Appendix C: Market Monitoring Unit Report

Long Island Offshore Wind Export Public Policy Transmission Planning Report

A Report from the New York Independent System Operator

DRAFT for May 31, 2023, MC

DRAFT – FOR DISCUSSION PURPOSES ONLY

NYISO MMU Evaluation of the Long Island Offshore Wind Export PPTP Report

POTOMAC ECONOMICS

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I. Executive Summary

The NYISO tariff allows for recovery of the costs of transmission projects that are built to achieve Public Policy Requirements ("PPRs") from New York State laws or regulations. The tariff requires NYISO to issue a report detailing its evaluation of the proposed projects and identifying which (if any) is the more efficient or cost-effective project for satisfying the Public Policy Transmission Need ("PPTN"). The tariff also requires the Market Monitoring Unit ("MMU") to "review and consider" any impact on the ISO-administered markets from regulated transmission solutions proposed to satisfy the PPTN, and then the MMU is to provide a report containing its evaluation to stakeholders before the Management Committee advisory vote on the Public Policy Transmission Planning ("PPTP") Report.[1]

In 2019, New York State enacted the Climate Leadership and Community Protection Act ("CLCPA"), which mandates 70 percent of electricity from renewables by 2030, the installation of 9 GW of offshore wind by 2035, and zero emissions from the electricity sector by 2040. In 2021, the NYPSC issued an order identifying the Long Island Offshore Wind Export PPTN and referring it to the NYISO for solicitation and evaluation under its PPTP Process.[2] The order declared that the CLCPA constitutes a PPR driving a need for transmission to increase export capability from Long Island to the rest of New York State to ensure deliverability of the full output of offshore wind interconnected to Long Island. The order defined the PPTN 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.

The order indicated that the PPTN was driven by the 2030 and 2035 mandates in the CLCPA. It discusses the need for transmission to satisfy the 2035 mandate to install 9 GW of offshore wind assuming that 3 GW would likely interconnect on Long Island.

Developers submitted 19 proposals for satisfying the PPTN. The NYISO found 16 transmission solutions that would satisfy the Viability and Sufficiency Criteria of allowing 3 GW of offshore wind to connect to Long Island without being curtailed. The NYISO performed a study of the costs and benefits of these projects.

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1 See NYISO Market Services Tariff Section 30.4.6.8.5.

2 See PSC 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).

The NYISO estimated the overnight capital costs and assessed potential development risks and proposed cost caps of each project against the projected:

- Economic benefits from lower electricity production costs,
- Cost savings from reducing investment in (a) renewable generation in upstate areas and (b) dispatchable generation in downstate areas,
- Reduced curtailment of offshore wind generation on Long Island, and
- Other benefits from enhancing the bulk power system such as: expandability of new infrastructure and operability of transmission equipment.

Based on its evaluation, NYISO staff has recommended that the NYISO Board of Directors select Project T051, also known as Propel NY's Alternative 5.

As MMU, we evaluate the market effects of individual projects considering that an inefficient project can harm the electricity markets by distorting energy and capacity prices in the short-term, crowding-out more cost-effective investment, and inflating market risks in the long-term. However, this assessment of projects' economic efficiency must include factors that are not priced in the NYISO markets (such as the degree to which they facilitate renewable energy production). Inefficient projects (i.e., projects whose costs exceed the priced and unpriced benefits they produce) harm the NYISO markets and ultimately raise the cost of satisfying the Public Policy Requirement. This principle is discussed in more detail in Section II. The remainder of this executive summary discusses our evaluation and conclusions. Sections II, III, and IV present our evaluation and Section V provides our conclusions and recommendations.

Quantitative Evaluation Metrics

NYISO staff presented several quantitative and qualitative metrics of the projects' market and reliability impacts and investment costs and outlined how these metrics were considered in its recommendation of Project T051. The following summarizes how we consider the diverse set of metrics and modeling results calculated by the NYISO or derived from its evaluation:

- Production Cost Savings – These include reductions in fuel costs, variable O&M costs, CO_2 emissions allowance costs, and other generator production costs across the region. However, the impacts of Renewable Energy Credits ("RECs") on incremental energy offers are excluded from this category and considered separately as discussed below.
- Avoided Cost of Investment in Dispatchable Generation that would otherwise be needed to satisfy the minimum resource adequacy and transmission security planning standards.
- Avoided Cost of Investment in Renewable Generation that would otherwise be needed to satisfy the CLCPA because of increased deliverability of offshore wind.
- Transmission Financing and O&M Costs – It is important to consider the full construction and life-cycle costs of new transmission investments, although the NYISO did not consider these in its evaluation.

- Reduced Curtailment of Offshore Wind – The primary rationale for the Public Policy Requirement was that it would increase deliverability of offshore wind on Long Island.

We include the first four categories above in a single Benefit-Cost Ratio ("B-C Ratio"), which provides an overall measure of the cost of the project relative to the benefits. The benefits are the cost savings that result from satisfying the CLCPA goals with the transmission project versus without it.[3] Hence, the B-C Ratio indicates whether the proposed transmission project is a cost-effective means of achieving the CLCPA goals. In addition, we combine the five categories above into another comprehensive metric:

- Implied Net REC ("INREC") Cost – This is the average cost of increased renewable production resulting from the new transmission project (after netting out the value of wholesale market benefits). This allows us to compare the net cost of a transmission investment to unbottle renewables with other alternatives for supporting higher renewable production, including investing in energy storage that reduces curtailment of renewables or simply building more renewables. Transmission projects are cost-effective when their INREC Cost is lower than these alternatives.

The inputs to the Benefit-Cost Ratio and Implied Net REC Cost are provided on an annual basis to illuminate how the benefits of the project change relative to the levelized costs over the first 20 years of investment. Sections III and IV provide additional details about these quantitative metrics including key differences between our methodology and the NYISO methodology.[4]

Qualitative Evaluation Metrics

In recommending project T051, the NYISO discussed several qualitative benefits including the expandability and operability benefits of a project that adds three 345 kV circuits between Long Island and other zones. Expandability is the degree to which a project may facilitate additional expansion of generation and transmission. Operability is the extent that a project affects flexibility in operating the system, such as access to operating reserves, access to ancillary services, or the ability to remove transmission for maintenance.

While these benefits are material, it is important to quantify benefits in a manner that enables a fair comparison of projects and facilitates competition among developers. Regarding "expandability", capacity expansion models quantify the impact of proposed projects on other future investments, so the NYISO's capacity expansion model is designed to quantify the

3 Since the CLCPA goals are achieved with or without the project, the accumulation of RECs is not counted as an additional category of benefit in the B-C Ratio of the transmission project.

4 We omit the NYISO's "Capacity Benefit LOLE Reduction" metric from our evaluation because the NYISO's methodology for calculating capacity benefits is flawed and because most of the real capacity benefit is reflected in our Dispatchable Generation Investment Cost Savings. While this does not include real capacity benefits of improved reliability, we expect this reliability benefit to be relatively small for this solicitation (because of the reduction in dispatchable generation investment). See our discussion of capacity benefits in Appendix G of the *AC Transmission Public Policy Transmission Planning Report*.

economic value of expandability. As the NYISO refines its capacity expansion model, it should be able to rely less on the "expandability" metric in future studies.

The value of "operability" depends on system conditions, the costs of maintaining security and reliability, and how they are affected by new transmission facilities. Hence, the value of operability is already partially reflected in the production cost savings and avoided cost of investment metrics. Such benefits could be quantified more fully by enhancing the production cost model to account for outages, ancillary services, and other real factors affecting the value of transmission. These enhancements would allow the NYISO to rely more on quantitative measures in future studies, which provide a better basis for comparing competing solutions.

Summary of Assessment of Cost and Benefits

Given the limited time available to review the NYISO evaluation, our review focuses on the NYISO's Policy + Barrett-VS + P95 Variability Scenario ("Policy+B-VS+P95"). Key features of this scenario include:

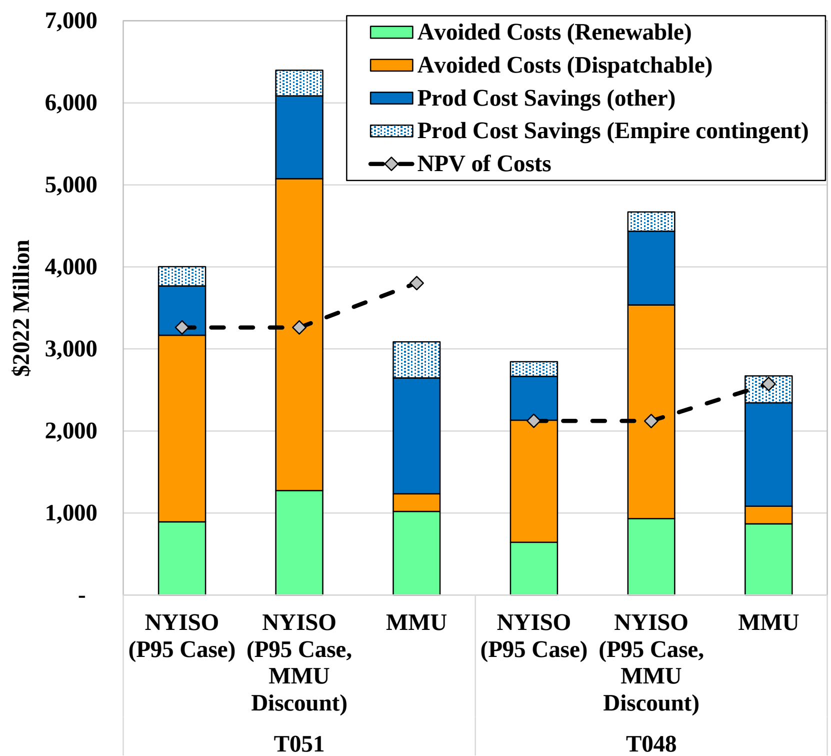
- Policy Case offshore wind buildout – This assumes 2.5 GW of Long Island offshore wind is installed by 2030 and 3.7 GW by 2035. This scenario assumes that more than 3 GW of the 9 GW mandated by 2035 would be installed in Long Island.
- The Barrett-Valley Stream constraint – Accounts for the transmission constraint responsible for most offshore wind curtailments through 2035 (rather than assuming the affected wind developer will resolve the constraint or relocate its interconnection point).
- P95 Net Load Variability impact – Assumes some transmission capability between Long Island and other regions will be used to manage intermittent generation variability, thereby reducing available capability for power transfers to and from Long Island. While this scenario approximates these transmission effects, the other scenarios underestimate the offshore wind curtailments that will result from net load variability and uncertainty.

Of the scenarios modeled, the Policy+B-VS+P95 Policy provides the best overall indication of the impacts of the proposed transmission projects. We also limit our review to NYISO's recommended project (T051) and Project T048 ("Propel NY's Base Solution 2") because T048 was the top-tier proposal with the lowest capital costs while retaining much of the benefits of T051. The evaluation of both projects in the Policy+B-VS+P95 Scenario is presented below.

(i) Benefit-Cost Ratio

Based on our recalculation of both benefits and costs, Figure 1 compares the benefits and costs of the projects based on the NYISO assessment and our MMU assessment. Our assessment shows that the combined benefits for the T051 project are substantially less than the costs, yielding a Benefit-Cost Ratio of 0.81 over the 20-year period from 2030 to 2049. "NYISO (P95 Case)" implies higher overall benefits and lower costs. The estimate labeled "NYISO (P95 Case, MMU Discount)" shows that the benefits would be higher if they were appropriately discounted to 2022 dollars.[5] Our estimates of benefits and costs differ from the NYISO estimates in several ways, which are explained below (while Section IV provides a more detailed discussion of differences).

Figure 1: NPV of Benefits and Costs



Avoided dispatchable generation. This accounts for the largest difference in benefit values. We find the NYISO's analysis to be unrealistic in this area.[6] The NYISO assumes a substantial cost difference for building Dispatchable Emission-Free Resources ("DEFR") on Long Island versus upstate NY. Therefore, if new transmission reduces the need for DEFRs on Long Island, the need for them can be met by building them upstate. This raises two issues. First, we do not yet know what potential DEFR technologies will exist by 2040, so the costs and characteristics of future DEFRs are very speculative.[7] Our estimate assumes that the marginal resource to satisfy future capacity requirements will be a peaking technology that is a lower-fixed cost, higher-variable cost option. Second and more troubling is that such resources cannot reasonably be shifted from Long Island to upstate NY because the transmission network would not support such a shift. Our estimate assumes that the UPNY-ConEd interface between the Hudson Valley and downstate areas would require that the DEFRs remain in downstate NY.

5 We show the NPV of benefits calculated by NYISO for the P95 Case. This is equivalent to the NPV of benefits in the BVS case summarized in Figure 39 of NYISO's report plus the NPV of additional benefits in the BVS P95 Case reported in Figure 32 of Appendix L of NYISO's report. In the "P95, MMU Discount" case we use the benefits estimated by NYISO, but correct for an issue with discounting that causes the NPV presented by NYISO to be understated (see Section IV.A.2).

6 Section IV.B discusses the NYISO and MMU estimates of avoided costs of dispatchable generation.

7 Indeed, the PSC issued an order in CASE 15-E-0302 on May 18, 2023 inviting comments and announcing a technical conference to discuss what technologies might be considered zero-emissions for purposes of the 2040 mandate. The order solicits comments on the following technologies: advanced nuclear, long-duration storage, green hydrogen, renewable natural gas, and carbon capture and sequestration.

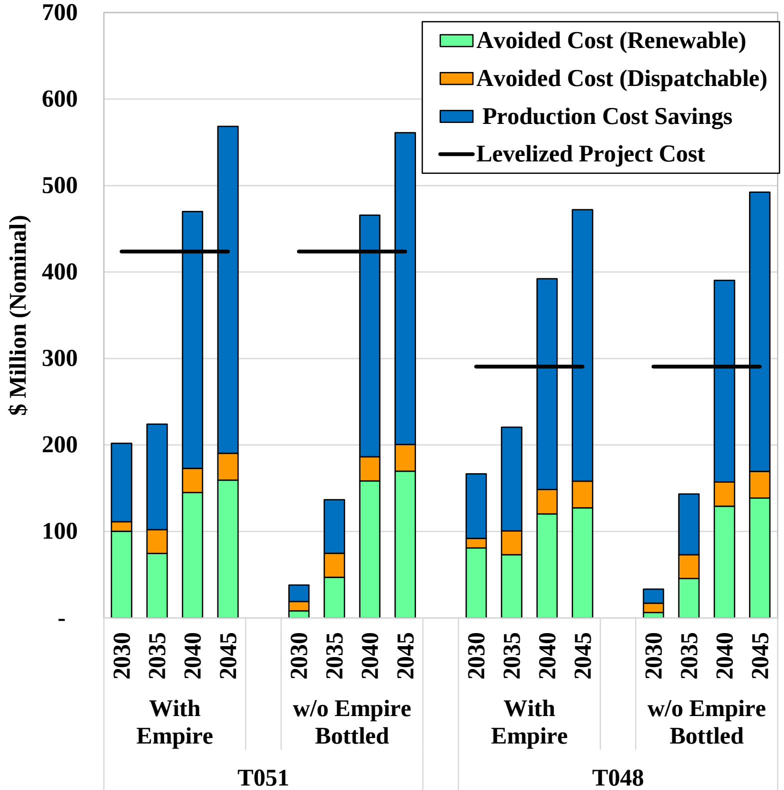
Production Cost Savings. We show larger production cost savings because we adjust for the tendency of the hourly GE-MAPS production cost model to underestimate congestion that occurs under actual market conditions. See Section IV.D.

Cost of Projects. Our calculation includes costs of O&M and financing during construction for the new transmission project. These are major cost elements for each of the new transmission projects and omitting them significantly understates the true costs of the projects.

Taken together, the lower benefits and higher costs in our assessment of the projects accounts for the reduction in the B-C Ratio for T051 of 34 percent. Figure 1 also shows our estimate of the overall Benefit-Cost Ratio of 1.04 for project T048. Our estimated B-C Ratio is higher for T048 (than for T051) because it has much lower capital costs, but only slightly lower benefits. In contrast, the NYISO evaluation of benefits would result in a lower B-C Ratio for T048 than for T051 primarily because it estimates higher avoided costs for dispatchable generating capacity investment for T051 than for T048. Overall, in consideration of the recalculated quantitative metrics, we find that T048 appears to be a more cost-effective project than T051.

The benefits of new transmission vary considerably during the study period, so Figure 2 shows annualized costs and benefits amortized over the first 20 years of investment in 2030, 2035, 2040, and 2045. This is provided for T051 and T048 both with and without the Empire Wind II generator at its proposed point of interconnection. This highlights several key findings. First, the annual benefits from the projects would be very low relative to the annualized costs in 2030 and 2035. The production cost savings rise sharply in 2040 for reasons that we discuss below.

Figure 2: Annual Benefits and Costs



Second, most of the benefits in 2030 are contingent on the status of the Empire Wind II generator. If Empire Wind II does not proceed with construction, builds its own upgrade to become deliverable, or simply moves to a less constrained point of interconnection, most of the benefits would be lost in the initial years of the study period. This highlights the substantial uncertainty associated with these early benefits.

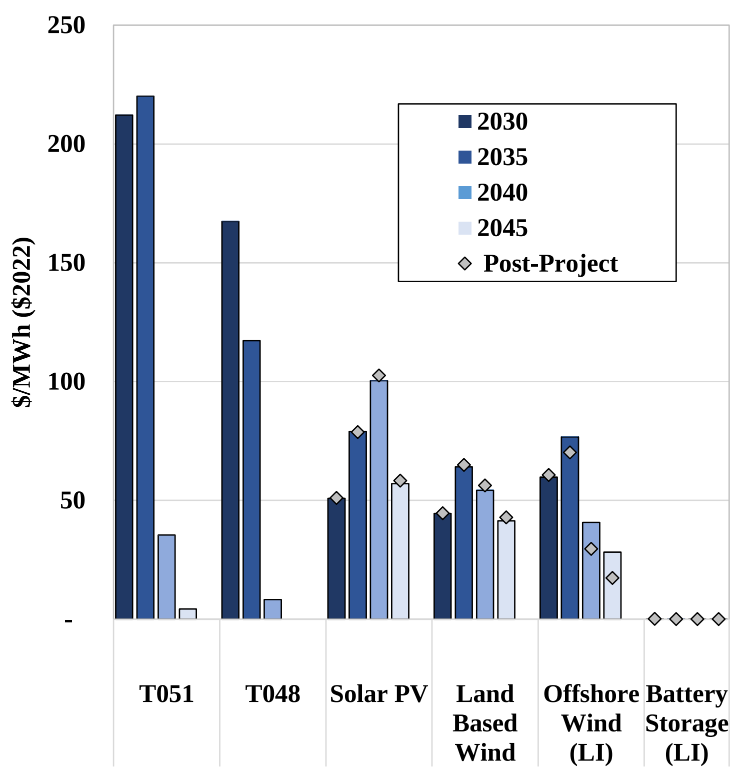
Third, our estimated benefits rise significantly over time making both projects appear cost-effective by 2040 when the State would become much more reliant on Dispatchable Emission Free Resources ("DEFR"). This occurs because DEFRs are assumed to have a relatively high marginal cost ($150 per MWh) compared to conventional resources. Therefore, every MWh of avoided offshore wind curtailment saves $150 per MWh in 2040 when DEFRs are assumed to be on the margin. This benefit is extremely uncertain because some zero carbon technologies are likely to be developed that have much lower marginal costs, such as small modular nuclear reactors. A mix of resources could be developed (e.g., carbon capture for conventional resources or green hydrogen technology) with a range of fixed and variable costs. To the extent that the future resource mix relies more on lower variable cost resources, the estimated production cost savings would fall sharply and the B-C Ratio for both projects would likely be less than 1.0 over the entire study period.

(ii) Implied Net REC Cost

This report also estimates the relative costs of producing more renewable energy through alternative investments using the INREC Cost metric. The two proposed transmission investments are the first two alternatives that would facilitate more renewable energy by reducing curtailments. We also estimate the INREC cost for generic alternative investments in renewable generation and battery storage. Since the PPTN is to facilitate the installation of offshore wind on Long Island, we also show the impact of the recommended transmission project on the INREC cost of generic offshore wind on Long Island. Figure 3 shows these estimates every five years during the study period, which highlights several factors. First, the INREC Cost of T048 is significantly lower than that of T051 throughout the period.

Second, the costs of increasing output from renewables by investing in T051 or T048 are significantly higher than the cost of investments in additional renewable resources or battery storage in 2030 and 2035. The transmission projects become more cost-effective by 2040 because of the sharp increase in production cost savings caused by reliance on DEFRs, thereby reducing the INREC Cost of transmission.

Figure 3: Implied Net REC Cost



Third, the INREC Cost of battery storage is less than zero during the study period, indicating that investments in battery storage would be cost-effective even without any compensation for increasing renewable production by reducing their curtailment. This suggests that the NYISO modeled inefficiently low levels of battery storage penetration and that a substantial amount of additional battery storage could be used to reduce offshore wind curtailments on Long Island at a much lower cost than building transmission. However, additional simulations would be needed to determine how much more battery storage penetration would have been cost-effective.

Fourth, the proposed transmission projects have no effect on INREC Cost of generic offshore wind on Long Island in 2030, and only a relatively small effect from 2035 through 2045. This indicates that they would provide only modest benefits in facilitating additional offshore wind.

Hence, we find that increasing renewable generation by investing in one of the proposed transmission projects would provide no significant benefits to generic offshore wind in Long Island in 2030, and the transmission projects would not be cost-effective until after 2035. In 2040, they would only be cost effective if the system would otherwise rely on DEFRs with relatively high dispatch costs as discussed above. If the system does not come to rely exclusively on DEFRs with high dispatch costs, but a mix of technologies evolve including some with moderate to low dispatch costs, the transmission projects would likely remain uneconomic throughout the study period. One of the costs of investing in transmission projects that are not economic is that they tend to crowd-out other more cost-effective investments.

(iii) Reducing Curtailment of Offshore Wind Generation

Without the proposed transmission projects, the Policy+B-VS+P95 Scenario shows 2.5 TWh or 25 percent of Long Island offshore wind curtailed in 2030 and 2.4 TWh in 2035, rising to 4.5 TWh in 2040. The Empire Wind II project accounts for a disproportionately large share of Long Island offshore wind curtailment – 93, 77, and 15 percent in 2030, 2035, and 2040, respectively.[8] Given that most of the reductions in offshore wind curtailment is of the Empire Wind II project before 2040, the benefits of both projects in the early half of the study period are highly dependent on whether the Empire Wind II facility is built and whether it maintains its currently planned interconnection point. As both projects are well over $2 billion in total costs, moving the interconnection point or otherwise mitigating the impact of this project would be valuable.

Observations Regarding the Public Policy Transmission Need Defined by the PSC

The New York PSC order defining the PPTN stated that the goals of the CLCPA constitute a Public Policy Requirement. The CLCPA mandates 70 percent renewable generation by 2030, 9

8 These values reflect curtailment in the BVS P95 case based on production cost model data provided by NYISO. We estimate the portion attributable to Empire Wind II based on the difference in total curtailment between the BVS and non-BVS policy cases. See also Appendix L of NYISO's report.

GW of offshore wind capacity by 2035, and zero emissions from electricity by 2040. The PPTN order calls for upgrades to local and interzonal transmission between Long Island and neighboring zones to allow up to 3 GW of offshore wind on Long Island to be fully deliverable.

While the PPTN provided no specifics regarding the timing of new transmission investment, the most relevant element of the Public Policy Requirement is the 2035 goal of 9 GW of offshore wind, assuming one-third would interconnect on Long Island. Accordingly, the NYISO's Baseline and Policy Cases model 3.1 and 3.7 GW of offshore wind on Long Island, and a total of 9 and 9.7 GW for the State in 2035. This grows to 6 GW on Long Island and 12 GW statewide in the Policy Case in 2040. The NYISO study includes numerous modeling details that reveal the impact of the proposed transmission projects on satisfying the 2030, 2035, and 2040 goals.

The NYISO analyses suggest that while the proposed transmission projects are cost-effective by 2040 and would help satisfy 2035 offshore wind mandate, they provide little benefit before 2035. In 2030, both T051 and T048 would crowd-out more cost-effective investments in solar PV generation and battery storage, increasing the cost of satisfying the 2030 mandate.

In the initial phase of the study, a large share of the transmission benefits would accrue to the developer of the Empire Wind II project because it would be able to avoid a significant amount of interconnection costs that would otherwise be its responsibility under its long-term PPA with NYSERDA. When transmission expansion is not anticipated until after a contract is awarded to a specific generation developer, the transmission expansion will result in a financial windfall for the generation developer, which could be addressed in the cost allocation.

Finally, it would be beneficial for the NYISO to provide additional information on the costs and benefits of generic potential transmission investments before the PSC determines future Public Policy Transmission Needs. This would be valuable partly because uneconomic transmission investment can crowd out more efficient investment that could achieve the State's policy goals at a lower cost and potentially earlier than large-scale transmission.

Conclusions and Recommendations

The recommended project (T051) fulfills the Public Policy Transmission Need that was defined by the PSC and contributes towards meeting the goals of the underlying Public Policy Requirement of connecting 9 GW of OSW by 2035. However, it would provide little benefit before 2040 and increase the cost of satisfying the 2030 mandate of satisfying 70 percent of load with renewable generation. The T048 project exhibits a significantly higher benefit-cost ratio, but it is similarly uneconomic before 2040.

For example, we estimate both projects to have a benefit-cost ratio close to 0.1 in 2030 if the Empire Wind II project is not built or relocates. Although the benefits rise if the Empire Wind II project proceeds at its current location, the benefit-cost ratio remains well below 1.0 and most of the added benefits would accrue to the Empire Wind developer since it is already under contract with NYSERDA and the costs and savings of the project will not affect the contract price.

Given the poor economics of these projects in these early years, they would undermine incentives for lower-cost clean energy investments or energy storage that could reduce offshore wind curtailments at a much lower cost. While both T051 and T048 become cost-effective by 2040, the benefits depend on highly speculative assumptions about the costs and operating characteristics of future dispatchable generation investments. The NYISO assumed DEFRs have high capital costs and variable costs, very flexible characteristics, and that they do not withdraw electricity from the power system to generate fuel. However, the estimated benefits would be significantly lower in 2040 if the NYISO assumed that future dispatchable generators:

- Consume surplus electricity to create renewable fuel – If DEFRs are fired by fuel synthesized from surplus renewable output that would otherwise be curtailed, it would reduce the estimated benefits of the transmission projects.
- Have lower variable production costs – The NYISO assumes DEFRs will have high capital costs (with large regional variations) and high variable costs. If technologies emerge with lower variable costs, the sharp increase in benefits in 2040 and beyond will be reduced or eliminated.

Ultimately, the proposed transmission projects are not estimated to be helpful for satisfying the 2030 mandate and they would make relatively modest contributions toward satisfying the 2035 mandate. Furthermore, the majority of the benefits of new transmission over the study period depend on the future costs and characteristics of DEFRs, which will likely be clarified in the coming years. In addition, investment in storage could be used to satisfy the 2030 and 2035 mandates more cost-effectively if it is not crowded-out by the new transmission. Given the estimated investment lead time of around six years and small benefits before 2040, it is premature to move forward with a capital-intensive transmission project at this time. These results support the following conclusions and recommendations:

- It is not advisable to move forward with one of the proposed transmission projects at this time given the magnitude and timing of the potential benefits. This process could be re-initiated in future years if warranted.
- If the NYISO determines that it must or should select a project, we recommend that it reconsider its recommendation of T051 since it does not appear to be the most cost-effective project.
- We recommend that the NYISO provide initial estimates of costs and benefits of generic potential transmission solutions to the PSC to inform future PPTN determinations.

In addition to these recommendations, we identify recommended improvements to the NYISO's evaluation process and analysis in Section IV. In general, we found the NYISO's methodologies for this assessment are reasonable. However, we identify several methodological enhancements for NYISO to consider in future public policy transmission evaluations.

A complete set of recommendations is provided in the Section V of this report.

II. Principles for the Evaluation of Market Effects of Projects

The purpose of the PPTP process is to identify transmission investments that would provide significant public policy and wholesale market benefits. However, it is critical for the PPTP process to function in a manner that supports the NYISO's competitive wholesale markets. This section discusses the principles we use for evaluating the qualitative and quantitative benefit metrics against the estimated costs of proposed projects and ensuring that the PPTP process does not undermine the wholesale market.

Transmission upgrades can provide many wholesale market and public policy benefits to the system, including:

- Increasing the utilization of low-cost generation, which lowers production costs; and
- Satisfying public policy objectives, such as reducing environmental emissions by facilitating increased development and dispatch of lower-emitting resources.

To assess the value of a proposed transmission project, it is important to fully quantify these benefits to determine whether the project is efficient.[9] The NYISO's economic transmission planning process does not consider several key wholesale market benefits and public policy benefits. This is partly why no transmission project proposal has ever been deemed to be cost-effective in the economic planning process. The PPTP process allows the NYISO to consider additional benefits for a more complete assessment of whether a proposed project is efficient.

In Section III.A of this report, we discuss a framework for quantifying the different categories of wholesale market and public policy benefits. This framework includes cost savings, reliability benefits, and environmental impacts that assist in evaluating the impact on wholesale electricity markets from the proposed projects. Section III.B provides the results of the Benefit-Cost Ratio metric which indicates whether the proposed project would enable policy mandates to be met at a lower overall cost than alternative investments. In addition, the Implied Net REC Cost is calculated for each investment to determine whether the recommended project is more cost-effective in increasing the deliverability of renewables than alternative clean energy investments.

Although reducing transmission congestion will always produce benefits, these benefits must exceed the costs of the transmission project to conclude that the project is efficient compared with alternative investments. Inefficient transmission investment can distort wholesale prices, crowd-out efficient private investment, and ultimately increase the cost of satisfying public policy objectives.

Therefore, our criteria for determining that a public policy transmission project is efficient for purposes of this evaluation is: *the benefits of the project exceeds its costs.* For projects that are

9 We recognize that some of the public policy benefits are subjective and may not be quantified easily.

effective in facilitating renewable generation, this generally occurs when the Implied Net REC Cost of transmission is lower than alternative clean energy investments.

Projects that do not satisfy this general principle will undermine the markets and ultimately raise costs to consumers in New York. Therefore, we evaluate the costs and benefits of each of the proposed projects, which includes a review of the assumptions used to estimate the projects' benefits. We then apply this principle to determine whether the project recommended for selection by the NYISO would adversely affect the NYISO's wholesale electricity markets.

III. Evaluation of Proposed Transmission Projects

The NYISO presented several quantitative and qualitative metrics of the impacts and costs of each project and outlined how these metrics were ultimately considered in its recommended selection of Project T051. While estimates of cost and economic value are relatively straightforward to interpret, it can be difficult to evaluate metrics that are either qualitative or quantified in non-dollar terms. This section discusses: (i) our approach to quantifying the economic, environmental, and reliability benefits that would be provided by each project; (ii) the results of the evaluation; and (iii) a discussion of the other quantitative benefits of the each project.

A. Metrics for Evaluating Costs and Benefits

The NYISO employed a diverse set of metrics for satisfying the PPTN, which can be used to derive the economic, environmental, and reliability benefits that would come from the recommended transmission projects. The principle quantitative benefits include:

- *Production Cost Savings* – the projects are expected to reduce system production costs by relieving transmission congestion, allowing lower-cost resources to serve load. For the Long Island PPTN, production cost savings result both from unbottling offshore wind generation on Long Island and from allowing more energy imported from upstate to displace higher-cost generation on Long Island. The incremental production cost savings from unbottling Empire Wind II are reported separately.
- *Avoided Cost of Investment in Capacity Needed for Reliability* – Projects increase transfer capability into Long Island, potentially reducing the amount of generation capacity that must be maintained there to satisfy reliability criteria. This may result in cost savings if the PPTN projects allow capacity needed to satisfy the state's Installed Reserve Margin to be built in lower-cost upstate areas instead of higher cost downstate ones.[10]
- *Avoided Cost of Investment to Satisfy State Policy Goals* – New York's electric sector is required by law to be 70 percent renewable by 2030 and 100 percent zero-emissions by 2040. To meet these targets, many renewable generation investments will be required in addition to the mandated 9 GW of offshore wind. By reducing curtailment of offshore wind, the PPTN projects would reduce the amount of renewable capacity or RECs the state will need to procure from other sources in order to meet its targets. This approach captures the climate policy benefits of the PPTN projects because it indicates how much they will reduce the cost of achieving the 2030, 2035, and 2040 mandates compared to

[10] In our report on the previous PPTN evaluation for the AC Transmission Projects, we also recommended that NYISO quantify the benefits of more reliable service. We recommended measuring this as the reduction in loss of load expectation (LOLE) provided by the projects, valued at the cost of obtaining the same reliability improvement in the capacity market. The NYISO performed an analysis of the projects' LOLE reduction benefit (Appendix M of NYISO's report), but the NYISO's analysis includes key methodological flaws, such as beginning from a base case system set to at-criteria (i.e., LOLE equal to 0.1 days per year) conditions instead of a level that would be consistent with its modeled conditions. Nevertheless, we expect that the LOLE benefits from the proposed projects would be relatively small in this solicitation (if estimated appropriately).

alternative means.[11] The portion of avoided costs that are contingent on unbottling Empire Wind II are reported separately.

The three benefits above can be added together to estimate a total project benefit encompassing economic, reliability, and public policy value in dollars terms. We also evaluated the following key project benefits that are not directly additive these:

Offshore Wind Curtailment Reduction – This is a key benefit because reducing offshore wind curtailment is the stated purpose of the PPTN. It should be noted that the value of reduced curtailment is effectively contained in the economic benefit metrics described above. This is because the value of increased deliveries of offshore wind lies in (1) lower production costs, and (2) public policy benefits in the form of increased zero-emissions generation that would otherwise need to be procured from another source. Hence, a benefit-cost analysis based on the three principle benefits described above implicitly values the degree to which the proposed projects successfully achieve the PPTN.

Implied Net REC Cost – The PPTN process is designed to identify transmission investments that advance New York State policy goals. There are many potential transmission, generation, and storage projects that can contribute to New York's clean energy targets. NYISO markets indicate the value of competing solutions and provide incentives for the most efficient projects to come forward. To avoid crowding-out more cost-effective solutions, an efficient PPTN solution should advance Public Policy Requirements (such as an increase in offshore wind energy or total clean energy) at lower cost than other generic investments that provide comparable contributions towards those goals. The Implied Net REC Cost metric assesses the efficiency of the proposed transmission projects by quantifying the net cost per unit of renewable energy it provides.

B. Evaluation of the Proposed Public Policy Transmission Projects

We have reviewed results of modeling performed by NYISO for the recommended project. We modified these results to account for key factors affecting project benefits and costs that NYISO did not consider in its evaluation, discussed in detail in Section IV. Using these results and the project costs presented in the NYISO report, we compared total expected benefits of the T051 project to its total costs. In addition, we also evaluate the benefits and costs of Project T048 because it was the lowest-cost project among the top-tier. This subsection discusses the results of our benefit/cost analysis and compares it to NYISO's results.

Figure 4 and Figure 5 show our estimated benefits and costs for projects T051 and T048 over the 20-year evaluation period. Project costs are shown on a levelized basis. Overall, we estimate

[11] While the NYISO quantified CO_2 emissions reductions resulting from the projects, the results are not impactful in this evaluation because the NYISO system is assumed to reach a state of zero emissions with or without the PPTN projects. Hence, the climate policy benefits of the PPTN projects stem from their ability to help achieve the zero emissions target at lower cost than if they were not built.

that T051 would produce benefits significantly below its costs until the late 2030s, when benefits would begin to exceed costs. On the other hand, we estimate that T048 would begin to produce benefits consistent with its costs two years earlier.

Figure 4: MMU Estimated Annual Benefits and Costs of T051 Project

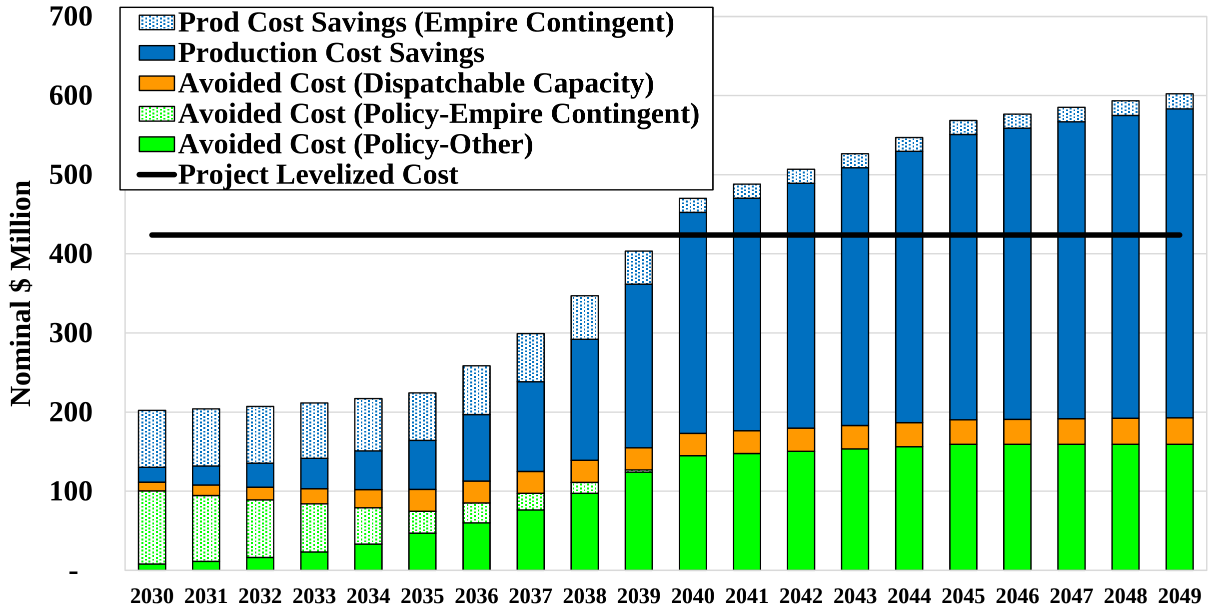
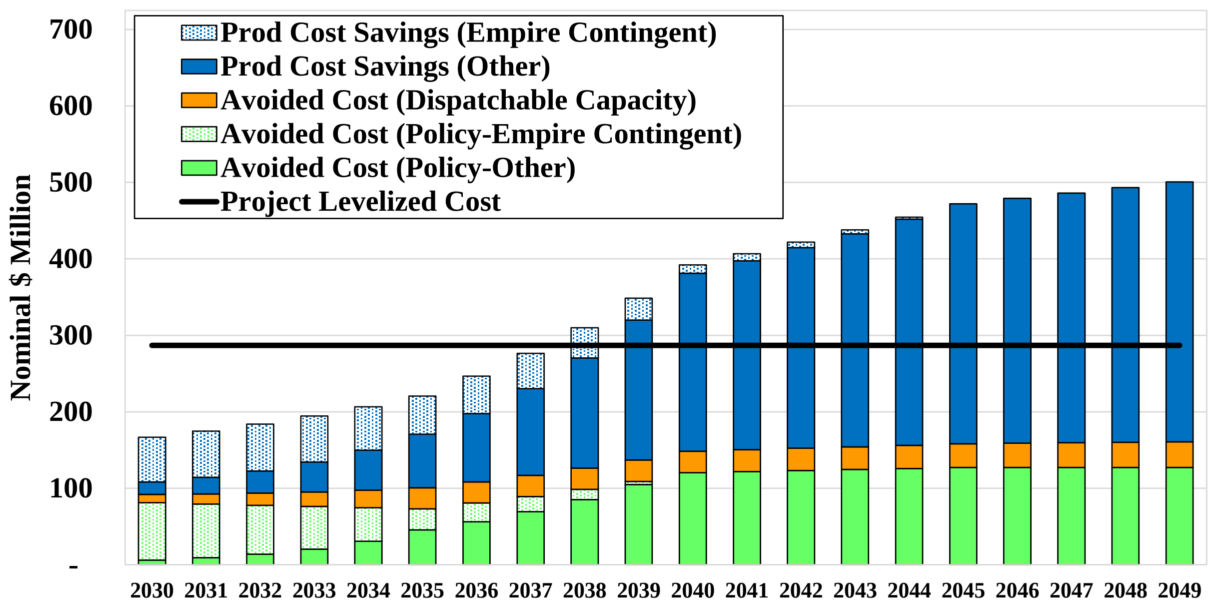


Figure 5: MMU Estimated Annual Benefits and Costs of T048



Production cost savings are the largest source of long-term benefits for both projects. For the first five years of the evaluation period, these would be expected to be come mainly from reducing curtailment of the planned Empire Wind II offshore wind facility by reducing congestion on the Barrett – Valley Stream 138 kV line.[12] The developers of Empire Wind II recently rejected transmission upgrades identified in NYISO's interconnection process that would have increased its deliverability, with an estimated capital cost of $265 million. The NYISO did not evaluate whether the Empire Wind II interconnection upgrades alone would have achieved the PPTN's goal of allowing 3 GW of offshore wind to be deployed on Long Island.

In the long-term, production cost savings are expected to increase because of: (1) assumed deployment of 6 GW of offshore wind on Long Island by 2040 in NYISO's policy case, and (2) a large increase in the cost of dispatchable energy as existing fossil units are replaced by dispatchable emissions free resources ("DEFRs"). DEFRs are assumed to have much higher variable costs than conventional generation. Because DEFRs are unknown technologies with assumed costs, the production costs savings later in the study period are highly uncertain.

Overall, our estimates of the NPV of benefits are significantly lower than the NYISO estimates. This is primarily because NYISO's evaluation did not adequately consider key factors that would limit the avoided capacity investment costs of the proposed projects. Notably, NYISO did not evaluate whether upstream transmission bottlenecks would limit the amount of generation capacity that could be held in upstate New York instead of Long Island. In our evaluation, we found that nearly all of the avoided capacity investment benefit estimated by NYISO cannot be realized without upgrading key upstream constraints that are not addressed by the PPTN projects.

We estimate a higher NPV of production cost savings and avoided public policy costs than NYISO after we adjust for aspects of NYISO's modeling that are likely to understate them. Our changes include (i) an adjustment to account for the general downward bias in production costs estimated using hourly production cost models such as GE MAPS, and (ii) inclusion of fixed O&M and local transmission upgrades in the avoided costs of renewable investments. We also include estimated life cycle O&M costs of the proposed transmission projects, which NYISO did not include in its NPV estimates. As a result, we find that the recommended project (T051) has an expected Benefit-Cost Ratio of 0.81, while the lower-cost alternative (T048) has a B-C Ratio of 1.04. It is important to note that these estimates include the project's contribution to meeting New York's clean energy goals, which are quantified through the avoided policy savings benefit.

The long-term benefits of the recommended project and our preferred alternative are highly uncertain, especially in the years following the state's zero emissions electricity mandate. This is because the production and investment cost savings estimated by NYISO are primarily driven by the avoided cost of building and producing energy from DEFRs, a technology that is currently unspecified. Additionally, the NYISO did not thoroughly analyze key factors affecting project benefits, including the impact of upstream transmission constraints and the impact of operating reserve requirements on production cost savings.

12 We estimated the production cost savings attributable to unbottling of Empire Wind II as the difference in savings between NYISO's GE-MAPS cases with and without the Barrett-Valley Stream constraints modeled.

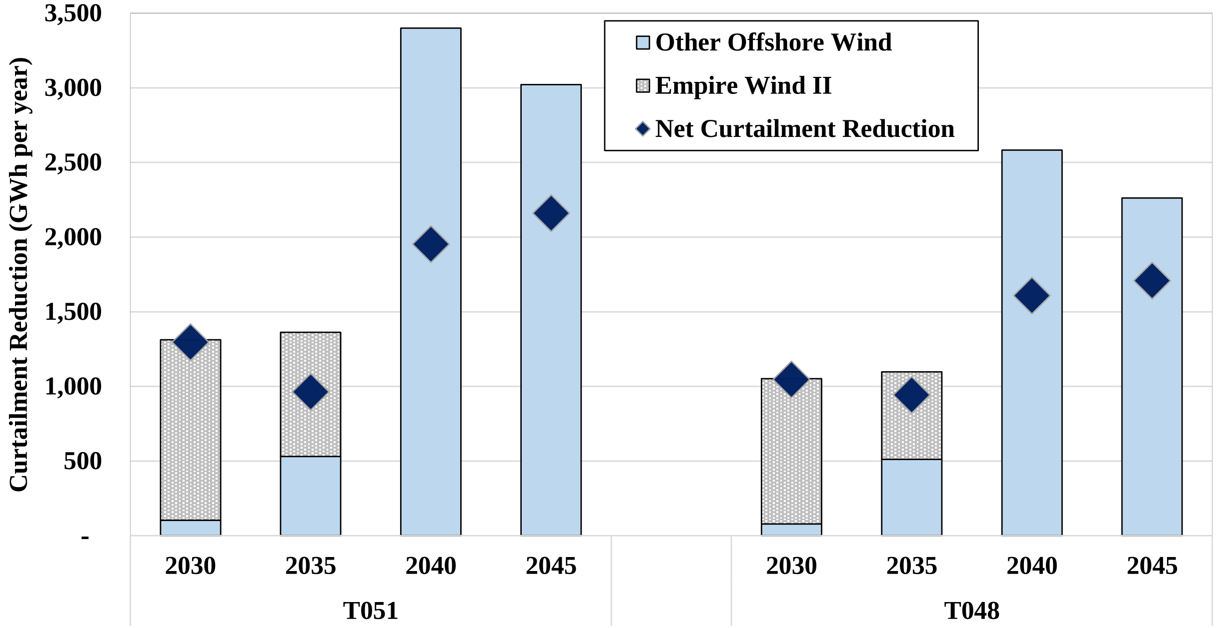
C. Other Quantitative Measures of Impact

This subsection discusses results of benefit metrics that complement the benefit-cost ratio presented above.

1. Offshore Wind Curtailment

Figure 6 summarizes the T051's impact on annual renewable curtailment based on NYISO's GE MAPS results.[13]

Figure 6: Impact of Projects on Curtailment of Offshore Wind and Other Renewables



In NYISO's 2030 and 2035 cases, the vast majority of offshore wind energy unbottled by T051 results from relieving congestion on the Barrett-Valley Stream facility limiting output from Empire Wind II, instead of from expanding Long Island's export capability. T051 partially resolves the constraint affecting Empire Wind II, which experiences 46 to 49 percent curtailment in the pre-project case and 19 to 21 percent curtailment in the project case. In 2040 and beyond, T051 is expected to eliminate more curtailment because of the assumed deployment of 6 GW of offshore wind on Long Island. T048 exhibits somewhat smaller impacts on curtailment of offshore wind over the study period.

13 The height of the bars in Figure 6 reflect the total difference in offshore wind curtailment between the base and project case versions of NYISO's Policy Barrett-Valley Stream CRM Case MAPS simulations. Net curtailment is calculated as the difference in offshore wind curtailment less the difference in curtailment of land based wind, solar, hydro and hydro imports in NYISO. We estimate the portion of avoided curtailment attributable to Empire Wind II based on the increase in avoided curtailment in the Barrett-Valley Stream case compared to the case in which this constraint is not modeled, using data reported in Figures 8 and 9 of Appendix L of NYISO's report.

Beginning in 2035, the offshore wind unbottled by the T051 project causes curtailment of other renewable resources (including wind, solar and hydro) in other parts of the state. Approximately one-third of the offshore wind unbottled after 2035 causes curtailment of other renewable resources.[14] We use this 'net' impact on curtailment to calculate the Implied Net REC of the proposed projects below.

2. Implied Net REC

The Implied Net REC ("INREC") Cost is the average cost of increased renewable production resulting from the new transmission project (after netting out the value of wholesale market benefits). This is used to compare the net cost of a transmission investment to unbottle renewables with REC program costs and/or the net cost of energy storage projects that reduce curtailment of renewables. When the INREC Cost is lower for a transmission project than for competing investments in renewable generation or battery storage, the transmission project is cost-effective. However, if the INREC Cost is higher, then the transmission project is likely to crowd-out other more economic clean energy investments.

Figure 7 compares the estimated INREC Cost of the T051 and T048 projects over the evaluation period to alternative investments in renewables.[15] The T051 and T048 INREC Costs are estimated using the benefits and net curtailment reductions discussed above. The INREC Costs of renewables and storage are estimated using NYISO's policy base case, which does not include the proposed transmission projects.[16] NYISO did not model local transmission constraints in upstate regions that would impact energy deliverability and revenues of renewables there, so we include in the renewable INREC cost the estimated cost of local transmission upgrades based on

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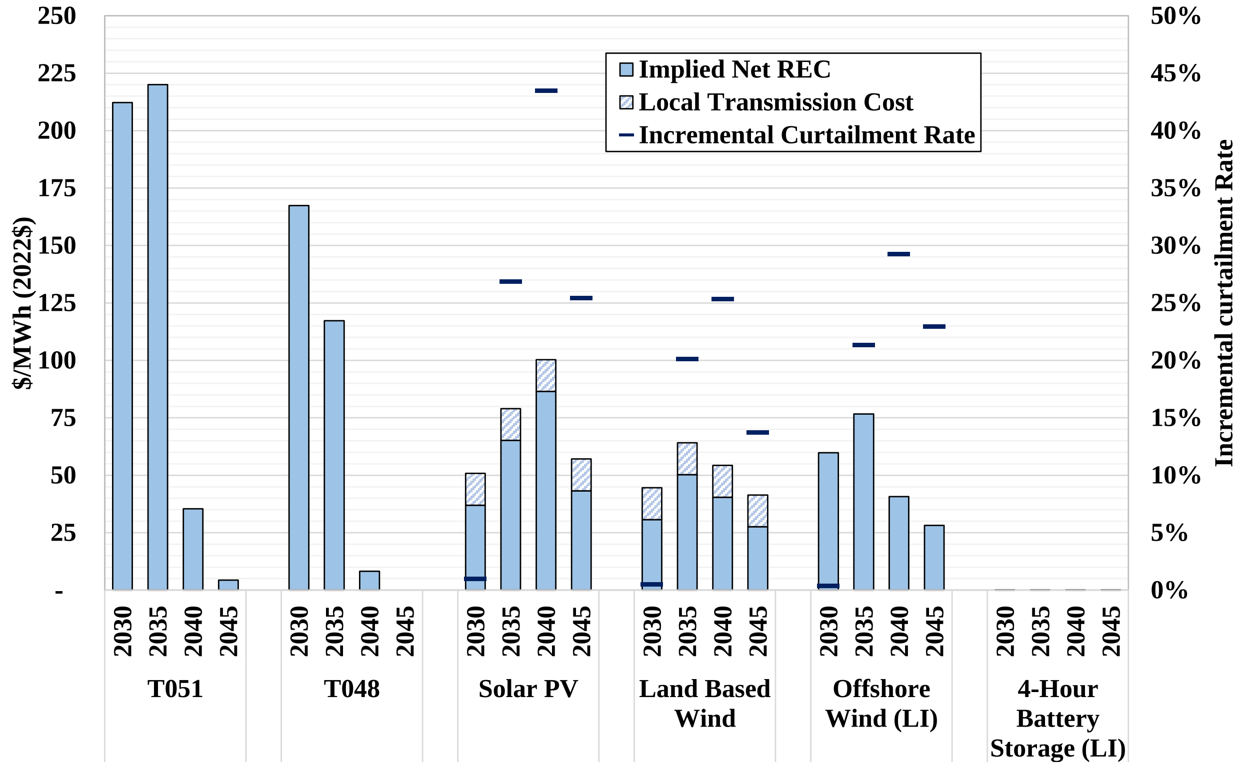
14 This finding is based on data for the BVS P095 case provided by NYISO. See also figures 18 and 19 of Appendix L of NYISO's report.

15 The INREC cost of the transmission project is estimated as its levelized cost net of annual production cost savings and avoided capacity investment benefits, divided by the annual net reduction of renewable curtailment it provides. The INREC Costs of renewables are estimated as the levelized cost per megawatt of an additional unit of that technology net of estimated market revenues in the production cost model base case, divided by the annual net increase in renewable generation it provides (e.g. its annual output excluding hours when the resource would be curtailed or cause another renewable resource to be curtailed). The INREC cost of storage is estimated as the levelized cost of a 1 MW, 4 Hour battery on Long Island net of expected energy, ancillary services and capacity revenues, divided by the incremental MWh of renewable energy the battery would provide each year by charging to reduce renewable curtailment. Since this is a comparative metric of the cost of procuring a REC, we exclude avoided policy investment costs (which are equivalent to avoided REC costs) from the calculation of the PPTN project INREC Cost and exclude the negative portion of LBMPs from the calculation of renewable and storage INREC Costs.

16 We exclude federal ITC and PTC incentives when calculating the levelized cost of renewables, so that the INREC cost represents the total social cost of obtaining a REC. We calculate INREC Cost for a land-based wind project in Zone C and the average of solar PV in zones C and F.

projects recently approved by the NYPSC.[17] We also show the incremental curtailment rate of each renewable resource, which is considered in the INREC calculation. For example, an additional offshore wind project on Long Island in 2035 would face curtailment of 21 percent of its output, and the INREC cost of its remaining deliverable energy after accounting for this curtailment is $75 per MWh.

Figure 7: Implied Net REC Cost of T051, T048, and Generic Investments



The INREC cost of T051 is initially very high (~$212 per MWh in $2022 in 2030) because it has low expected economic benefits relative to its costs during that period. This indicates that T051 is a very costly means to increase the supply of renewable energy during this period compared to investing in additional renewable capacity, even after accounting for partial curtailment of the renewables. The INREC Cost of T048 is significantly lower but remains higher than other technologies until around 2038. In 2040 and beyond, the INREC cost of the proposed transmission projects falls rapidly because it is projected to provide much greater production cost benefits (reducing its net cost) and reduce more offshore wind curtailment. This suggests that

17 See February 16, 2023 *Order Approving Phase 2 Areas of Concern Transmission Upgrades* in NYPSC Docket 20-E-0197. We estimate local transmission costs based on the levelized value of the estimated $4.4 billion cost of the approved Phase 2 upgrades divided by the 30,332 GWh of energy deliverability headroom they are expected to provide. There is still significant curtailment of renewables in NYISO's model results because of the presence of inter-zonal high voltage bottlenecks, but this is already reflected in the INREC Cost calculation through the incremental curtailment rate.

T051 would not be a cost-effective way to increase the supply of RECs (compared to investing in additional renewable capacity) until 2040.

We calculate an INREC Cost of $0 per MWh for storage on Long Island in NYISO's Policy Case. This suggests that it would be economic for additional storage to enter the market and reduce curtailment of offshore wind by charging to absorb curtailed wind energy.[18] In the pre-project case, an incremental megawatt of battery capacity with 4- or 8-hour duration would reduce curtailment by approximately 979 to 1,819 MWh per year if located at the Barrett substation, or 430 to 670 MWh per year by 2035 and 762 to 1,343 MWh per year by 2040 if located elsewhere on Long Island.[19] The net cost of batteries is low because of high energy and capacity revenues in the Policy Case, even after accounting for declining marginal capacity value of storage. These results suggest that both the T051 and T048 projects may crowd out storage investments that could more cost-effectively reduce curtailment of offshore wind.

18 This may also indicate that the NYISO's capacity expansion model is building less than the optimal amount of battery storage capacity. This may be due to the tendency of storage resources to profit from price volatility and the difficulty of modeling price volatility in the NYISO's capacity expansion model, which models time in larger chunks than an hourly or interval-level model.

19 We estimate incremental avoided curtailment a storage unit could provide using GE-MAPS data provided by NYISO. Storage is assumed to reduce curtailment when it would economically charge during hours where the LBMP is zero or less.

IV. Key Assumptions Used to Estimate Benefits and Costs

This section discusses key assumptions used in the NYISO's estimates of the costs and benefits of the proposed projects. We also discuss several factors that were not considered in the NYISO's estimates. Ultimately, we find that the overall effect of addressing these factors would likely be a significant reduction of the overall benefit-cost ratios for the recommended projects. We recommend the NYISO address these issues in future evaluations.

Subsection A discusses the estimation of individual transmission project costs. Subsection B addresses the NYISO's assumptions regarding avoided costs of dispatchable generation needed for reliability. Subsection C addresses NYISO's estimate of the avoided cost of satisfying state policy mandates. Subsection D evaluates the assumptions used in the production cost simulation model.

A. Factors Affecting Transmission Investment Costs

This section reviews the NYISO's approach to estimating project costs and describes alternative assumptions used in our analysis.

1. Exclusion of Operating and Maintenance Costs and AFUDC

NYISO's evaluation considered only the proposed projects' overnight capital costs. It did not consider operating and maintenance (O&M) costs or allowance for funds used during construction (AFUDC), which can significantly affect a transmission project's total life cycle cost.[20] For example, in the last PPTN evaluation (the AC Transmission Projects evaluation completed in 2019), data provided by the NY Department of Public Service and the Brattle Group indicated that O&M costs would add approximately 39 percent to the net present value of the project's costs over a 45-year period and AFUDC would add over 9 percent.[21]

In our evaluation, we accounted for AFUDC by assuming funds will be committed for an average of two years (based on construction timelines estimated by NYISO's independent consultant) at a real weighted average cost of capital of 5.1 percent, resulting in a 10.5 percent increase in the project's capital cost above the overnight estimate in real terms.

Estimating O&M costs is challenging in the absence of information provided by developers. It is likely not possible to extrapolate O&M estimates used in the AC Transmission process, which reflected projects consisting mainly of overhead lines in upstate New York. A large portion of the T051 and T048 projects consist of new underground and submarine transmission cables,

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20 See section 3.2 of NYISO's report.

21 See slides 4 and 5 of the Brattle Group's October 8, 2015 presentation on *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades* in NYPSC Case 12-T-0502.

which have different maintenance profiles compared to overhead lines. Based on the O&M costs reported per circuit-mile of underground lines and per substation in FERC Form 1 filings of downstate utilities, we conservatively estimated annual O&M costs to be approximately 0.5 percent of overnight capital costs for the T051 and T048 projects. However, we recommend that the NYISO estimate these savings as part of its evaluation in future PPTP evaluations.

2. Capital Costs and Discounting

NYISO considered two estimates of the overnight cost of each project: one based on the voluntary cost cap submitted by each developer, and one developed by NYISO's independent consultant. For the T051 and T048 projects, NYISO estimated overnight capital costs of $3.26 billion and $2.12 billion by adjusting the developer's cost cap using the independent consultant's estimate. These costs are expressed using 2022 prices.[22]

It is important to discount costs and benefits that take place at different times in a consistent manner. NYISO's evaluation used the following parameters and assumptions: (1) the project is assumed to enter service in 2030, (2) benefits are evaluated over a 20-year time horizon (2030 to 2049), (3) benefits are discounted using a 7.1 percent discount rate intended to reflect a regulated utility cost of capital, and (4) all values are presented in 2022 dollars. NYISO discounted project benefits to 2022 using the 7.1 percent discount rate, instead of discounting to the initial year of the evaluation period (2030). For production cost benefits, NYISO estimated savings at five year intervals (2030, 2035, 2040, and 2045) and assumed that savings are the same in nominal terms between intervals (e.g. the same value for 2030 through 2034).

In our evaluation, we discount future benefits to 2030 using NYISO's 7.1 percent discount rate. We apply a 2 percent annual inflation escalator to NYISO's 2022$ capital cost estimate to estimate its nominal cost in 2030. We express annualized project costs as a levelized value over 20 years based on the cost estimate as of 2030. Hence, project costs and benefits are uniformly discounted to the same date. We present our results in 2022$ by applying a 2 percent annual inflation deflator to 2030 present values. We also interpolate production cost savings benefits for years between model run years. In Figure 1, we calculate the NPV of benefits estimated by NYISO using this discounting approach, so that the NYISO's benefit-cost ratio can be compared directly to ours.

B. Avoided Cost of Investment in Dispatchable Capacity Needed for Reliability

The proposed transmission projects would increase transfer capability into Long Island, potentially reducing the amount of capacity needed in Long Island and other downstate areas to maintain reliability. In the long term, this would reduce system costs by allowing peaking capacity to be built or maintained in upstate areas where it is less expensive instead of Long

22 See section 3.2 of NYISO's report.

Island. In NYISO's evaluation, this is the largest benefit of the T051 and T048 projects and accounts for the majority of their values on a NPV basis.[23]

We identify two flaws in NYISO's evaluation that cause the avoided cost of capacity benefits of T051 and other proposed projects to be significantly overstated. First, NYISO did not consider whether upstream transmission constraints not addressed by the projects would limit the impacts on Long Island's capacity requirements. Second, NYISO adopted speculative assumptions regarding the cost of future peaking plants that result in extremely high cost savings for each megawatt that can be shifted from Long Island to upstate. We discuss these flaws below.

1. Effect of Upstream Transmission Constraints

NYISO quantified the increase in potential transfers into Long Island provided by each proposed PPTN project. NYISO then assumed that an amount of capacity proportional to this increase can be held in upstate New York instead of Long Island if the project is built.[24] This analysis is incomplete because NYISO did not evaluate whether upstream constraints other than those directly upgraded by the project would limit the ability to remove capacity from Long Island in a resource adequacy planning assessment.

Shortcomings of NYISO's Approach

NYISO estimated the PPTN projects' impacts on the Long Island capacity requirement by replicating only one component of its methodology to determine Locational Capacity Requirements (LCRs). NYISO determines LCRs each year so that the capacity market will procure enough supply in each region to satisfy reliability criteria, considering major transmission bottlenecks and the cost of new supply in each area. NYISO's LCR Optimizer process determines LCRs using GE-MARS, a probabilistic model that considers the ability of the transmission system to move power throughout the entire NYCA region during peak conditions. NYISO also calculates minimum LCR floors based on Transmission Security Limits (TSLs), which consider contingencies that would affect transfers on facilities directly into each region. The LCR is the higher of the values determined by the Optimizer and TSL approaches.

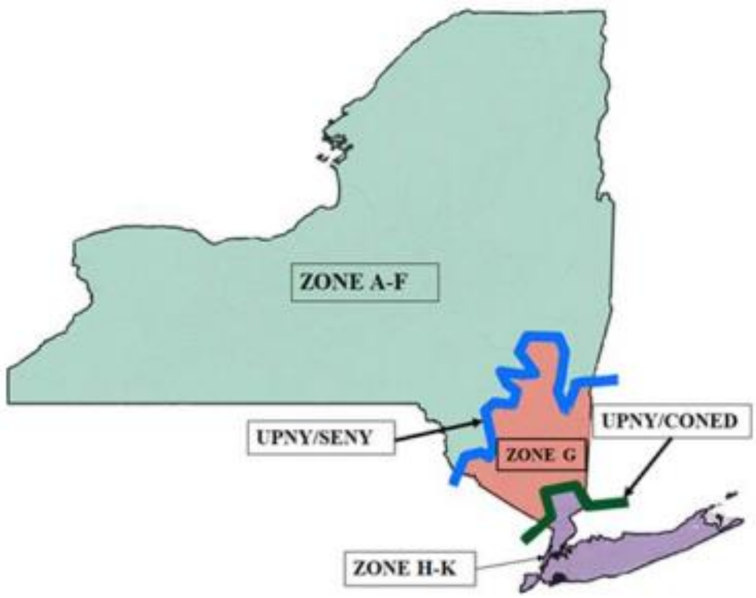
NYISO's evaluation determined that the PPTN projects would cause the TSL-based requirement in Long Island to fall by adding new transfer capability directly onto the island from nearby areas. The proposed PPTN projects are generally designed to increase the transfer capability between Long Island (Zone K) and the Con Edison service territory in Westchester County (Zones H and I). Some projects, including T051, also upgrade transfer capability between Long Island and New York City (Zone J).

23 See Figures 38 and 39 of NYISO's report.

24 See Appendix N of NYISO's report.

NYISO assumed without any analysis that the LCR in Long Island will fall by the same amount as the reduction in its TSL-based requirement. This ignores the fact that the LCR Optimizer considers many other transmission constraints that may limit flows between the upstate region and Long Island. If upstream bottlenecks restrict the ability of additional upstate capacity to serve downstate New York, an increase in the transfer limit to Long Island from other downstate areas will not allow more capacity to be held upstate unless those upstream constraints are also upgraded.[25] Figure 8 below shows a simplified representation of the location of key constraints impacting flows between upstate and downstate New York.

Figure 8: Illustration of Upstream Transmission Constraints



These constraints include the UPNY-CONED constraint (between zones G and H) and the UPNY-SENY constraint (between zones A through F and zone G). The proposed transmission projects would increase transfer capability between Long Island and other zones within the H-K group, but none of them would increase transfer capability across UPNY-CONED or UPNY-SENY interfaces. However, (though NYISO did capture these interface limits in the capacity expansion and production cost models) the NYISO did not use its resource adequacy model to

25 NYISO used a zonal capacity expansion model that includes upstream transmission limits. However, the presence of these constraints in the capacity expansion model does **not** allow it to usefully quantify their impact on zonal capacity requirements. The capacity expansion model is not designed to determine capacity requirements internally. It uses an average load forecast and groups hourly load and resource availability into multi-hour “time slices” that average across multiple hours, so it does not simulate probabilistic hourly net peak load conditions affected by load forecast uncertainty as is done in a resource adequacy model such as GE MARS. Capacity requirements derived from MARS are driven by the individual hours of highest load, greatest resource unavailability and load forecast uncertainty. Hence, NYISO’s capacity expansion tool simply models fixed zonal capacity requirements that are defined by user input and assigns each resource type an assumed contribution towards those requirements. In this evaluation, NYISO derived the inputted project case zonal capacity requirements from its analysis of TSL based limits discussed in this section.

assess whether the UPNY-SENY and UPNY-CONED interfaces would limit the system's ability to relocate capacity from Zone K to zones A through F.

MMU Analysis of Avoided Capacity Costs

We performed an analysis to examine whether upstream constraints might materially impact the amount of capacity that can be shifted from downstate to upstate by the T051 project. We used a simplified hourly resource adequacy model that considers load, resource availability and transfer limits between NYISO zones, using inputs consistent with NYISO's Policy Case resource adequacy analysis.[26] Our model determines zonal capacity requirements designed to satisfy NYISO's resource adequacy criteria using a method comparable to the LCR Optimizer.

Our analysis found that the T051 project would reduce downstate capacity requirements by much less than NYISO's evaluation assumed. NYISO assumed that approximately 2 GW of capacity could be held in zones A through F instead of zone K as a result of the T051 project. By contrast, we found that the UPNY-CONED constraint is likely to bind during the study period, so that little or no capacity can be shifted from downstate to upstate as a result of T051. However, we also found that the project would allow some capacity to be shifted from New York City to Long Island, where it is comparably less costly, providing potential cost savings.

Recent market outcomes support the finding that little or no capacity can be shifted upstate without upgrading UPNY-CONED. The UPNY-CONED interface was binding in the 2020/21, 2021/22 and 2023/24 LCR studies following the retirement of the Indian Point nuclear plant in Zone H.[27] This suggests that an attempt to shift significantly more capacity upstream would aggravate this constraint. Table 1 illustrates the significance of UPNY-CONED using assumptions derived from NYISO's 2030 Policy Case.

Table 1 shows that when flows via UPNY-CONED into downstate New York are at maximum levels, the transfer limits from zone I to zones J and K are near binding in the base case, but have

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26 NYISO based its analysis in the Policy Case on the 2030 Policy Case conducted for the 2022 Reliability Needs Assessment (RNA), with adjustments to align with the PPTN evaluation. Our resource adequacy tool considers a zonal hourly load forecast based on the Outlook S2 Case, with load forecast uncertainty adjustment based on the 2023/24 IRM Study. It models the renewable resources included in the PPTN Policy Case with hourly capacity factor profiles derived from the Outlook assumptions. We model zonal emergency transfer limits based on the 2026-32 RNA Topology Case (Fig. 25 of the 2022 RNA Appendix), which includes the impacts of the AC Transmission Projects. We also include the Clean Path New York project as a transfer interface between zones A-F and Zone J. We modeled a simplified zones and interzonal limits for the A-F, G, H-I, J and K regions based on the 2022 RNA Policy case plus Clean Path NY.

27 See our Annual Report on the NYISO Markets for 2020 and 2022. The retirement of Indian Point resulted in an increased need for imports from upstate into zones H through K. Beginning in the 2021 capability year, Con Edison made operational changes to certain transmission facilities which increased the UPNY-CONED limit modeled in the IRM study. The UPNY-CONED transfer limit in the IRM study was 7,000 MW in 2021/22 and 2022/23, and 6,675 MW in 2023/24 after Con Edison's operational changed were reverted. The UPNY-CONED transfer limit in the 2030 RNA Policy Case is 7,050 MW.

significant spare capability in the project case. Unfortunately, this spare capability does not allow capacity to be relocated upstate. Hence, our analysis indicates that all or most of the capacity investment benefits estimated by NYISO cannot be realized without also upgrading UPNY-CONED and potentially other interfaces, such as UPNY-SENY. Additional upstream upgrades would substantially increase the cost of realizing any capacity investment savings.

Table 1: Comparison of Downstate Transfers Limits and 2030 Load Forecast

MW		Pre-Project	T051
UPNY-CONED Emergency Limit	(a)	7,050	7,050
Peak Load in zones H and I	(b)	1,830	1,830
Supply in zones H and I	(c)	456	456
Supply Available for Transfer to J and K	(d) = (a) - (b) + (c)	5,676	5,676
Zone I → Zones J and K Emergency Limit	(e)	5,693	7,093
Unused Transfer Capability to J and K	**(f) = (e) - (d)**	**17**	**1,417**

2. Impact of Peaking Plant Cost Assumptions

New York's Climate Leadership and Community Protection Act (CLCPA) requires the state's electric system to be zero emissions by 2040. Various studies have shown that a reliable zero emissions system will require a large amount of generation capacity that is dispatchable for long periods and can operate when intermittent renewable output is low. Hence, NYISO began including generic DEFRs in its long term planning studies in 2022.

NYISO's evaluation considers cost savings from building future additions of peaking capacity upstate instead of on Long Island. All of these savings are in the form of avoided investments in DEFRs, a hypothetical peaking technology assumed to be compliant with state environmental laws.[28] Hence, the savings determined by NYISO are driven by the difference in the assumed cost of building a DEFR in Long Island compared to other regions of the state. NYISO assumed that DEFRs will be extraordinarily expensive to build, resulting in apparent cost savings that are highly speculative.

Impact of DEFR Assumptions on NYISO's Evaluation

NYISO's evaluation used a base case in which 5.2 GW of DEFR capacity is built in Long Island and 27.2 GW statewide by 2040. All of the avoided capacity investment cost determined by NYISO comes from shifting DEFR capacity from Long Island to zones A through F. NYISO assumed that the capital cost of DEFRs will be $4,500 per kilowatt in Rest of State and $5,850 per kilowatt in Long Island ($2021).[29] By contrast, the NYISO's last Demand Curve Reset study found the capital cost of a dual-fuel H-Frame combustion turbine to be $1,042 per kW in Rest of

28 See Figures 12 and 13 of Appendix N of NYISO's report.

29 See Appendix D of NYISO's 2021 System & Resource Outlook study at p. 7, available here.

State and $1,158 per kW in Long Island. As a result, each MW of capacity investment that can be shifted from Long Island to Rest of State avoids over 11 times more capital cost under NYISO's assumptions than it would using current technologies.

As a result, NYISO calculates large investment cost savings because the assumed costs of the generation projects that are shifted upstate are extremely high. In particular, NYISO's pre-project case includes the addition of 1.7 GW of new DEFR capacity in Long Island built between 2030 and 2035, at a cost of $9.8 billion ($2022). NYISO's project case for T051 allows these DEFRs to instead be built in the Rest of State region in 2037 at a cost of $7.7 billion ($2022). This $2.1 billion difference largely accounts for the capacity saving benefit estimated by NYISO.

Speculative Nature of DEFR Assumptions

The assumed future DEFR costs used in NYISO's evaluation are highly speculative. NYISO originally contemplated three potential DEFR technologies:[30]

- *Low capital / high operating cost* technology with a capital cost of $1,000 per kW roughly equivalent to a combustion turbine burning renewable natural gas,
- *Low operating / high capital cost* technology with a capital cost of $8,000 per kW roughly equivalent to nuclear, and
- *Medium capital / operating cost* technology whose cost ($4,500 per kW) is a simple average of the first two options.

In the PPTN evaluation, only the "medium capital / operating cost" option was considered in the capacity expansion model, although this option does not correspond to any known generating technology. Hence, while the DEFR capital cost is a key parameter driving NYISO's evaluation, its costs and other characteristics are highly speculative.

New York State has not yet issued guidance on what dispatchable technologies will comply with the CLCPA, and there has been little deployment of potentially viable technologies to date. However, peaking technologies are generally chosen to minimize capital costs and it is reasonable to expect that low-capital, high-operating cost technologies will be pursued as demand for non-emitting peaking capacity grows. For example, MIT researchers Hernandez and Gençer (2021) estimate the capital cost of a gas turbine capable of burning hydrogen to be $1,320 per kW—similar to the "Low capital / high operating cost" technology.[31]

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30 See December 17, 2021 NYISO Electric System Planning Working Group presentation "System & Resource Outlook Update" at slide 14, available here. NYISO refers to a study commissioned by New York State that employed a proxy zero emissions technology with costs above those of modern peaking plants, but the 'medium capital / operating' DEFR assumption has capital costs 80 percent higher than this technology.

31 See Hernandez and Gençer (2021), "Techno-economic analysis of balancing California's power system on a seasonal basis: Hydrogen vs. lithium-ion batteries", *Applied Energy* Volume 300, available here.

While green hydrogen is not currently traded as an energy commodity, it may become available in the future at a high price to support something similar to the "Low capital / high operating cost" technology. Additionally, if green hydrogen becomes a traded commodity, then the production of green hydrogen from surplus renewable generation would result in market incentives that could reduce curtailment in a study like the Long Island Offshore Wind Export PPTN evaluation. Hence, there is a wide range of potential technologies that could be viable in the future, and the costs and characteristics of those technologies will have dramatic effects on the mix of transmission, generation, and storage that will be cost-effective in the future.

NYISO's base case assumes that 27 GW of DEFRs are built by 2040 at a cost of $150 billion ($2022), exceeding the combined cost of all of the renewables and storage New York must build to meet its zero emissions mandate.[32] It is unclear whether these assumptions are realistic or if they can provide a reasonable basis for major investment decisions at this time.

Conclusions on Avoided Peaking Plant Costs

NYISO's evaluation vastly overstates the amount of capacity that could be shifted from Long Island to upstate as a result of the PPTN projects by not considering upstream transmission constraints that are not addressed by the PPTN projects. Further, NYISO uses speculative assumptions for the savings resulting from each megawatt shifted.

Consequently, the true capacity savings benefit is likely to be much smaller than NYISO's estimates. Since the avoided cost of peaking capacity is the largest benefit estimated by NYISO for most proposals, these issues have a major impact on benefit-cost ratios. Overestimating avoided capacity savings will bias the selection process in favor of less efficient projects that provide larger increases in the Long Island import transfer limit.

In our evaluation, we make the following adjustments to estimate avoided cost of peaking capacity. As a result, we estimate avoided peaking capacity benefits that are much smaller than NYISO's estimates:

- We estimate the change in optimized capacity requirements in each zone in the project case vs. the base case based on the resource adequacy model analysis described above.
- We use a $1,320 per kW ($2020) base capital cost for a hypothetical DEFR technology and $14 per kW-year fixed operating cost, based on estimates by Hernandez and Gençer (2021) for a hydrogen-fueled combustion turbine with selective catalytic reduction. We apply the same zonal cost ratios as in NYISO's evaluation (1.00 for Rest of State, 1.14 for Hudson Valley, 1.39 for New York City and 1.30 for Long Island).

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32 See "Outlook Policy Case Additions" for the S2 Case of NYISO's 2021 System & Resource Outlook, available here in the Outlook Data Catalogue, and assumed generation investments costs in Appendix D of the 2021 Outlook, available here

- Based on the above assumptions, we quantify annual avoided costs of peaker capacity as the difference in optimized capacity requirement in each zone in the project case vs. the base case, multiplied by the levelized carrying cost of peaking capacity in the same zone.

C. Avoided Cost of Investment to Satisfy State Policy Mandates

NYISO's evaluation quantified the ability of the proposed PPTN projects to avoid or defer investments in renewable generating capacity needed to satisfy the state's electricity sector mandates. Specifically, the CLCPA requires 70 percent renewable energy by 2030 and 100 percent zero emissions by 2040. NYISO developed its Policy Case assuming that these mandates are met, using a capacity expansion model to determine the amount of investment in wind and solar capacity that would be needed by 2040. NYISO then assumed that the increase in deliverable offshore wind energy resulting from the proposed PPTN projects would reduce the amount of land-based wind and solar the state would need to procure in order to meet its clean energy targets. After re-running the capacity expansion model to include the impact of the proposed PPTN projects, NYISO found that approximately 1.3 GW of investment in solar PV capacity could be avoided by 2040.[33]

This is a reasonable approach to estimate the environmental policy benefits of the proposed PPTN projects (e.g., their ability to reduce the cost of achieving environmental goals). However, NYISO's calculation can be improved in the following ways:

- *Impact of Avoided Investments on Production Costs*: NYISO's evaluation did not consider that renewable generation investments that are avoided by the proposed PPTN projects would no longer be available to provide production cost benefits. This results in double-counting of project benefits by assuming that the avoided solar projects continue to provide zero-cost energy even if they are never built.
- *Annualization of Avoided Costs*: NYISO calculated avoided cost savings by discounting the capital cost of each investment deferred or avoided in each year, rather than the annualized carrying charge of the investment. This misaligns the timing of when the savings are counted from the actual delivered benefit, which is the reduction of carrying costs over the lifetime of the avoided investment. Additionally, NYISO did not consider avoided O&M costs of renewable investments.
- *Avoided Local Transmission Investment*: NYISO used a zonal capacity expansion model to determine the amount of upstate renewable investment that could be avoided. However, NYISO's 2021 System & Resource Outlook study found that local transmission constraints will result in significant curtailment of renewables at many locations in upstate zones if they are not addressed. Hence, NYISO's analysis likely understates the avoided cost of renewable investments upstate, which may need to be accompanied by local transmission upgrades not considered in the capacity expansion model.

33 See Figures 8 and 9 of Appendix N of NYISO's report.

- *Cost of Incremental Offshore Wind Energy*: NYISO's Policy Case included 6 GW of offshore wind on Long Island and 12 GW statewide by 2040. This is significantly more than is required either by the PPTN (3 GW on Long Island) or by state policies (9 GW by 2035). It is also more than NYISO forecasted would be developed by 2040 as part of an efficient buildout of renewables to meet the 2040 zero emissions mandate in its System & Resource Outlook S2 Case, which only slightly exceeded the 9 GW mandate. NYISO's evaluation did not account for the incremental net cost of deploying additional offshore wind to Long Island, which would offset avoided policy costs.

In our B-C Ratio, we estimated avoided policy costs using a methodology that is comparable to the one used by NYISO but accounts for the factors discussed above. We multiplied the net reduction of renewable curtailment provided by the proposed PPTN project in each year by Implied Net REC cost of procuring an equivalent amount of solar generation in that year. Our estimate of the avoided Implied Net REC cost of solar includes O&M costs and an estimate of the cost of local transmission upgrades per annual megawatt-hour of generation, based on the "Phase II" local transmission projects recently approved by the NYPSC.[34] In 2040 and beyond, we subtract out the Implied Net REC cost of additional offshore wind procurement needed to realize the project benefits from the avoided policy costs. This continues to yield positive savings because the INREC cost of offshore wind is projected to be below solar by that time.

D. Production Cost Modeling Assumptions

The NYISO estimated production cost benefits using the GE MAPS production cost model database developed as part of the 2021 System & Resource Outlook study (the "Outlook"). The NYISO relied on the "S2" case developed in the Outlook to model a resource mix that complies with New York state policy, specifically the requirement for an electric sector that is 70 percent renewable by 2030 and 100 percent zero-emissions by 2040, including 9 GW of offshore wind by 2035. In the "Policy" case for the PPTN evaluation, NYISO modified the Outlook S2 database to include 12 GW of offshore wind by 2040, with 6 GW located in Long Island.[35]

While it is reasonable for the NYISO to rely primarily on the Outlook models, there are several modeling assumptions that could be modified to improve the accuracy of the estimated production cost savings.

1. Underestimation of Production Costs in GE MAPS

34 See February 16, 2023 *Order Approving Phase 2 Areas of Concern Transmission Upgrades* in NYPSC Docket 20-E-0197. We estimate local transmission costs per megawatt-hour based on the levelized value of the estimated $4.4 billion cost of the approved Phase 2 upgrades divided by the 30,332 GWh of energy deliverability headroom they are expected to provide.

35 See Appendix L of NYISO's report.

The current GE-MAPS model does not include transmission outages and unforeseen factors such as load forecast error that exacerbate congestion during actual market operations and, as such, does not fully capture the value of new transmission lines that may help mitigate the impact of such factors. Transmission outages drive a large share of congestion in market operations, especially in areas with renewable generation. In the AC Transmission Proceeding, the Brattle Group presented analysis showing that accounting for transmission outages and real world variability of system conditions would have increased estimated production cost savings by 40 percent.[36] We accounted for this issue in our B-C Ratio by incorporating the 40 percent adder. Considering these factors would significantly increase the estimated benefits of new transmission, we recommend that future production cost simulations explicitly consider them.[37,38]

2. Impact of Long Island Reserve Requirements

NYISO's GE-MAPS analysis inaccurately estimates production cost savings and offshore wind curtailment benefits because it does not consider operating reserve requirements on Long Island. NYISO typically requires up to 1.3 GW of reserves on Long Island to maintain security and reliability following the two largest contingencies. Most of this is currently satisfied by older peaking capacity currently on Long Island with a portion of the reserves held on steam turbine units with long startup notification times. Given the sizes of offshore wind facilities in the interconnection queue, the reserve requirement for Long Island could rise up to 2.6 GW during periods of high wind production. Furthermore, the NYISO is evaluating the use of a reserve requirement to cover intermittent generation uncertainty based on the difference between the (POE50) wind generation forecast and the POE95 or POE99 forecast.[39] Holding reserves to cover this uncertainty will require the NYISO to commit thermal units on many days with high wind forecasts. This will lead to additional curtailment of offshore wind on Long Island because online thermal generation will reduce the amount of offshore wind that can be injected without curtailment. However, the baseline MAPS case does not model these reserve requirements.

In the long term, the impact of Long Island reserve requirements on offshore wind curtailments and production costs is highly uncertain. On one hand, large amounts of offshore wind may cause reserve requirements on Long Island to increase significantly in some time periods to secure against the loss or over-forecast of large wind resources. On the other hand, existing

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36 See slides 13-18 of the Brattle Group's October 8th 2015 presentation on *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades.*

37 See Recommendation P19-6 in Section V.

38 While the NYISO evaluated the reliability benefits from the proposed projects under various maintenance conditions as part of the Operability metric, this metric does not include a monetary valuation of the economic, environmental, and reliability impacts under maintenance conditions.

39 The POE95 forecast refers to the MW level that has a 95 percent likelihood of being exceeded.

aging steam turbines may eventually be replaced by resources that can provide reserves without being committed to produce energy, such as battery storage or new dispatchable emissions-free technologies with fast startup times.

NYISO attempted to account for the impact of reserve requirements in the 'P95 Case' production cost model runs.[40] In this case, NYISO estimated the amount of transmission capability that would not be available for bulk imports and exports because it would be needed to account for ramping, regulation, and other unforeseen variations in net load (i.e., load minus wind and solar output) on Long Island. This was based on the 95th percentile (i.e., value which is exceeded 5 percent of the time) of changes in hourly net load on Long Island in each run year. This measure was intended to serve as a proxy for net load forecast *uncertainty*, which differs from net load *change* (because some of the hour-to-hour change in net load is predictable). NYISO deducted this value from the thermal limits of transmission lines between Long Island and neighboring areas, reducing the amount of capacity that can be imported or exported.

NYISO's approach to quantifying the impact of Long Island reserve needs is quite simplistic and does not account for the dynamic factors described above. NYISO applied the same reduction of transmission capability in all hours of the year, instead of applying hourly values driven by factors that would affect reserve needs at different times (such as offshore wind output levels). This analysis assumes that reserves are held in the form of reduced utilization of the transmission interface, instead of being provided by local generators. As noted above, some generators can provide reserves while offline and avoid the need to restrict transmission capability. By not considering these factors, the CRM case provides only a very rough estimate of how ramping, regulation, and reserve needs will affect production cost benefits.

In our B-C Ratio we use NYISO's CRM Case, since it is likely that a case with no adjustment for this issue will grossly understate benefits, especially as reserve requirements increase in the future. However, detailed modeling is needed to reliably estimate this benefit and the projected cost savings should be assumed to have an extremely high degree of uncertainty, especially in the outer years of the analysis when the dispatchable fleet is replaced by storage and unspecified new resource types.

3. Importance of Future Zero Emissions Fuel Cost Assumptions

NYISO's evaluation assumed that there will be no remaining fossil generation in New York by 2040, consistent with the CLCPA's zero emissions mandate. Hence, long term production cost savings are driven by the variable costs of dispatchable emissions free resources (DEFRs) that are assumed to replace the fossil fleet, as well as the cost of imports from other areas. NYISO assumed that the variable cost of DEFRs will be approximately \$150 per MWh (\$2022). As a

[40] See the subsection titled "Long Island Net-Load Variability Sensitivity" in Appendix L of NYISO's report.

result, forecasted LBMPs increase rapidly during the study period. This is the main driver of the large increase in production cost savings attributed to the projects after 2035.

It is impossible to know what the fuel and variable operating costs of future zero-emissions dispatchable technologies will be. While it is generally expected that zero emissions fuels will be more costly than natural gas today, their precise costs will depend on many presently unknown factors. Hence, we recommend that NYISO examine multiple scenarios of DEFR cost assumptions in future PPTP evaluations. Ultimately, the DEFR cost assumptions result in an outsized importance of highly uncertain outer year production cost savings to the project's NPV. This suggests that it would be optimal to defer selection of a project until closer to the time when these large benefits are projected and more reliable information becomes available.

V. Conclusions and Recommendations

The NYPSC issued an order stating the CLCPA constitutes a Public Policy Requirement, including the mandate to generate 70 percent of electricity from renewable sources by 2030 and the mandate to install 9 GW of offshore wind by 2035. The order identified a PPTN to support these mandates by increasing deliverability of offshore wind on Long Island to other areas of the State. In accordance with its tariff, NYISO evaluated 19 proposed projects that were proposed to address the PPTN. The NYISO published the Public Policy Transmission Planning report that summarizes the need, the proposed projects, V&S assessment, and the evaluation projects. NYISO has recommended the Board of Directors select Project T051.

We reviewed NYISO's report and evaluated the costs and benefits of the proposed projects in the context of assessing their effects on the NYISO markets. Based on this evaluation, we find that the proposed transmission projects are not estimated to be helpful for satisfying the 2030 mandate and they would make relatively modest contributions toward satisfying the 2035 mandate. Furthermore, the majority of the benefits of new transmission over the study period depend on the future costs and characteristics of DEFRs, which will likely be clarified in the coming years. In addition, investment in storage could be used to satisfy the 2030 and 2035 mandates more cost-effectively if it is not crowded-out by the new transmission. Given the estimated investment lead time of around six years and small benefits before 2040, it is premature to move forward with a capital-intensive transmission project at this time. These results support the following conclusions and recommendations:

- It is not advisable to move forward with one of the proposed transmission projects at this time given the magnitude and timing of the potential benefits. This process could be re-initiated in future years if warranted.
- If the NYISO determines that it must or should select a project, we recommend that it reconsider its recommendation of T051 since it does not appear to be the most cost-effective project.
- We recommend that the NYISO provide initial estimates of costs and benefits of generic potential transmission solutions to the PSC to inform future PPTN determinations.

In general, we found the NYISO's methodologies for this assessment are reasonable. However, we identify several methodological enhancements for NYISO to consider in future public policy transmission evaluations. Recommended enhancements are summarized below. Each recommendation is identified with a number indicating the year it was first published and the number it had in that document.

Recommendations for Future Modeling Enhancements

- P23-1: Evaluate capacity benefits of transmission using realistic local capacity requirements to estimate: (a) the avoided cost of generation investment that would otherwise be needed for reliability, plus (b) the economic value of improved resource adequacy.
- P23-2: Model DEFRs (dispatchable emission-free resources) with a range of costs and characteristics to understand how they will affect the future value of new transmission.
- P22-1: Model procurement of ancillary services in production cost models, considering how future needs will be driven by resource mix changes. Consider adoption of different production cost modeling software if needed to accomplish this.
- P22-2: Perform an ‘optimized’ production cost model sensitivity case in which renewable capacity in locations with high marginal rates of curtailment is relocated to locations with lower marginal rates of curtailment.
- P22-3: Improve modeling of energy storage to more accurately estimate the benefits of storage in the capacity expansion and production cost models.[41]
- P22-4: Include options for 2-, 6- and 8-hour storage in the Capacity Expansion Model.
- P19-6: Consider transmission outages and other unforeseen factors in estimating production cost savings.

Recommendations for Transmission Planners (including NYISO, utilities, and State agencies)

- P23-3: Provide additional information on costs and benefits of generic potential transmission solutions in comments to the PSC before its determination of the PPTN.
- P22-5: Estimate the Implied Net REC Cost of proposed regulated transmission projects and compare it to market-based alternatives including merchant battery storage and renewables. This will indicate if the transmission project is a cost-effective means to increase the supply of RECs to load compared to other investments.
- P22-6: Exercise caution when evaluating benefits of transmission projects whose value is strongly linked to uncertain long-term generator-siting decisions.
- P19-2: Estimate O&M costs of new and decommissioned facilities.

Recommendations for Policymakers

- P22-7: Price incremental clean energy from new and existing renewables in a uniform manner so that environmental goals can be satisfied in a more cost-effective manner.

[41] Specifically, we recommend modifying (a) storage costs in the capacity expansion model to offset under-valuation of its benefits due to lower locational and temporal granularity, and (b) the siting and dispatch pattern of storage in MAPS to more realistically minimize renewable curtailment based on market incentives.