner Plans (LTPs)[14] as they relate to the BPTF to determine whether any proposed regional Public Policy Transmission Project on the BTPF can (1) more efficiently or cost-effectively satisfy any local needs driven by a Public Policy Requirement identified in the LTPs or (2) might more efficiently or cost-effectively satisfy the identified regional Public Policy Transmission Needs than any local transmission solutions driven by Public Policy Requirements identified in the LTPs.

The Transmission Owners' current LTPs have not identified any needs driven by a Public Policy Requirement in New York State. Accordingly, the NYISO determined that there are no proposed regional Public Policy Transmission Projects that could more efficiently or cost-effectively satisfy a need driven by a Public Policy Requirement identified in an LTP. In the absence of any public policy needs in the LTPs, it is also not necessary for the NYISO to determine whether a regional transmission project would more efficiently or cost effectively satisfy such a transmission need on the BPTF than a local transmission solution.

[12] See OATT Sections 31.4.10 and 31.4.8.1.9.

[13] See OATT Section 31.4.11.1 (The draft report will be provided to the Market Monitoring Unit for its review and consideration).

[14] See OATT Section 31.2.1.1.2.1

4. Recommendations

4.1 Summary of Project Evaluations

The project evaluations are summarized in this section based on their individual performance. Below is a brief summary of the key design differences and the highlighted evaluation results for each project.

T035: LS Power

- The Developer proposes a hard Cost Cap of $3,074M.
- The total calculated cost estimate is $3,152M. The independent cost estimate for included costs is $5,920M and significantly higher than the Cost Cap.
- Good operability range, expandability, and transfer capability.
- Possible restrictions on HVDC transmission operations with high offshore wind variability.
- Highest resiliency score based on substation design.
- Comparable production cost benefits in Baseline and Policy Scenarios.
- Addresses the existing Barrett-Valley Stream 138 kV constraint and could lead to high production cost savings and unbottling of more offshore wind generation.
- Lowest property and constructability risks with notable risks related to HVDC equipment procurement.

T036: NextEra Core 1

- The Developer proposes a soft Cost Cap of $5,882M with 50% of Included Capital Cost above the cap covered by the Developer.
- The total calculated cost estimate is $7,019M. The independent cost estimate for included costs is $3,230M and significantly lower than the Cost Cap.
- Good operability, expandability, and transfer capability.
- Comparable production cost benefits in Baseline and Policy Scenarios
- Does not address the existing Barrett–Valley Stream 138 kV constraint.
- Medium property and constructability risks with notable risks related to the proposed expansion of the Dunwoodie, Sprain Brook, and Jamaica substations.

T037: NextEra Core 2

- The Developer proposed a soft Cost Cap of $6,867M with 50% of Included Capital Cost above the cap covered by the Developer.
- The total calculated cost estimate is $8,126M. The independent cost estimate for included costs is $3,627M and significantly lower than the Cost Cap.

- Good operability, expandability, and transfer capability.
- Comparable production cost benefits in Baseline and Policy Scenarios
- Does not address the existing Barrett–Valley Stream 138 kV constraint.
- High property and constructability risks with notable risks related to the proposed expansion of the Farragut, Dunwoodie, Sprain Brook, and Jamaica substations.

<u>T038: NextEra Core 3</u>

- The Developer proposed a soft Cost Cap of $7,444M with 50% of Included Capital Cost above the cap covered by the Developer.
- The total calculated cost estimate is $8,653M. The independent cost estimate for included costs is $4,252M and significantly lower than the Cost Cap.
- Good operability, expandability, and transfer capability.
- Comparable production cost benefits in Baseline and Policy Scenarios.
- Does not address the existing Barrett–Valley Stream 138 kV constraint.
- High property and constructability risks with notable risks related to the proposed expansion of the Farragut, Dunwoodie, Sprain Brook, and Jamaica substations.

<u>T039: NextEra Core 4</u>

- The Developer proposed a soft Cost Cap of $7,211M with 50% of Included Capital Cost above the cap covered by the Developer.
- The total calculated cost estimate is $8,483M. The independent cost estimate for included costs is $4,457M and significantly lower than the Cost Cap.
- Good operability, expandability, and transfer capability.
- Comparable production cost benefits in Baseline and Policy Scenarios.
- Does not address the existing Barrett–Valley Stream 138 kV constraint.
- High property and constructability risks with notable risks related to the proposed expansion of the Farragut, Dunwoodie, Sprain Brook, and Jamaica substations and the proposed routing of submarine cables through Hudson River.

<u>T040: NextEra Core 5</u>

- The Developer proposed a soft Cost Cap of $5,898M with 50% of Included Capital Cost above the cap covered by the Developer.
- The total calculated cost estimate is $6,984M. The independent cost estimate for included costs is $3,610M and significantly lower than the Cost Cap.
- Good operability, expandability, and transfer capability.

- Comparable production cost benefits in Baseline and Policy Scenarios.
- Does not address the existing Barrett–Valley Stream 138 kV constraint.
- Medium property and constructability risks with notable risks related to the expansion of the Dunwoodie, Sprain Brook, and Jamaica substations.

T041: NextEra Core 6

- The Developer proposed a soft Cost Cap of $6,774M with 50% of Included Capital Cost above the cap covered by the Developer.
- The total calculated cost estimate is $7,912 M. The independent cost estimate for included costs is $4,448M and significantly lower than the Cost Cap.
- Good operability, expandability, and transfer capability.
- Comparable production cost benefits in Baseline and Policy Scenarios.
- Does not address the existing Barrett–Valley Stream 138 kV constraint.
- High property and constructability risks with notable risks related to the proposed expansion of the Dunwoodie, Sprain Brook, and Jamaica substations, HVDC equipment procurement lead time and converter space requirements.

T042: NextEra Core 7

- The Developer proposed a soft Cost Cap of $10,373M with 50% of Included Capital Cost above the cap covered by the Developer.
- The total calculated cost estimate is $13,192M. The independent cost estimate for included costs is $13,750M and significantly higher than the Cost Cap.
- Good operability and transfer capability, excellent expandability with connector to an offshore wind lease area.
- Comparable production cost benefits in Baseline and Policy Scenarios.
- Does not address the existing Barrett–Valley Stream 138 kV constraint.
- High property and constructability risks with notable risks related to the proposed expansion of the Dunwoodie, Sprain Brook, and Jamaica substations, HVDC equipment procurement lead time;, and the routing of submarine cables through Hudson River.

T043: NextEra Enhanced 1

- The Developer proposed a soft Cost Cap of $11,471M with 50% of Included Capital Cost above the cap covered by the Developer.
- The total calculated cost estimate is $12,769M. The independent cost estimate for included costs is $8,753M and significantly lower than the Cost Cap.
- Good operability and transfer capability, excellent expandability.

- Better production cost benefits in Baseline and Policy Scenarios.
- Addresses the existing Barrett–Valley Stream 138 kV constraint.
- Very High property and constructability risks with notable risks related to the proposed expansion of the Farragut, Dunwoodie, Sprain Brook, and Jamaica substations, HVDC equipment procurement lead time, and the routing of submarine cables through Hudson River.

T044: NextEra Enhanced 2

- The Developer proposed a soft Cost Cap of $14,991M with 50% of Included Capital Cost above the cap covered by the Developer.
- The total calculated cost estimate is $16,898 M—the highest among the proposed projects. The independent cost estimate for included costs is $16,128M and slightly higher than the Cost Cap.
- Good operability and transfer capability, excellent expandability with connector to offshore wind lease area.
- Better production cost benefits in Baseline and Policy Scenarios.
- Partially addresses the existing Barrett–Valley Stream 138 kV constraint.
- Very High property and constructability risks with notable risks related to the proposed expansion of the Farragut, Dunwoodie, Sprain Brook, and Jamaica substation, HVDC equipment procurement, and the routing of submarine cables through Hudson River.

T047: Propel Base Solution 1

- The Developer proposed a soft Cost Cap of $1,877M with 20% of Included Capital Cost above the cap covered by the Developer.
- The total calculated cost estimate is $2,480M. The independent cost estimate for included costs is $2,269M and slightly higher than the Cost Cap.
- Fair operability, expandability, and transfer capability.
- Comparable production cost benefits in Baseline and Policy Scenarios.
- Partially addresses the existing Barrett–Valley Stream 138 kV constraint, could lead to additional production cost savings, and could unbottle more offshore wind generation.
- Low property and constructability risks with notable risk factors related to property rights for the East Garden City substation and the expansion of the Tremont substation to accommodate the proposed interconnection.

T048: Propel Base Solution 2

- The Developer proposed a soft cost cap of $1,687M with 20% of Included Capital Cost above the cap covered by the Developer.
- The total calculated cost estimate is $2,121M—the lowest among the proposed projects. The independent cost estimate for included costs is $1,966M and slightly higher than the Cost Cap.

- Fair operability, expandability, and transfer capability.
- Comparable production cost benefits in Baseline and Policy Scenarios.
- Partially addresses the existing Barrett – Valley Stream 138 kV constraint, could lead to additional production cost savings, and could unbottle more offshore wind generation.
- Low property and constructability risks with notable risk factors related to the expansion of the Tremont substation to accommodate the proposed interconnection.

T049: Propel Base Solution 3

- The Developer proposed a soft cost cap of $2,131M with 20% of Included Capital Cost above the cap covered by the Developer.
- The total calculated cost estimate is $2,835M. The independent cost estimate for included costs is $2,642M and moderately higher than the Cost Cap.
- Fair operability, expandability, and transfer capability.
- Comparable production cost benefits in Baseline and Policy Scenarios.
- Addresses the existing Barrett–Valley Stream 138 kV constraint, could lead to high production cost savings, and could unbottle more offshore wind generation.
- Low property and constructability risks with notable risk factors related to property rights for the East Garden City substation and the expansion of the Tremont substation to accommodate the proposed interconnection.

T051: Propel Alternate Solution 5

- The Developer proposed a soft cost cap of $2,554M with 20% of Included Capital Cost above the cap covered by the Developer.
- The total calculated cost estimate is $3,262M. The independent cost estimate for included costs is $2,902M and slightly higher than the Cost Cap.
- Average operability, expandability, and transfer capability.
- Comparable production cost benefits in Baseline and Policy Scenarios.
- Partially addresses the existing Barrett–Valley Stream 138 kV constraint, could lead to additional production cost savings, and could unbottle more offshore wind generation.
- Medium property and constructability risks with notable risk factors related to property rights for the East Garden City substation and the expansion of the Tremont substation to accommodate the proposed interconnection.

T052: Propel Alternate Solution 6

- The Developer proposed a soft Cost Cap of $3,953M with 20% of Included Capital Cost above the cap covered by the Developer.

- The total calculated cost estimate is $4,705M. The independent cost estimate for included costs is $4,071M and slightly higher than the Cost Cap.
- Good operability, expandability, and transfer capability.
- Comparable production cost benefits in Baseline and Policy Scenarios.
- Partially addresses the existing Barrett–Valley Stream 138 kV constraint, could lead to additional production cost savings, and could unbottle more offshore wind generation.
- Medium property and constructability risks with notable risk factors related to property rights for the East Garden City substation and the expansion of the Tremont substation to accommodate the proposed interconnection.

T053: Propel Alternate Solution 7

- The Developer proposed a soft Cost Cap of $5,118M with 20% of Included Capital Cost above the cap covered by the Developer.
- The total calculated cost estimate is $5,576 M. The independent cost estimate for included costs is $5,113M and slightly higher than the Cost Cap.
- Fair operability, expandability, and transfer capability. Can accommodate higher offshore wind amounts only if future offshore wind generators connect to Barrett.
- Comparable production cost benefits in Baseline and Policy Scenarios.
- Partially addresses Barrett–Valley Stream constraint and could lead to additional production cost savings and unbottle more offshore wind generation.
- Medium property and constructability risks with notable risk factors related to property rights for the East Garden City and Eastern Queens substations, the expansion of the Tremont substation to accommodate the proposed interconnection, and HVDC equipment procurement lead time and converter space requirements.

Figure 30 summarizes the metric evaluation for the projects.

Figure 30: Summary of Metric Evaluation

Project+B3:R21	Routing, Permitting, Construction		Capital Cost Estimates	Expandability		Operability: Two Outages			Cost per MW: Two Outages			Performance: 20-year OSW Unbottling		Production Cost 20-year Savings		Capacity Savings
	Severity of Risk	Probability of Risk	Total Cost ($M)	OSW Capability - Light Load (MW)	Additional POIs	Import (MW)	Export (MW)	Range (MW)	Import ($M/MW)	Export ($M/MW)	Range ($M/MW)	Policy Case (TWh)	B-VS Sensitivity (TWh)	Policy Case ($M)	B-VS Sensitivity ($M)	Annual ICAP Savings ($M)
T035 - LS Power	Low	Low	$3,152	4,350	3	2,540	865	3,405	$ 1.24	$ 3.64	$ 0.93	27.4	55.4	$ 340	$ 906	$ 65.85
T036 - NextEra Core 1	Med	Med	$7,019	4,450	13	2,400	1,230	3,630	$ 2.92	$ 5.71	$ 1.93	29.0	20.2	$ 303	$ 291	$ 54.98
T037 - NextEra Core 2	High	Med	$8,126	4,150	13	2,535	1,335	3,870	$ 3.21	$ 6.09	$ 2.10	28.8	21.4	$ 364	$ 378	$ 97.25
T038 - NextEra Core 3	High	Med	$8,653	4,600	16	3,035	1,615	4,650	$ 2.85	$ 5.36	$ 1.86	30.5	23.6	$ 380	$ 402	$ 116.35
T039 - NextEra Core 4	High	High	$8,483	4,400	16	3,060	1,185	4,245	$ 2.77	$ 7.16	$ 2.00	30.3	22.1	$ 305	$ 307	$ 29.28
T040 - NextEra Core 5	Med	Med	$6,984	4,375	17	3,035	1,215	4,250	$ 2.30	$ 5.75	$ 1.64	30.1	21.8	$ 339	$ 332	$ 29.28
T041 - NextEra Core 6	Med	High	$7,912	4,475	15	3,000	1,530	4,530	$ 2.64	$ 5.17	$ 1.75	30.5	23.3	$ 291	$ 308	$ 34.80
T042 - NextEra Core 7	High	High	$13,193	4,500	17	3,005	1,535	4,540	$ 4.39	$ 8.59	$ 2.91	30.5	23.3	$ 291	$ 308	$ 34.80
T043 - NextEra Enhanced 1	Very High	Very High	$12,769	5,400	8	3,280	1,900	5,180	$ 3.89	$ 6.72	$ 2.47	31.5	41.4	$ 458	$ 745	$ 120.40
T044 - NextEra Enhanced 2	Very High	Very High	$16,898	4,900	13	3,275	1,945	5,220	$ 5.16	$ 8.69	$ 3.24	31.5	34.0	$ 441	$ 582	$ 105.90
T047 - Propel Base 1	Low	Low	$2,480	3,750	1	1,635	615	2,250	$ 1.52	$ 4.03	$ 1.10	29.2	34.7	$ 337	$ 568	$ 112.85
T048 - Propel Base 2	Low	Low	$2,121	3,725	1	1,660	285	1,945	$ 1.28	$ 7.44	$ 1.09	25.4	31.3	$ 313	$ 513	$ 113.35
T049 - Propel Base 3	Low	Low	$2,835	3,750	0	1,610	635	2,245	$ 1.76	$ 4.46	$ 1.26	29.5	54.3	$ 344	$ 902	$ 112.85
T051 - Propel Alt 5	Low	Low	$3,262	4,300	1	2,320	1,175	3,495	$ 1.41	$ 2.78	$ 0.93	30.6	38.4	$ 341	$ 609	$ 113.73
T052 - Propel Alt 6	Med	Low	$4,705	5,075	0	2,815	1,880	4,695	$ 1.67	$ 2.50	$ 1.00	30.7	38.3	$ 352	$ 618	$ 94.90
T053 - Propel Alt 7	Med	Med	$5,576	4,350	1	3,150	520	3,670	$ 1.77	$ 10.72	$ 1.52	30.3	37.7	$ 360	$ 622	$ 97.03

4.2 Top-Tier Projects

The NYISO evaluated all viable and sufficient Public Policy Transmission Projects for each metric set forth in the OATT and identified in the PSC Order for the Long Island PPTN. The NYISO then compared the results for the projects against each other to identify the major performance and risk differences. Based on consideration of all metrics and the comparison of the projects' performance relative to each other, the NYISO identified seven projects as the top-tier projects that warrant further, focused analysis to effectively distinguish them from each other and determine a final ranking. The top-tier projects include, in no particular order:

- T035 LS Power,
- T036 NextEra Core 1,
- T040 NextEra Core 5,
- T048 Propel Base 2,
- T049 Propel Base 3,
- T051 Propel Alternate 5, and
- T052 Propel Alternate 6.

The NYISO observed some key considerations in identifying the projects in the Top Tier. For a project with high or very high risks in construction, property rights, or permitting risks, the other benefits provided by the projects, such as expandability, operability, and performance, were not substantial enough to overcome the project risks relative to other projects. T035 is included in the Top Tier due to its low routing, permitting, and construction risks when compared to other projects and its performance across several metrics. T036 NextEra Core 1 and T040 NextEra Core 5 projects are included in the Top Tier because they propose four new Long Island tie lines and rank high in the expandability and operability metrics. T048 Base Solution 2 is the least cost solution and, therefore, is included in the Top Tier. T047 Base Solution 1 and T049 Base Solution 3 each perform similarly across several metrics, but T049 is included in the Top Tier because it addresses the transmission constraints on the Barrett – Valley Stream 138 kV paths near Empire Wind II. T051 Propel Alternate 5 and T052 Propel Alternate 6 have higher expandability, operability, and performance results than smaller projects and, therefore, are included in the Top Tier. T053 Propel Alternate 7 is not included in the Top Tier due to unique risk factors and dependence on future offshore wind projects interconnecting at a single substation.

4.3 Ranking

This section will be filled out in a future version of the report.

4.4 Selection Recommendation

This section will be filled out in a future version of the report.

4.5 Designation of Designated Public Policy Projects

This section will be filled out in a future version of the report.