Considerations for Selecting the Most Beneficial Proposal in ISO-NE's 2025 LTTP Request for Proposal

PREPARED BY

Johannes P. Pfeifenberger
J. Michael Hagerty
Peter Heller
Linquan Bai

PREPARED FOR

National Grid Ventures (NGV)
Massachusetts Municipal Wholesale Electric Company (MMWEC)
Energy New England Transmission (ENE-T)

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nationalgrid ventures

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Executive Summary

The Independent System Operator of New England (ISO-NE) is currently implementing its first longer-term transmission planning (LTTP) process at the request of the New England States Committee on Electricity (NESCOE).[1] The LTTP process is a major step forward for improving the effectiveness and proactive nature of regional transmission planning in New England by identifying long-term strategic investments that deliver value to New England consumers.

ISO-NE's first LTTP solicitation seeks transmission proposals that increase transfer capability from Maine to southern New England, a long-standing bottleneck identified as a "high-likelihood concern" in ISO-NE's 2050 Transmission Study. NESCOE encouraged developers to propose solutions that increase transfer capability of the required interfaces beyond minimum thresholds and upgrade additional interfaces, such as the Boston import limit, to maximize customer benefits. Transmission developers responded by submitting six proposals that fall into two categories: (1) onshore high-voltage alternating current (HVAC) upgrades between Maine and New Hampshire that meet at least the minimum requirements; and (2) subsea high-voltage direct current (HVDC) links between Maine and the Boston area that provide an expanded scope of upgrades beyond minimum requirements.[2]

After screening the bids to ensure they meet minimum requirements, ISO-NE will evaluate the qualified proposals based on economic benefit metrics and a broad set of additional evaluation factors. This white paper reviews ISO-NE's benefit metrics and additional evaluation factors and recommends enhancements to ensure the LTTP proposals are accurately evaluated so that the selected solution will provide customers with the largest net benefits.

While the ISO-NE developed comprehensive, multi-value benefit metrics, we find that the metrics do not fully capture the value of LTTP proposals and as a result likely introduce a bias against expanded-scope solutions. In particular, several of the quantitative benefit metrics understate consumer benefits, including avoided capital cost of local resources, production cost and congestion savings, and avoided transmission investment.

ISO-NE can improve the LTTP evaluation within its current framework by: (1) supplementing its analysis of the quantitative benefit metrics with additional sensitivity analyses that estimate the missing value of the proposals and (2) giving sufficient weight to the additional evaluation factors when selecting the preferred solution. The improvements we recommend will assist ISO-NE in

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[1] NESCOE, Letter to Al McBride, Vice President, System Planning, ISO New England re Transmission Needs for a Longer-term Transmission Planning RFP, December 13, 2024 ("NESCOE Letter") and D. Schwarting (ISO-NE), Post-NECEC Maine Transfer Limits – Revision 1: Revision to the December 18, 2024, Presentation, December 18, 2024.

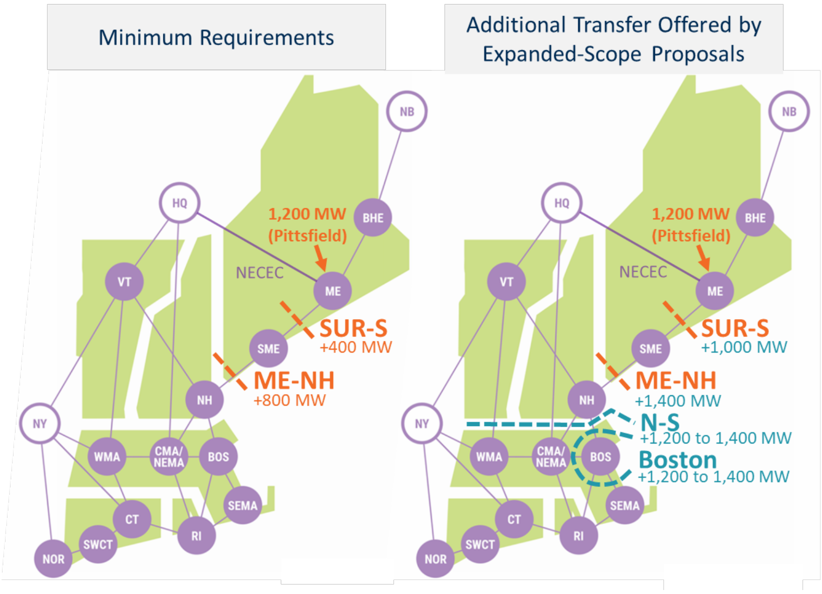
[2] ISO-NE's summary does not identify which projects only meet minimum requirements and which offer an expanded scope, but indicated some only meet (while others significantly exceed) the minimum requirements.

ensuring that the evaluation process results in the selection of the highest-value project for New England consumers consistent with NESCOE's stated objective for this LTTP solicitation.

A. Proposed Solutions and Evaluation Process

In response to a request from NESCOE, ISO-NE initiated the LTTP solicitation to upgrade the Maine-New Hampshire (ME-NH) and Surowiec-South (SUR-S, located in Maine) interfaces and enable at least 1,200 megawatts (MW) of new onshore wind in Maine by 2035.[3] NESCOE's stated goal for this procurement is to "enable proactive, competitive transmission investments that will meet New England's future needs and provide net benefits to New England's consumers."[4] In addition, NESCOE emphasized that the requested scope represents minimum requirements and encouraged developers to pursue an expanded scope such as "increasing Boston import interface capacity" or "enabling additional generation capacity," assuming the incremental benefits of the expanded scope "would be captured by ISO-NE in the LTTP evaluation process."

FIGURE ES-1. MINIMUM REQUIREMENTS AND. EXPANDED-SCOPE PROPOSALS



Qualified transmission developers submitted six proposals to the LTTP solicitation with significantly different scopes as shown in Figure ES-1 and costs ranging from $1 billion to $4 billion. Proposals utilizing onshore HVAC upgrades provide tailored solutions to increase transfer capability of the targeted constraints (ME-NH and SUR-S) to at least the minimum requirements. The subsea HVDC solutions go beyond the minimum requirements by creating a new controllable path into the Boston area that further increases the capability of the targeted constraints, while

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[3] This corridor has been a long-term constraint to accessing lower cost generation resources. ISO-NE studied this corridor through three Maine Renewable Integration Studies that concluded in 2017, 2020, and 2024.

[4] NESCOE Letter, p. 1.

also enhancing two additional interfaces, the North-South (N-S) and Boston Import constraints.[5] Resolving these constraints could unlock additional benefits and address longer-term needs identified in ISO-NE's 2050 Transmission Study in a proactive and holistic manner.

ISO-NE's initial screening of the proposals identified concerns with the design of four proposals, including all expanded-scope projects. This led ISO-NE to release a disqualification notice to the Planning Advisory Committee.[6] ISO-NE indicated they would communicate with developers to clarify the modeling of the proposals and review ISO-NE's analysis, which may result in some of the proposals continuing to the next phase of the evaluation. If ISO-NE were to reject proposals for not meeting the RFP objectives due to minor changes in design, New England could miss an opportunity to develop the most valuable, cost-effective solution for addressing regional needs.[7]

ISO-NE specified a detailed framework for evaluating the value of the proposals that is consistent with its tariff and relies on a combination of quantitative benefit-cost analysis and additional evaluation factors. The quantitative evaluation metrics specified by ISO-NE include: (1) production cost and congestion savings; (2) avoided capital cost of generation resources; (3) avoided transmission investments; (4) reduction of transmission losses (and associated costs); and (5) improved reliability.[8] Based on these benefit metrics, ISO-NE will calculate the 20-year present value of benefits and costs and the benefit-cost ratio (BCR) for each solution.[9] Projects that exceed a 1.0 BCR will then be evaluated based on a combination of the solutions' BCR and the additional evaluation factors.[10] Amongst proposals with a BCR above 1.0, ISO-NE will select the preferred solution, which NESCOE can either accept or reject.

B. Risk of Undervaluing LTTP Solutions

While evaluating the diverse set of proposed LTTP solutions, the primary question for ISO-NE and NESCOE to consider should be which proposal can most cost-effectively meet the region's transmission needs—and not how the LTTP's minimum requirements can be satisfied at the lowest cost. Transmission facilities sized to address multiple system needs are likely to provide

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[5] Interface increases have not yet been verified by ISO-NE but are anticipated based on the scope of proposals.

[6] ISO-NE, Initial Review & RFP Objective Results: Revision to the March 24, 2026 Presentation, presented to Planning Advisory Committee, March 24, 2026.

[7] Attachment K Section 16.4(g) of ISO-NE's tariff: "If the ISO identifies any minor deficiencies in the information provided in connection with a Longer-Term Proposal, the ISO will notify the Qualified Transmission Project Sponsor … and provide an opportunity … to cure the deficiencies. [T]he Qualified Transmission Project Sponsor may not modify its project materially or submit a new project." A determination that minor changes in design are deemed "material" would not be in line with competitive solicitation practices in other regions, undermine the value of the solicitations, and create uncertainties that reduce participation in future solicitations.

[8] ISO-NE, Request for Proposal Longer-Term Transmission Upgrade ("LTTU"), Part 1, March 31, 2025, pp. 2, 16–18.

[9] ISO-NE, 2025 Maine Longer-Term Transmission Planning RFP: Plans and Schedule, January 23, 2025 and ISO-NE Lifecycle Spreadsheet.

[10] R. Collins, P. Boughan, and D. Schwarting (ISO-NE), 2025 Longer-Term Transmission Planning (LTTP) RFP Revision 1: Analysis Details, Revision to the February 26, 2025 Presentation, February 26, 2025, p. 35.

greater savings to consumers, including by avoiding (or significantly deferring) transmission upgrades needed when (or soon after) the selected project is energized.

ISO-NE's LTTP evaluation framework includes a broad set of benefit metrics, but its methodologies risk undervaluing customer benefits, especially for expanded-scope proposals. This could favor minimum-requirement options and result in overlooking more cost-effective or long-term solutions for broader transmission needs. Well-designed metrics are essential to avoid prioritizing lower upfront costs at the expense of higher overall system costs.

For example, the expanded-scope HVDC solutions increase transfer capability on the targeted interfaces as well as the N-S and Boston import interfaces, which likely would further reduce congestion on constrained interfaces and address a broader set of identified 2035 to 2040 transmission needs. Unfortunately, many of these benefits will not be fully captured in the LTTP benefits assessment, including the benefit of avoiding or deferring future transmission needs. In addition, several assumptions in the ISO's economic benefit analysis understate the generation-related value of any increase in transfer capability into the Boston area.

Specifically, three of the benefit metrics included in the calculation of the BCR will significantly understate consumer benefits that disproportionally disadvantage expanded-scope solutions:

- **Avoided Capital Cost of Local Resources.** ISO-NE's capacity expansion model assumptions understate generation cost savings by assuming costs are uniform across New England and overbuilding solar in high-cost regions (e.g., ~20 GW in Massachusetts, including 5 GW in Boston). In reality, 20-30% lower development costs in Maine imply an additional $0.8–$1.8 billion in savings for expanded-scope projects that enable additional north-to-south transfers.
- **Production Cost and Congestion Savings.** The LTTP production cost model understates congestion relief and variable cost savings by simulating only normalized conditions with perfect foresight and no outages, missing high-value stress periods (e.g., cold snaps, heat waves, and transmission and generation outages) when transmission is most valuable. Elevated congestion during the January 2026 cold snap demonstrates this value. Empirical benchmarking suggests these benefits may be understated by roughly 35%.[11]
- **Avoided Transmission Costs.** ISO-NE understates avoided transmission costs by limiting the analysis to near-term projects on the Regional System Plan (RSP), Asset Condition List (ACL), or facilities over 40 years old, excluding substantial 2035-2040 upgrades identified in long-term planning. We estimate that expanded-scope proposals designed to increase N-S and Boston Import capability could defer or avoid at least $1.3 billion in future transmission investments not currently captured in the ISO-NE metric.[12,13]

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[11] R. Kornitsky and E. Ross, 2024 Economic Study: Final Benchmark Scenario Results Publishing of the Public Benchmark Scenario Policy Scenario Assumptions, August 21, 2024, p. 11.

[12] To avoid double counting of transmission- and generation-related benefits, transmission facilities avoided by the solutions would need to be modeled in the "base case" (i.e., system without the solution) and removed in the "change case" (i.e., system with the solution) of the capacity expansion and production cost analyses.

[13] ISO-NE, *2050 Transmission Study*: Technical Appendix, February 13, 2024, p.35.

Additionally, ISO-NE's reliance on a high discount rate of 8.2% and just the first 20 years of benefits and costs (for assets that typically operate for 40-plus years) risks understating total customer savings. Higher-cost, expanded-scope solutions may also deliver larger net benefits even with lower BCRs. Using a high discount rate over only 20 years ignores the long-term growth of benefits and declining costs for transmission facilities with much longer lifespans, understating BCRs by roughly 20% compared to a 40-year sensitivity.

These concerns do not invalidate the LTTP evaluation framework, which quantifies some of the key cost savings provided by transmission projects. Under the framework, however, projects that address a broader set of transmission needs and provide a broader set of benefits are likely to appear less valuable than they are in reality and may not be selected over projects that address only minimum requirements at lower costs—particularly if the additional evaluation factors are not given adequate weight in the evaluation process.

An example illustrates the issue of focusing too heavily on the reported BCR ratio, which may overlook opportunities for larger overall consumer savings. Notably, a higher-cost project with a lower BCR may offer higher savings than a less expensive project with a higher BCR. For example, as shown in Table ES-1 below, a $1 billion project with a BCR of 3.0 offers $3 billion in benefits and net savings of $2 billion, while a $2 billion project with a lower BCR of 2.5 offers $5 billion in benefits and $3 billion in net savings. In this case, selecting the lower-cost project with the higher BCR would leave consumers $1 billion worse off.

TABLE ES-1. NET SAVINGS OF PROJECTS WITH DIFFERENT COSTS AND BCRS

	Total Cost ($)	Total Benefit ($)	Net Savings ($)	BCR
Case A	$1 billion	$3 billion	$2 billion	**3**
Case B	$2 billion	$5 billion	**$3 billion**	2.5

C. Incremental Value of Expanded-Scope Solutions

To identify the most cost-effective LTTP proposal, the evaluation approach needs to accurately capture the value that proposals of various designs offer and appropriately weigh that value against their costs. The proposed expanded-scope solutions provide incremental value to the New England system by addressing the N-S and Boston Import constraints and resilience gaps identified in the ISO-NE long-term studies. More specifically, they reduce or avoid:

- Additional multi-billion-dollar upgrades needed in the 2035–2040 timeframe;
- Congestion across the N-S and Boston Import interfaces;
- Continued exposure to extreme weather price spikes;
- Higher cumulative generation capital costs; and
- Increased operational risk in stressed system conditions.

In addition, the proposed subsea HVDC solutions would:

- Establish a physically separate transmission corridor between Maine and the Boston area;
- Provide directly controllable power flows;
- Supply dynamic voltage support and reactive power;
- Enhance grid performance during extreme contingencies;
- Assist in black-start system restoration;
- Improve winter reliability and fuel security (particularly in the greater Boston area); and
- Reduce congestion costs associated with future construction-related outages by creating a parallel transmission path for power flow.

These attributes of HVDC solutions are not fully captured in the BCR metrics but are increasingly recognized by system operators for their benefits, emphasizing the importance of properly weighting the additional evaluation criteria in the LTTP process. For example, the Ontario Independent Electricity System Operator's (IESO) recommendation of a higher-cost HVDC project into downtown Toronto demonstrates the importance of valuing the additional benefits of enhanced-scope HVDC solutions.[14] Despite higher upfront costs, IESO selected the HVDC option based on the avoidance of extensive onshore upgrades, controllability, ancillary services, least-land-use impact, and enhanced resilience. These types of benefits are also be provided by the expanded-scope HVDC solutions and should be given sufficient weight in the LTTP evaluation.

D. Enhancing the LTTP Evaluation Process

The 2025 LTTP project selection presents an opportunity for New England to strategically invest in a solution that holistically addresses a broader set of system needs. We provide several recommendations to enhance the application of the LTTP evaluation factors and ensure the assessment fully considers proposed projects' full economic, resilience, and system performance benefits, thereby offering the greatest net benefits to consumers.

We recommend that ISO-NE consider enhancing its evaluation process, consistent with the framework already established in the tariff, to better capture the benefits that are not currently quantified (or are understated) in the BCR metrics. Specifically, for project benefits not fully quantified, we recommend that ISO-NE (1) quantify the additional benefits through sensitivity analyses utilizing updated assumptions and (2) give appropriate weights to the specified additional evaluation factors in the selection process to reflect the full value provided by the proposals. Even if the disqualification of all enhanced-scope proposals holds in this solicitation, it is important to understand the potential for underestimating the benefits of LTTP proposals and to consider these recommendations in future LTTP solicitations.

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[14] IESO, *Toronto Integrated Regional Resource Plan*, October 31, 2025, pp. 61–72 and Ontario Newsroom, "Ontario Focused on Economy by Approving New Toronto Transmission Line," News Release, January 7, 2026.

We recommend the following sensitivity analyses to supplement the LTTP evaluation process and more fully quantify the value of the proposals:

1. Identify avoidable transmission costs beyond the RSP list;
2. Value the resilience benefit of an additional transmission corridor;
3. Update the capacity expansion model's capital cost assumptions to account for regional cost differences and recent cost escalation;
4. Update the capacity expansion model's build limits to account for reasonable limitations on new generation development, particularly in the Boston area;
5. Calibrate the production cost model to recent market conditions;
6. Optimize HVDC dispatch to fully capture the value of the expanded-scope solutions;
7. Simulate challenging market and weather conditions when transmission is most valuable;
8. Consider longer-term values with a lower discount rate and longer evaluation horizon;
9. Estimate the value of lower congestion during construction outages; and,
10. Consider the value of facilitating future transmission expansions.

While the LTTP solicitation outcome is poised to enhance reliability and drive economic growth across New England, enhancing the evaluation process will ensure that the project selected delivers the greatest net benefits for New England consumers, addresses the region's broader set of transmission needs, and prepares the region for the future. We also encourage ISO-NE to implement these recommendations for future LTTP solicitations to more accurately assess the benefits transmission investments will deliver to New England.

I. LTTP Solicitation Background

The Independent System Operator of New England (ISO-NE) is completing its first longer-term transmission planning (LTTP)-based solicitation process, the 2025 Longer-Term Transmission Upgrade (LTTU), for procuring transmission capacity in response to a request by the New England States Committee on Electricity (NESCOE) from December 13, 2024.[15] The LTTP framework is a major step in increasing the effectiveness and proactive nature of regional transmission planning in New England as it supplements traditional, near-term reliability-driven transmission planning and creates a process to procure multi-value regional transmission that addresses longer-term needs and broadly benefits the region.[16] Under this framework, NESCOE can request that ISO-NE initiate the process to solicit proposals from Qualified Transmission Project Sponsors (QTPS) to address identified needs for the region.

This first LTTP solicitation is based on ISO-NE's 2050 Transmission Study and other recent analyses,[17] which identified several "high-likelihood concerns" requiring proactive regional transmission investment. Among these concerns, NESCOE prioritized addressing persistent transmission constraints between northern New England (specifically Maine) and southern New England to enhance reliability and enable integration of additional low-cost generation resources to meet demand growth and support the region's policy objectives.

A. LTTP RFP Overview and Requirements

The 2025 LTTU solicitation reflects NESCOE's final requested scope and asks for transmission proposals that will achieve the following by 2035:[18]

- Increase the Maine-New Hampshire (ME-NH) interface capacity to at least 3,000 megawatts (MW);
- Increase the Surowiec-South (SUR-S) interface capacity to at least 3,200 MW;
- Accommodate the interconnection of at least 1,200 MW (nameplate) of onshore wind through a new infrastructure (e.g., substation) at or near Pittsfield, Maine.

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[15] NESCOE letter to ISO-NE, "Transmission Needs for a Longer-term Transmission Planning RFP," December 13, 2024 ("NESCOE RFP Request Letter").

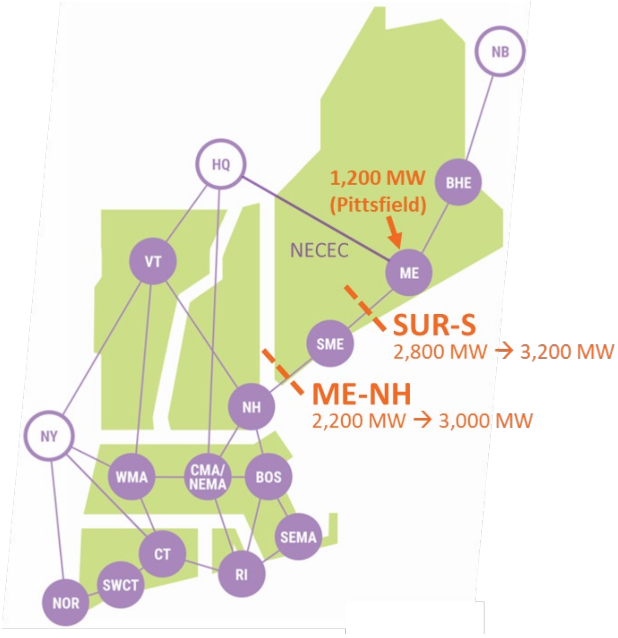
[16] *See* ISO-NE Open Access Transmission Tariff, Attachment K ("Regional System Planning Process"), Section 16.4 ("Competitive Solution Process for Longer-Term Transmission Upgrades").

[17] The NESCOE RFP Request Letter specifically refers to the 2050 Transmission Study (February 2024), the *Economic Planning for the Clean Energy Transition* study (October 2024), and the 2021 Economic Study: *Future Grid Reliability Study Phase I* (July 2022).

[18] NESCOE RFP Request Letter, p. 3.

After the successful completion and commercial operations for the New England Clean Energy Connect (NECEC) transmission line, these interfaces currently have 2,200 MW (ME-NH interface, formerly limited to 2,000 MW) and 2,800 MW (SUR-S interface, formerly limited to 1,800 MW).[19] Consequently, proposed solutions must increase the ME-NH interface by a minimum of 800 MW and the SUR-S interface by a minimum of 400 MW. The targeted interfaces and the RFP's minimum requirements are illustrated in Figure 1.

FIGURE 1. TARGETED INTERFACES AND MINIMUM LTTP REQUEST FOR PROPOSAL (RFP) REQUIREMENTS



Sources and Notes: Base map from ISO-NE's Maps and Diagrams. Transmission interfaces are added in dotted orange lines, based on ISO-NE "Locational Marginal Prices & Interface Flows," April 2017, p. 3. Indicated interface transfer capabilities reflect the existing limits (after NECEC in-service) and the minimum RFP required capability.

These requirements reflect the minimum capability increases that NESCOE expects the proposals to provide; however, NESCOE emphasized in its letter that proposals can, and are encouraged to, propose transmission solutions that exceed the minimum requirements if the expanded scope is cost-effective, given that the "benefits of an expanded scope (for example, increasing Boston import interface capacity, enabling additional generation capacity, or other scope expansions suggested by some commenters) would be captured by ISO-NE in the LTTP evaluation process."[20] Additional ISO-NE future regional transmission needs, such as those specified in ISO-NE's 2050 Transmission Study, are briefly summarized in below in Section I.C.

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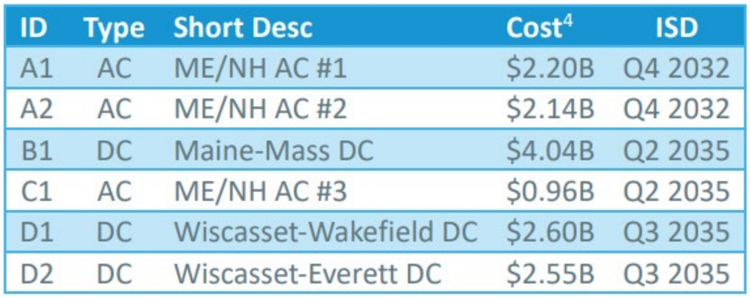
[19] ISO-NE, "Impacts of Updated Maine (ME) Interface Transfer Limits to Transmission Transfer Capabilities," April 29, 2025, p. 7.

[20] NESCOE RFP Request Letter, p. 3.

QTPS Respondents submitted six proposals that include both onshore alternating current (AC) upgrades and subsea high-voltage direct current (HVDC) solutions, ranging in installed costs from $1 billion to $4 billion as shown in ISO-NE's summary table below.[21] The onshore AC upgrades provide tailored solutions that increase transfer capability of the two targeted constraints (ME-NH and SUR-S) to meet at least the minimum required levels, at capital costs ranging from $960 million to $2.2 billion. The three HVDC proposals (capital costs ranging from $2.55 billion to $4.04 billion) are primarily subsea transmission lines connecting Maine and the Boston area, which provide an expanded scope of upgrades beyond the minimum requirements.[22]

TABLE 1. SUMMARY OF 2025 LTTP PROPOSALS RECEIVED



ID	Type	Short Desc	Cost[4]	ISD
A1	AC	ME/NH AC #1	$2.20B	Q4 2032
A2	AC	ME/NH AC #2	$2.14B	Q4 2032
B1	DC	Maine-Mass DC	$4.04B	Q2 2035
C1	AC	ME/NH AC #3	$0.96B	Q2 2035
D1	DC	Wiscasset-Wakefield DC	$2.60B	Q3 2035
D2	DC	Wiscasset-Everett DC	$2.55B	Q3 2035

Source: 2025 LTTP RFP Longer-Term Proposal Summary, p. 7.

All six of the proposals claim to support 1,200 MW of onshore wind injection in Northern Maine and meet the minimum requirement to increase the ME-NH interface capacity to 3,000 MW and the SUR-S interface to 3,200 MW. Some of the proposals claim to exceed these minimum requirements, with limits ranging up to 3,600 MW for the ME-NH interface and up to 3,800 MW for SUR-S. With injection into the NEMA/Boston area, the three HVDC proposals will provide additional benefit to the region by upgrading the N-S and Boston Import limits in the 1,200 MW to 1,400 MW range (consistent with the proposed HVDC transmission capability and as indicated by ISO-NE's summary of proposal B1 including a parallel, controllable HVDC line with expected delivery of 1,200 MW).[23] The HVDC lines additionally create a new transmission corridor between central Maine and the Boston area, increase system resilience, and offer operational benefits of HVDC technology. Figure 2 illustrates the minimum required interface increases and the additional increases to interfaces across the region provided by the "expanded-scope" proposals.

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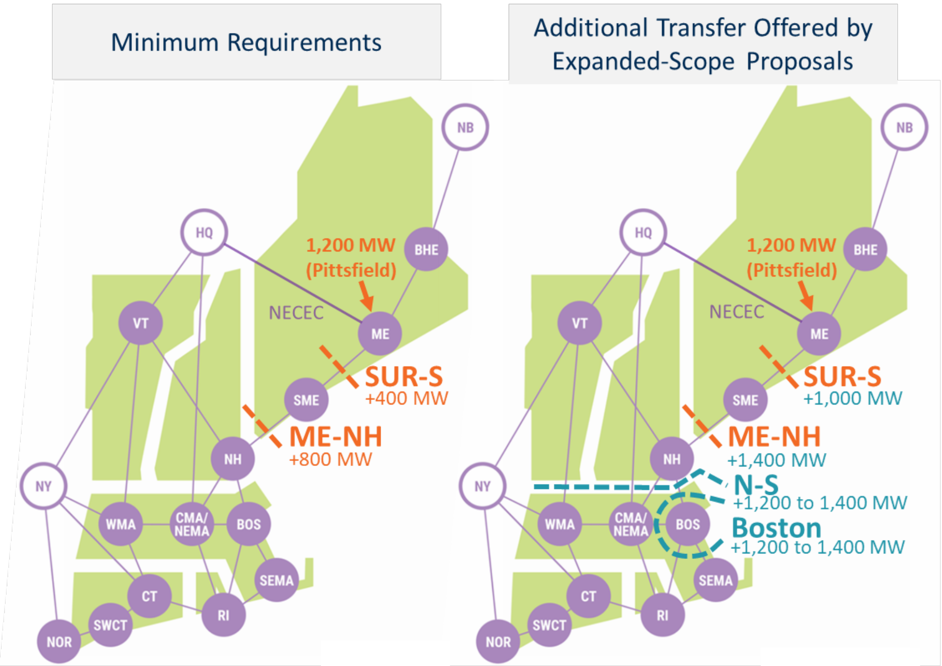
[21] ISO-NE, "Longer-Term Proposals Summary," Rev. 1, December 5, 2025, Table 1 ("2025 LTTP RFP Longer-Term Proposal Summary"), p. 7. Note that ISO-NE identified that some proposals included corollary upgrades, which will instead be replaced by estimates provided by the transmission owner's modification to existing equipment.

[22] *Id.*

[23] ISO-NE, "Longer-Term Proposals Summary," December 5, 2025, p. 15. Note that the HVDC solutions will also increase the Northern New England Scobie Interface, which has been congested during the recent cold snap.

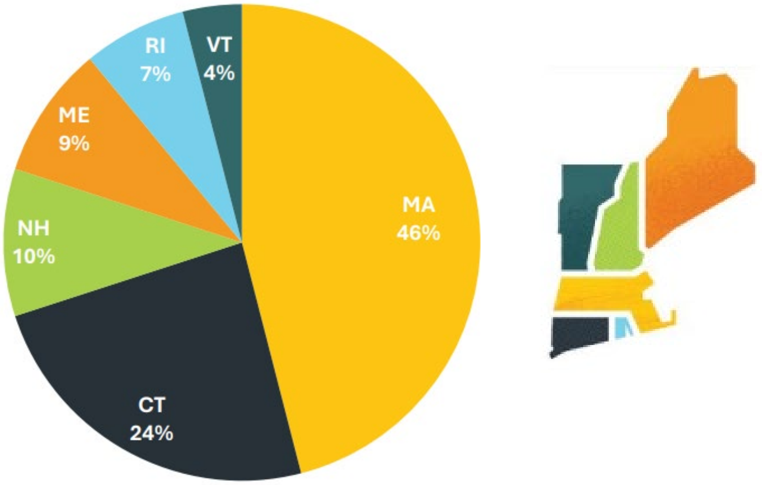
FIGURE 2. INTERFACE UPGRADES: MINIMUM RFP REQUIREMENTS VS. EXPANDED-SCOPE PROPOSALS



Sources and Notes: Base map from ISO-NE's Maps and Diagrams. Transmission interfaces based on ISO-NE, "Locational Marginal Prices & Interface Flows," April 2017, p. 3. The orange interfaces and MW values represent targeted interfaces and the minimum increase of capability required by the RFP. The teal interfaces and MW values represent the range of increased interface transfer capabilities resulting from some of the six proposals. Increases on the SUR-S and ME-NE interfaces are derived from ISO-NE's Longer-Term Proposals Summary, p. 7. The range of increases on the N-S and Boston interfaces are estimated based on ISO-NE's summary of proposals in which a parallel, controllable HVDC line has an expected delivery of "at least 1,200 MW" and typical capacity of 320kV and 400kV HVDC lines.

The transmission costs for the project selected by ISO-NE in this LTTP RFP will be allocated on a regional basis, with costs shared among all New England states proportional to their electricity demand (load share), unless NESCOE proposes alternative cost-sharing structures. The default allocations (based on 2024 load shares) are shown in Figure 3 below. While the LTTP RFP addresses transmission constraints located in Maine and the ME-NH border, the chart shows that Maine would be allocated approximately 9% of total project costs while Massachusetts and the rest of southern New England would be allocated over 75% of total costs.

FIGURE 3. DEFAULT LTTP TRANSMISSION COST ALLOCATIONS



Source: ISO-NE, Overview of Transmission Planning, July 17, 2025 p. 15.

B. ISO-NE's LTTP Evaluation of Proposals

To select a preferred longer-term solution, consistent with NESCOE's request and ISO-NE's Open Access Transmission Tariff (the Tariff), ISO-NE specified a clear and broad set of quantitative metrics and additional evaluation criteria. ISO-NE will evaluate each proposal based on:

- Confirmation that the proposal meets the RFP's minimum requirements using steady state thermal and voltage, stability, and short circuit analyses and a transfer analysis to test minimum interface capabilities;
- Economic analyses that quantify specified benefits of the proposals and estimate a benefit-to-cost ratio (BCR);
- Additional evaluation factors for proposals with a BCR above 1.0 (specified in Attachment A of NESCOE's RFP request as a prioritized list of the factors listed in Attachment K of the Tariff).

During the March 2026 Planning Advisory Committee meeting, ISO-NE communicated to stakeholders concerns with the design of four of the six LTTP proposals received, including all of the expanded-scope HVDC links, that led to an initial disqualification notice.[24] ISO-NE indicated they would further communicate with the developers to clarify the design of the proposals and review ISO-NE's analysis, the outcome of which may allow some or all of the proposals to continue through the LTTP evaluation.[25] If ISO-NE were to reject proposals for not meeting the

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[24] ISO-NE, Initial Review & RFP Objective Results: Revision to the March 24, 2026 Presentation, Presented to Planning Advisory Committee, March 24, 2026.

[25] We understand that, based on discussions between stakeholders and ISO-NE staff during the March 2026 Planning Advisory Committee (PAC) meeting, ISO-NE stated that it would provide detailed study data to each QTPS upon request for the specific stage gate at which the project did not advance. This information establishes

Continued on next page

RFP objectives due to the need for minor changes in their design, ISO-NE, NESCOE, and New England ratepayers could miss an opportunity to understand the value that expanded-scope proposals could offer and, as a result, miss selecting and developing the most valuable transmission solutions.[26] For the purpose of the following analyses and discussions, we thus assume that at least one of the expanded scope proposals will continue to be evaluated further.

As part of the next steps in its evaluation, ISO-NE will calculate a BCR for each proposal to determine which are eligible to be considered for the preliminary preferred solution. The BCR methodology employed by ISO-NE for the RFP evaluation will consider five types of cost savings and reliability benefits, reflecting the extent to which the solution will:[27]

1. Reduce congestion and the variable costs to produce electricity ("production cost and congestion savings")
2. Reduce the generation capital costs of resources needed to meet projected loads ("avoided capacity cost of local resources needed to serve demand")
3. Avoid transmission costs associated with the RSP and ACL and replacement of aging infrastructure ("avoided transmission investment")
4. Reduce transmission losses ("reduction in energy losses")
5. Improve resource adequacy by reducing the region's expected unserved energy (EUE) ("reduction in EUE").

The primary analytical tools to quantify these benefit metrics include an ISO-NE capacity expansion model, an ISO-NE nodal production cost model, and an ISO-NE resource adequacy model. Benefits and costs will each be calculated over a 20-year evaluation horizon beginning with a project's in-service date.[28] Separate from the models, ISO-NE will calculate an avoided transmission investment benefit to the extent a proposal eliminates or defers projects already identified on the RSP list, replaces assets on the ACL, or rebuilds equipment likely to require replacement due to age (defined as assets over 40 years old by 2035).

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a defined, if limited, reconsideration path under which projects may re-enter the evaluation process if the modeling issues identified by ISO-NE can be resolved without material modifications to the submitted bid.

[26] Section 16.4(g) of Attachment K of ISO-NE's tariff specifies that "[i]f the ISO identifies any minor deficiencies in the information provided in connection with a Longer-Term Proposal, the ISO will notify the Qualified Transmission Project Sponsor … and provide an opportunity … to cure the deficiencies … [However,] the Qualified Transmission Project Sponsor may not modify its project materially or submit a new project." A determination that even minor modifications in the design are deemed "material" would not be in line with competitive transmission solicitation practices in other regions. Disqualifying proposals for even immaterial necessary changes in their design would undermine the value of the solicitations and create uncertainties that would likely reduce the willingness of developers to participate in future LTTP solicitations.

[27] ISO-NE RFP Section 1.3 ("Financial Benefits"), p. 2.

[28] For a description of the benefit calculations, see ISO-NE RFP Section 4.4 ("Benefit to Cost Ratio Calculation of the Longer-Term Proposals"), p. 16.

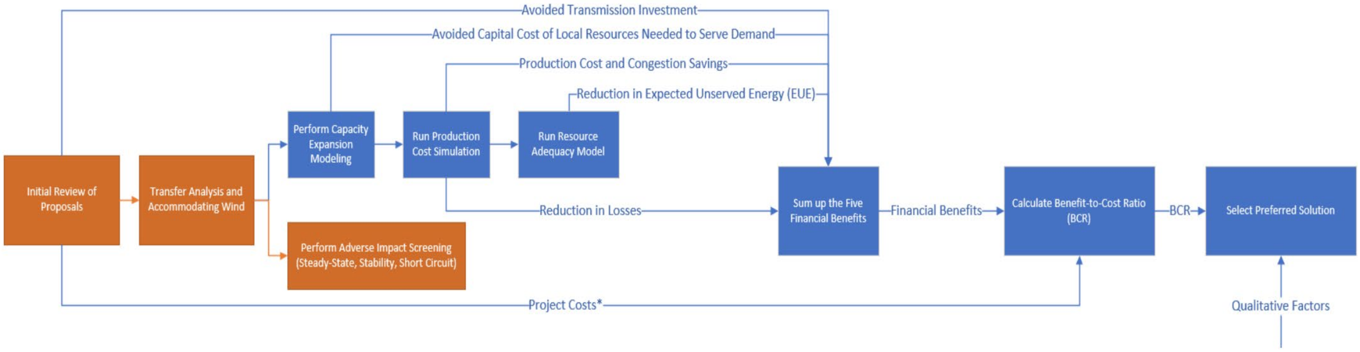
The ISO-NE's capacity expansion model is a zonal, long-term planning model that selects new generation and energy storage resources to meet load growth and state emissions requirements at least total system cost. Transmission upgrades are represented as increases in interzonal transfer capability, and projects that enable access to lower-cost resources reduce future generation build and fixed costs. The resulting difference in capital costs between pre- and post-project systems is used to calculate avoided local resource capital costs.

Production cost impacts are evaluated using the ISO-NE's full nodal model that simulates regional system operations for two individual years (2035 and 2050) to minimize total operating costs including fuel, emissions, startup costs, variable costs, and penalties for unserved energy. The model explicitly represents proposed transmission upgrades and calculates production cost and congestion savings, as well as reductions in system losses.

Resource adequacy impacts are assessed using ISO-NE's zonal Monte Carlo model that simulates forced outages across multiple weather years to estimate EUE. Reductions in EUE attributable to increased transmission capability are monetized using an assumed value of lost load ($3,500/megawatt hour, MWh).[29] ISO-NE notes that EUE-related benefits are expected to be small relative to production cost and capacity expansion benefits.

To determine a proposal's BCR, a 20-year horizon is used, meaning that the present value of the quantified benefits and the present value of the annual revenue requirements for the first 20 years of the project's life will be used.[30] The discount rate used to calculate the present value is 8.2%.[31] ISO-NE will produce an independent verification of cost estimates provided by each proposal to be used in the BCR calculation.

ISO-NE has summarized its evaluation process as follows:



Source: ISO-NE, "2025 Longer-Term Transmission Planning (LTTP) RFP, Revision 1," February 26, 2025, p. 6.

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[29] ISO-NE, "2025 Longer-Term Transmission Planning (LTTP) RFP Revision 1: Analysis Details," February 26, 2025, p. 29.

[30] ISO-NE RFP Section 4.4 ("Benefit to Cost Ratio Calculation of the Longer-Term Proposals"), fn 24–25, pp. 16–17.

[31] ISO-NE, 2025 Maine Longer-Term Transmission Planning RFP: Plans and Schedule, January 23, 2025 and ISO-NE Lifecycle Spreadsheet (found in ISO-NE RFP zip file).

For projects that produce a BCR greater than one, ISO-NE will select the preferred solution based on a combination of the BCR and the twenty additional evaluation factors listed in Table 2 below.[32] These factors are based on Attachment K of the Tariff, but NESCOE included three additional factors and grouped the criteria by priority (highest, second, and third) for ISO-NE when evaluating proposals. ISO-NE has indicated that "[n]o quantitative weighting or scoring factors will be used for these evaluation factors; instead, the overall performance of a Longer-Term Proposal on all evaluation factors will be considered holistically along with the quantitative analysis of the proposal's financial benefits."[33]

As discussed later in this whitepaper, it is important that the additional evaluation factors are considered in a way such that the preferred proposal selected provides the greatest consumer benefit, especially if the quantified benefits do not fully capture the true benefit of projects.

TABLE 2. ADDITIONAL EVALUATION FACTORS, AS PRIORITIZED BY NESCOE

A Factors—Highest Priority	B Factors—Second Priority	C Factors—Third Priority
Life-cycle cost	Extreme contingency performance	Project constructability
Cost cap or containment provisions	Impact on interface limits other than those in scope	Generation and transmission facility outages during construction
Siting/permitting issues or delays	Operational impacts	Incremental cost for potential resource retirements
Future expandability	Winter reliability impacts	Consistency with Good Utility Practice
In-service date	Environmental impact	Design standards
QTPS capabilities		Joint proposals
System performance		Deployment of advanced transmission technologies
Impact on NPCC Bulk Power System (BPS) classification		

Sources and Notes: These criteria and their ranking are provided in ISO-NE's RFP Appendix A ("Evaluation Factors") publishes as part of ISO-NE's RFP on March 31, 2025. They have the same criteria and priority groupings as those in NESCOE's attachment A to the letter requesting that ISO-NE initiate the RFP.

C. ISO-NE's Longer-Term Transmission Needs

The proposed LTTP solutions can support several key near-term and longer-term needs in the ISO-NE system beyond the minimum RFP requirements, as encouraged by NESCOE. While the 2025 LTTP solicitation is anchored in addressing a specific set of transmission constraints, it should not be viewed as a one-off procurement or evaluated in isolation from the broader longer-

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[32] ISO-NE, "2025 Longer-Term Transmission Planning (LTTP) RFP Revision 1: Analysis Details," February 26, 2025, p. 35.

[33] ISO-NE, "Request for Proposal Longer-Term Transmission Upgrade (LTTU) Part 1 – Appendix A: Evaluation Factors," March 31, 2025, p. 1.

term system needs. In fact, the LTTP framework is expressly designed to consider how transmission investments approved now can advance broader system-wide objectives and reduce the need for future and potentially more costly upgrades. As a result, selection of an LTTP solution should be informed by how well it positions the system to address the known and emerging needs identified in ISO-NE's longer-term planning studies beyond the minimum requirements of the RFP.

The 2025 LTTP solicitation is primarily focused on increasing access to lower-cost generation resources located in Maine and improving the deliverability of those resources across the constrained SUR-S and ME-NH interfaces. The ISO-NE 2050 Transmission Study identified the ME-NH interface as a high-likelihood concern, driven by a combination of thermal overloads and transfer limitations that were observed under multiple future scenarios. These constraints were most pronounced during winter peak conditions and were precipitated by large volumes of renewable generation flowing from "relatively generation-heavy and light-load areas in Maine and New Hampshire into the high-load areas in southern New England."[34] Addressing these north-to-south transfer constraints is therefore a central objective of the LTTP solicitation and an important step toward enabling the region's future resource mix at least cost to consumers.

Importantly, however, the 2050 Transmission Study also identified additional longer-term transmission needs in New England, including the need for increased capability between Northern into Southern New England and into the Greater Boston area by 2035.[35] Southern New England hosts a number of critical load centers characterized by limited local generation, increasing electrification-driven demand, and growing reliance on imports across constrained transmission paths that include the North-South (N-S) and Boston Import interfaces. The expanded-scope HVDC proposals submitted in response to the RFP go beyond the minimum requirements by increasing not only the SUR-S and ME-NH interfaces but also adding transfer capability into Southern New England across the broader N-S interface and the Boston Import interface. These expanded-scope RFP responses therefore address the multiple 2035–2040 transmission needs already identified in ISO-NE's longer-term studies with a single, integrated investment as encouraged by NESCOE.

With the addition of the NECEC and additional generation development in Maine, increasing transfer capability beyond minimum requirements is likely to be very valuable to the broader New England market, particularly during challenging system conditions. As shown in Figure 4 for the recent January 2026 cold snap, real-time congestion on the ME-NH interface was over $200/MWh (purple line) for several hours, limiting low-cost exports from Maine to the rest of the New England market. Congestion between New Hampshire and southern New England (blue line) illustrates that interfaces beyond those targeted by the RFP are starting to constrain power flows from moving beyond New Hampshire. We expect congestion on these interfaces to become more significant with the development of additional wind resources in Maine and the upgrades of the targeted interfaces.

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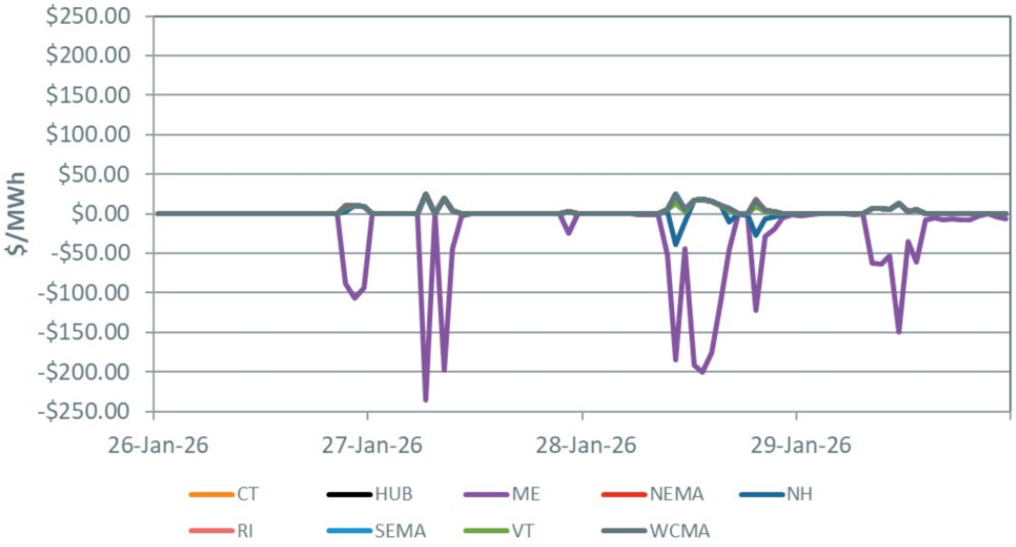
[34] ISO-NE, "2050 Transmission Study," February 12, 2024, p. 22.

[35] *Id.*, p. 23.

In addition to improving access to lower-cost generation, expanded-scope LTTP solutions may deliver broader system benefits that merit consideration in ISO-NE's evaluation. These include reducing congestion and reliability risks associated with Boston import constraints, supporting emissions reductions by enabling greater utilization of low-carbon resources, and limiting the hours in which high-cost, local resources must be dispatched during times of critical system stress.[36] Additionally, by increasing the system's ability to import energy during periods of fuel scarcity, certain LTTP solutions can help mitigate the cost impacts of natural gas price spikes, particularly during winter peak conditions when New England has historically experienced elevated energy prices and reliability risks. Collectively, these benefits underscore the importance of evaluating LTTP proposals through the lens of how effectively they advance ISO-NE's longer-term transmission needs and deliver durable value to New England ratepayers.

FIGURE 4. REAL-TIME CONGESTION OF ISO-NE PRICES DURING JANUARY 2026 COLD SNAP



Source: ISO-NE, "Mid-Week Market Update," n.d.

II. Assessment of Proposed Evaluation Criteria

ISO-NE's prespecified evaluation criteria, summarized above, are clear and cover a broad set of benefits of transmission upgrades. However, the central question for the evaluation phase of the LTTP process is whether ISO-NE's quantitative benefit metrics and additional evaluation criteria will fully capture the value of proposals that address significantly different scopes, including lower-cost onshore AC solutions tailored to the minimum requirements and higher-cost subsea HVDC solutions that provide an expanded scope of upgrades. If the evaluation framework understates the benefits associated with higher-cost expanded-scope solutions, the selection

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[36] NESCOE explicitly requested that ISO-NE "quantify any carbon reductions associated with proposals" at fn 11 in the NESCOE RFP Request Letter.

process may inadvertently favor lower-cost proposals that satisfy minimum thresholds but forgo opportunities to avoid larger downstream investments and operational risks.

Based on our review of ISO-NE's evaluation framework, the proposed benefit metrics and additional evaluation factors risk undervaluing the benefits of all proposals, and particularly expanded-scope proposals, which would bias the selection toward minimum-threshold LTTP proposals. ISO-NE will consider additional evaluation factors beyond the quantitative BCR metric; it is unclear the weight that the BCR will carry relative to additional evaluation factors in selecting the preferred solution. Unless understated quantitative benefit metrics are recognized and the additional evaluation factors are weighted appropriately, the evaluation framework risks favoring lower-cost solutions that provide a narrower set of total benefits while not fully recognizing that broader (but more expensive) solutions may provide higher long-term benefits.

The first step of calculating the BCR based on the five specified metrics will capture multiple benefits that the long-term transmission proposals may provide to consumers in the region. However, the BCR methodology, and other evaluation criteria (as further discussed below), will likely result in understated quantified consumer benefits relative to the actual benefits that proposed projects would likely provide. Consequently, ISO-NE and New England policymakers should consider proper weighting and possible reprioritization of the additional evaluation factors to account for unquantified benefits. Doing so would be necessary to ensure the selection of a proposed solution that most cost-effectively addresses the region's longer-term needs and maximizes the economic, resilience, and strategic value to produce the highest cost savings to New England ratepayers.

The understatement of quantified benefits creates the potential for two unintended consequences for the evaluation process:

- The premature rejection of proposed solutions with ISO-NE-calculated BCRs below 1.0, even when a more complete accounting of benefits would yield a BCR well above that; and
- A selection process that is biased toward lower-cost projects, which meet the minimum RFP requirements but do not provide cost-effective opportunities to address New England's broader set of transmission needs.

Importantly, an understatement of benefits does not affect all proposals equally. The risk is most acute for proposals that exceed the RFP's minimum requirements by providing expanded scope and higher performance across multiple critical interfaces to address the regions longer-term needs, as encouraged by NESCOE. Projects with a larger scope and higher upfront cost are likely to generate benefits that are only partially captured by the specified benefit metrics and BCR framework, such as avoided future transmission investments beyond those on the RSP list, expanded interface capability, enhanced resilience, or operational flexibility. When only a portion of these benefits is quantified and quantitative benefit metrics understate the actual value of the projects, the missing value tends to disadvantage a larger project more than a smaller project. Doing so then risks biasing the selection towards smaller projects, unless the benefits not quantified are fully considered through additional sensitivity analyses or appropriately weighted additional evaluation factors.

The example shown in Table 3 illustrates this point. Suppose that there are two proposed solutions: a lower-cost $1 billion project that meets the minimum requirements (Project A) and a higher-cost $2 billion project that exceeds minimum requirements and provides greater consumer cost savings by addressing additional, and in some cases longer-term, needs (Project B).

As the table shows, the benefits for Project A have been quantified as $2 billion for a calculated BCR of 2.0. The quantified benefits for Project B are $3.5 billion for a BCR of 1.75. If project selection were based solely on the calculated BCR, the approach would select Project A with the higher BCR. Note, however, that Project A offers calculated net consumer benefits of only $1 billion ($2 billion in quantified benefits less $1 billion in costs), while Project B offers net consumer benefits of $1.5 billion ($3.5 billion in quantified benefits less $2 billion in costs). Thus, even relying on calculated net benefits, Project B would offer higher consumer benefits than Project A, despite the fact that the smaller Project A offers a higher benefit-cost ratio.

TABLE 3. ILLUSTRATIVE EXAMPLE OF IMPORTANCE OF ACCURATELY QUANTIFYING BENEFITS

Project	PV Revenue Req. ($b)	PV Quantified Benefit ($b)	Calculated BCR	Actual Benefit Understated by	PV Actual Project Benefit ($b)	Actual BCR	Actual Net Benefit ($b)
A	1	2	**2.0**	25%	2.5	**2.5**	**1.5**
B	2	3.5	**1.75**	42%	5.0	**2.5**	**3.0**

Now assume that actual project benefits exceed quantified benefits as indicated by the orange column in Table 3. As shown in the right half of the table, the actual benefit offered by Project A is $2.5 billion, which means the quantified benefits are understated by 25%; and assume Project B offers an actual benefit of $5 billion because quantified benefits are similarly understated and additional benefits not quantified at all, with a result that quantified benefits understate actual benefits by about 40%. This consideration of additional benefits not quantified by the specified metrics would mean both projects offer an "actual benefit-cost ratio" of 2.5—and a result in which the $3 billion in "actual net benefits" of Project B are double the net benefits of Project A. The results highlighted in the two red circles, Project B offers twice the net benefits (i.e., $3 billion vs. only $1.5 billion) even though the calculated BCR is higher for Project A.[37]

The example shows that selection solely based on calculated BCR does not reliably select the project that offers the highest consumer benefit. This dynamic may mirror the LTTP portfolio, where several higher-cost HVDC options with broader scope may yield larger absolute net benefits despite lower calculated BCRs.

While the evaluation process ISO-NE will use for the evaluation of the received proposals is not based solely on the calculated BCR but includes additional qualitative considerations, the above

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[37] Also note that enhanced-scope projects can offer larger consumer savings even if their BCR is lower. For example, a $1 billion project with a BCR of 3.0 offers $3 billion in benefits and net savings of $2 billion, while a $2 billion project with a BCR of 2.5 offers $5 billion in benefits and $3 billion in net savings. In this case, selecting the lower-cost project with the higher BCR would leave consumers $1 billion worse off.

example illustrates that it is important to consider beyond the BCR both (1) the absolute size of quantified benefits (rather than just the BCR) as well as (2) the likely magnitude of benefits understated and not quantified at all. The first consideration is important because even if two projects have the same BCR, the larger scope project will offer larger consumer savings. If the latter is considered only qualitatively, as is the case in the LTTP evaluation, it is important that the weight attributed to the qualitative consideration is roughly consistent with the likely magnitude of the unquantified benefits.

In other words, while both Projects A and B of the example would meet the threshold of BCR greater than one for consideration, the process risks selecting Project A even though Project B would provide larger net benefit and associated cost savings to consumers in the region.

Even if the full magnitude of actual benefits cannot be easily quantified, placing additional weight on the additional evaluation factors that produce the additional benefit (e.g., system performance, future flexibility, etc.) can ensure that more expensive projects that provide these additional benefits are not dismissed inadvertently in the selection process. The recent recommendation of an HVDC project into downtown Toronto by the Ontario IESO provides a useful example of how added benefits and qualitative evaluations for larger, higher-cost solutions can be considered in the preferred solution selection and is discussed as a case study in Section V.B.3 of this report.

This issue is particularly relevant in the current LTTP solicitation, where several bidders proposed solutions that materially exceed the minimum RFP requirements. As ISO-NE has noted, multiple RFP responses claim to increase transfer capability of the ME-NH interface to 3,600 MW, compared to the minimum 3,000 MW, and to increase the SUR-S interface to 3,800 MW, compared to the minimum 3,200 MW requirement. In addition, three proposals include HVDC transmission lines that also increase the N-S and Boston interface limits while providing additional operational and regional resilience benefits relative to the other proposals. However, to the extent ISO-NE's benefit metrics and BCR methodology do not fully capture the consumer benefits associated with expanded-scope proposal, the selection process risks rejecting solutions that offer the largest net benefits to the region's consumers. To avoid such an outcome, the absolute size of net benefits will need to be considered in addition to the BCR and the unquantified portion of consumer value must at least be reflected through the qualitative evaluation framework and assigned sufficient weighting to avoid biasing the selection toward narrower, lower-cost solutions.

III. Understated ISO-NE Consumer Benefit Metrics

ISO-NE has specified in the RFP document how it will evaluate the cost savings and other benefits of the submitted proposals that meet minimum RFP requirements—first by calculating the BCR for each proposal using five benefit metrics and then considering additional evaluation factors for proposals with a BCR above 1.0. The BCR is a central quantitative metric in the ISO-NE's evaluation of LTTP proposals and is thus expected to play a decisive role in identifying the preferred solution. If material categories of benefits are understated in the quantified metrics or not quantified at all, the resulting benefit-cost analysis risks biasing the process towards smaller, less expensive projects as shown in Section II above. Understating the quantified benefits potentially limits which solutions are further evaluated based on the additional evaluation factors, many of which could provide significant benefits to consumers, and will tend to favor lower cost solutions that provide less net benefit and are less advantageous to the region. Therefore, this section explores the extent to which the quantified metrics might be understating benefits (possibly even rejecting beneficial projects).

After reviewing ISO-NE's five quantitative benefit metrics and approach to calculating the BCR, we have identified three metrics that will significantly understate the actual consumer benefits of the proposed projects. The understated metrics include: (1) avoided generation capital costs, (2) production cost and congestion savings, and (3) avoided transmission investment. Understatement of these metrics risks the selection of a solution that may not provide the greatest net benefits and overall cost savings for consumers in New England—unless the extent to which these metrics are understated are captured in the prioritization of the additional evaluation factors. In addition, (4) the BCR calculated based on ISO-NE's 20-year horizon for determining the present values of benefits and costs will understate the true benefits-cost ratio that the proposed transmission projects offer over their much longer useful life.

A. Understated Avoided Capital Costs of Local Generation Resources Needed to Serve Future Loads

ISO-NE will identify the avoided capital costs of the local generating resources needed to serve future demand as one of the primary benefits to be quantified in its evaluation of the proposed transmission solutions. This metric captures the cost savings that the transmission upgrades provide by allowing access to lower capital cost resources further from load centers. To quantify this avoided capital cost benefit metric, ISO-NE is utilizing a capacity expansion model that allows for shifts in generation resource types to lower-cost locations as enabled by the proposed transmission projects.[38] For the current LTTP solicitation, this benefit is particularly important because several proposals materially increase N-S transfer capability and deliver power into

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[38] We understand that the capacity expansion model builds resources in annual blocks, year-by-year, with the objective function of minimizing the present value of total costs in each year. This appears to mean that each year's investment decision is not looking forward to future years, which would mean that the capacity buildout is not necessarily efficient from a long-term perspective—although we do not further pursue this concern within the scope of this whitepaper. *See* ISO-NE, "2024 Economic Study: Final Benchmark Scenario Results," presentation by Richard Kornitsky and Elinor Ross, August 21, 2024, p. 28.

constrained areas such as Greater Boston, where local generation development is expected to be more expensive.

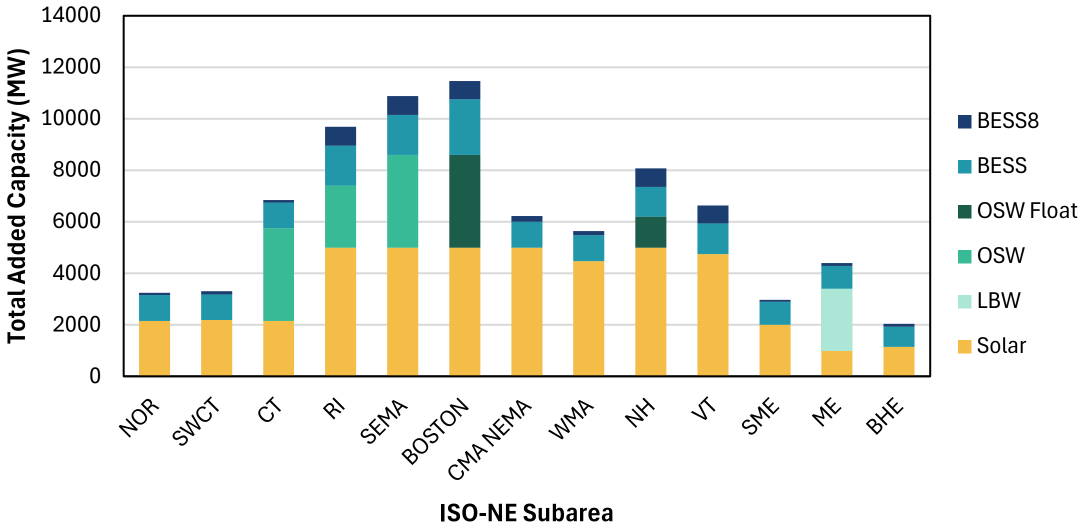
Accurately reflecting future market conditions in the capacity expansion model is essential to quantifying the benefits of the proposed transmission solutions. Based on our review, the assumptions used in ISO-NE's capacity expansion simulations will yield results that significantly underestimate the value of projects that increase transfer capacity between northern and southern New England, specifically solutions that increase transmission capacity into the congested Boston area. This understatement in capital costs savings is due to three factors.

1. ISO-NE's cost assumptions for generation technology do not appear to vary across the ISO-NE footprint. This means the assumptions do not reflect the value of transmission proposals that allow for shifting more new resource additions to lower-cost locations, such as Maine, which are generally further from load centers. This is especially important for the proposals that offer larger upgrades to the region's north-to-south constraints, including into Boston where solar development costs will be especially high.
2. The ISO-NE evaluation approach assumes that up to 45,000 MW of solar generation could be developed across the region, with up to 5,000 MW in each ISO-NE zone (including the Boston area). This assumption allows the capacity expansion model to build 20,000 MW of solar generation additions in Massachusetts. This is likely an unrealistic outcome that will tend to understate the cost savings offered by the proposed upgrades to the interfaces in Maine and New Hampshire as well as, for some of the proposals, from northern New England into southern New England and Boston.
3. The assumed capital costs of new generation technologies are based on 2024 cost assumptions. Capital costs have increased significantly since these assumptions were set, which would result in understated avoided capital costs of the evaluated proposals.

As a result of these three types of modeling assumptions, the avoided capital costs quantified using ISO-NE's model will almost certainly understate the true value of enabling increased generation development in northern New England (specifically Maine) and reducing the need for higher-cost local resources in southern New England and specifically the Boston area. **We conservatively estimate that the total avoided capital cost benefit risks will be understated by at least $0.8–1.8 billion for larger-scope projects that increase transfer capability between southern and northern New England beyond the minimum requirements**.

To provide more detail on the ISO-NE capacity expansion model, we note that the base capacity expansion model made available by ISO-NE (before any proposals are modeled) shows that there is an 81 gigawatt (GW) projected build out of renewable and storage resources across New England by 2050 to meet future state renewable energy and GHG emissions policies. Figure 5, below, shows the 2035 to 2050 capacity expansion results by ISO-NE subarea based on this ISO-NE-provided base case.

FIGURE 5. BASE CASE CAPACITY EXPANSION RESULTS BY ISO-NE SUBAREA FROM 2035 TO 2050



Sources and Notes: The capacity buildout was provided to Brattle by National Grid Ventures from the base case provided by ISO-NE in the public model version released for this RFP. These values are the sum of resources expected to be constructed in each subarea between 2035 and 2050 in the ISO-NE capacity expansion model. BESS: Battery Energy Storage System; OSW: Offshore Wind; LBW: Land-Based Wind.

As shown, the majority of new generation capacity built between 2035 and 2050 is solar (over 45 GW) and battery storage (over 20 GW) with 14 GW of offshore wind (OSW) and 2 GW of Maine land-based wind (LBW). ISO-NE set the same limit on solar builds for all zones in its capacity expansion model (5 GW per zone) regardless of the ability to build that amount of solar in each zone. For example, the ISO-NE base case (without the proposed transmission upgrades) assumes the development of 5,000 MW solar generation in the Boston, Central/Northeastern Massachusetts, New Hampshire (including eastern Vermont and southwestern Maine), Rhode Island, and Southeastern Massachusetts subareas. The western and central Maine (including Saco Valley, New Hampshire) and northeastern Maine subareas have the lowest expansion of solar capacity, with only around 1,000 MW each.

Building more resources in southern New England in the capacity expansion model will undervalue transmission upgrades that provide access to lower-cost resources in Maine. The capacity expansion model preference for building solar in Massachusetts and the rest of southern New England indicates that the ISO-NE model does not sufficiently account for differences in the costs of developing solar resources across different areas in New England.

Based on the information ISO-NE posted for its 2024 economic study and the assumptions stated for this evaluation, the ISO-NE capacity expansion model relies on the new generation resource cost assumptions from the National Laboratory of the Rockies' (NREL's) 2024 Annual Technology Baseline (ATB) moderate case for New England. Importantly, the 2024 NREL ATB data used in the capacity expansion modeling assumptions does not account for cost differences across regions.[39,40] In addition, the ATB costs are specific to a project size (e.g., 100 MW for solar). The reason for why costs can differ across the region in the ISO-NE model is based on the amount of capacity built. The model assumes increasing costs as the capacity additions grow in each zone: adding 10% to solar capital costs and 5% to battery storage capital costs for every 1 GW that is deployed within a zone.[41] This assumption increases costs in areas with significant solar additions and demonstrates the importance of accounting for cost differences across areas. However, much larger cost differences exist across New England that, if reflected in the capacity expansion simulations, would increase the quantified avoided capital costs of transmission. This is because, for example, if the cost of building solar plants in Maine is assumed to be the same as the cost of building the plants in Boston, the benefit of a transmission expansion allowing to shift more generation development to Maine will be greatly understated if not zero.

In reality, the cost of building new generation resources is not uniform across New England and will vary significantly based on location. While the NREL ATB data does not explicitly incorporate regional and intra-regional differences, its documentation demonstrates this can be incorporated by referencing the Regional Energy Deployment System (ReEDS) regional multipliers for capital costs of similar project types (accounting for technology and capacity). These multipliers reflect that solar and land-based wind capital costs in New England are higher than the national average and, additionally, vary across the region.[42] The costs of similarly sized solar plants in southern New England are 5–15% higher than the national average while costs in northern New England are only 0–5% higher. For land-based wind, this multiplier ranges from 25–35% above the baseline ATB assumptions. However, ISO-NE did not apply these regional multipliers to its assumptions and so does not account for the cost savings of building new resources in lower-cost locations within New England.

Beyond the ReEDS multipliers, we have identified two primary drivers for intra-regional differences in resource costs across New England:

1. Land and labor costs are less expensive in northern New England (e.g., Maine) than southern New England (e.g., Connecticut, Massachusetts, and the Boston area).

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[39] Kornitsky, Richard and Elinor Ross, "2024 Economic Study: Final Benchmark Scenario Results," ISO-NE, August 12, 2024, p. 33.

[40] *See* Capacity Expansion Model, posted to ISO-NE Economic Studies materials on June 10, 2025. The capital costs include overnight capital cost plus grid connection costs times a financing factor.

[41] This assumption reflects "tightness in supply chains/labor and increases in interconnection cost as development grows." This increase applied to overnight capital cost creates differing costs among the same technology based on the amount deployed within in each ISO-NE subarea. For example, the fifth GW of solar installed in the Boston subarea (BOSTON) will have a 10% higher capital cost than the fourth GW installed, which has a 10% higher cost than the third GW, and so on. Kornitsky, Richard and Elinor Ross, "2024 Economic Study: Final Benchmark Scenario Results," ISO-NE, August 12, 2024, p. 33.

[42] Ho, Johnathan, et al., "Regional Energy Deployment System (ReEDS) Model Documentation: Version 2020," *National Renewable Energy Laboratory*, June 2021, Figure 21 ("Maps of regional capital cost multipliers for the various technology types"), p. 46.

2. Projects in northern New England tend to be larger in size (due to larger parcels of available land), taking advantage of economies of scale.

As shown in Table 4, data from the US Department of Agriculture (USDA) indicate that farmland and cropland cost about five times more in Massachusetts and Rhode Island than in Maine and Vermont.[43] This is consistent with assumptions made in the Massachusetts 2050 Decarbonization Roadmap, which explicitly states that, "[l]imits to solar development in Massachusetts will likely encourage solar deployment in other states, especially in Northern New England where the cost of land is lower."[44]

TABLE 4. FARM AND CROPLAND AVERAGE VALUE ACROSS NEW ENGLAND

State	Farm Avg. Value (2025$/Acre)	Cropland Avg. Value (2025$/Acre)
CT	$14,400	$22,700
MA	**$14,900**	**$26,000**
ME	**$3,350**	**$4,600**
NH	$6,500	$9,900
RI	**$22,500**	**$32,900**
VT	**$4,400**	**$4,350**

Source: USDA National Agricultural Statistics Service

Additionally, location-based capital cost adjustments for labor and technology implementation in national benchmarking analyses indicate higher costs in southern New England. For single axis tracking solar technology, the location-specific scaling factor applied to the national average is 1.11 for Massachusetts while the factor is only 1.01 for Maine.[45]

Beyond land and labor costs, projects in northern New England are expected to be larger on average, allowing developers to capture economies of scale that reduce per-unit capital costs. The larger possible project sizes will mean that resources in northern New England will be among the lowest-cost new supply options available to serve the region's load. Based on data compiled by Cleanview's project tracker shown in Table 5, the average project size in Massachusetts and Rhode Island is about one-tenth of the average size in other New England states.[46]

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[43] *See* USDA National Agricultural Statistics Service, "Land Values: 2025 Summary," ISSN 1949-1867, August 2025.

[44] Massachusetts Executive Office of Energy and Environmental Affairs and The Cadmus Group, "Massachusetts 2050 Decarbonization Roadmap," December 2020, p. 59.

[45] Sargent & Lundy, "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies," prepared for US Energy Information Administration and Z Federal, December 6, 2023, Appendix A, Table 1.16 ("Locational Adjustment for Solar-PV w/ Single Axis Tracking").

[46] Cleanview, Planned Solar Projects in the US, ISO-NE at https://cleanview.co/planned-solar-projects/iso-ne

TABLE 5. AVERAGE SOLAR PROJECT SIZE (MW) FOR NEW ENGLAND STATES

State	Average Solar Project Size (MW)
CT	52
MA	4
ME	52
NH	42
RI	4
VT	27

Sources and Notes: Estimates for solar projects in development are sourced from Cleanview's public project tracker. The average project size is calculated by dividing the total planned capacity in each state by the total number of projects in development.

The difference in solar project size is an important consideration for installed cost. According to a recent study by Lawrence Berkeley National Laboratory (LBNL), larger solar projects can be significantly cheaper per MW of installed capacity than smaller projects. Specifically, LBNL found that projects in the 20–100 MW range cost 18% less on average in $/MW terms than projects less than 20 MW.[47] These savings increase to 37% lower installed costs for projects over 250 MW when compared to projects 20 MW or less. These scale-related cost differences are not reflected in the current modeling assumptions, which are all based on 100 MW solar plants in every zone of ISO-NE.[48]

Projects in Massachusetts additionally have an incentive to not exceed 5 MW. The Solar Massachusetts Renewable Target (SMART) program provides financial incentives to support the development of solar generation in Massachusetts; however, projects receive declining incentive as project size increases, up to a cap on project size of 5 MW (up to 10 MW in some cases eligible for exception).[49] While many projects may choose to develop several adjacent 5 MW projects, this fails to take advantage of some economies of scale and drives the need to model different capital cost assumptions between the regions within New England. Because ISO-NE modeling assumptions do not fully reflect total costs and locational cost differences, the ISO-NE capacity expansion model will understate the savings associated with larger amounts of cost-effective generation that could be developed in northern New England and delivered to southern New England (as opposed to building higher-cost facilities in Southern New England), thereby understating the economic value offered by transmission expansions that increase transfer capability between these areas.

Additionally, achieving nearly 20 GW of solar generation in Massachusetts (5 GW alone in the Boston subarea)—as produced by the existing capacity expansion modeling assumptions—does

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[47] Seel, Joachim, et al., "US Utility-Scale Solar: 2025 Data Update," Lawrence Berkeley National Lab, October 2025, p. 33.

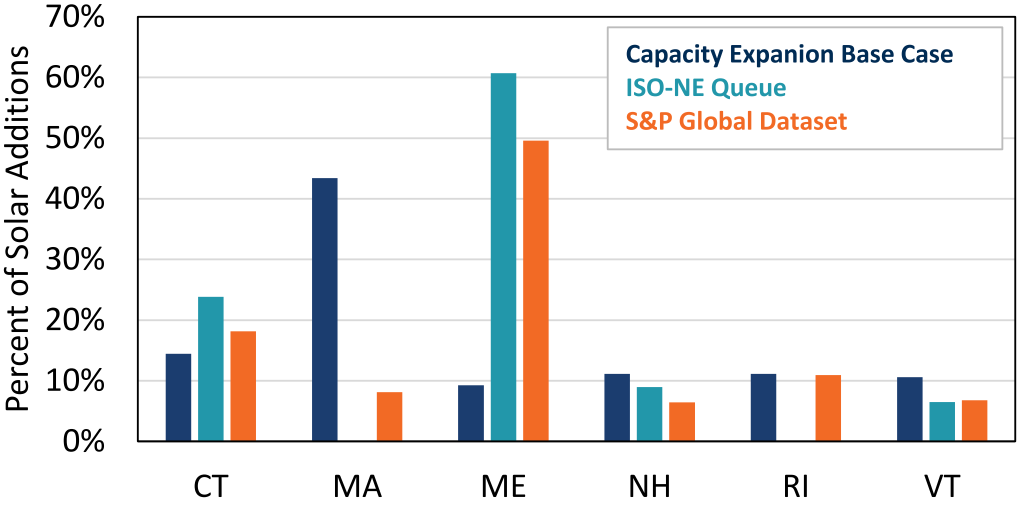
[48] *See* NREL 2024 ATB. In the associated Microsoft Excel workbook, on tab [Solar – Utility PV], the assumptions state that the "representative plant is single-axis tracking with capacity of 100 MW DC."

[49] *See* SMART 3.0 Program Details, https://www.mass.gov/info-details/smart-30-program-details.

not align with current trends, commercial interest, or the significant barriers to building solar in Massachusetts and other regions within southern New England. Both the ISO-NE interconnection queue (as of January 2026) and the S&P Global active project database show a substantially different outlook for solar development across the region than the results from ISO-NE's capacity expansion model.[50]

Figure 6 shows the share of solar capacity developed by state in the ISO-NE model compared to solar capacity in the ISO-NE interconnection queue and the S&P Global database. As reflected by the interconnection queue and active projects data, developer interest in utility-scale solar projects is more heavily concentrated in northern New England, especially Maine where over 60% of projects seeking interconnection and 50% of projects in development are currently located. In contrast, the capacity expansion model builds over 40% of regional solar capacity in Massachusetts, even though less than 10% of the existing queue and active projects in New England are in Massachusetts. This pattern suggests that solar developers perceive Maine as a lower-cost or lower-risk development opportunity, realities not captured in the ISO-NE capacity expansion model that will understate the value of transmission expansion between Maine and southern New England.

FIGURE 6. SHARE OF TOTAL SOLAR CAPACITY EXPANSION BY STATE IN ISO-NE CAPACITY EXPANSION MODEL VS. CURRENT INTERCONNECTION QUEUE DATA AND ACTIVE PROJECT DATA



Sources and Notes: ISO-NE capacity expansion modeling base case (provided to Brattle by NGV). To aggregate the ISO-NE sub-areas into states, they were combined based on the state in which most of the subarea was located. Interconnection queue data is sourced from ISO-NE as of January 12, 2026, and is provided at the state level. Data from S&P Global was obtained through S&P CapIQ Pro and was provided at the state level.

Lastly, relying on 2024 ATB assumptions understates total capital cost as recent market trends have increased the costs of new generation. The 2024 ATB relied on historical cost data through 2022 to create its long-term projections and so does not account for all of the recent cost

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[50] We reviewed projects in the S&P Global Detailed Projects by ISO: New England that were listed with a development status of construction begun, advanced development, early development, and announced.

escalation in its estimated capital costs.[51] The data also "do not reflect every local or near-term market conditions, nor are the longer-term ATB projections informed by recent changes."[52] Recent reports on trends in new generation costs show a significant increase in capital costs of new generation since 2022.[53] For example, the recent SMART program aggregated cost survey results show that ground-mounted 1–5 MW solar projects have a median installed cost of $2,750/kilowatt (kW) in Massachusetts.[54] If we apply the LBNL findings that projects 20–100 MW are 18% less than projects less than 20 MW to this cost estimate, this suggests that projects up to 100 MW could cost around $2,255/kW in Massachusetts. However, the ATB cost estimate used by ISO-NE for solar deployment in 2025 for a 100 MW installation is $1,685/kW, which is nearly 25% lower.[55]

The ATB cost estimates also rely on the generic grid connection costs of $100–120/kW, which understate the generator interconnection costs recently incurred in ISO-NE. Table 6 below shows ISO-NE solar interconnection costs of $187–337/kW based on LBNL's interconnection cost analysis for ISO-NE in June 2023[56]—$67–217/kW higher than the ATB estimates used in the ISO-NE model).

TABLE 6. COMPARISON OF NREL ATB AND ISO-NE INTERCONNECTION COSTS (2022$)

Technology	NREL ATB Grid Connection Cost	ISO-NE Interconnection Cost
Solar	$120/kW	$187–337/kW
LBW	$100/kW	$42–325/kW
Storage	$100/kW	$170/kW

Sources and Notes: NREL ATB grid connection cost is sourced from the Moderate case across technologies in the 2024 NREL ATB for the year 2023. ISO-NE interconnection costs are sourced from LBNL analysis on the ISO-NE interconnection queue point of interconnection costs. The range of values for interconnection costs is the mean costs for completed and active projects in the queue (see fn 12 of the report). Because the LBNL study was published in 2023, we use the 2023 NREL ATB grid connection cost for comparison.

Taken together, we believe that these factors will mean that ISO-NE capacity expansion modeling will significantly understate the avoided capital cost of local generation resources in the BCR analysis.

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[51] "The ATB includes estimates (for the Base Year) and projections (for the projected years) for each technology. Projections are based on trend lines between historical data and long-term (2030 and 2050) estimated costs. For most technologies, the Base Year (2022) is the final year of historical data." NREL, 2024 Electricity ATB Technologies and Data Overview, accessed February 10, 2026.

[52] *Ibid.*

[53] Seel, Joachim, et al., U.S. Utility-Scale Solar 2025 Data Update, October 2025, p. 52.

[54] *See* SMART 3.0 Program Aggregated Cost Survey results (October 2025). This median estimate is based on a sample size of 13.

[55] The NREL ATB estimate for a 100 MW utility-scale solar installation in 2025 is $1,491/kW (2022$). This value is inflated to $1,685/kW (2025$) using the US Bureau of Labor Statistics Consumer Price Indices for 2022 and 2025. We assume that the SMART Aggregated Cost Survey presents values in 2025$.

[56] *See* NREL 2024 ATB. *See also* LBNL, "Interconnection Cost Analysis in ISO-New England," June 2023.

To understand how much the uniform cost assumptions will understate project benefits, we conservatively estimate that capital costs of solar plants in Massachusetts exceed those in Maine by 20–30%. Based on NGV's analysis using the ISO-NE-provided public capacity expansion model, it is projected that the larger proposed transmission solutions would shift 2 GW to 3 GW of solar generation from southern New England to Maine. Applying the estimated cost savings due to locational differences to a conservative base-case solar development cost assumption of $2,000/kW results in an **additional consumer cost savings of $0.8 to $1.8 billion** due to lower generation capital costs not captured by ISO-NE's analysis.[57] The cost savings are likely to be even greater if more solar investment shifts from higher-cost southern regions in New England (like the Boston metro area, where the ISO-NE model builds 5 GW of solar) to lower-cost areas in Maine.

B. Understated Production Cost and Congestion Savings

ISO-NE identified production cost and congestion savings as another benefit it will consider in the evaluation of the transmission proposals. This metric captures the cost savings transmission upgrades provide by reducing congestion in the ISO-NE energy market and avoiding the need to operate higher variable-cost generating resources. To quantify this production cost savings benefit metric, ISO-NE will utilize a nodal production cost model to simulate generation dispatch in 2035 and 2050 based on the resource mix identified in its capacity expansion model. ISO-NE will run a base case without the proposed transmission projects and a change case with the upgrades to estimate the change (i.e., savings) in the variable production costs incurred in serving load. The ISO-NE provided base case appears to include approximately $150 million in annual congestion costs on the N-S interface, which points to potentially significant (but, as discussed, understated) savings of the expanded-scope proposals that increase the N-S interface capacity.[58]

While this approach to estimating production cost savings is common in long-term economic transmission planning studies, the approach does not account for several factors that drive the value of transmission upgrades, which understate the quantified benefits of the upgrades.[59] Based on our review of the production cost model (PCM) ISO-NE will use for the evaluation, ISO-NE's modeling framework will similarly understate production cost and congestion savings. The benefits will be understated because the ISO-NE PCM: (a) simulates only normalized grid conditions (i.e., does not include heat waves, cold snaps, fuel price spikes associated with many

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[57] To obtain this range of potential additional consumer cost savings, we apply 20% lower costs in Maine to the low-end estimate of 2 GW of solar resources shifted there (20% * $2,000/kW * 2 GW * 10^6 kW/GW = $800 million) and 30% lower costs in Maine to the high estimate of 3 GW shifted there (30% * $2,000/kW * 3 GW * 10^6 kW/GW = $1.8 billion. Estimates are in nominal dollars over the study period.

[58] ISO-NE base case results provided by NGV.

[59] The limitations of standard approaches to calculating production cost savings are summarized and addressed in Section IV.2 and Appendix B of J. Pfeifenberger, et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021.

real-world conditions that disproportionately drive transmission value); (b) has perfect foresight of all system conditions (i.e., does not capture the higher costs, including renewable generation curtailments, during unexpected real-time market conditions when system flexibility is more limited); (c) does not consider the impacts of transmission outages (including construction-related transmission outages). These limitations bias the simulation results toward "average" operating conditions, even though extreme conditions and events are the primary drivers of system risk and congestion costs. As a result, the PCM modeling framework does not capture the many challenging and often unpredictable system conditions that ISO-NE has been and will be encountering in its future day-ahead and real-time markets.

The importance of modeling challenging market conditions is captured in a recent analysis by LBNL. LBNL analysis of a decade of historical market prices demonstrates that approximately 50% of total regional and interregional transmission value is concentrated in just 5% of all hours, with 20–30% concentrated in only 1% of hours.[60] Importantly, a substantial portion of this value is not reflected in day-ahead markets and instead materializes during real-time operations. LBNL finds that "unforeseen intraday variance, high net load, cold weather, or high renewable generation conditions are present in over 90% of the hours with peak transmission value."[61]

A typical production cost modeling framework (based on normalized conditions and simulations with perfect foresight) does not include challenges/events that stress the system (e.g., cold snaps or outages of major transmission lines between Maine and southern New England). As a consequence, it will not be able to capture the value of mitigating high-impact operating conditions and therefore will fail to account for a substantial share of transmission value. Indeed, LBNL research shows that the average value of transmission during real-time market operations exceeds the value captured in day-ahead energy markets by approximately 40%.[62] This gap persists even though day-ahead markets (unlike production cost simulations) already reflect forecasts of challenging conditions such as heat waves, cold snaps, fuel price spikes, and elevated transmission outages.

Consistent with the findings that most production cost models do not capture challenging market conditions, ISO-NE's 2024 benchmarking analysis of its production cost model (summarized in Table 7 below) showed that simulated 2023 market prices are materially below observed prices. While the average real-time locational marginal pricing (LMP) in 2023 was $35.70/MWh, the PCM benchmark simulation produced an average price of only $26.40/MWh.[63] ISO-NE attributed this gap to generator and transmission outages and real-time operational challenges that are not reflected in the PCM simulations.

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[60] D. Millstein, et al. (Lawrence Berkeley National Laboratory), Empirical Estimates of Transmission Value using Locational Marginal Prices, August 2022, p. 27.

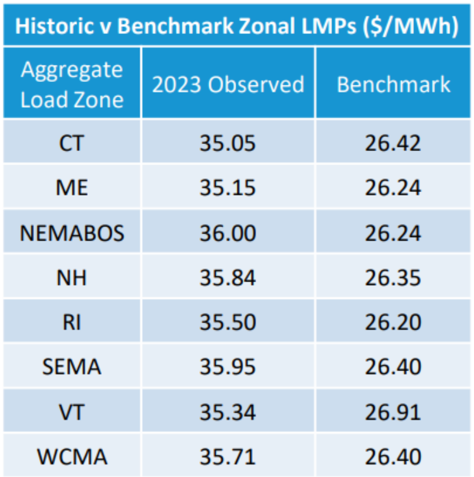
[61] J. Kemp, et al. (Lawrence Berkeley National Laboratory), Electric Transmission Value and Its Drivers in United States Power Markets, August 2025, p. 9.

[62] *Id*, p. 7.

[63] R. Kornitsky and E. Ross, 2024 Economic Study: Final Benchmark Scenario Results Publishing of the Public Benchmark Scenario Policy Scenario Assumptions, August 21, 2024, p. 11.

If the PCM understates actual market prices, it necessarily will understate congestion costs and the value of congestion relief provided by the proposed transmission solutions. Since ISO-NE 2023 simulations show that the model produced market prices approximately 35% below observed prices due to real-world conditions missing from the model, it suggests that future congestion costs and the transmission benefits of relieving that congestion are understated by a similar amount.

TABLE 7. ISO-NE 2024 PRODUCTION COST MODEL VALIDATION RESULTS



Historic v Benchmark Zonal LMPs ($/MWh)		
Aggregate Load Zone	2023 Observed	Benchmark
CT	35.05	26.42
ME	35.15	26.24
NEMABOS	36.00	26.24
NH	35.84	26.35
RI	35.50	26.20
SEMA	35.95	26.40
VT	35.34	26.91
WCMA	35.71	26.40

Increasing simulated congestion relief benefits by 35% is conservative compared to similar adjustments to model results used in New York. The New York Independent System Operator (NYISO), based on similar benchmarking analyses, applies upward adjustments of approximately 40% (and in some cases up to 56%) to simulated production cost savings to account for real-time operational conditions that are not captured in normalized production cost simulations.[64] Relative to the NYISO precedents, applying a 35% adder to ISO-NE's PCM results may even be conservative.

Accordingly, any production cost savings estimated for RFP responses should be increased by a comparable factor to the difference between observed and estimated model validation results (e.g., 35%) in order to reflect more realistic real-world conditions and avoid systematically understating transmission benefits in BCR calculations. For example, NGV modeling based on the ISO-NE's public version of the PCM provided for the purpose of RFP benefit quantification estimated congestion cost savings of one of its proposed HVDC solutions at $300 million in 2035. Applying the 35% adjustment factor to this result would estimate an additional $105 million in

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[64] *See* NYISO Manual 35, "Economic Planning Process Manual," (November 2023). *See also* "Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," Section V.B. (developing multipliers ranging from 6% to 56% to account for understated simulation results for congestion, market heat rates, and clean energy values). The New York Market Monitors' independent analysis of transmission benefits similarly concluded that a 40% adder is appropriate to account for understated simulation results (Potomac Economics, Market Monitoring Unit for the NYISO, NYISO MMU Evaluation of the Proposed AC Public Policy Transmission Projects, dated February 2019, at 16).

2035 production cost savings. An additional $100 million in cost savings annually over the 20-year study period of the ISO-NE evaluation would mean the **ISO-NE production cost metric must be expected to understate the present value of consumer savings associated with congestion-relief benefits of HVDC solutions by about $1 billion.**

Another key factor that could significantly understate the production cost savings of the proposed transmission projects is locating unrealistic levels of generating resources close to load in the Base Case (without the proposed projects). As noted above, the capacity expansion runs that determine the location of new resources in the production cost models assume significantly more resources could be developed in southern New England, and specifically in Massachusetts and the Boston area, than commercial interest and cost considerations appear to support. Adding resources near load that are unlikely to materialize will reduce simulated congestion on the system by reflecting that lower-cost resources dispatched tend to be further from load. The model will thus need to re-dispatch the system less frequently due to transmission constraints and identify smaller production cost savings from transmission expansions than would occur with more realistic future resource additions. Notably, the current assumption of locating 5 GW of solar in the Boston area will reduce the value of the higher-capacity transmission proposals that also offer an increase capacity into the Boston area (but will have limited impact on the proposed transmission solutions that focus only on the RFP's targeted interfaces and minimum requirements).

Finally, the ISO-NE production cost modeling framework does not capture the operational cost impacts of construction-related transmission and generation outages associated with building the selected transmission proposals. While ISO-NE and transmission owners seek to schedule outages during periods with less challenging conditions, multi-season construction-related outages while rebuilding existing lines can be lengthy, geographically concentrated, and worsen periods of system stress, materially reducing transfer capability and operational flexibility during critical hours and further increasing congestion and production cost on the system. As ISO-NE evaluates the benefits and costs of different solutions, it should assess the operational impacts of construction-related outages necessary for the addition of each proposal. We understand that outages during construction are considered in the additional evaluation factors, but this factor could more easily be given proper weight if informed through the production cost modeling.

C. Understated Avoided Transmission Investments

ISO-NE identified avoided transmission investment cost as a benefit metric for its evaluation of the transmission proposals. This metric captures the savings from reducing other transmission costs if the proposed project avoids the need for such other upgrades. To quantify this benefit metric, ISO-NE defines a universe of transmission projects that might be avoided by the proposed projects based on the 2025 RSP Project List, the ACL, or facilities that are more than 40 years old.[65] Transmission solutions that still need to be designed to address projected future transmission needs will not be reflected in these lists.

While this approach reflects the benefit of possibly avoiding already specified transmission projects and aging-asset related transmission needs, it does not account for potentially avoiding future upgrades that are not yet on ISO-NE's lists but will nevertheless be critical to address the region's long-term needs. As a result, ISO-NE's avoided transmission benefit metric may be significantly understated as it does not capture proposed future solutions necessary to address the region's long-term needs. In particular, transmission upgrades that could potentially be deferred or avoided due to the RFP solutions' expanded-scope transfer capabilities include additional reinforcements on the ME-NH and SUR-S and adding capacity to the N-S and Boston import interfaces. However, the need to expand these interfaces beyond the RFP's minimum requirements has already been identified in prior planning analyses and will need to be addressed in future transmission planning cycles.

The potential significance of these future needs is illustrated by the scale of investments identified in ISO-NE's 2050 Study for the N-S and Boston import limits. The 2050 Study estimated $5.0–6.5 billion of transmission expenditures between 2035 and 2040 would be necessary to support the region's long-term reliability and public policy objectives. To the extent that RFP solutions reduce or defer a portion of these future N-S and Boston Import upgrades, the associated avoided transmission costs could be material, potentially on the order of billions of dollars.[66]

A key challenge for the LTTP RFP's evaluation process is that avoided future transmission costs may involve upgrades needed through 2050. However, the current RSP Project List and ACL reflect only projects identified in studies that were focused primarily on reliability needs during the next 5 years. As a result, the RSP Project List simply will not capture much (if any) of the $5.0–$6.5 billion of investments that ISO-NE estimates could be required over the 2035–2040 timeframe to upgrade the N-S and Boston Import limits.

ISO-NE's 2050 transmission study identified some of the most significant upgrades that would be needed to these two interfaces to reliably serve load. For example, under the "DC Roadmap," ISO-NE evaluated upgrades to address the N-S and Boston Import constraints that would include a new HVDC undersea cable from Surowiec to Mystic, targeted for service by 2035. This project would mitigate multiple overloads in Maine, particularly those caused by the loss of major existing transmission lines that would otherwise constrain the large north-to-south power transfers likely in the future. The cost of that HVDC project, which would likely be avoided by the

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[65] Evaluation Analysis Details, at 8-9.

[66] Assuming more transmission upgrades in the Base Case would tend to increase avoided transmission costs but may reduce some of the production cost savings and capital cost savings captured by the other benefit metrics. To avoid double counting avoided transmission costs and generation-related benefits and accurately estimate the cost savings of the proposed projects, all avoidable transmission upgrades would need to be in the "base case" for the purpose of capacity expansion and production cost modeling.

RFP's expanded-scope HVDC solutions, was estimated at approximately $2.6 billion (in 2023 dollars).[67]

The RFP's proposed expanded-scope solutions might, alternatively, avoid or defer the need for additional AC transmission upgrades further south than the interfaces targeted in this LTTP solicitation, including the N-S and Boston Import interfaces. For example, the 2050 Study's "AC Roadmap" includes construction of a new 345 kilovolt (kV) overhead line from Timber Swamp to Ward Hill in Haverhill, Massachusetts that would upgrade the N-S interface, as well as a new 345 kV hybrid overhead/underground line from Ward Hill to Wakefield Junction to Mystic within the Boston metro area, which would upgrade the Boston Import limit. Both of these AC Roadmap upgrades are projected to be needed by 2035 to address numerous overloads into the Boston area following the loss of major transmission lines, which would otherwise limit the amount of power that can be imported into Boston. **These AC upgrades, likely avoided or deferred by the LTTP's proposed HVDC solutions, are estimated to cost approximately $1.3 billion (in 2023 dollars).**[68] However, by not considering future needs beyond the currently planned upgrades on the RSP list, ISO-NE's evaluation approach will significantly understate avoided transmission benefits.

D. The BCR Methodology Understates Total Consumer Benefits

ISO-NE's LTTP BCR methodology compares the present value of quantified benefits to the present value of a project's annual revenue requirement over a 20-year evaluation horizon, discounted at 8.2%. This approach has important implications for the calculation of the present value of the costs and benefits of the proposed projects and will understate the total consumer benefits of long-lived transmission investments.

The ISO-NE BCR framework places disproportionate weight on early-year costs relative to later-year benefits. Transmission revenue requirements are typically front-loaded, reflecting depreciation schedules and other factors. As a result, evaluating the present value of the first 20 years of revenue requirements captures a substantial portion of total project costs, even though the physical asset is expected to remain in service well beyond 20 years. In contrast, many transmission benefits (e.g., reduced production cost and avoided capital costs for generation) tend to increase over time as load grows, electrification occurs, fuel costs increase, and existing generation assets retire.

Figure 7 below provides a realistic illustrative example of a 20-year and 40-year outlook for project costs (light blue) and project benefits (dark blue). The project costs follow a typical trend for revenue requirements for a transmission asset declining over time as the original rate base

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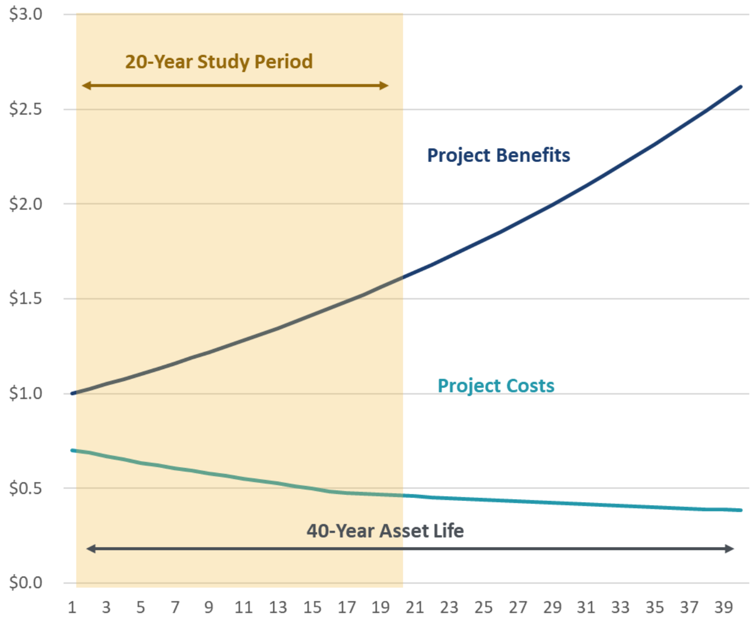
[67] *2050 Transmission Study Technical Appendix, P. 37 and 48 (CEII-restricted).*

[68] *2050 Transmission Study Technical Appendix, P. 36 (CEII-restricted).*

depreciates. The benefits are assumed to increase in nominal terms at a 2.5% inflation rate. As the figure illustrates, evaluating the project based on only the first 20 years of costs and benefits will leave out at least 20 years (if not more) of the transmission project's useful life, when annual benefits significantly exceed the annual costs.

FIGURE 7: EXAMPLE OF LONG-TERM TRANSMISSION BENEFITS AND COSTS



Source: Appendix A

In this example, the project would have a BCR of 2.0 based on the proposed 20-year study period. A sensitivity that increased the study period to 40 years—which would be aligned with other regional transmission planners, such as the Midcontinent Independent System Operator (MISO), the Southwest Power Pool (SPP), and the California Independent System Operator (CAISO)—would increase the present value of costs by 15% while increasing the present value of benefits by 34%. As a result, increasing the time frame considered in present value calculations from 20 years to 40 years increases the BCR from 2.0 to 2.34 in this example—a 17% increase compared to the 20-year BCR.

The asymmetric weighting of costs and benefits is further amplified by the 8.2% discount rate applied, which is high relative to the estimated after-tax weighted average cost of capital (ATWACC) that should be applied when evaluating investments with regulated cost recovery. A more appropriate discount rate would be the ATWACC of transmission owners or the ATWACC typically applied to regulated utilities in New England—which generally falls in the 6.5–7% range.[69] Applying the higher 8.2% discount rate reduces the present value of long-term benefits relative to annual transmission revenue requirements. In the example above, reducing the

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[69] For example, the ATWACC would only be 6.8% for a regulated company with a 10% allowed return on equity, and a capital structure with 50% equity, and a 5% cost of debt (yielding an after-tax cost of debt of approximately 3.66%): (10% × 0.5) + (3.66% × 0.5) = 6.8%

discount rate from 8.2% to 7.0% over the 20-year study period increases the BCR to 2.44 and increases the present value of benefits by 57%. The combined effect of shortened benefit horizon and a high discount rate thus risks underestimating the true long-term BCR value of the proposed projects by 22%.

Unless the evaluation process accounts for the likely value of post-20-year benefits and costs—either through sensitivity analyses using longer horizons and lower discount rates or through appropriately weighted additional evaluation criteria—the ISO-NE selection process risks understating total consumer savings and biasing outcomes toward solutions that perform well under near-term financial metrics but deliver less value and higher-cost outcomes over the longer-term.

IV. Importance of Additional Evaluation Factors in Evaluating Tradeoffs of Different Scope Proposals

The LTTP selection requires evaluating benefits of proposals with materially different scopes, operational characteristics, and long-term system impacts. In addition to its quantitative BCR analysis, ISO-NE will evaluate all proposals with a BCR greater than 1.0 with twenty additional evaluation factors that are part of the Tariff and have been prioritized by NESCOE in the request for this RFP. Because many benefits of enhanced-scope projects will be captured less fully in the BCR methodology, it is even more important that the evaluation process carefully consider these additional evaluation factors when selecting the preferred transmission solution.

The RFP documentation does not specify a clear methodology for how ISO-NE will evaluate or weigh the additional evaluation factors against the calculated BCR. To capture these additional benefits and how they vary across proposals when selecting the preferred solution, several of these factors are particularly relevant to capture the broader system value of the LTTP proposals, specifically those with expanded scope: impact on interface limits other than those in scope, generation and transmission facility outages during construction, extreme contingency performance and winter reliability, system performance, and operational impacts.

A. Impacts on Interface Limits and Construction-Related Outages Benefits

ISO-NE's evaluation considers "impact on interface limits other than those defined in scope" to be one of the second highest-priority additional evaluation factors, and "generation and transmission facility outages required during construction," a third priority criterion. Proposals that increase transfer capability on interfaces beyond ME-NH and SUR-S—such as the N-S and Boston Import interfaces—provide incremental system value that may reduce congestion, improve reliability margins, and lessen the need for future reinforcements on downstream constraints that have already been identified in ISO-NE's longer-term studies. Additionally, expanded-scope proposals that add new transmission corridors and/or create parallel paths can improve future expandability to reduce the scope, cost, and complexity of subsequent upgrades. This is particularly important when considering future upgrades that may be avoided as a result of expanded interface capability.

Although the avoided capital cost of local resources, production cost and congestion savings, and avoided transmission investment metrics will partially capture the associated cost savings, the full value of increasing transfer limits beyond minimum requirements and adding new corridors should be fully reflected through the additional evaluation factors. Expanded transfer capability provides incremental headroom that may not appear as valuable under normalized conditions but becomes critically valuable during periods of stress, downstream congestion, or future system expansion. In addition, adding a new corridor reduces dependence on existing constrained rights-of-way and provides operational flexibility during future system upgrades. Specifically in this case, the three expanded-scope HVDC proposals add a new path between Maine and Boston that will increase additional interface limits and provide a parallel path for power to flow when additional onshore upgrades are eventually required.

This creation of a parallel path is important when considering construction-related outages. Construction-related outages can impose real and material system costs that are not reflected in the BCR analysis. All transmission solutions involve some amount of reconductoring, rebuilding, or uprating existing AC facilities and so require construction-related outages of transmission and generation facilities, temporary derates, or complex switching arrangements to maintain reliability during construction. These outages can increase congestion and reliance on higher-cost local generation that may increase energy prices to consumers and can reduce operational flexibility over multi-year construction periods. While NESCOE categorized construction outages as a lower-priority qualitative consideration, the associated system impact costs are not captured in the benefit metrics and therefore risk being given insufficient weight. As mentioned previously in Section III.B, the cost of such construction-related outages could be more significant for some of the proposals and should also be considered in relation to future upgrades. Creating a new (parallel) transmission corridor with significant transfer capability before upgrading the existing corridors would facilitate future upgrades of the existing transmission corridors by reducing future cost of construction-related outages, thereby reducing system impacts and consumer costs.

B. Extreme Contingency Performance and Winter Reliability

In addition to interface impacts, ISO-NE will consider "extreme contingency performance" and "winter reliability impacts" as second-tier evaluation factors. While these criteria are influenced by increased transfer capability during periods of high system stress, they address a distinct dimension of system value. Extreme contingency performance and winter reliability evaluate how the system performs under stressed, low-probability operating events—such as major transmission element losses, fuel scarcity, or severe weather (such as winter cold snaps)—that are not reflected in the quantified BCR metrics.

Proposals that expand transfer capability beyond minimum requirements or introduce a geographically distinct transmission path between northern and southern New England may materially improve system robustness under such conditions. A new corridor can reduce reliance on a limited number of existing rights-of-way, improve post-contingency transfer capability following the loss of major transmission elements, and enhance the system's ability to maintain service during severe weather events. These resilience and performance benefits may not appear prominently in economic simulations because they arise during relatively infrequent but high-impact system conditions.

Furthermore, proposals that include subsea transmission infrastructure may further enhance performance under certain extreme weather scenarios by being submerged and physically separated from onshore corridors and therefore less exposed to the storm outage risks affecting overhead facilities. Geographic diversity and physical separation can contribute to improved contingency performance and winter reliability even if those benefits are not directly monetized.

Under extreme contingency or weather events, transfer flexibility, geographic diversity, and alternative transmission pathways provide important reliability and resilience benefits that are difficult to quantify in BCR analyses. Adding sensitivities that include extreme conditions can capture some of these additional benefits. These additional benefits during extreme contingency or weather events can then be included in the LTTP evaluation process during the review of the additional evaluation factors to ensure that the proposal selection reflects the total system value. Some proposals submitted may offer high value provided under these evaluation factors that should be given sufficient weight in selecting the preferred proposal.

C. Advanced HVDC Benefits Not Captured in Economic Metrics

Three of the six expanded-scope proposals include HVDC transmission solutions based on advanced voltage-source converter (VSC) technology that would provide important system benefits in addition to the benefits described above. While ISO-NE's evaluation framework appropriately recognizes "system performance" and "operational impacts" as additional evaluation factors, it risks understating the total value of HVDC-related benefits in its economic metrics and additional evaluation factors. Some HVDC-related benefits, such as bidirectionally controllable power flows, can be captured partly through production cost simulations and the associated BCR metrics if modeled explicitly; however, there are many additional benefits offered by advanced HVDC solutions—such as operational benefits and increased resiliency—that are either challenging to quantify in the proposed economic metrics or not given enough weight as an additional evaluation factor.

Compared to traditional AC transmission, modern HVDC lines give system operators far more control over how real and reactive power flows across the grid. Modern HVDC technology provides continuously controllable power flows, which allows operators to reduce congestion on the AC grid, keep equipment operating safely below its limits, and better manage the system during outages or maintenance, compared to AC solutions that rely on power flows that follow the path of least electrical resistance. By being able to control reactive power independently from real power at the converters on each end of the HVDC line, HVDC systems provide reliable voltage support up to the capacity of the converters (and even if the HVDC line itself in on outage). In addition, through dynamic voltage control, fault recovery, frequency regulation, and black start system restoration capabilities, the proposed VSC-based HVDC solutions can enhance the resilience of the existing AC grid.[70] The ancillary benefits of VSC-based HVDC technology can increase stability in weak grid areas and provide controllable support while contributing only limited short-circuit current in load centers, enable faster restoration after major outages and, if designed to do so, provide black-start capability to help restore the grid following extreme events. Some of these benefits are captured as possible factors to be considered as part of "system performance" but needs to be given sufficient weight, particularly in New England where many interfaces and load centers are stability limited.

System operators across North America are starting to incorporate HVDC-specific planning and benefit analysis. For example, the CAISO's 2021–2022 Transmission Plan highlighted a number of VSC-HVDC benefits that are considered in their planning process, including the fact that it does not require reactive power support at the converter station and it is suitable for delivering power to urban areas and systems with low short-circuit levels.[71] More broadly, system planners are recognizing that controllable transmission technologies can provide operational flexibility, resilience, and system performance benefits that are not always fully captured in conventional economic metrics. A recent example from Ontario's Independent Electricity System Operator (IESO), which we describe below, illustrates how these considerations can influence the selection of a preferred transmission solution when comparing alternatives with differing scope and capabilities.

D. Case Study: Ontario IESO Toronto IRRP

The Ontario IESO recommended an underwater HVDC transmission solution as the preferred option to address transmission needs in its Toronto Integrated Regional Resource Plan (IRRP). The Toronto IRRP provides an instructive example of why selection frameworks for proactive transmission solution should explicitly consider benefits even if they are challenging to quantify. Doing so is particularly important when comparing solutions with different scope, functionality, and long-term system implications. In the Toronto IRRP, the IESO evaluated three transmission

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[70] For a detailed description of HVDC features see Tables 6, 7, and 8 in Brattle and DNV's report. Pfeifenberger, et al., "The Operational and Market Benefits of HVDC to System Operators," September 2023.

[71] CAISO, "2021–2022 Transmission Plan," March 17, 2022, pp. 224–225.

solutions to address growing demand and reliability risks in the Toronto metropolitan area: two conventional onshore AC expansion options with estimated capital costs of approximately CAD $800–900 million and an underwater HVDC option with an estimated capital cost of approximately CAD $1.5 billion. Despite the HVDC option's higher upfront cost and greater cost uncertainty, the IESO concluded that the HVDC option provides superior system value and, while acknowledging that many of these benefits are difficult to fully quantify, the bulk system benefits could yield several hundred million dollars in consumer savings.

The IESO justified recommending the higher-cost HVDC solution because it delivers greater value to ratepayers and improved reliability and resilience for the system as a whole.[72] A central reason for this decision was that the HVDC option provided the largest increase in load-serving capability among the alternatives and materially improved system performance both locally and upstream. The evaluation found that the other two proposals would only defer system needs into the future, whereas the larger-scale HVDC solution, when coupled with local upgrades, could meet longer-term electrification forecasts.

The IESO further emphasized the unique capabilities of HVDC systems with voltage-source converter technology, including the ability to provide dynamic reactive power and voltage control independent of real-power flows. These capabilities allow HVDC converter stations to operate in STATCOM mode and continue supporting grid stability even if the transmission cable itself is out of service. The IRRP explicitly notes that many of these reliability and voltage-support benefits were expected to be specified only in later design stages, underscoring that they were not fully captured in early-stage economic comparisons.

The IESO also placed significant weight on resilience and system restoration benefits, even though they are inherently difficult to quantify. The HVDC option introduced a new, geographically and electrically separated supply path into the Toronto urban area, effectively creating a true third source of supply for downtown Toronto. While the IRRP acknowledged that "system resilience itself is not easily measured," it emphasized that resilience improves with supply diversity and the ability of different sources to support one another during outages.[73] The study highlighted historical flooding events at Manby Transformer Station and estimated that an eight-hour outage of comparable magnitude could impose economic losses on the order of CAD $400 million. In this context, the VSC technology's ability to provide blackstart service to support system restoration following extreme outage events and the HVDC line's reduced exposure to extreme weather—given that the cables are submerged under Lake Ontario—were decisive factors.

Many of the operational flexibility factors discussed previously were also considered by the IESO, including high controllability and alleviating barriers to increased distributed energy resource penetration rates. Beyond these benefits, the Toronto IRRP emphasized that only the higher-cost HVDC option delivered material bulk-system benefits. By providing a new path directly into the

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[72] IESO Toronto IRRP, p. 62.

[73] *Id.*, p. 63.

load center, the HVDC option reduced bulk power system congestion, deferred or avoided the need for additional transformation capacity, and potentially eliminated the need for future 500 kV reinforcements. The IESO estimated that these bulk-system benefits alone could amount to several hundred million dollars, significantly narrowing the effective cost gap between the HVDC and AC options.[74] The IESO concluded that "[a]s the HVDC and the two AC options have very different performance attributes and deliver different benefits … it is not appropriate to select the preferred option based on the initial cost alone."[75]

In response to this assessment, the Ontario government approved the IESO's recommended subsea HVDC solution, noting specifically that the line "will deliver more capacity than any other options and meet the system needs beyond 2044, reducing the need for additional, costly upgrades and expansions."[76]

The Toronto IRRP demonstrates that larger-scope, higher-cost transmission solutions can deliver disproportionately greater system value, much of which may not be fully captured by typical BCR metrics quantified over limited horizons. It illustrates how a planning authority explicitly recognized and weighed qualitative considerations—such as resilience, operational flexibility, future expandability, and bulk-system impacts—when those benefits were known to be significant and relevant to long-term system needs, even if they were difficult to quantify.

This precedent is directly relevant to ISO-NE's LTTP selection process, where three HVDC proposals exceed minimum requirements and offer broader system benefits that will not be fully reflected in the quantitative BCR but are central to achieving cost-effective outcomes for New England consumers.

V. Summary of LTTP Benefits Captured by Evaluation Criteria

The benefits likely provided by LTTP proposals are summarized in Table 8 below, along with the ISO-NE economic metrics and additional evaluation factors and the extent to which the ISO-NE evaluation approach (as we understand it) will likely capture quantitatively the value of these benefits.

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[74] *Id.,* p. 65.

[75] *Id.*, p. 67.

[76] *See* Ontario Government, "Ontario Focused on Economy by Approving New Toronto Transmission Line: Province launches first IESO-led competitive transmission selection process to maximize benefits," January 7, 2026 (Accessed on February 8, 2026).

TABLE 8. SUMMARY OF LTTP PROJECT BENEFITS, EVALUATION CRITERIA, AND EXTENT TO WHICH THE BENEFITS ARE QUANTIFIED

Benefits LTTP Solutions Can Provide	LTTP Evaluation Metrics that Capture Benefit	Extent to which Benefits are Quantified by LTTP Evaluation Metrics
1. Lower dispatch costs and congestion relief	Quantified by "production cost and congestion savings" metric with PCM	**Partially Quantified:** PCM simulates dispatch based on normalized grid conditions, assumes perfect foresight between DA and RT, and omits outage-driven system stress
2. Avoided/deferred transmission investments	Quantified by "avoided transmission investment" metric based on list of RSP and Asset Condition projects	**Partially Quantified:** ISO-NE approach based on the limited set of near-term RSP & Asset Condition projects misses avoided future projects to address 2035-40 needs
3. Avoided higher-cost local generation resource buildout	Quantified by "avoided capital cost of local resources needed to serve demand" metric with Capacity Expansion Model (CEM)	**Partially Quantified:** CEM assumes uniform capital costs across region and unrealistic build limits; may not account for cost escalation since 2024
4. Reduced energy losses on transmission grid	Quantified by "reduction in losses" metric with PCM	**Partially Quantified:** PCM does not capture losses during high loads conditions due to heat waves or transmission outages, etc. (not reflected in normalized PCM)
5. Resource Adequacy Benefit	Quantified by "reduction in unserved energy" metric with ISO-NE's zonal EUE model	**Quantified:** ISO-NE utilizes its LOLE model (used to set planning reserve margins and zonal requirements) to estimate this benefit, but benefits likely to be small
6. Mitigation of costs during extreme weather events	Qualitatively considered as "extreme contingency performance" (B Factor)	**Not Quantified:** PCM could quantify this benefit if extreme events were added as sensitivity
7. Future expandability and mitigation of costs during construction G&T outages	Qualitatively considered as "generation and transmission facility outages during construction" (C Factor)	**Not Quantified:** PCM could quantify this benefit if generation and transmission facility outages during construction were added as sensitivity
8. Expanded interface capacity beyond minimum requirements	Qualitatively considered as "impact on interface limits other than those in scope" (B Factor)	**Partially Quantified:** PCM and CEM can reflect higher transfer capability in simulations, but will not fully capture benefits as noted above
9. Resilience benefit of creating new transmission corridor	Qualitatively considered as "extreme contingencies" and "winter performance" (B Factors)	**Not Quantified:** PCM, CEM, and zonal EUE simulations could quantify this benefit if extreme contingencies were added as a sensitivity
10. Improved system performance & flexibility	Qualitatively considered as "system performance" (B Factor)	**Not Quantified.** Could be quantified in reliability metrics or monetized as avoided cost of providing these benefits through other means
11. Operational benefits of bidirectionally controllable HVDC flows	Qualitatively considered as "system performance" (A Factor) and "operational impacts" (B Factor)	**Partially Quantified:** PCM likely captures this HVDC capability, but only partially (as noted above)
12. Operational benefits of HVDC-provided ancillary services	Qualitatively considered as "system performance" (A Factor)	**Not Quantified**: ISO-NE does not calculate avoided cost of providing voltage support, black-start capability, etc.

Note: NESCOE priority of additional factors: Highest Priority (A Factors), Second Priority (B Factors), Third Priority (C Factors)

VI. Recommendations for a Robust LTTP Selection Process

ISO-NE specified a clear and broad set of quantitative metrics and additional evaluation factors to evaluate the project proposals received in the first LTTP solicitation and select a winning proposal. Based on our review of the LTTP evaluation process, the proposed evaluation approach will not capture the full value of its quantified benefits. Unless appropriate weight is given to the additional evaluation factors, the LTTP evaluation approach risks undervaluing the benefits of expanded-scope proposals that address the region's long-term needs. This, in turn, means that the selected solution will not offer the largest benefit in terms of addressing the region's longer-term needs, unless economic metrics are more fully quantified or additional evaluation factors are given sufficient weight.

Given that ISO-NE has already specified the modeling assumptions, benefit metrics, and evaluation criteria for this RFP, and noted that all projects with a BCR greater than 1.0 will be eligible for consideration as the preferred project solution, we recommend that ISO-NE supplement the specified LTTP evaluation criteria, where possible, through (1) sensitivity analyses to estimate the specified benefit metrics utilizing updated assumptions to more fully capture actual projects benefits and (2) by giving sufficient weight to additional evaluation factors to capture their likely importance in terms of long-term consumer benefits. A better understanding of the magnitude of understated or not quantified benefits would allow ISO-NE to mitigate the risk that the evaluation process selects a solution that does not offer the highest net benefits and overall cost savings to consumers in New England.

Sensitivity analyses to quantify the value of the LTTP proposals may include the following:

1. **Identify Avoidable Transmission Costs Beyond RSP List:** Estimate the avoidable transmission costs associated with the expanded-scope solutions beyond the projects already on the RSP list, such as avoided costs of upgrades to the N-S/Boston interfaces that address the 2035-2040 transmission system needs identified in the 2050 study;
2. **Value the Resilience Benefit of an Additional Transmission Corridor:** Explicitly recognize (and if possible quantify) the resilience benefits of the additional transmission corridor between Maine and Boston that is created by the three expanded-scope HVDC solutions (e.g., by simulating the EUE and production cost implications of extreme contingencies and winter reliability impacts, including associated fuel scarcity and price spikes);
3. **Update Capacity Expansion Model Capital Costs**: Update the capital costs of generating resources in the capacity expansion simulations for (1) the regional cost differences that exist within New England and (2) cost increases since 2024 to better account for future generation costs, cost-effective locations of new resources, and specifically the transmission benefit arising from locational differences in costs within ISO-NE region, and then re-run the

production cost simulations with the new outlook for generation resources, ensuring realistic build limits;

4. **Update Capacity Expansion Model Build Limits:** Improve representation of transmission and generation development assumptions to limit the amount of resources that could realistically be built in the Boston, Massachusetts, and southern New England planning zones, so that the value of expanding the targeted ME-NH, N-S, and Boston import limits is more realistically reflected in the capacity expansion and production-cost simulations;
5. **Calibrate Production Cost Model**: Benchmark its simulated prices against recent market prices to identify the magnitude of production costs (and future production cost savings) not captured in the model relative to actual market outcomes and consider using the validation results or the benchmarking results from the 2024 study, indicating that the simulation understates actual market prices by approximately 35%, to better capture the production cost savings of the proposals;
6. **Optimize HVDC Dispatch**: Ensure the production cost simulations optimize the dispatch of the proposed HVDC transmission lines and quantify the voltage support and blackstart capability that the HVDC solutions can offer;
7. **Simulate Challenging Market and Weather Conditions**: Estimate the production cost savings of the transmission projects associated with extreme contingencies, extreme weather conditions (such as heat waves and cold snaps), including fuel scarcity and price spikes such as those recently experienced;
8. **Consider Longer-term Value:** Evaluate the present value of projected benefits and costs over a 40-year timeframe (similar to MISO, SPP, and CAISO) and a lower discount rate to more accurately reflect the present value of longer-term benefits relative to costs;
9. **Consider Congestion During Construction Outages:** Assess the construction-phase transmission outages that would likely be associated with the proposed solutions and possibly simulate the production costs associated with these outages; and
10. **Consider the Value of Facilitating Future Expansions:** Estimate the value of facilitating future AC grid upgrades necessary to meet longer-term regional needs through the creation of a new transmission path between Maine and Boston that reduces the cost of future construction-related transmission and generation outages.

Through these analyses, project benefits not quantified (or understated) in the ISO-NE benefits metrics could either be (1) considered explicitly for their monetary value or (2) be weighted appropriately as an additional factor in the evaluation process. Even if it is not feasible to estimate the extent to which benefit metrics understate or do not capture actual project benefits, the unquantified benefits should be considered qualitatively and be given sufficient weight to capture their likely importance for long-term consumer savings based on the examples provided in Sections III and IV above.

We recommend ISO-NE to pursue an enhanced LTTP evaluation process regardless of the outcome of the initial review of the proposals against the minimum requirements, such that any proposals with clarified technical analysis or minor changes are considered in the context of broader benefits, as the holistic evaluation criteria intends. We also encourage ISO-NE to implement these recommendations for future LTTP solicitations to more accurately assess the benefits transmission investments will deliver to New England.

Finally, we recommend that the evaluation process also consider the overall size of proposed projects' consumer benefits in addition to their BCR, recognizing that of two projects with the same BCR, the more expensive project that addresses more of the region's longer-term needs will offer larger consumer benefits.

List of Acronyms

AC	Alternating Current
ATB	Annual Technology Baseline
ATWACC	After-Tax Weighted Average Cost of Capital
BCR	Benefit-Cost Ratio
BESS	Battery Energy Storage System
BHE	Bangor Hydro Electric (ISO-NE zone)
BOS	Boston (ISO-NE zone)
BPS	Bulk Power System
CAD	Canadian Dollar
CAISO	California Independent System Operator
CEM	Capacity Expansion Model
CMA	Central Massachusetts (ISO-NE zone)
CT	Connecticut (ISO-NE zone)
DC	Direct Current
EUE	Expected Unserved Energy
GW	Gigawatt
HQ	Hydro Quebec (ISO-NE intertie)
HVDC	High-Voltage Direct Current
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
ISO-NE	Independent System Operator of New England
kV	Kilovolt
kW	Kilowatt
LBNL	Lawrence Berkeley National Laboratory
LBW	Land-Based Wind
LMP	Locational Marginal Pricing
LTTP	Longer-Term Transmission Planning
LTTU	Longer-Term Transmission Upgrade
ME	Central Maine (ISO-NE zone)
ME-NH	Maine–New Hampshire
MISO	Midcontinent Independent System Operator
MMU	Market Monitoring Unit
MW	Megawatt
MWh	Megawatt Hour
N-S	North-South (ISO-NE interface)
NB	New Brunswick (ISO-NE intertie)
NECEC	New England Clean Energy Connect
NEMA	Northeastern Massachusetts (ISO-NE zone)
NEMABOS	NEMA and Boston (ISO-NE zone)
NESCOE	New England States Committee on Electricity
NGV	National Grid Ventures

NH	New Hampshire (ISO-NE zone)
NOR	Norwalk/Stamford, Connecticut (ISO-NE zone)
NPPC	Northeast Power Coordination Council
NREL	National Laboratory of the Rockies (formerly National Renewable Energy Laboratory)
NY	New York (ISO-NE intertie)
NYISO	New York Independent System Operator
OSW	Offshore Wind
PCM	Production Cost Model
PV	Photo Voltaic
QTPS	Qualified Transmission Project Sponsors
ReEDS	Regional Energy Deployment System
RFP	Request for Proposal
RI	Rhode Island (ISO-NE zone)
RSP	Regional System Plan
SEMA	Southeastern Massachusetts (ISO-NE zone)
SMART	Solar Massachusetts Renewable Target
SME	Southern Maine (ISO-NE zone)
SPP	Southwest Power Pool
SUR-S	Surowiec-South (ISO-NE interface)
SWCT	Southwestern Connecticut (ISO-NE zone)
USDA	US Department of Agriculture
VSC	Voltage-Source Converter
VT	Vermont (ISO-NE zone)
WCMA	Western and Central Massachusetts (ISO-NE zone)
WMA	Western Massachusetts (ISO-NE zone)

Appendix A: 20- and 40-Year Cost-Benefit Analysis

Figure 7 above presents an example calculation of long-term transmission costs and benefits over a 20-year period and a 40-year period to demonstrate the impact different time horizons can have on the calculated BCR for each of the LTTP proposed solutions.

The calculation of long-term assumes the following:

- First-year transmission benefits of $1.0 million;
- Annual transmission benefits escalation rate of 2.5% per year;
- First-year annual transmission revenue requirements of $0.7 million;
- Transmission revenue requirement declines due to depreciation (based on standard regulatory accounting assumptions); and
- Discount rate (DR) of 8.2% based on the LTTP evaluation and an alternative discount rate of 7.0%.

Table A-1 below summarizes the calculated present value of long-term transmission benefits and costs based on the assumptions above for several combinations of time period studied (20 years and 40 years) and discount rate (8.2% and 7.0%).

TABLE A-1. TRANSMISSION BENEFITS AND COSTS CALCULATION RESULTS

Case	Present Value of Benefits	Present Value of Costs	Benefit-Cost Ratio
20 years with 8.2% DR	$11.6 million	$5.8 million	2.00
20 years with 7.0% DR	$12.8 million	$6.3 million	2.04
40 years with 8.2% DR	$15.5 million	$6.7 million	2.34
40 years with 7.0% DR	$18.2 million	$7.5 million	2.44