Long Island Offshore Wind Export Public Policy Transmission Planning Report

A Report from the New York Independent System Operator

DRAFT for May 24, 2023 BIC

DRAFT – FOR DISCUSSION PURPOSES ONLY

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Executive Summary

This report presents the results of the Public Policy Transmission Planning Process administered by the New York Independent System Operator, Inc. (NYISO) for the Long Island Offshore Wind Export Public Policy Transmission Need (Long Island Need or PPTN). It represents the culmination of a multi-year, joint effort by the NYISO, the New York State Public Service Commission (PSC), Developers, and stakeholders to address transmission needs in and around Long Island that are driven by Public Policy Requirements for delivering future offshore wind power as part of the Climate Leadership and Community Protection Act (CLCPA). The NYISO conducted extensive evaluations and ranking of the proposed transmission projects and recommends the selection of the more efficient or cost-effective transmission solution to the Long Island Need as described herein.

Since 2016, the NYISO highlighted that reinforcing the transmission system on Long Island is necessary to reliably deliver offshore wind resources, first driven by the Clean Energy Standard and followed by the CLCPA that mandates 9,000 MW of offshore wind power by 2035. Given the multi-year lead time necessary for transmission development in New York, the NYISO supported a finding of transmission needs throughout the last three cycles of its Public Policy Transmission Planning Process. Moreover, the NYISO's system planning studies have supported these recommendations, including the recent *2021-2040 System & Resource Outlook* (The Outlook), which determined that future offshore wind connected to Long Island would be at a high risk of curtailment. With five offshore wind projects in active development totaling more than 4,300 MW scheduled to enter service within the next five years, New York has an urgent need for transmission solutions to deliver that renewable energy to consumers.

The NYISO commenced the 2020-2021 Public Policy Transmission Planning Process cycle by soliciting proposed transmission needs driven by Public Policy Requirements from the NYISO's stakeholders and other interested parties. The NYISO filed the proposed transmission needs for consideration by the PSC, nine of which highlighted the need for transmission associated with delivery of offshore wind energy. Long Island Power Authority (LIPA) also filed its determination that new transmission within Long Island and connecting Long Island to the rest of the state was necessary to support the development of offshore wind. Upon considering various comments submitted, including the NYISO's support for transmission needs related to Long Island, the PSC issued an order declaring that the CLCPA constitutes a Public Policy Requirement driving the need for transmission to, among other things, increase the export capability from Long Island to the rest of the state to ensure the full output of a minimum of 3,000 MW of offshore wind.

Immediately following the PSC's adoption of the Long Island Need, the NYISO performed baseline analysis to identify the specific transmission constraints that restrict the delivery of offshore wind power from Long Island to the rest of New York State. Following review of the baseline analysis and discussions with stakeholders and prospective Developers, the NYISO issued a solicitation for solutions to address the Long Island Need. The NYISO conducted the Viability and Sufficiency Assessment for 19 projects to address the need and identified 16 viable and sufficient projects eligible for selection under the Public Policy Transmission Process.

The NYISO commenced a detailed evaluation of each viable and sufficient transmission proposal with the assistance of its independent consultant, Substation Engineering Company (SECO). The transmission projects include one proposal from LS Power Grid Corporation I (LS Power), nine from NextEra Energy Transmission New York, Inc. (NextEra), and six from Propel NY (a partnership between NY Transco and the New York Power Authority). The proposals offer a wide variety of solutions that differ in the number and location of new Long Island tie lines, the extent of new and upgraded transmission on Long Island, and transmission technology (i.e., free-flow alternating current, high-voltage direct current, and phase angle regulators). Details of the proposed projects are provided in Section 2.

In determining which of the eligible proposed transmission projects is the more efficient or cost-effective solution to satisfy the Long Island Need, the NYISO considered the metrics set forth in the tariff and directed by the PSC and performed a comparative review to rank each proposed project based on its performance under these metrics. These metrics include capital costs, voluntary cost cap, cost per MW, expandability, operability, performance, property rights and routing, development schedule, and other metrics such as production cost savings, capacity savings (including avoided cost savings), locational based marginal price (LBMP) savings, emissions savings, and congestion.

A core concept of the NYISO's evaluation and selection process is the use of an independent consultant to review each proposed project and apply a consistent methodology across all projects for establishing cost estimates, schedule estimates, and routing and constructability assessments. Utilizing detailed project information provided by the Developers, SECO developed independent capital cost and schedule estimates considering material and labor cost by equipment, engineering, and design work, permitting, site acquisition, procurement and construction work, and commissioning needed for the proposed project. SECO's cost estimates for the proposed transmission projects range from approximately $2.1 billion to $16.9 billion, with schedules ranging from 71 months to 109 months following the NYISO's selection.

The independent cost estimates are also evaluated against proposed Cost Caps. A Developer may voluntarily submit a Cost Cap as a binding commitment to contain certain categories of capital costs—defined as "Included Capital Costs"—for a proposed Public Policy Transmission Project. A Developer may submit a Cost Cap either in the form of a hard Cost Cap or a soft Cost Cap. The calculation of the total cost estimate depends on whether a Developer submits a Cost Cap and the nature of a submitted Cost Cap. All Developers submitted voluntary Cost Caps in their proposals for the Long Island Need. LS Power submitted a hard Cost Cap, while NextEra and Propel NY submitted a range of different soft Cost Caps for their respective projects. The NYISO assessed the proposed Cost Caps for effectiveness to incentivize cost containment, protect ratepayers from overruns of Included Capital Costs, and the likelihood that the project can be constructed at the Cost Cap amount.

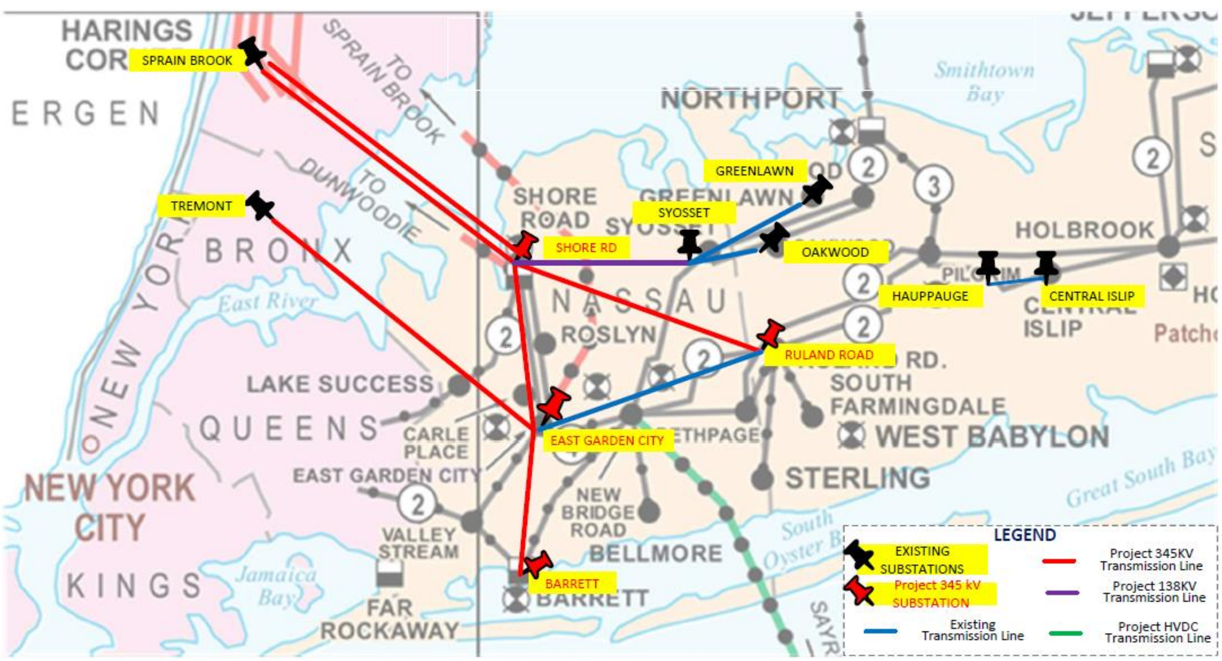
The Long Island Need introduces several unique challenges as compared to the prior Western New York and AC Transmission Public Policy Needs. Namely, these proposals mainly use underground and submarine cables proposed in new rights-of-way through densely populated areas. Therefore, a key component of the evaluation was to assess the relative risks to potential increases in project cost and schedule due to property rights, permitting concerns, and general constructability. For this assessment, SECO enlisted various sub-contractors with extensive expertise in permitting, construction, and cable design in the Long Island and New York City areas and for underground and submarine cables.

A key objective of the Long Island Need is to provide transmission capability to fully deliver the energy from at least 3,000 MW of offshore wind connected to Long Island. Each project's efficiency in achieving this objective is measured in a number of ways utilizing power flow and production cost simulations under a variety of system dispatches and conditions. Power flow results indicate that projects provide a wide range of import and export capabilities to transfer power between Long Island and the rest of the state, while providing for possible offshore wind output between 3,700 MW and 6,000 MW. Further, the increased transfer capability and relief of New York transmission constraints would result in production cost savings of as much as $900 million over the first 20 years of a project being in service. One of the more informative metrics was capacity savings determined through avoided cost analysis, which shows that additional transmission between Long Island and the rest of the state with the development of offshore wind will greatly reduce the cost of new generation buildout required for the grid transition to meet the CLCPA mandates by 2040.

The NYISO also considers qualitative metrics such as expandability, operability, performance, and the risks associated with each project. The NYISO considered how the proposed projects affect flexibility in operating the system, such as the effect of different technologies on future grid operations and the ability to operate during outage conditions. Certain projects afford greater operational flexibility through the addition of free-flow AC circuits between Long Island and the rest of the state grid, which will be important to enable the future resource mix transition.

Following consideration of all initial evaluation results, the NYISO first distinguished the proposed projects into two tiers based on their performance relative to their costs and construction risks with the projects in the top tier requiring further detailed analysis to distinguish their performance. The top-tier projects are LS Power's T035, NextEra's T036 and T040, and Propel NY's T048, T049, T051, and T052. Three metrics that significantly impacted this tiered ranking are: (1) total capital costs and cost caps, (2) property rights and routing risks, and (3) cost per MW relative to the operability range. The seven top-tier projects offer increased efficiencies in the overall performance and utilization of the transmission system resulting in greater delivery of offshore energy, while also offering cost-effective, lower-risk designs that would provide economic advantages to the New York electric grid.

Based on consideration of all the evaluation metrics for efficiency or cost effectiveness, together with input from Developers, stakeholders, and DPS and performing a detailed comparative review among the projects, the NYISO staff recommends that the Board of Directors select Propel NY's T051 Alternate 5 proposal as the more efficient or cost-effective transmission solution to satisfy the Long Island Need for cost allocation purposes. The following map shows the location of the major components proposed by T051.



T051 proposes three new 345 kV Long Island tie lines: two between Shore Road and Sprain Brook and one between East Garden City and Tremont. The project is bolstered by a Shore Road – Ruland Road – East Garden City 345 kV backbone and other transmission facilities in Long Island. T051 has a total capital cost estimate of $3,262M and Propel NY proposed a soft Cost Cap of $2,902M with a commitment to not recover 20% of Included Capital Costs above the cap from ratepayers.

T051 adds a strong 345 kV backbone to the Long Island transmission system that not only allows the delivery of offshore wind power but also will effectuate the efficient transfer of power in the future, providing optionality for resource planning and expansion needed to achieve the CLCPA mandates. With the new facilities, the project provides 1) effective operability under a variety of outage conditions, 2) low cost per MW for transfer capability, expandability, and operating range, and 3) lower project cost and risks than larger projects. The project also provides consistent economic benefits across various future scenarios. Additionally, while the Long Island Need projects were not required to relieve the congestion on the Barrett-Valley Stream 138 kV path within Long Island, T051 partially relieves this constraint by adding a new Barrett – East Garden City 345 kV line. Furthermore, T051's potential economic benefits, estimated to be as high as $3.6 billion over 20 years, are comparable with the project cost.

The Required Project In-Service Date for the selected project is May 2030. This report identifies Propel NY, LIPA, the New York Power Authority, and Consolidated Edison Company of New York, Inc. as the Designated Entities responsible for building, owning, and recovering the costs of the project. Following the approval of this report by the NYISO Board of Directors and the finalization of the Designated Entities, the NYISO will tender a Development Agreement for each entities' respective portion of the selected transmission project.

1. Long Island Offshore Wind Export Public Policy Transmission Need

1.1 The Public Policy Transmission Planning Process

The Public Policy Transmission Planning Process (Public Policy Process) is part of the NYISO's Comprehensive System Planning Process and considers transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes. The Public Policy Transmission Planning Process was developed in consultation with NYISO stakeholders and the New York State Public Service Commission (PSC) and was approved by the Federal Energy Regulatory Commission (FERC) under Order No. 1000. At its core, the Public Policy Process provides for the NYISO's evaluation and selection of transmission solutions to satisfy a transmission need driven by Public Policy Requirements. The process encourages both incumbent and non-incumbent transmission developers to propose projects in response to an identified need.

The NYISO is responsible for administering the Public Policy Process in accordance with Attachment Y to its Open Access Transmission Tariff (OATT). Consistent with its obligations to regulate and oversee the electric industry under New York State law, the PSC has the primary responsibility for the identification of transmission needs driven by Public Policy Requirements.

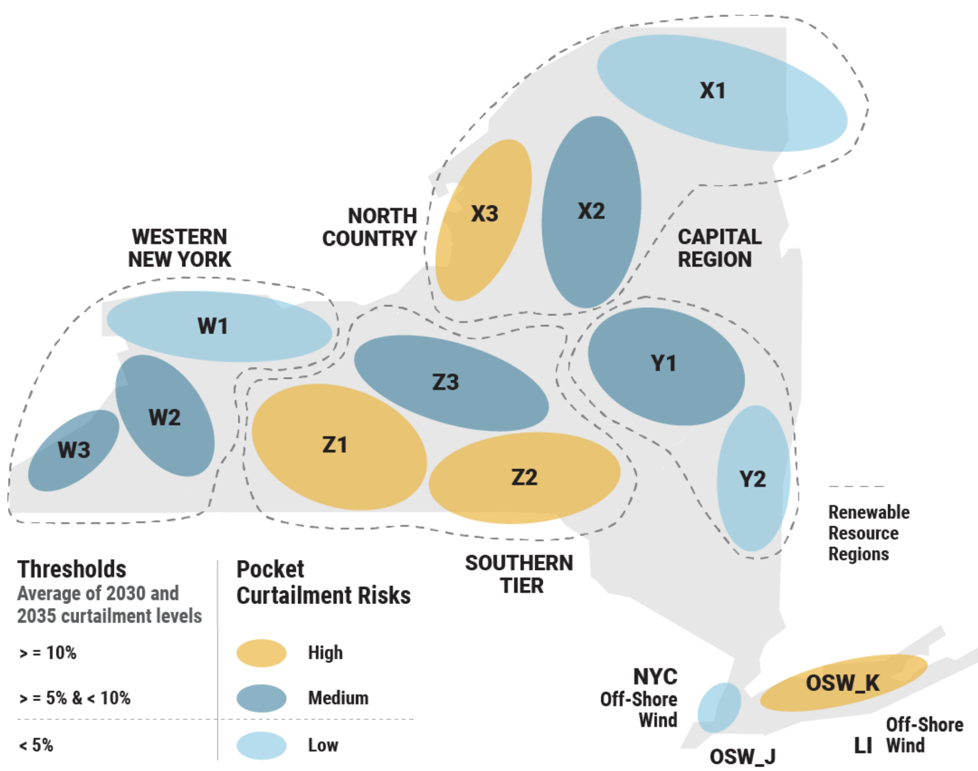
A Public Policy Process cycle typically commences every two years following the posting of the draft *Reliability Needs Assessment* study results, and consists of four core steps (1) the identification of a Public Policy Transmission Need, (2) developers proposing solutions to satisfy the identified Public Policy Transmission Need, (3) an evaluation of the viability and sufficiency of the proposed Public Policy Transmission Projects and Other Public Policy Projects, and (4) a comparative evaluation of the viable and sufficient projects for the NYISO Board of Directors to select the more efficient or cost-effective Public Policy Transmission Project that satisfies the Public Policy Transmission Need, if the PSC confirms that there is a need for transmission. The selected Public Policy Transmission Project is eligible for cost allocation and cost recovery under the OATT.

1.2 Long Island Offshore Wind Export Public Policy Transmission Need

The Climate Leadership and Community Protection Act (CLCPA) mandates that 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 Long Island (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 the state would result in periods of wind energy curtailment.

Since 2016, the NYISO highlighted that reinforcing the transmission system on Long Island is necessary to reliably deliver offshore wind resources that were driven by the public policy requirements of the Clean Energy Standard, followed by the CLCPA. Given the multi-year lead time necessary for transmission development in New York, the NYISO supported a finding of transmission needs throughout the last three cycles of the Public Policy Process.[1] Moreover, 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 evaluated 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.

Figure 1: New York Renewable Generation Pocket Map



[1] *See e.g.*, Case No. 20-E-0497, *Matter of New York Independent System Operator, Inc.'s Proposed Public Policy Transmission Needs for Consideration for 2018,* Comment of the New York Independent System Operator, Inc. (January 19, 2021); Case No. 18-E-0623, *Matter of New York Independent System Operator, Inc.'s Proposed Public Policy Transmission Needs for Consideration for 2018,* Comment of the New York Independent System Operator, Inc. (January 22, 2019); Case No. 16-E-0558, *Matter of New York Independent System Operator, Inc.'s Proposed Public Policy Transmission Needs for Consideration for 2016,* Comment of the New York Independent System Operator, Inc. (December 5, 2016).

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

On August 3, 2020, the 2020-2021 cycle of the Public Policy 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 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[2] 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 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.[3]

[2] 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}

[3] *Id.* at p 23.

2. Proposed Solutions

2.1 Solicitation for Solutions

After the PSC issued the Order establishing the Long Island PPTN, 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[4] 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[5] 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 A. 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).[6]

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 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

[4] https://www.nyiso.com/documents/20142/22968753/LI-PPTN-TechConference.pdf/

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

[6] 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/

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 A.

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 certain reserved rights 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[7] contained 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[8] to its website on June 10, 2022, and is included in Appendix F.

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 E contains a more detailed description and map of each project.

T035 LS Power Atlantic Gateway

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

T036 NextEra Core 1

- East Garden City – Dunwoodie 345 kV PAR-controlled 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

[7] "Public Policy Transmission Upgrades" are defined as 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.

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

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 138 kV 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 138 kV 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 138 kV line

<u>T042 NextEra Core 7</u>

- 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 138 kV line

<u>T043 NextEra Enhanced 1</u>

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

<u>T044 NextEra Enhanced 2</u>

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

T047 Propel Base Solution 1

- 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

T048 Propel Base Solution 2

- 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

T049 Propel Base Solution 3

- 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 chosen scenarios based upon the nature of the proposed Public Policy Transmission Need. 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.

Figure 2: Criteria and Metrics for Long Island PPTN

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 normal and emergency operating conditions**	X	X	Transmission security analysis is included in all interconnection studies, which are performed in parallel with the Public Policy Process.
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 138 kV 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 Constraint Scenario** (Policy + B-VS Scenario): evaluates the system condition built upon the Policy Scenario and excludes the assumed upgrades on the Barrett – Valley Stream 138 kV 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. In the first quarter of 2023, Empire Wind II accepted its cost allocation for local System Upgrade Facilities but rejected its cost allocation for 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 performed additional sensitivities to the above-identified scenarios to further distinguish between the proposed solutions. The details of the databases are described in Appendix G.

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,[9]
4. Unforeseeable environmental remediation and environmental mitigation costs, and

[9] 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.

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).

Quantitative Review of Cost Caps

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

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 3 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 below and used throughout the report takes the Developer's Cost Cap into consideration, as detailed above.

Figure 3: 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

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)
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

* In calculating the total cost estimate in this table, the NYISO, consistent with the OATT, did not estimate or add to the Excluded Capital Costs of any costs concerning unforeseeable environmental mitigation or remediation costs or the financing of the proposed project, such as debt costs or allowance for funds used during construction.

Qualitative Evaluation of Cost Caps

To address the potential scenarios where the quantitative evaluation may not fully capture the benefit or risks of a Developer's Cost Cap, the NYISO's evaluation also includes qualitative criteria for assessing proposed Cost Caps.

Criterion I (Cost Containment Incentive) assesses "[t]he effectiveness of the proposed Cost Cap in providing an incentive to the Developers to contain their Included Capital Costs." It assesses how well aligned is the Developer's incentive to maximize its profits by avoiding cost overruns compared to the level of risk exposure to consumers and what degree of risk is the Developer assuming to pay for cost overruns. This criterion is closely connected with the percentage of the proposed Cost Cap, but the effectiveness of a proposed Cost Cap can become decoupled from the cost sharing percentage if there is a sufficient "buffer" or gap between the independent cost estimate and the Developer's submitted amount for the Cost Cap. A Cost Cap that pressures the Developer to keep costs down is considered to have a profit motive well aligned with consumer interest.

Criterion II (Consumer Risk, Exposure & Uncertainty) assesses "[t]he effectiveness of the proposed Cost Cap in protecting ratepayers from Included Capital Cost overruns." This criterion assesses the likelihood and magnitude of identified project risks and how effective the Cost Cap is at protecting consumers from those overruns. Unlike in the Criterion I, having a comfortable buffer between the Developer's submitted amount for the Cost Cap and the independent cost estimates can help to alleviate concerns associated with identified project risks by ensuring adequate funding to overcome risks associated with the development and construction of the proposed project.

Criterion III (Expected Costs vs. Developer's Cap) assesses "[t]he magnitude of the difference between the Cost Cap and the independent cost estimate." Although this criterion plays heavily into the analysis of the prior two criteria, there are additional considerations considered here for submitted Cost Caps. Specifically, Criterion III looks at the Cost Cap depending on whether the amount of the Cost Cap is above or below the independent cost estimate. If a proposed Cost Cap is below the independent cost estimate, this assessment considers how close, or far below, is the proposed Cost Cap amount to the independent cost estimate considering (a) the Developer's financial and technical qualifications to construct the project and (b) the likelihood that the project can be constructed at the Cost Cap amount. For instance, if there is a large mismatch between the Cost Cap amount and the independent cost estimate, the NYISO assessed the potential "risk of project abandonment" due to a project developing into a financial loss. The NYISO also considered rationales supporting the lower amount of the Included Capital Costs underlying the Cost Cap and the likelihood that the Included Capital Costs will be less than the independent cost estimates based on those reasons.

Conversely, if a proposed Cost Cap is above the independent cost estimate, this criterion assesses whether the proposed Cost Cap will meaningfully contain Included Capital Costs at all. Specifically, the NYISO assesses (a) how close, or far above, is the proposed Cost Cap amount to the independent cost estimate and whether the amount of the Cost Cap that is above the independent cost estimate is either so significant that it is unlikely to bind the Developer and provide benefit to ratepayers or so small that it can still protect ratepayers from cost overruns.

In performing this qualitative evaluation, the NYISO considered the level at which the submitted Cost Caps satisfies the criteria together with the construction risks identified for the corresponding project. Projects with higher construction risks have a greater probability of developing at higher costs (e.g., T036 and T040). In some cases, the NYISO conducted further examination under Criterion III of potential additional costs to consumers stemming from additional information on the rationale for the level of the Cost Cap amount discovered during the evaluation.

The following details each Developer's submitted Cost Caps for their submitted project or projects.

<u>LS Power Submitted Cost Cap Proposal</u>

- LS Power proposed a $3.074B hard Cost Cap for T036.
- The NYISO's consultant, SECO, estimated the Included Capital Costs of the project to be approximately $5.92B.

- The independent cost estimate of Included Capital Costs and LS Power's proposed Cost Cap amount differ substantially.

Criterion I: (Cost Containment Incentive)
Considering the hard Cost Cap and an independent cost estimate much higher than the amount of the Cost Cap, LS Power will experience considerable pressure to keep project costs low enough so as to achieve its targeted returns for its investors. Profit motive and consumer interest are well aligned.

Criterion II: (Consumer Risk, Exposure & Uncertainty)
LS Power's submitted Cost Cap amount comes in well below the independent cost estimate. The potential for the project's Included Capital Costs to exceed the hard Cost Cap is high relative to the other proposed projects. Nevertheless, LS Power's proposed hard Cost Cap eliminates consumer exposure in the event of that the Included Capital Costs exceed the Cost Cap amount.

Criterion III: (Expected Costs vs. Developer's Cap)
The magnitude of the discrepancy between LS Power's amount of the Cost Cap (i.e., Included Capital Costs) and the independent cost estimate is concerning.

<u>NextEra Submitted Cost Cap Proposals</u>

- NextEra proposes a 50/50 soft Cost Cap for all of its projects.
- The amount of NextEra's Cost Cap for its projects were generally several billion higher than the independent cost estimates for the Included Capital Costs.
- The independent cost estimates for the Excluded Capital Costs for each of the NextEra projects ranged from $1.1B to $1.3B.

Criterion I: (Cost Containment Incentive)
The significantly higher amount of the Cost Cap in comparison to the independent cost estimate for Included Capital Costs seriously calls into question the effective of the Cost Cap to incentivize NextEra to contain its costs. NextEra's profit motive is not aligned with consumer interest for the several billion dollars of Included Capital Costs that exceed the independent cost estimates. As a result, NextEra's incentive to maximize profits would not compel it to develop its projects at a cost that is less than the Cost Cap amount.

Criterion II: (Risk, Exposure & Uncertainty)
NextEra's proposed 50/50 cost sharing does insulate consumers from a significant amount of cost overruns but only in the unlikely event that the Included Capital Costs exceed the billions of margin. In other words, if actual Included Capital Costs for the project are more in line with the independent cost estimate, then consumers will be responsible for all of those costs up until the Cost Cap and fifty percent of the Included Capital Costs that may exceed the Cost Cap as well.

Criterion III: (Expected Costs vs. Developer's Cap)
Some margin above the projected Included Capital Costs is to be expected in a proposed Cost Cap.

The magnitude of the amount that is contained in NextEra's proposal is concerning.

Propel NY Submitted Cost Cap Proposals

- Propel NY proposes a 20/80 soft Cost Cap for its projects—the minimum amount permitted under the tariff.
- The amount of Propel NY's Cost Cap for its projects were $0.1B to $0.5B lower than the independent cost estimate for Included Capital Costs.
- The independent cost estimates for the Excluded Capital Costs for each of the Propel NY projects ranged from just over $0.2B to $0.6B.

Criterion I: (Cost Containment Incentive)
Propel NY's proposed 20/80 cost sharing is the minimum amount allowed under the tariff. The reason for this minimum is that anything below 20% cost sharing for a Developer is unlikely to be enough of a burden on the Developer to counterbalance a FERC-approved rate of return on equity. While it cannot be known definitively until after the Developer's rate is approved by FERC, Propel NY's proposal to assume 20% of the Included Capital Costs above the contained amount is less favorable than the proposed sharing commitments by other Developers and may leave Propel NY to lack an effective profit motive to contain costs.

Criterion II: (Risk, Exposure & Uncertainty)
Under Propel NY's submitted soft Cost Caps, consumers would be responsible for 80% of Included Capital Cost overruns. This means that Propel NY would be able to recover the majority of any overruns through its FERC-approved rate. As a result, Included Capital Cost overruns are more likely with Propel NY's projects than with the other two Developers given the lack of an effective profit motive. However, given the overall proposed Included Capital Costs of T047, T048, and T049, the risks to consumers of overruns are not as significant as T051, T052, and T053.

Criterion III: (Expected Costs vs. Developer's Cap)
Propel NY's proposed Cost Cap amount is 15-20% lower than the independent cost estimate of Included Capital Costs and provides a realistic margin that would encourage a motivated Developer to identify efficiency improvements and cost savings in order to ensure the Included Capital Costs for the project come in under the Cost Cap amount.

Figure 4: Qualitative Cost Cap Comparison

Project	Developer Cost Cap Share (%)	Qualitative Criteria I	Qualitative Criteria II	Qualitative Criteria III
T035 - LSPower	100	Excellent	Good	Poor
T036 - NextEra Core 1	50	Fair	Fair	Poor
T037 - NextEra Core 2	50	Fair	Fair	Poor
T038 - NextEra Core 3	50	Fair	Fair	Poor
T039 - NextEra Core 4	50	Fair	Fair	Poor
T040 - NextEra Core 5	50	Fair	Fair	Poor
T041 - NextEra Core 6	50	Fair	Fair	Poor
T042 - NextEra Core 7	50	Fair	Good	Fair
T043 - NextEra Enh 1	50	Fair	Fair	Poor
T044 - NextEra Enh 2	50	Fair	Fair	Good
T047 - Propel Base 1	20	Poor	Fair	Excellent
T048 - Propel Base 2	20	Poor	Fair	Excellent
T049 - Propel Base 3	20	Poor	Fair	Good
T051 - Propel Alt 5	20	Poor	Poor	Excellent
T052 - Propel Alt 6	20	Poor	Poor	Good
T053 - Propel Alt 7	20	Poor	Poor	Good

Key Findings

✓ **The project cost estimates range from $2.1B to $16.9B**. This wide-ranging total cost estimates result from the combination of project designs and Cost Caps.

✓ **LS Power's hard Cost Cap proposal provides significant protection to consumers; however, such protection is somewhat offset by the risks associated with the significant difference between the amount of the Cost Cap and the independent cost estimate for its project.**

✓ **NextEra's proposed 50/50 Cost Cap provides decent protection to consumers; however, such protection is offset by the significant difference between the amount of the Cost Caps and the independent consultants estimates for its projects.**

✓ **Propel NY's proposed 20/80 Cost Cap provides the minimum protection to consumers under the tariff. Generally, the lower protections from the 20/80 Cost Cap are mitigated by the lower estimated cost of Propel NY's projects and, therefore, pose a lower proportional risk to consumers in the event of overruns compared to other more expensive projects.**

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:

I. 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[10] by the following three different MW values to help inform how efficiently each project meets the Long Island PPTN:

- Increase in normal transfer limit of the Long Island export interface. See Appendix I 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 metric for more details.

The results are shown in Figure 5 and Figure 6, with highest performing projects having low $/MW across all transfer, expandability, and operating range values.

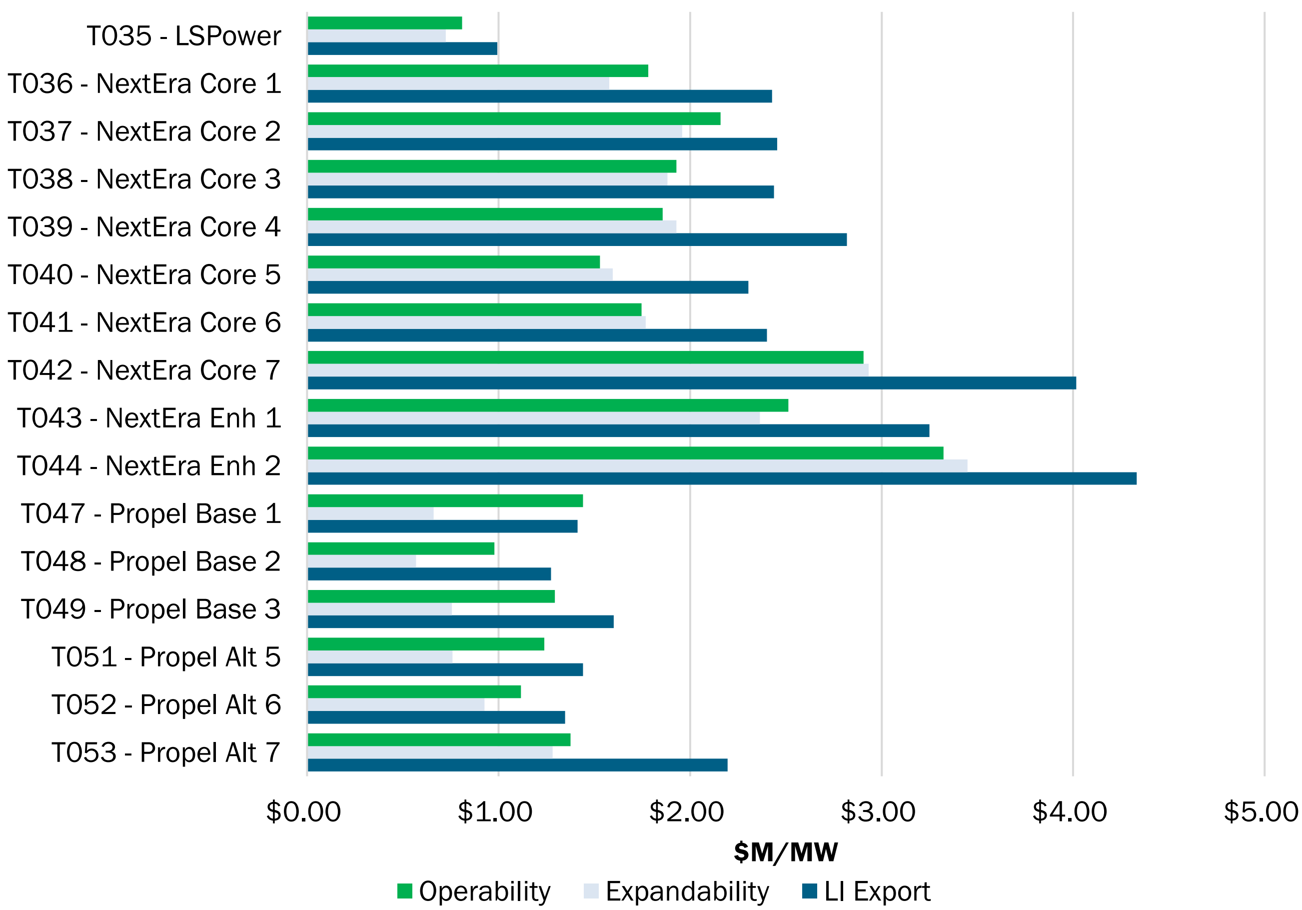
Figure 5: Transfer Capability & Cost Per MW Ratios

Project	LI Export Increase (MW)	$M/MW	OSW Expandability (MW)	$M/MW	Second Outage Operating Range (MW)	$M/MW
T035 – LS Power	3,175	$0.99	4,350	$0.72	3,895	$0.81
T036 – NextEra Core 1	2,890	$2.43	4,450	$1.58	3,940	$1.78
T037 – NextEra Core 2	3,310	$2.45	4,150	$1.96	4,260	$1.91
T038 – NextEra Core 3	3,550	$2.44	4,600	$1.88	5,420	$1.60
T039 – NextEra Core 4	3,010	$2.82	4,400	$1.93	4,570	$1.86
T040 – NextEra Core 5	3,030	$2.30	4,375	$1.60	4,565	$1.53
T041 – NextEra Core 6	3,295	$2.40	4,475	$1.77	4,530	$1.75
T042 – NextEra Core 7	3,285	$4.02	4,500	$2.93	4,540	$2.91
T043 – NextEra Enh 1	3,930	$3.25	5,400	$2.36	5,790	$2.21
T044 – NextEra Enh 2	3,900	$4.33	4,900	$3.45	5,740	$2.94

[10] The cost per MW metric uses the Total Cost Estimate described in Section 4.1 of this report, 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 Capital Costs is considered in the cost containment metric.

T047 – Propel Base 1	1,755	$1.41	3,750	$0.66	2,260	$1.10
T048 – Propel Base 2	1,665	$1.27	3,725	$0.57	2,170	$0.98
T049 – Propel Base 3	1,770	$1.60	3,750	$0.76	2,270	$1.25
T051 – Propel Alt 5	2,265	$1.44	4,300	$0.76	3,510	$0.93
T052 – Propel Alt 6	3,490	$1.35	5,075	$0.93	5,215	$0.90
T053 – Propel Alt 7	2,540	$2.20	4,350	$1.28	4,055	$1.38

Figure 6: 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 7 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 8 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 8 by redistributing offshore wind interconnections to different POIs. Appendix J details the physical and electrical expandability, respectively.

Figure 7: Physical Expandability

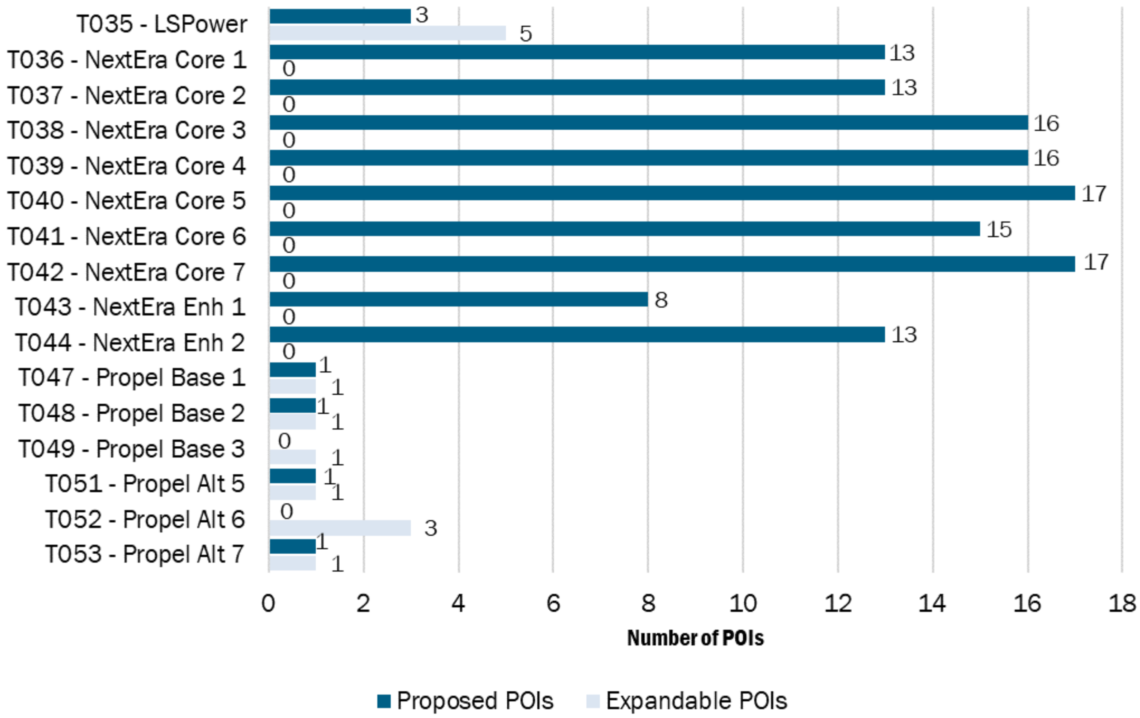
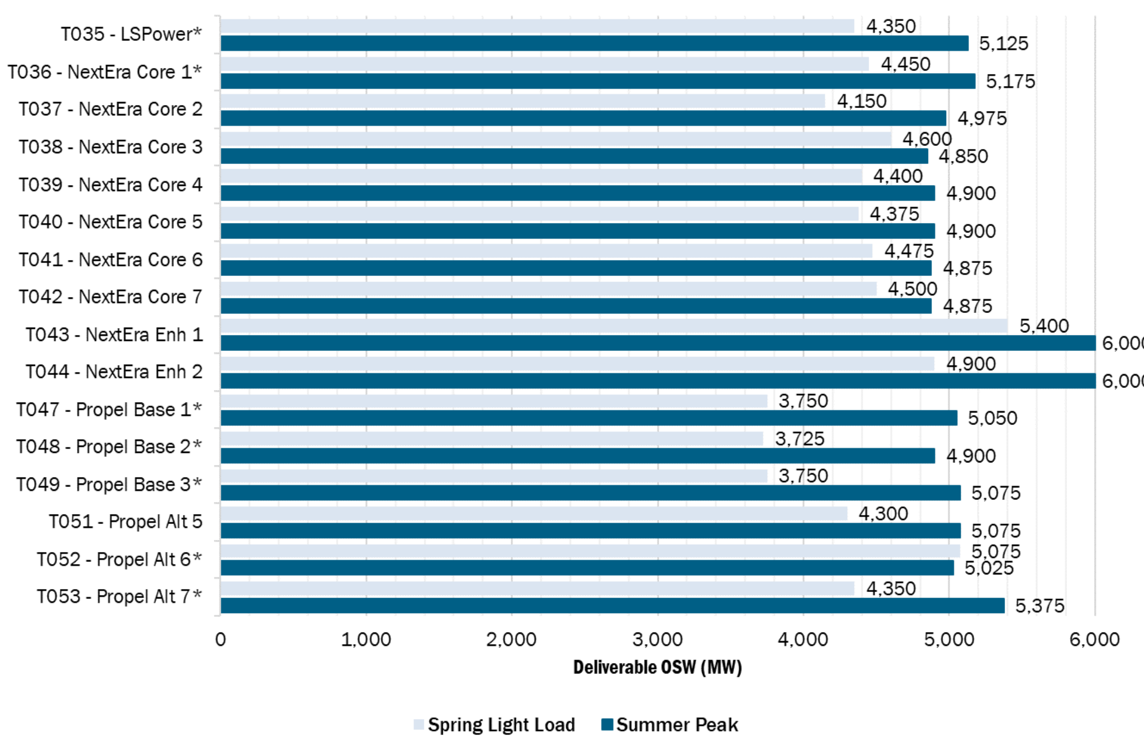


Figure 8: Electrical Expandability



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 for a subset of projects.

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 9: Policy Scenario: Single & Double Outage Import & Export Limits

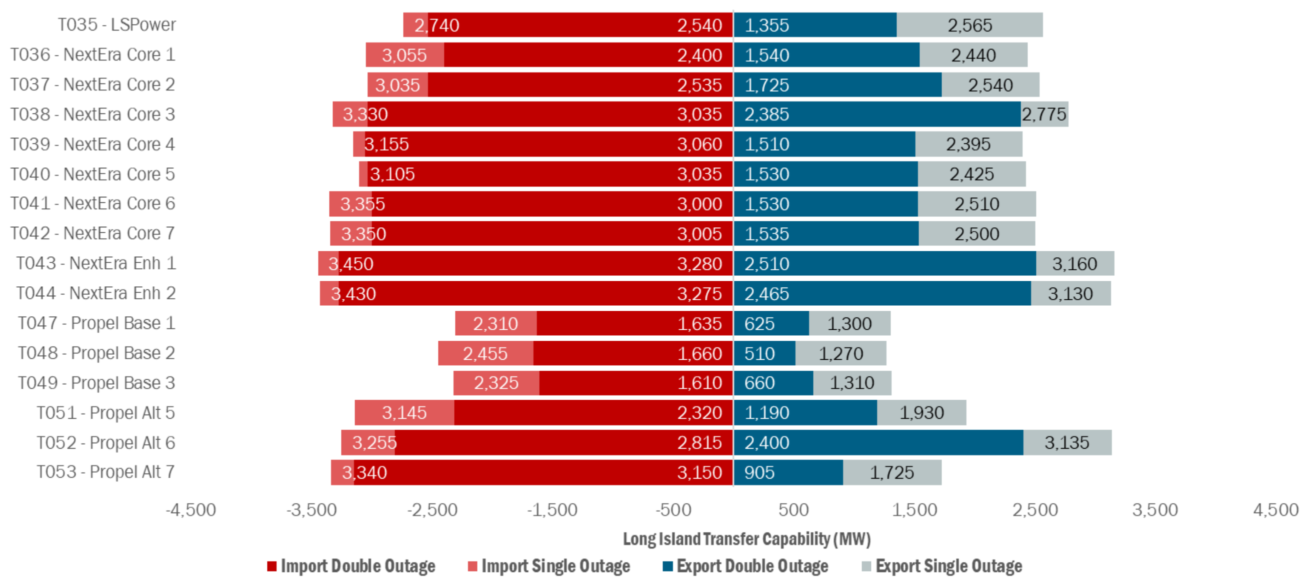
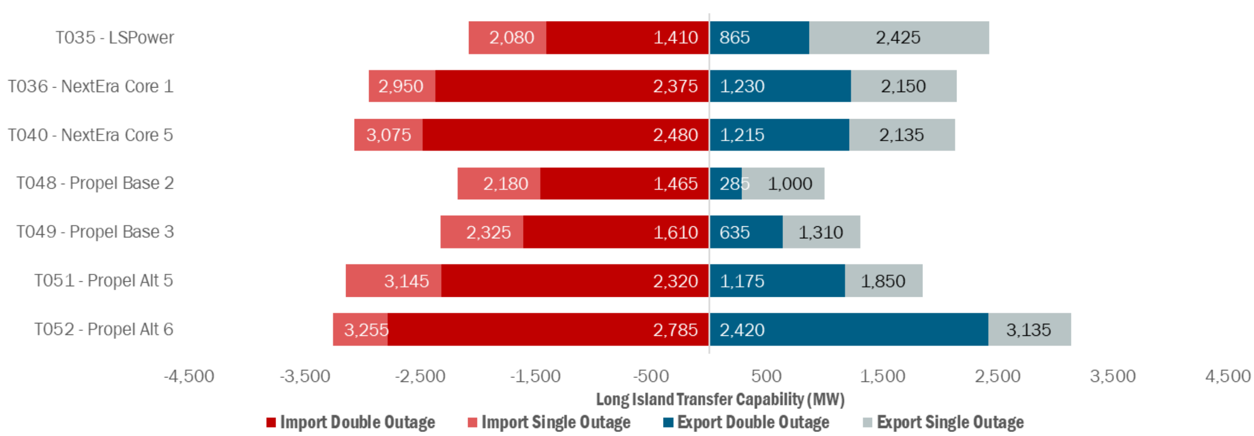


Figure 10: Policy + B-VS Scenario: Single & Double Outage Import & Export Limits



3.5.2 Operability – Transmission Operations for the Future Grid

In the 2019 Report on "Reliability and Market Considerations for a Grid in Transition,"[11] the NYISO identified potential reliability concerns when operating under future high levels of intermittent generation with system and locational demand requirements that may be difficult to forecast in real-time operations.

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

One of the identified reliability concerns relates to the NYISO's continued ability to maintain secure bulk electric system transmission operations within applicable reliability requirements, including all North American Reliability Corporation (NERC) Standards, Northeast Power Coordinating Council (NPCC) Requirements, and New York State Reliability Council (NYSRC) Reliability Rules.

In evaluating the ability to maintain secure operations, the NYISO considered a number of risk factors in accessing the expected transmission operations performance of each project given the anticipated future grid conditions. The primary areas of future risk that the NYISO considered include the impact of offshore wind variability, net-load variability, forecasting errors, and transmission outages.

Offshore Wind Variability, Net-Load Variability, and Forecasting Error

The Long Island zone is unique in its limited transmission connections to the rest of New York State, and this creates challenges when faced with variability in both demand and resources. Net-load variability is the combined amount of MW variability that will exist in a future grid due to real-time changes in electrical demand and output of both behind-the-meter and utility-scale solar photovoltaic resources connected to the Long Island system. The combined variability of net-load and offshore wind coupled with the inherent error margin in forecasting demand and wind output results in the total amount of variability that will need to be managed over the real-time scheduling period.

Based on the NYISO's experience in operating the AC lines connecting Long Island to the rest of the state, the higher voltage transmission grid (345 kV) naturally responds to impacts due to Long Island net-load forecasting errors and variability. Such variability and forecasting errors can adversely impact the NYISO's ability to maintain reliable transmission operations. Reliable transmission operation requires the NYISO to maintain bulk electric transmission line power flows and station voltages within normal operating limits. Consistent with NYISO Operation's existing practices, this is achieved by reserving a certain level of transmission margin on the impacted AC transmission facilities to address operational impacts, such as the Long Island net-load forecasting errors and variability.

Under existing practices in operating today's grid, a 100 MW transmission constraint margin is applied for the existing 345 kV AC transmission lines connecting Long Island to the rest of the state grid to manage the current level of Long Island net-load forecasting errors and variability. For the future grid, the NYISO expects that the transmission constraint margin applied to the AC transmission lines would need to be increased to at least 600 MW to accommodate the variability of 3,000 MW of offshore wind resources connected to Long Island, and the margin could be greater than 1,000 MW as Long Island offshore wind resources approach 6,000 MW. As further discussed below, the impact of this necessary margin on grid operations becomes a limiting factor when there are fewer AC tie lines between Long Island and the rest of the state. HVDC transmission lines connecting Long Island to the rest of the state would not naturally respond to net-load variability because such lines would be operated based on a fixed schedule over the real-time scheduling period during which the impacts of Long Island variability and net-load forecasting errors occur. HVDC is a viable technology in many other applications, but the unique proposal by LS Power (T035) would introduce operational complexities based on the need to actively control the HVDC and manage flow on the weaker parallel AC system in response to variability on the future Long Island grid.

Transmission Outages

In addition to the impact of Long Island net-load variability and forecasting errors, the NYISO also considers the potential impact of line outages on maintaining secure transmission operations. In evaluating the operability for each project, the NYISO considered the impact of significant transmission facility outages for extended periods of time. Assuming a single outage condition of one of the two existing 345 kV AC lines between Long Island and the rest of the state, higher levels of forecasting errors and variability impacts are expected to exceed the thermal operating capability of the existing 345 kV AC lines. Without additional AC tie line capability, the NYISO expects that during line outage conditions high levels of Long Island offshore wind output (i.e., greater than 3,000 MW) would need to be curtailed in order to maintain reliable transmission operations.

Estimated Operating Ranges for Proposed Projects

The figure below illustrates the estimated 345 kV AC line operating ranges for different transmission expansion scenarios as well as expected variability of 3,000 MW and 6,000 MW offshore wind resources connected to Long Island. The calculations assume an approximate 700 MW thermal rating for each of the existing and proposed 345 kV AC transmission lines connecting Long Island to the rest of the state grid. An estimated operating range with a positive value reflects the NYISO's ability to maintain reliable transmission operations to address the impacts of increased forecasting errors and variability impacts of the future grid. A negative value for the operating range indicates that there is insufficient ability to accommodate variability of offshore wind resources connected to Long Island.

Figure 11: 345 kV AC Line Operating Range Under Single Line Out Conditions (MW)

Project	600 MW Variability Future Grid (3,000 MW Offshore Wind)	1,000 MW Variability Future Grid (6,000 MW Offshore Wind)
Pre-Project	200	-600
Projects with no additional 345 kV AC tie-line	200	-600
Projects with 1 additional 345 kV AC tie-line	1,600	800

Project	600 MW Variability Future Grid (3,000 MW Offshore Wind)	1,000 MW Variability Future Grid (6,000 MW Offshore Wind)
Projects with 2 additional 345 kV AC tie-line	3,000	2,200
Projects with 3 additional 345 kV AC tie-line	4,400	3,600

The figure illustrates that those projects with one or more new 345 kV AC lines have a greater operating range that would allow for larger or unexpected values of forecast uncertainty and variability of the future grid. For example, for the pre-project condition with only the existing 345 kV AC lines connecting Long Island to the rest of the state grid, the figure indicates a 600 MW deficiency in operating range when managing variability of 1,000 MW associated with 6,000 MW of offshore wind connected to Long Island. The illustrative calculation is:

-600 MW = (700 MW Import Capability - 1,000 MW Variability) + (700 MW Export Capability – 1,000 MW Variability).

Each additional 345 kV AC line connecting Long Island to the rest of the state grid would result in a 1,400 MW increase in operating range. The illustrative calculation is:

1,400 MW = (700 MW Import Capability) + (700 MW Export Capability).

All but one of the identified top-tier projects for the Long Island PPTN include additional 345 kV AC transmission lines connecting Long Island to the rest of the state grid. The T035 LS Power proposal includes three 1,200 MW bi-directional HVDC lines between Long Island and the rest of the state. Without additional AC lines connecting Long Island to the rest of the state, the impact of offshore wind variability and Long Island net-load forecasting errors will arise only on the existing 345 kV AC lines connecting Long Island to the rest of the state grid.

All of the proposed projects that include one or more 345 kV AC lines connecting Long Island to the rest of the state grid would accommodate the variability associated with 6,000 MW of offshore wind connected to Long Island under line outage conditions. Given that the T035 LS Power proposal does not include any additional 345 kV AC tie lines, it is expected that the proposal could accommodate the variability of 3,000 MW of Long Island offshore wind but would not accommodate the variability of 6,000 MW of offshore wind assuming one of the existing 345 kV AC transmission lines is out of service. This represents a significant limitation for the future operability of the T035 LS Power proposal, assuming offshore wind expansion greater than 3,000 MW.

3.5.3 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 NERC does not have a minimum WSCR criterion, a higher WSCR generally indicates a stronger system. The WSCR results are shown in Figure 12 and more details on the analysis can be found in Appendix K. 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 12: Weighted Short-Circuit Ratio (WSCR)

Project	WSCR			
	N-0	N-1	N-2	N-3
Pre-Project	1.94	1.83	1.61	n/a
T035 - LS Power	0.82	0.78	0.7	n/a
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

3.5.4 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 13: Total Resiliency Score

Project	Total Resiliency Score
T035 - LSPower	13.5
T036 - NextEra Core1	33.5
T037 - NextEra Core 2	41.5
T038 - NextEra Core 3	61
T039 - NextEra Core 4	66
T040 - NextEra Core 5	52
T041 - NextEra Core 6	49.5
T042 - NextEra Core 7	41.5
T043 - NextEra Enh 1	63
T044 - NextEra Enh 2	75.5
T047 - Propel Base 1	34
T048 - Propel Base 2	31.5
T049 - Propel Base 3	34
T051 - Propel Alt 5	34
T052 - Propel Alt 6	34
T053 - Propel Alt 7	46

3.5.5 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.

- ✓ **All of the proposed projects that include one or more additional 345 kV AC lines connecting Long Island to the rest of the state grid would accommodate variability of up to 6,000 MW of offshore wind connected to Long Island.**

- ✓ **For projects that do not include additional 345 kV AC tie lines between Long Island and the rest of the state (e.g., T035 LS Power), the system would handle the variability of 3,000 MW of offshore wind connected to Long Island, but it could not accommodate the level of variability associated with 6,000 MW of offshore wind, thus limiting the operability of the project and the grid.**

- ✓ **While there are 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 NYCA 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

The NYISO evaluates the economic and performance benefits of proposed projects based on several key metrics that consider production cost savings, Long Island import and export energy enhancements, offshore wind curtailment improvements, and carbon dioxide (CO_2) emissions reductions.

3.6.1 Production Cost Benefits

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

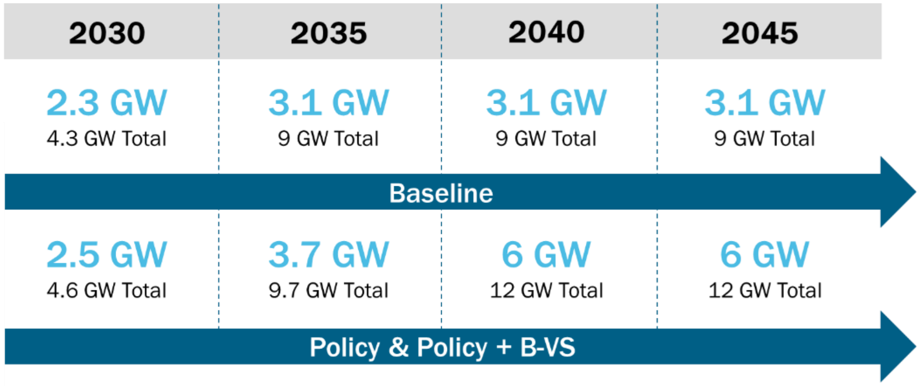
Considerations:

- 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 L. The offshore wind capacity varies between the Baseline and Policy Scenarios as shown in the figure below.

Figure 14: 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 15: 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 16: Production Cost Savings Over 20 Years (2022 $M)

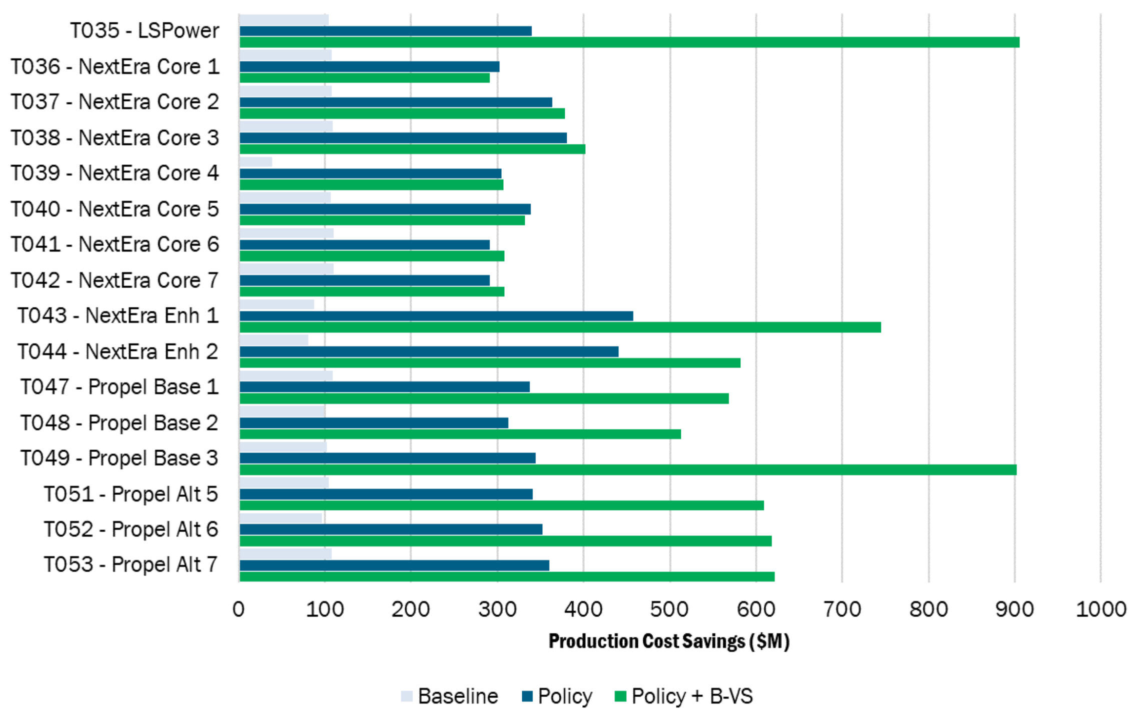
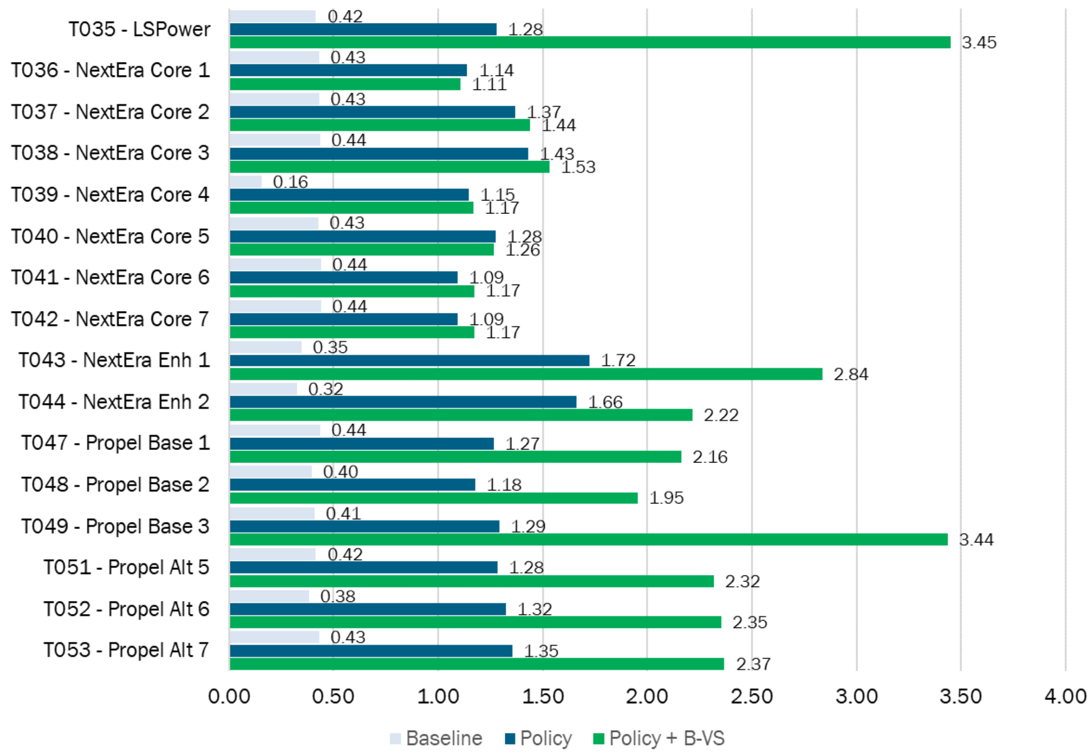


Figure 17: Savings As Percentage of Total NYCA-Wide Production Cost



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% of 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.

Additionally, the NYISO investigated the impact of an increase in transmission constraint margins needed to accommodate the increased net-load variability caused by offshore wind generation in Long Island (see Section 3.5.2 above). Higher constraint margins were shown to increase pre-project offshore wind curtailment energy by up to 22%. These findings bolster the production cost benefits of projects analyzed by up to three times the original Policy + B-VS Scenario savings. See Appendix L for additional details.

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.

3.6.2 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 NYCA. 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.

3.6.2.1 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 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 18: Baseline Scenario 20-Year Transmission Utilization

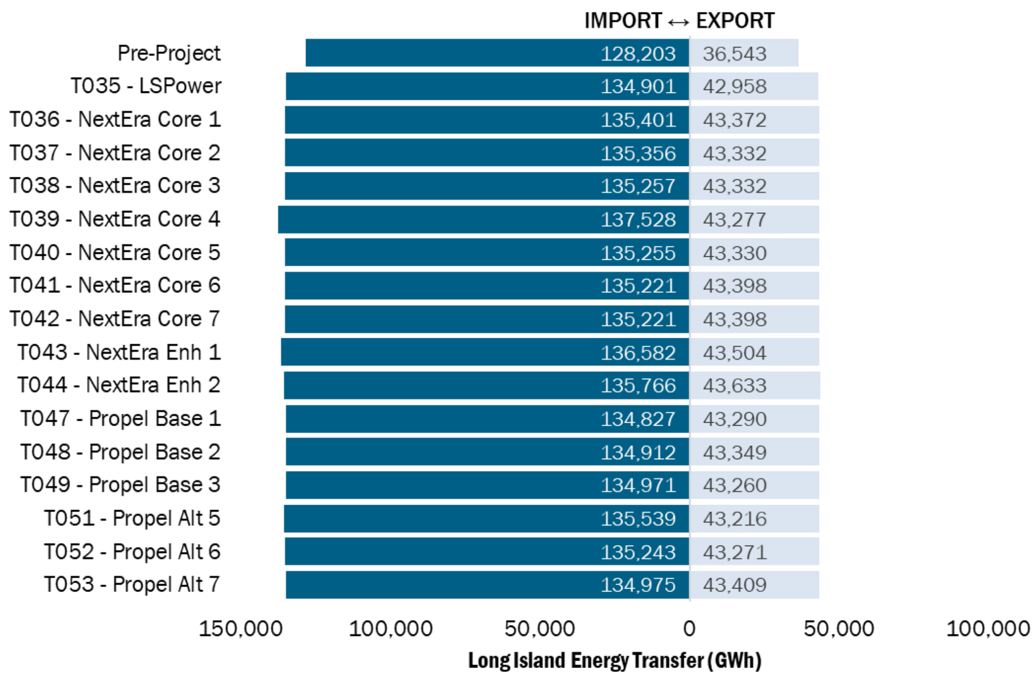


Figure 19: Policy Scenario 20-Year Transmission Utilization

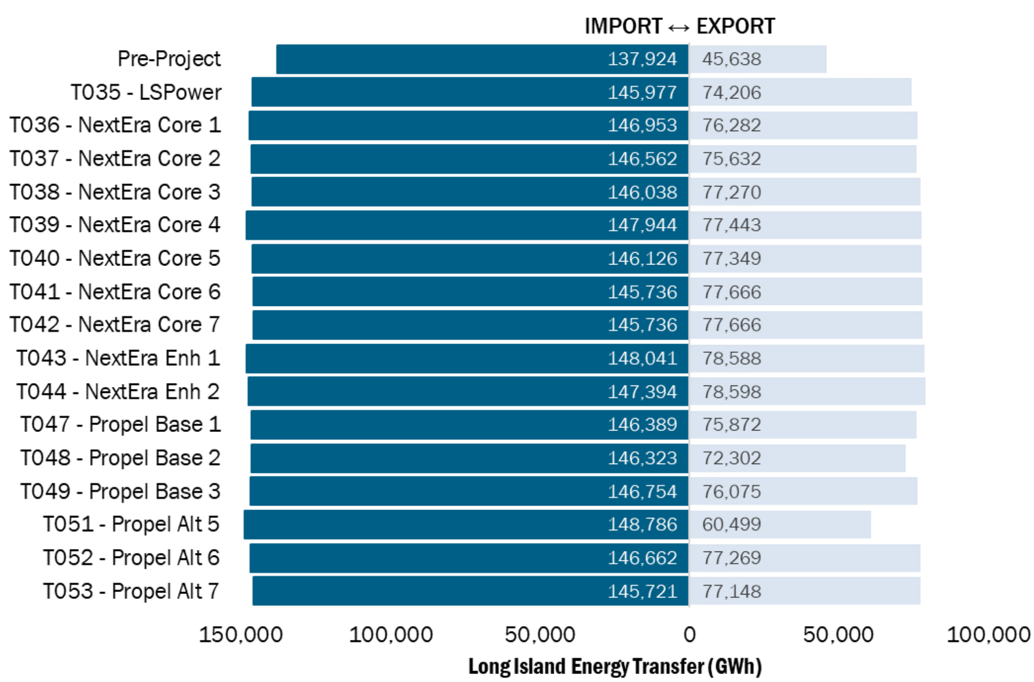
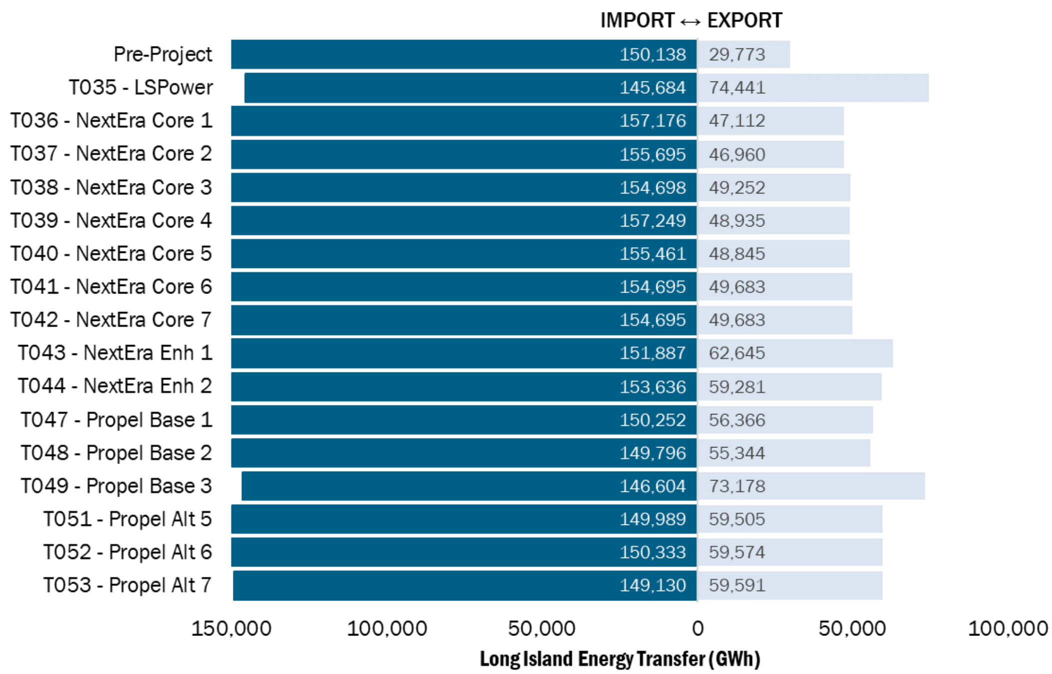


Figure 20: Policy + B-VS Scenario 20-Year Transmission Utilization



3.6.2.2 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 21: 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 22: Policy Scenario Long Island Offshore Wind Energy Deliverability

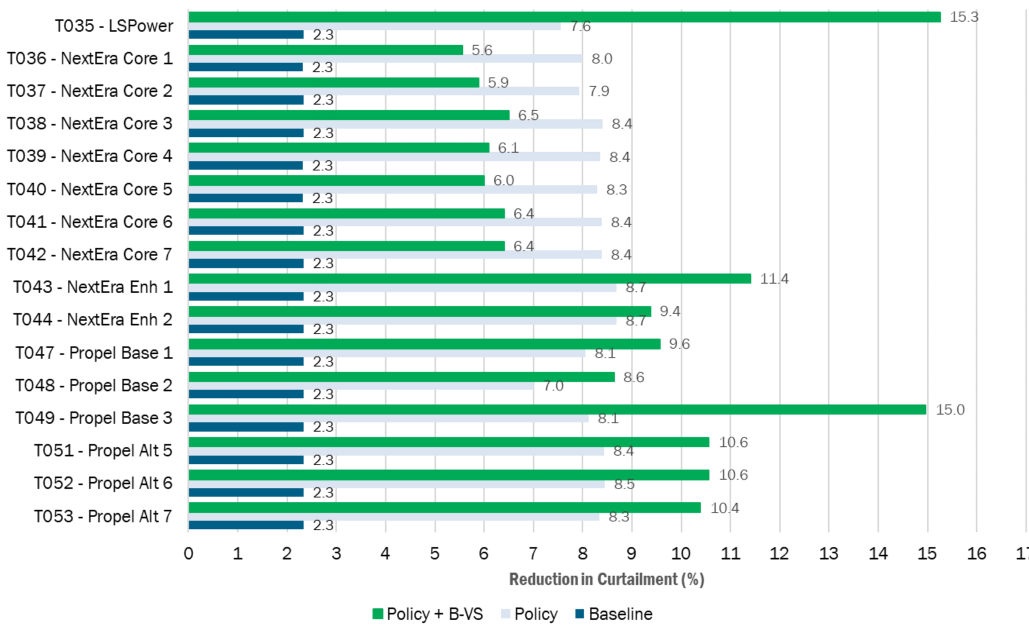
Project	2030	2035	2040	2045
Policy Case	98.3%	96.3%	87.0%	89.7%
T035 - LS Power	99.5%	99.9%	98.4%	98.4%
T036 - NextEra Core 1	99.0%	99.9%	99.1%	99.3%
T037 - NextEra Core 2	99.0%	99.9%	99.1%	99.1%
T038 - NextEra Core 3	99.0%	99.9%	99.8%	99.8%
T039 - NextEra Core 4	99.0%	99.8%	99.6%	99.8%
T040 - NextEra 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 23: Policy + B-VS 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.

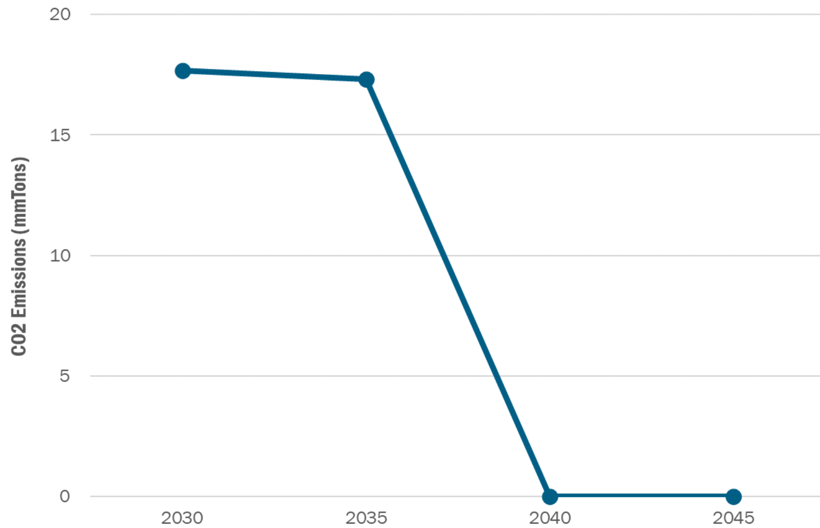
Figure 24: Unbottled Offshore Wind Production



3.6.2.3 CO_2 Emissions

Each scenario model includes thermal generation capacity that burn fossil fuel to generate energy and, through that process, emit 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 New York policy. The Policy and Policy + B-VS Scenario model the full achievement of CLCPA mandates 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 Scenarios (without the addition of the proposed projects) and highlights the elimination of CO_2 emissions beyond 2040.

Figure 25: Annual NYCA CO_2 Emissions in Policy Scenarios



The figures below quantify the estimated 20-year CO_2 emissions for the Baseline, Policy, and Policy + B-VS Scenarios for the pre-project and post-project simulations.

Figure 26: Baseline Scenario 20-Year Estimated CO_2 Emissions (Million Tons)

Project	LI	NYC	NYCA	Regional
Baseline (Pre-Project)	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 27: Policy Scenario 20-Year Estimated CO_2 Emissions (Million Tons)

Project	LI	NYC	NYCA	Regional
Policy (Pre-Project)	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 28: Policy + B-VS Scenario 20-Year Estimated CO_2 Emissions (Million Tons)

Project	LI	NYC	NYCA	Regional
Policy + B-VS (Pre-Project)	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 Policy Scenarios as the models include full achievement of the CLCPA mandate for 100% carbon-free generation by 2040. In 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 when internal generation is more cost effective than external generation. 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 increase 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 CO_2 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 the CLCPA 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.*[12] 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 29** summarizes the reliability benefit (i.e., LOLE reduction) of the proposed projects when

12 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 M for further detail on the capacity benefit evaluation.

Figure 29: Policy Scenario Delta NYCA LOLE (event day/year) on Study Year 2030

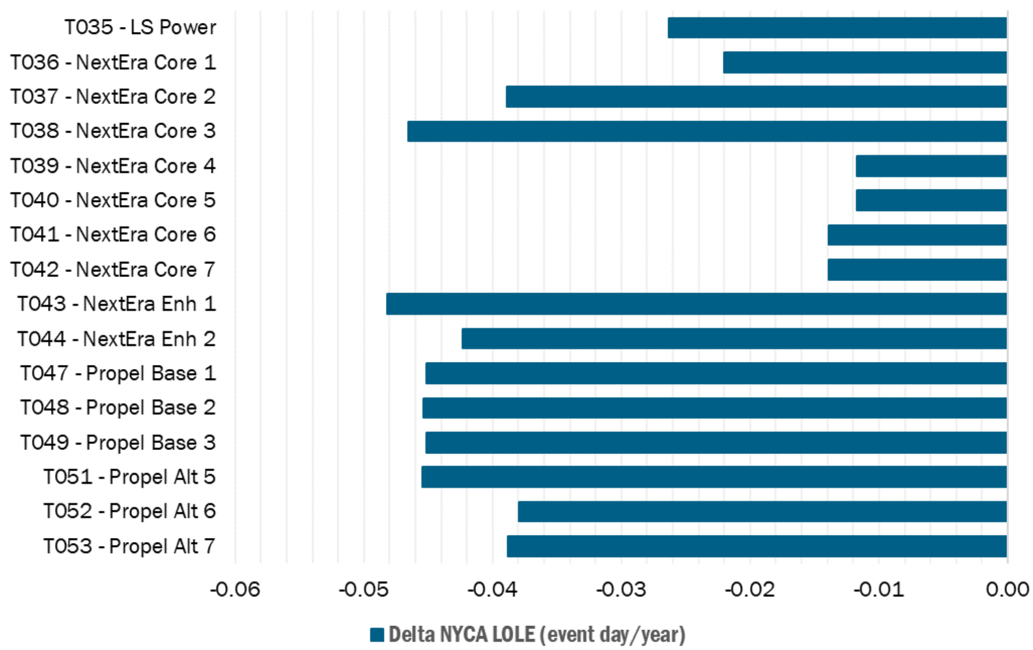
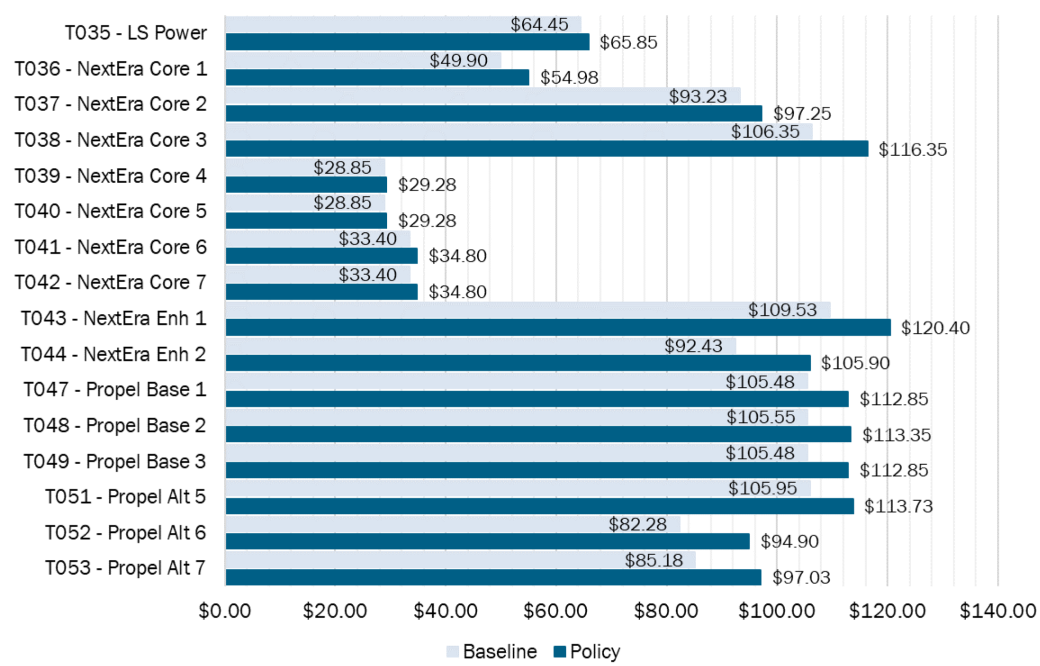


Figure 30: Annual Capacity Benefit (2022 $M)



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.**

3.8 Avoided Capital Cost Benefits

Evaluation Metric: Avoided Capital Cost

Purpose: Assesses the economic benefits related to the reduction and/or deferral of future generation projects needed to meet projected future energy demand and renewable policy objectives

Evaluation: Using capacity expansion simulations, model each project's impact on reducing OSW curtailment, increasing transfer capability to/from Long Island, and reducing Long Island capacity reserve requirement and measure reduction in future generation capital cost investment

Considerations:

- Reductions in the amount of upstate renewable generation capacity
- Re-location of Dispatchable Emission Free Resource capacity from Long Island to upstate zones
- Projects that reduce and relocate the most capacity will produce the highest avoided capital cost savings and are preferable

To meet future energy demand and State policies driven by CLCPA a significant amount of new zero emissions generation capacity will need to be installed in the NYISO system. The NYISO's *2021-2040 System & Resource Outlook* found that at least 95 GW of new generation projects and/or modifications to existing fossil plants will be needed by 2040. The addition of a Long Island Public Policy Transmission Project helps to reduce the need for new generation capacity consist with the CLPCA by increasing offshore wind generation production and through stronger transmission connections to Long Island. The avoided capital cost benefit assessment measures the future generation capital costs avoided due to the addition of Public Policy Transmission Project.

3.8.1 Avoided Capital Cost Assessment

The NYISO's capacity expansion model optimizes the future system buildout to meet projected energy and policy requirements while minimizing capital and energy costs. To quantify the capital cost investment in the NYCA, the NYISO used the capacity expansion model for Policy Case Scenario 2 from the NYISO's *2021-2040 System & Resource Outlook*. The NYISO modified the Policy Case Scenario 2 from The Outlook assumptions to include fixing the offshore wind generation buildout schedule per **Figure 14** and modeling transmission upgrades accordingly for each proposed project. This assessment was conducted for both the Policy and Policy + B-VS Scenarios for certain projects that necessitated additional evaluation to distinguish their economic benefits to the transmission system.

The proposed transmission projects are represented in the capacity expansion model through: 1) an increase offshore wind production due to reduced curtailment identified in the production cost models, 2) interzonal transfer limit changes identified in Appendix N, and 3) Zone K capacity reserve margin decreases driven by an increase in transmission security limits also described in Appendix N.

3.8.2 Avoided Capital Cost Results

The system improvements enabled by each transmission project reduce the amount of future generation capacity needed. The two primary factors that drive the magnitude of avoided generation capacity are reduced offshore wind energy curtailments and the increased Zone K import transmission limits. Unbottled offshore wind energy reduces the need to build as much solar capacity in upstate zones and, in turn, provides avoided capital cost savings. Increased import transfer limits into Long Island lower the zone's effective capacity margin requirement and enable the movement of Dispatchable Emissions Free Resource (DEFR) capacity from Zone K to upstate zones where capital costs are lower. The figures below show the results of the avoided cost analysis and disaggregates the impacts of reduced solar capacity buildout and relocated DEFR capacity.

Figure 31: Avoided Cost Savings – Policy Scenario Results

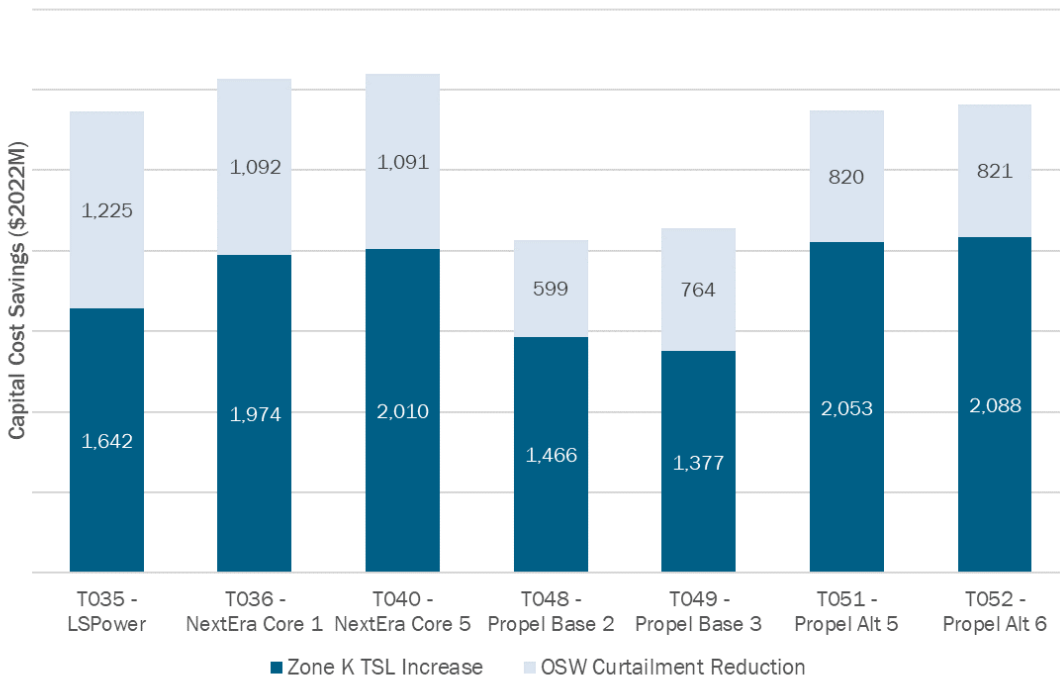
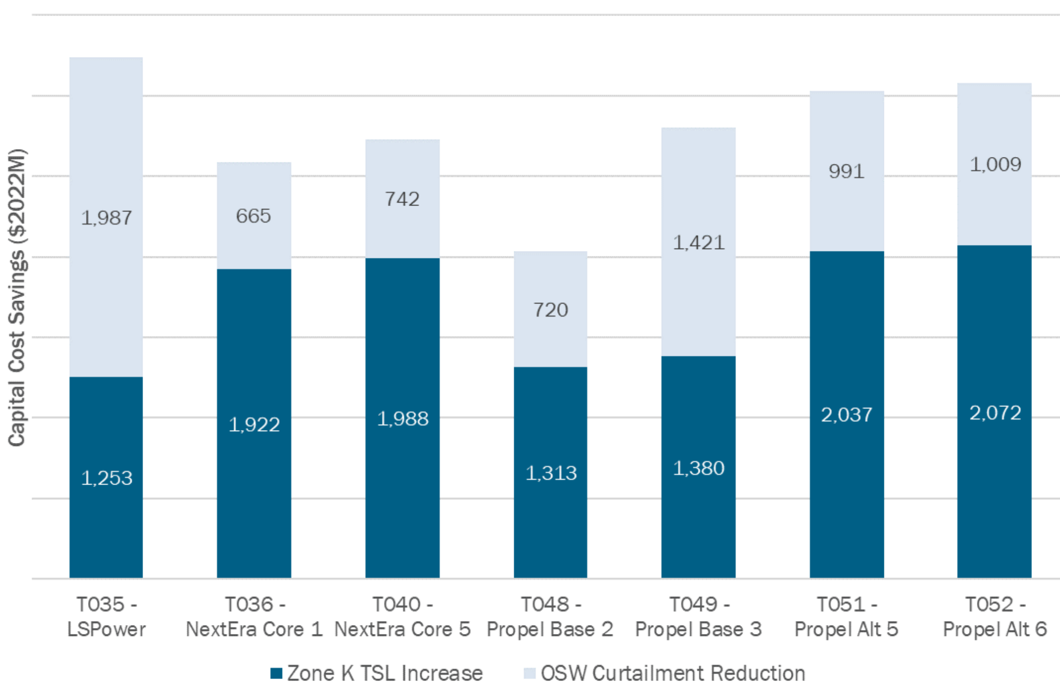


Figure 32: Avoided Cost Savings – Policy + B-VS Scenario Results



The magnitude of the capital cost savings for each project is generally correlated with the amount of increase in Zone K import capability and reduction in offshore wind curtailment. Some secondary factors, such as the zone that is connected to Long Island due to the project and the increase in Zone K export limit due to the project, impact the capital cost savings and tend to also differentiate projects.

The figure below summarizes the total avoided cost savings for each project analyzed.

Figure 33: Total Capital Cost Savings (2022 $M)

Project	Total Capital Cost Savings ($2022 M)	
	Policy Scenario	Policy + B-VS Scenario
T035 - LSPower	2,866	3,240
T036 - NextEra Core 1	3,066	2,586
T040 - NextEra Core 5	3,101	2,731
T048 - Propel Base 2	2,065	2,033
T049 - Propel Base 3	2,141	2,801
T051 - Propel Alt 5	2,873	3,028
T052 - Propel Alt 6	2,909	3,081

Key Findings

✓ **The Long Island Public Policy Projects under the avoid cost assessment produce between $2B and $3.2B of avoided capital cost savings.** Projects that enable higher reductions in Long Island offshore wind curtailment and increase import capability to Long Island had the highest savings.

✓ **All projects analyzed create capital cost savings through the reduction in upstate solar capacity additions.** Of the total avoided capital cost savings analyzed the avoided solar capacity represented less than half of the total capital cost savings calculated for a majority of the projects.

✓ **All projects analyzed helped to increase the Long Island transmission security limit and reduced the capacity reserve margin for Long Island.** With a reduced capacity reserve margin in Zone K, DEFR capacity was sited in less costly upstate areas, which constituted over half of the total avoided capital cost savings.

3.9 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 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 34 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 34: Estimated Minimum Duration for Project Development

Projects	Developer Proposed Total Duration	Estimated Minimum Duration
T035 – LS Power	70 Months	71 Months
T036 – NextEra Core 1	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 or conditions that may be imposed by federal, state, or local authorities unique the project or affected locales. The independent cost estimates in Section 3.1 and the minimum schedule review in Figure 34 are based upon evaluating the projects, as proposed, and are not projections of final project costs to ratepayers or actual in-service dates. The risks identified by SECO indicate factors that could increase project cost or time to construct based on information reasonably available at this stage. This evaluation is used to compare the relative foreseeable risks for each project. It is not intended to capture all obstacles or modifications the project may encounter in the permitting process prior to going in-service.

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, if available. 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 35: Cost and Schedule Risk

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

The most significant risks are summarized below.

3.9.1 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. 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:

LS Power

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 a planned 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.

NextEra

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

- Hempstead Harbor: The proposed location of the transition station for the submarine cables coming ashore at Tappen Beach is at an existing National Grid gas regulator station.

Propel NY

Proposals Alternate Solutions 6 & 7

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

3.9.2 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 reasonably 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. 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

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. A full environmental survey prior to construction will be required to ensure there is no soil contamination. The need to address the contamination could impact cost and schedule.

3.9.3 Design Concern

<u>NextEra</u>

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

- Jamaica Substation (all NextEra projects) and Farragut Substation (T037, T038, T039, T043 and T044): 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. Due to the low clearances of the transmission lines, it will be very difficult to transition the lines to underground cables while meeting the system outage and restoration requirements.

<u>Propel NY</u>

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

- Tremont Substation: The construction of the proposed Network Upgrade Facilities (NUF) will require an extensive outage of the two transformers and the line (X28).

3.9.4 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:

<u>LS Power</u>

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. Access to the site will be difficult due to the terrain and rock condition. In addition, the proposed installation for transition from overhead to GIS will require outages of lines to Pleasant Valley (W80, W81) and Buchanan (W97, W98) for extended periods of time.
- Long Lead Time: Due to high demand and equipment complexities, manufacturers are quoting lead times up to 4 years for onshore HVDC equipment. With three units being installed, it could take an additional six months for the second unit and another six months for the third unit to be installed, tested, and commissioned.
- Road Closure During Construction: Construction of the underground cables near the Port Chester and Cold Harbor Spring landing site may require road closures of that could eliminate the only access to homes and businesses.

<u>NextEra</u>

All NextEra Proposals

- Road Closure during construction: Construction of the underground cables near the Davenport Park transition station may require road closures that could eliminate access to homes on the peninsula.

Proposals T041, T042, T043, T044 – Core 6, 7 and Enhanced 1&2

- Long Lead Time: Due to high demand and equipment complexities, manufacturers are quoting lead times up to four years for onshore HVDC equipment. Additional six months may be needed to install, test, and commission a second unit.

<u>Propel NY</u>

Proposals T053 – Alternate Solutions 7

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

Key Findings

- ✓ **There are significant permitting and constructability risks for the NextEra projects that connect to the existing Farragut substation or have submarine cables routed through New York Harbor and the Hudson River.**
- ✓ **Connections to the existing 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 transmission outage risks have been identified for the LS Power project's connection to the existing Millwood substation, NextEra projects that propose to connect to the existing Dunwoodie substation, and the Propel NY projects that propose 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.**
- ✓ **Required NUFs and their final design 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.**

3.10 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 Study (SIS) in the NYISO's Transmission Interconnection Procedures. Figure 36 shows the interconnection queue numbers for all the proposed projects.

Figure 36: 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 SIS. 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.

3.11 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 SIS 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 SIS 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.

3.12 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.[13] Based on the transfer and production cost analysis results described in Sections 3.3 and 3.6, 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.[14]

3.13 Evaluation of Interaction with Local Transmission Owner Plans

In its Public Policy Process, the NYISO is required to review the Local Transmission Owner Plans (LTPs)[15] as they relate to the Bulk Power Transmission Facilities (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.

[13] *See* OATT Sections 31.4.10 and 31.4.8.1.9.
[14] *See* OATT Section 31.4.11.1 (The draft report will be provided to the Market Monitoring Unit for its review and consideration).
[15] *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 with a commitment to not recover the Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $3,152M. However, the independent cost estimate for Included Capital Costs is $5,920M, which is significantly higher than the submitted Cost Cap.
- LS Power's hard Cost Cap proposal provides significant protection to consumers; however, the project is expected to cost significantly more than the $3.1 billion Cost Cap, which the Developer could seek to recover some of the costs above the Cost Cap at FERC.
- Good operability range, expandability, and transfer capability.
- This unique design would introduce operational complexities based on the need to actively control the HVDC and manage flow on the weaker parallel AC system in response to variability on the future Long Island grid. Restrictions on HVDC transmission operations would be necessary with high offshore wind variability as offshore wind installations increase.
- 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.
- Low property and constructability risks with notable risks related to HVDC equipment procurement and the proposed Northgate substation.

T036: NextEra Core 1

- The Developer proposes a soft Cost Cap of $5,882M with a commitment to not recover 50% of Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $7,019M. The independent cost estimate for Included Capital Costs is $3,230M and significantly lower than the submitted Cost Cap.
- NextEra's proposed 50/50 Cost Cap provides decent protection to consumers; however, such protection is offset by the significant difference between the amount of the Cost Caps and the independent consultant estimates for its projects.
- 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 existing Dunwoodie, Sprain Brook, and Jamaica substations.

T037: NextEra Core 2

- The Developer proposed a soft Cost Cap of $6,867M with a commitment to not recover 50% of Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $8,126M. The independent cost estimate for Included Capital Costs is $3,627M and significantly lower than the submitted Cost Cap.
- NextEra's proposed 50/50 Cost Cap provides decent protection to consumers; however, such protection is offset by the significant difference between the amount of the Cost Caps and the independent consultant estimates for its projects.
- 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.

T038: NextEra Core 3

- The Developer proposed a soft Cost Cap of $7,444M with a commitment to not recover 50% of Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $8,653M. The independent cost estimate for Included Capital Costs is $4,252M and significantly lower than the submitted Cost Cap.
- NextEra's proposed 50/50 Cost Cap provides decent protection to consumers; however, such protection is offset by the significant difference between the amount of the Cost Caps and the independent consultant estimates for its projects.
- 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 existing Farragut, Dunwoodie, Sprain Brook, and Jamaica substations.

T039: NextEra Core 4

- The Developer proposed a soft Cost Cap of $7,211M with a commitment to not recover 50% of Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $8,483M. The independent cost estimate for Included Capital

Costs is $4,457M and significantly lower than the submitted Cost Cap.

- NextEra's proposed 50/50 Cost Cap provides decent protection to consumers; however, such protection is offset by the significant difference between the amount of the Cost Caps and the independent consultant estimates for its projects.
- 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 existing Farragut, Dunwoodie, Sprain Brook, and Jamaica substations and the proposed routing of submarine cables through Hudson River.

T040: NextEra Core 5

- The Developer proposed a soft Cost Cap of $5,898M with a commitment to not recover 50% of Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $6,984M. The independent cost estimate for Included Capital Costs is $3,610M and significantly lower than the submitted Cost Cap.
- NextEra's proposed 50/50 Cost Cap provides decent protection to consumers; however, such protection is offset by the significant difference between the amount of the Cost Caps and the independent consultant estimates for its projects.
- 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 existing Dunwoodie, Sprain Brook, and Jamaica substations.

T041: NextEra Core 6

- The Developer proposed a soft Cost Cap of $6,774M with a commitment to not recover 50% of Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $7,912 M. The independent cost estimate for Included Capital Costs is $4,448M and significantly lower than the submitted Cost Cap.
- NextEra's proposed 50/50 Cost Cap provides decent protection to consumers; however, such protection is offset by the significant difference between the amount of the Cost Caps and the independent consultant estimates for its projects.
- 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 existing Dunwoodie, Sprain Brook, and Jamaica substations, and HVDC equipment procurement lead time and converter space requirements.

T042: NextEra Core 7

- The Developer proposed a soft Cost Cap of $10,373M with a commitment to not recover 50% of Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $13,192M. The independent cost estimate for Included Capital Costs is $13,750M and significantly higher than the submitted Cost Cap.
- NextEra's proposed 50/50 Cost Cap provides decent protection to consumers; however, such protection is offset by the significant difference between the amount of the Cost Caps and the independent consultant estimates for its projects.
- Good operability and transfer capability, with 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 existing 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 a commitment to not recover 50% of Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $12,769M. The independent cost estimate for Included Capital Costs is $8,753M and significantly lower than the submitted Cost Cap.
- NextEra's proposed 50/50 Cost Cap provides decent protection to consumers; however, such protection is offset by the significant difference between the amount of the Cost Caps and the independent consultant estimates for its projects.
- Good operability and transfer capability, with 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 existing 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 a commitment to not recover 50% of

Included Capital Costs above the cap from ratepayers.

- The total calculated cost estimate is $16,898M—the highest cost among the proposed projects. The independent cost estimate for Included Capital Costs is $16,128M and slightly higher than the submitted Cost Cap.
- NextEra's proposed 50/50 Cost Cap provides decent protection to consumers; however, such protection is offset by the significant difference between the amount of the Cost Caps and the independent consultant estimates for its projects.
- Good operability and transfer capability, with 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 existing 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 a commitment to not recover 20% of Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $2,480M. The independent cost estimate for Included Capital Costs is $2,269M and slightly higher than the submitted Cost Cap.
- Propel NY's proposed 20/80 Cost Cap provides the minimum protection to consumers under the tariff. Generally, the lower protections from the 20/80 Cost Cap are mitigated by the lower estimated cost of Propel NY's projects and, therefore, pose a lower proportional risk to consumers in the event of overruns compared to other more expensive projects.
- 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 proposed 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 a commitment to not recover 20% of Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $2,121M—the lowest cost among the proposed projects. The independent cost estimate for Included Capital Costs is $1,966M and slightly higher than the

submitted Cost Cap.

- Propel NY's proposed 20/80 Cost Cap provides the minimum protection to consumers under the tariff. Generally, the lower protections from the 20/80 Cost Cap are mitigated by the lower estimated cost of Propel NY's projects and, therefore, pose a lower proportional risk to consumers in the event of overruns compared to other more expensive projects.
- 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 a commitment to not recover 20% of Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $2,835M. The independent cost estimate for Included Capital Costs is $2,642M and moderately higher than the submitted Cost Cap.
- Propel NY's proposed 20/80 Cost Cap provides the minimum protection to consumers under the tariff. Generally, the lower protections from the 20/80 Cost Cap are mitigated by the lower estimated cost of Propel NY's projects and, therefore, pose a lower proportional risk to consumers in the event of overruns compared to other more expensive projects.
- 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 a commitment to not recover 20% of Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $3,262M. The independent cost estimate for Included Capital Costs is $2,902M and slightly higher than the submitted Cost Cap.
- Propel NY's proposed 20/80 Cost Cap provides the minimum protection to consumers under the tariff. Generally, the lower protections from the 20/80 Cost Cap are mitigated by the lower estimated cost of Propel NY's projects and, therefore, pose a lower proportional risk to consumers

in the event of overruns compared to other more expensive projects.

- 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.
- 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.

T052: Propel Alternate Solution 6

- The Developer proposed a soft Cost Cap of $3,953M with a commitment to not recover 20% of Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $4,705M. The independent cost estimate for Included Capital Costs is $4,071M and slightly higher than the submitted Cost Cap.
- Propel NY's proposed 20/80 Cost Cap provides the minimum protection to consumers under the tariff. Generally, the lower protections from the 20/80 Cost Cap are mitigated by the lower estimated cost of Propel NY's projects and, therefore, pose a lower proportional risk to consumers in the event of overruns compared to other more expensive projects.
- 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 and Eastern Queens substations 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 a commitment to not recover 20% of Included Capital Costs above the cap from ratepayers.
- The total calculated cost estimate is $5,576M. The independent cost estimate for Included Capital Costs is $5,113M and slightly higher than the submitted Cost Cap.
- Propel NY's proposed 20/80 Cost Cap provides the minimum protection to consumers under the tariff. Generally, the lower protections from the 20/80 Cost Cap are mitigated by the lower estimated cost of Propel NY's projects and, therefore, pose a lower proportional risk to consumers in the event of overruns compared to other more expensive projects.
- 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 37 summarizes the metric evaluation for the projects.

Figure 37: Summary of Metric Evaluation

Project	Routing, Permitting, Construction		Capital Cost Estimates	Expandability		Operability: Two Outages (Policy Case)			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	Med	Low	$3,152	4,350	3	2,540	1,355	3,895	$1.24	$2.33	$0.81	27.4	55.4	$340	$906	$65.85
T036 - NextEra Core 1	High	Med	$7,019	4,450	13	2,400	1,540	3,940	$2.92	$4.56	$1.78	29	20.2	$303	$291	$54.98
T037 - NextEra Core 2	High	High	$8,126	4,150	13	2,535	1,725	4,260	$3.21	$4.71	$1.91	28.8	21.4	$364	$378	$97.25
T038 - NextEra Core 3	High	High	$8,653	4,600	16	3,035	2,385	5,420	$2.85	$3.63	$1.60	30.5	23.6	$380	$402	$116.35
T039 - NextEra Core 4	Very High	High	$8,483	4,400	16	3,060	1,510	4,570	$2.77	$5.62	$1.86	30.3	22.1	$305	$307	$29.28
T040 - NextEra Core 5	High	Med	$6,984	4,375	17	3,035	1,530	4,565	$2.30	$4.56	$1.53	30.1	21.8	$339	$332	$29.28
T041 - NextEra Core 6	High	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	Very 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	2,510	5,790	$3.89	$5.09	$2.21	31.5	41.4	$458	$745	$120.40
T044 - NextEra Enhanced 2	Very High	Very High	$16,898	4,900	13	3,275	2,465	5,740	$5.16	$6.86	$2.94	31.5	34	$441	$582	$105.90
T047 - Propel Base 1	Med	Low	$2,480	3,750	1	1,635	625	2,260	$1.52	$3.97	$1.10	29.2	34.7	$337	$568	$112.85
T048 - Propel Base 2	Med	Low	$2,121	3,725	1	1,660	510	2,170	$1.28	$4.16	$0.98	25.4	31.3	$313	$513	$113.35
T049 - Propel Base 3	Med	Low	$2,835	3,750	0	1,610	660	2,270	$1.76	$4.30	$1.25	29.5	54.3	$344	$902	$112.85
T051 - Propel Alt 5	Med	Low	$3,262	4,300	1	2,320	1,190	3,510	$1.41	$2.74	$0.93	30.6	38.4	$341	$609	$113.73
T052 - Propel Alt 6	Med	Low	$4,705	5,075	0	2,815	2,400	5,215	$1.67	$1.96	$0.90	30.7	38.3	$352	$618	$94.90
T053 - Propel Alt 7	Med	Med	$5,576	4,350	1	3,150	905	4,055	$1.77	$6.16	$1.38	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

The NYISO conducted further evaluation of the top-tier projects in performing sensitivity analysis for the capacity savings, performance, and operability and in assessing the qualitative nature of the Developers' proposed Cost Caps and to further distinguish the projects' satisfaction of these metrics. The following figures summarize the project specific economic benefits (e.g., production cost savings and avoided capital cost benefits) versus the capital costs for the top-tier projects.

Figure 38: Policy Scenario Summary of Benefits vs. Costs

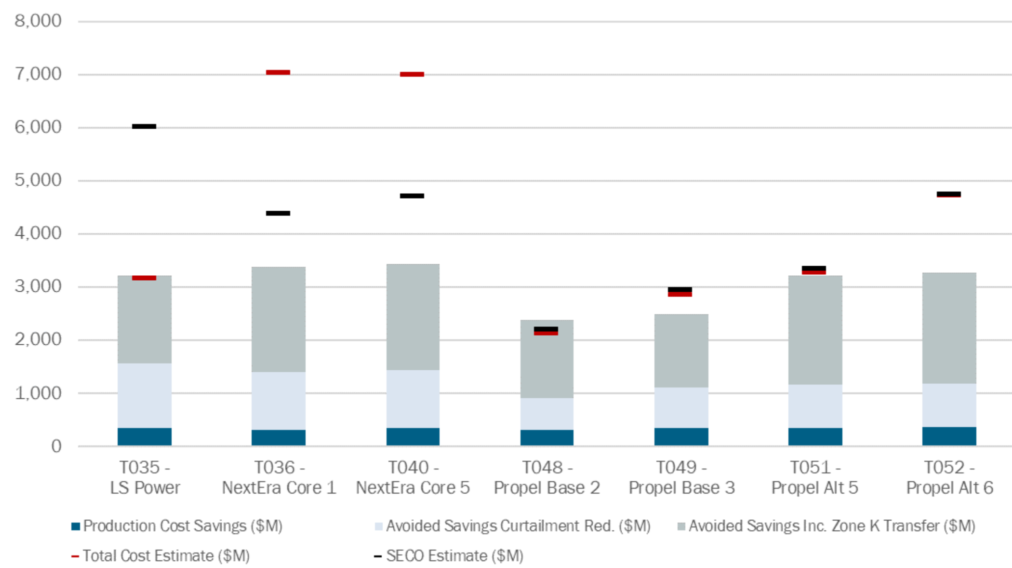
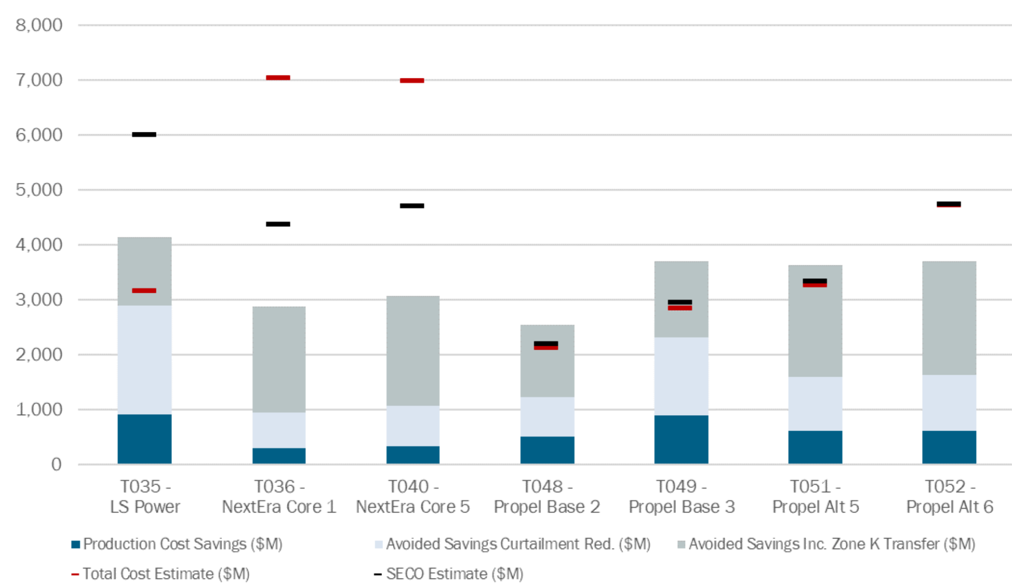


Figure 39: Policy + B-VS Scenario Summary of Benefits vs. Costs



Based on consideration of all the evaluation metrics described in Section 3 and detailed throughout this report and appendices, together with inputs from stakeholders and the New York State Department of Public Service (DPS), NYISO staff ranks the projects as shown in Figure 40.

Figure 40: Project Ranking

Ranking	Project ID	Developer	Project Name
1	T051	Propel NY	Alternate Solution 5
2	T049	Propel NY	Base Solution 3
3	T052	Propel NY	Alternate Solution 6
4	T035	LS Power	Atlantic Gateway
5	T048	Propel NY	Base Solution 2
6	T040	NextEra	Core 5
7	T036	NextEra	Core 1
8	T047	Propel NY	Base Solution 1
9	T053	Propel NY	Alternate Solution 7
10	T041	NextEra	Core 6
11	T037	NextEra	Core 2
12	T038	NextEra	Core 3
13	T039	NextEra	Core 4
14	T043	NextEra	Enhanced 1
15	T042	NextEra	Core 7
16	T044	NextEra	Enhanced 2

Critical comparison of the projects is detailed below:

- T051 adds three new AC tie lines and additional facilities across Long Island that create significant transfer capability for imports and exports between Long Island and the rest of NYCA. The additional facilities within Long Island will effectuate the efficient transfer of power in the future, providing optionality for resource planning and expansion. With the new facilities, the project provides 1) effective operability under a variety of outage conditions, 2) low cost per MW for transfer capability, expandability, and operating range, and 3) lower project cost and risks than larger projects. The project also provides consistent economic benefits across various future scenarios.

- T049 adds two new AC tie lines and additional facilities across Long Island—one less tie line than T051 and a different build-out across Long Island. This smaller, lower-cost design relative to T051 results in less operability under outage conditions and higher cost per MW and has less ability to enable expansion of the Long Island resource mix in the future. However, the project is very effective in relieving congestion along the Barrett-Valley Stream paths.

- T052 adds four new AC tie lines to Long Island and additional facilities across Long Island. This larger, higher-cost design relative to T051 results in the greatest range of operability under outage conditions at a comparable cost per MW. However, larger ranges of operability come with greater cost and project risks than T051 without meaningful increases in offshore wind unbottling or economic benefits.
- T035 adds three new HVDC tie lines to Long Island with a few additional facilities in Long Island. This unique design would introduce operational complexities based on the need to actively control the HVDC and manage flow on the weaker parallel AC system in response to variability on the future Long Island grid. The range of operability under outage conditions is on par with T049 and quite limited when compared to T051 or T052. The project proposes a hard Cost Cap; however, the project is expected to cost significantly more than the $3.1 billion Cost Cap, which the Developer could seek to recover some of the costs above the Cost Cap at FERC.
- T048 adds two new AC tie lines and minimum build out within Long Island—one less tie line and significantly less build out across Long Island than T051. This minimal design results in the least operability range under outage conditions and higher cost per MW than T051. The project also has a lower ability to enable expansion of the Long Island resource mix in the future.
- T040 adds three new 345 kV AC tie lines and one new 138 kV AC tie line with additional facilities across Long Island. The project also proposes the most additional points of interconnection for future expansion among the top-tier projects. This design results in an operability range on par with T051 but with a significantly higher cost per MW compared to other top-tier projects. It also has significantly more project risks related to the expansion of the existing Dunwoodie, Sprain Brook, and Jamaica substations.
- T036 adds three new 345 kV AC tie lines and one new 138 kV AC tie line with additional facilities across Long Island. T036 costs slightly more than T040 without meaningful performance benefits or reduction in project risks.
- The projects not in the top tier were ranked largely based on their relative risks and costs. While some of these projects offered creative designs and performed well under several metrics, any benefits were outweighed by the high permitting and construction risks.

4.4 Selection Recommendation

Based on consideration of all the evaluation metrics for efficiency or cost-effectiveness described in Section 3, together with input from Developers, stakeholders, and DPS and performing a detailed comparative review among the projects based on the satisfaction of those metrics, the NYISO staff recommends that the NYISO Board of Directors select Propel NY's T051 Alternate 5 proposal as the more efficient or cost-effective transmission solutions to satisfy the Long Island PPTN for purposes of cost allocation and recovery under the OATT.

T051 is the lowest cost solution that offers expandability and operability benefits from three new AC tie lines from Long Island to the rest of the state. It has relatively low procurement, permitting, and construction risks compared to other projects, reducing the potential for increases to project cost and schedule. T051 adds a strong 345 kV backbone to the Long Island transmission system that not only allows the export of offshore wind power but also will help serve Long Island load with the future generation changes needed to meet the CLCPA. Compared to T049, T051 does not fully address congestion on the Barrett-Valley Stream path, but it has a third 345 kV AC tie line that provides optionality for resource planning and expansion. Furthermore, T051's potential economic benefits are expected to be comparable with the project cost.

4.5 Designation of Designated Public Policy Projects

Propel NY designed and proposed T051 in a manner where it includes both new facilities and upgrades to existing transmission facilities owned by incumbent transmission owners. While Propel NY is the sponsoring Developer of T051, the NYISO's tariff respects certain rights of the incumbent transmission owners to build, own, and recover the costs of upgrades to their existing facilities. Therefore, if the NYISO selects a solution as the more efficient or cost-effective solution to a Public Policy Transmission Need, the NYISO designates components of the selected project to the sponsoring Developer or the applicable transmission owner based on whether the facility is a new facility or a Public Policy Transmission Upgrade, respectively.[16] If designated, the party will become the Designated Entity and is responsible for building, owning, and recovering the costs of its Designated Public Policy Project.

Consistent with the NYISO's characterization of facilities contained in Appendix F, T051 is made up of four Designated Public Policy Projects. Propel NY is the Designated Entity for the Designated Public Policy Project set forth in Appendix O. The Long Island Power Authority (LIPA) is the Designated Entity for the Designated Public Policy Project set forth in Appendix P. The New York Power Authority (NYPA) is the

[16] Under the tariff, a Public Policy Transmission Upgrade is defined as "[a]ny portion(s) of a Public Policy Transmission Project that satisfies the definition of upgrade in Section 31.6.4 of this Attachment Y."

Designated Entity for the Designated Public Policy Project set forth in Appendix Q. Consolidated Edison of New York, Inc. (Con Edison) is the Designated Entity for the Designated Public Policy Project set forth in Appendix R.

The Required Project In-Service Date for the selected project is May 2030 to satisfy the Long Island PPTN. Additional details related to each Designated Public Policy Project and any required in-service date specific to a component of a Designated Public Policy Project, if any, are set forth in Appendices O, P, Q, and R.

LIPA, NYPA, and Con Edison will have 30 days from the posting of the final report to inform the NYISO if they do not intend to serve as the Designate Entity for their respective Designated Public Policy Project. In the event that LIPA, NYPA, or Con Edison refuses to serve as the Designated Entity for one or more of the Public Policy Transmission Upgrades, Propel NY, as the sponsoring Developer, will be identified as the Designated Entity for the rejected facilities. The final list of Designated Public Policy Projects and the responsible Designated Entities will be posted to the NYISO's website following the conclusion of the 30-day notification period.