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

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While this LTTP solicitation is an important step towards more effective, proactive transmission planning, we recommend enhancements to the evaluation process to ensure the selected project delivers maximum value to New England customers.

New Longer-Term Transmission Planning (LTTP) Process

- ISO-NE is currently implementing its first LTTP solicitation at the request of NESCOE in a major step forward for improving cost-effective and proactive transmission planning in New England.
- ISO-NE received 6 proposals from 4 bidders in 2 categories: (1) onshore AC upgrades meeting at least minimum requirements, and (2) subsea HVDC expanded-scope proposals.
- ISO-NE announced it would disqualify 4 bids from 3 bidders (leaving 2 bids from 1 bidder) without allowing for modifications to address issues with meeting the technical requirements for the solicitation.

The evaluation risks understating customer benefits

- Particularly for expanded-scope proposals, the quantitative benefit metrics only partially capture the regional value of LTTP proposals, which is likely to introduce an inadvertent bias towards lowest-cost, lower-benefit projects.
- Specifically, our review identifies three quantitative metrics that understate customer savings: (1) avoided local resource costs, (2) production cost and congestion savings, and (3) avoided transmission investment .

Our Recommendations

We recommend that ISO-NE consider allowing minor modifications to bids and enhance its evaluation process to better capture the benefits that are not currently quantified or are understated in the BCR metrics by:

1. Quantifying benefits more fully through sensitivity analyses that utilize updated assumptions; and
2. Giving appropriate weight to the specified additional evaluation factors in the selection process to reflect the full value provided by the proposals.

LTTP Solicitation Background

LTTP RFP Overview & Requirements

In response to a letter from NESCOE, ISO-NE is implementing its first LTTP solicitation process, which is a **major step forward for improving the effectiveness and proactive nature of regional transmission planning in New England**.

The RFP seeks proposals that will achieve the following by 2035:

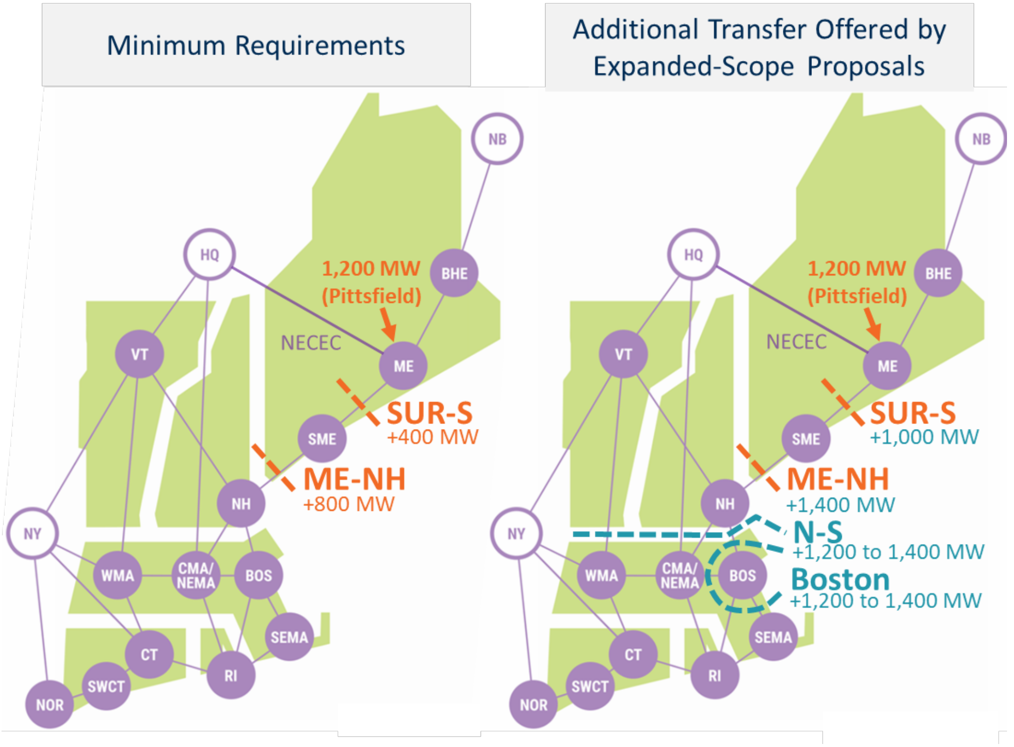
- Increase ME-NH interface capacity to at least 3,000 MW
- Increase the SUR-S interface capacity to at least 3,200 MW
- Accommodate interconnection of at least 1,200 MW of onshore wind interconnecting near Pittsfield, Maine

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 **benefits of the expanded scope “would be captured by ISO-NE in the LTTP evaluation process.”**

4 respondents submitted 6 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.

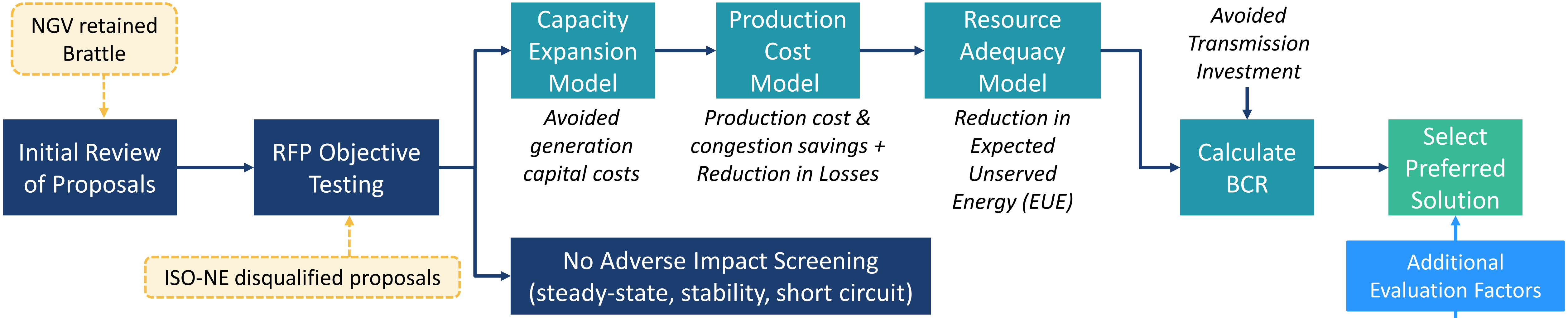
ID	Type	Short Desc	Cost	ISD
A1	AC	ME/NH AC #1	$2.20B	Q4 2032
A2	AC	ME/NH AC #2	$2.14B	Q4 2032
B1	DC	Maine-Mass DC	$4.04B	Q2 2035
C1	AC	ME/NH AC #3	$0.96B	Q2 2035
D1	DC	Wiscasset-Wakefield DC	$2.60B	Q3 2035
D2	DC	Wiscasset-Everett DC	$2.55B	Q3 2035

Note: Some (but not all) cost estimates shown above include costs for corollary upgrades, which will be replaced with estimated costs by the applicable PTO.



Sources: ISO-NE’s Maps and Diagrams; Locational Marginal Prices & Interface Flows; ISO-NE’s Longer-Term Proposals Summary.

ISO-NE Qualification and Evaluation Process



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

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

Disqualification of Projects

ISO-NE's screening of proposals identified concerns with four of the six proposals (and 3 of 4 bidders), including all of the expanded-scope proposals.

Respondents for C1, D1, and D2 requested to review the detailed results leading to their disqualification. This led to a change in C1's thermal and voltage results from fail to pass, but maintained their disqualification for stability failing. For D1 and D2, because minor modifications to satisfy the requirements were "not a clarification" of the proposal, ISO-NE reaffirmed their disqualification.[1]

By rejecting proposals for not meeting the evaluation's screening analyses and not allowing even minor changes in design to address the concerns, New England could miss the opportunity to achieve larger customer savings by developing a more valuable, cost-effective solution for addressing regional needs.

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D2	DC	Wiscasset-Everett DC	$2.55B	Q3 2035

(g) Proposal Deficiencies; Further Information

If the ISO identifies any minor deficiencies (compared with the requirements of Section 16.4(d)) in the information provided in connection with a Longer-Term Proposal, the ISO will notify the Qualified Transmission Project Sponsor that submitted the Longer-Term Proposal and provide an opportunity for the Qualified Transmission Project Sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, Qualified Transmission Project Sponsors of Longer-Term Proposals shall provide the ISO with additional information reasonably necessary for the ISO's evaluation of the proposed solutions. In providing information under this subsection (g), the Qualified Transmission Project Sponsor may not modify its project materially or submit a new project, but instead may clarify its Longer-Term Proposal.

Source: [1] ISO-NE, "RFP Objective Results Follow-Up," May 27, 2026, p. 6.

Why the Disqualifications Matter

A competitive LTTP process should balance rigorous technical screening with sufficient flexibility to preserve competition and identify the highest-value solution.

Competitive solicitations of solutions (not specific projects) work best with iterative bidder engagement to identify best solution

- Proposing different solutions is inherently more complex than submitting proposals to build a defined project
- Difficult for bidders to anticipate before submission all assumptions and study cases that ISO-NE will utilize for evaluations and screening
- Limited flexibility to address even minor design issues disadvantages innovative, broader-scope solutions and reduces competition

Other RTOs who solicit solutions (not projects) allow for flexibility

- For example: PJM works with bidders to allow for clarification, minor changes, and design optimization prior to the project selection (which may include combinations of proposed projects[1])

Risk of reduced competition in future solicitations

- ISO-NE's first competitive solicitation disqualified all but 4 out of 36 proposals, leading to fewer bidders/bids in this RFP
- The repeated exclusion of bids for minor deficiencies will likely discourage participation in future LTTP solicitations

	ISO-NE 1st Solicitation	This LTTP Solicitation	Next RFP
Bids	36 →	6	?
Bidders	8 →	4	?
Proposals Rejected	**31** (86%)	**4** (67%)	

This white paper and analysis was based on the assumption that at least some expanded-scope proposals would have qualified

Source: [1] PJM, "PJM Regional Transmission Expansion Planning (RTEP) Process," IPSAC, December 8, 2023, pp. 13-16.

Risk of Undervaluing LTTP Solutions

Risk of Selecting Lowest-Cost Instead of Highest-Value Bids

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.

ISO-NE's evaluation framework includes a broad set of benefit metrics, but its methodologies risk undervaluing customer benefits, especially for expanded scope proposals

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This could favor minimum-requirement options and result in overlooking more cost-effective solutions for broader needs that offer larger customer benefits

These concerns do not invalidate the LTTP evaluation framework, which quantifies some of the key cost savings; however, **projects that address a broader set of needs and provide a broader set of benefits are likely to appear less valuable than they are**.

BCR Alone May Not Identify the Highest-Value Solution

- Calculated BCR can favor smaller, lower-cost projects even when larger projects deliver greater net benefits to the region
- Understated benefits disproportionately affect expanded-scope projects because more of their value is unquantified
- Selection should consider both calculated BCR and total net customer benefits, including an appropriate weighting of qualitative factors

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**

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 much larger net benefit and associated cost savings to consumers in New England.

Understated Customer Benefit Metrics

Understated Avoided Future Transmission Investments

ISO-NE quantifies the value of LTTP projects that avoid or defer transmission upgrades.

However, the metric currently only considers:

- Existing Regional System Plan (RSP) projects
- Asset Condition List (ACL) projects
- Aging facilities (> 40 years old at time of operation)

This metric is focused mainly on reliability needs during the next 5 years—it does not capture any future (e.g., 2035-40) transmission needs beyond the current planning lists

Estimated Cumulative Costs for North-South/Boston Import Roadmaps

Year/Load Level	AC Roadmap	Minimization of New Lines Roadmap	Point-to-Point HVDC Roadmap	Offshore Grid Roadmap
2035	$4.4 Billion	$2.8 Billion	$5.0 Billion	$4.0 Billion
2040	$6.2 Billion	$5.0 Billion	$6.5 Billion	$5.8 Billion

Source: Duplicated from ISO-NE, 2050 Transmission Study, 2024 p. 49.

ISO-NE already identified **$3–$6.5 billion of 2035/2040 transmission upgrades** for the N-S and Boston Import interfaces, yet these investments are largely outside the current avoided-transmission-benefit metric. Expanded-scope solutions could defer or avoid some of these costs, including **$1.3 billion of AC Roadmap upgrades needed by 2035.**

By not considering these future transmission needs beyond planned upgrades on the RSP list, this metric will **significantly understate avoided transmission benefits.**

Understated Avoided Generation Capital Costs

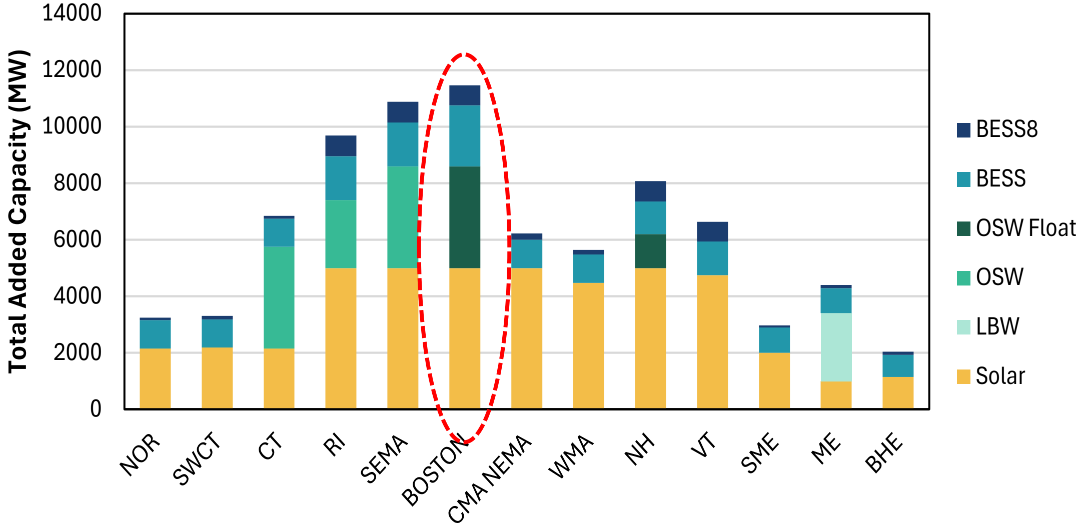
Key modeling assumptions likely understate benefits for projects that increase transfer capability beyond minimum requirements, leading to projected overbuilding in high-cost areas (e.g., Boston/MA) while under-developing lower-cost areas (e.g., ME):

1. **Uniform cost assumptions across region**
2. **Outdated capital cost assumptions**
3. **Unrealistically high build limits in certain regions**

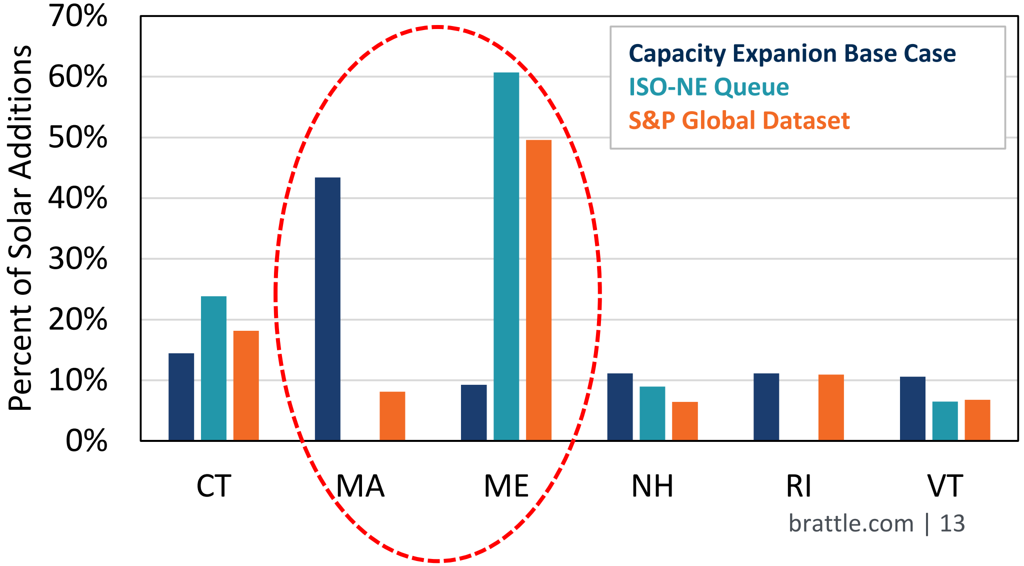
Expanded-scope projects that enable additional north-to-south transfers could shift several GW of solar to Maine from southern New England.

Estimated **20-30% lower development costs** in Maine versus Massachusetts imply an **additional $0.8-$1.8 billion in savings** not captured in this metric.

Base Case Capacity Expansion Results, 2035 to 2050



Share of Total Solar Capacity Expansion by State



Understated Production Cost & Congestion Savings

Production cost model likely understates benefits:

1. **Simulates only normalized conditions,** missing extreme weather, fuel price spikes, and system stress
2. **Assumes perfect foresight,** missing real-time operational challenges
3. **Does not capture outage impacts,** missing transmission outages and construction-related outages

These limitations bias results towards "average" operating conditions even though extreme conditions and events are primary drivers of system risk and congestion costs (*approximately 50% of total regional and interregional transmission value is concentrated in just 5% of all hours*[1]).

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

Source: 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.

ISO-NE 2023 simulations show that the model produced market prices approximately **35% below observed prices.**

NYISO applies **40–56% adders** to production cost savings to **reflect real-time operating conditions not captured in standard simulations.**

Source: *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; NYISO, NYISO MMU Evaluation of the Proposed AC Public Policy Transmission Projects, p. 16.

Applying the 35% adjustment factor to NGV's quantification of estimated congestion cost savings using the public model means **consumer savings would be understated by nearly $1 billion.**

Sources: [1] D. Millstein, et al. (Lawrence Berkeley National Laboratory), Empirical Estimates of Transmission Value using Locational Marginal Prices, August 2022, p. 27.

BCR Methodology Understates Total Consumer Benefits

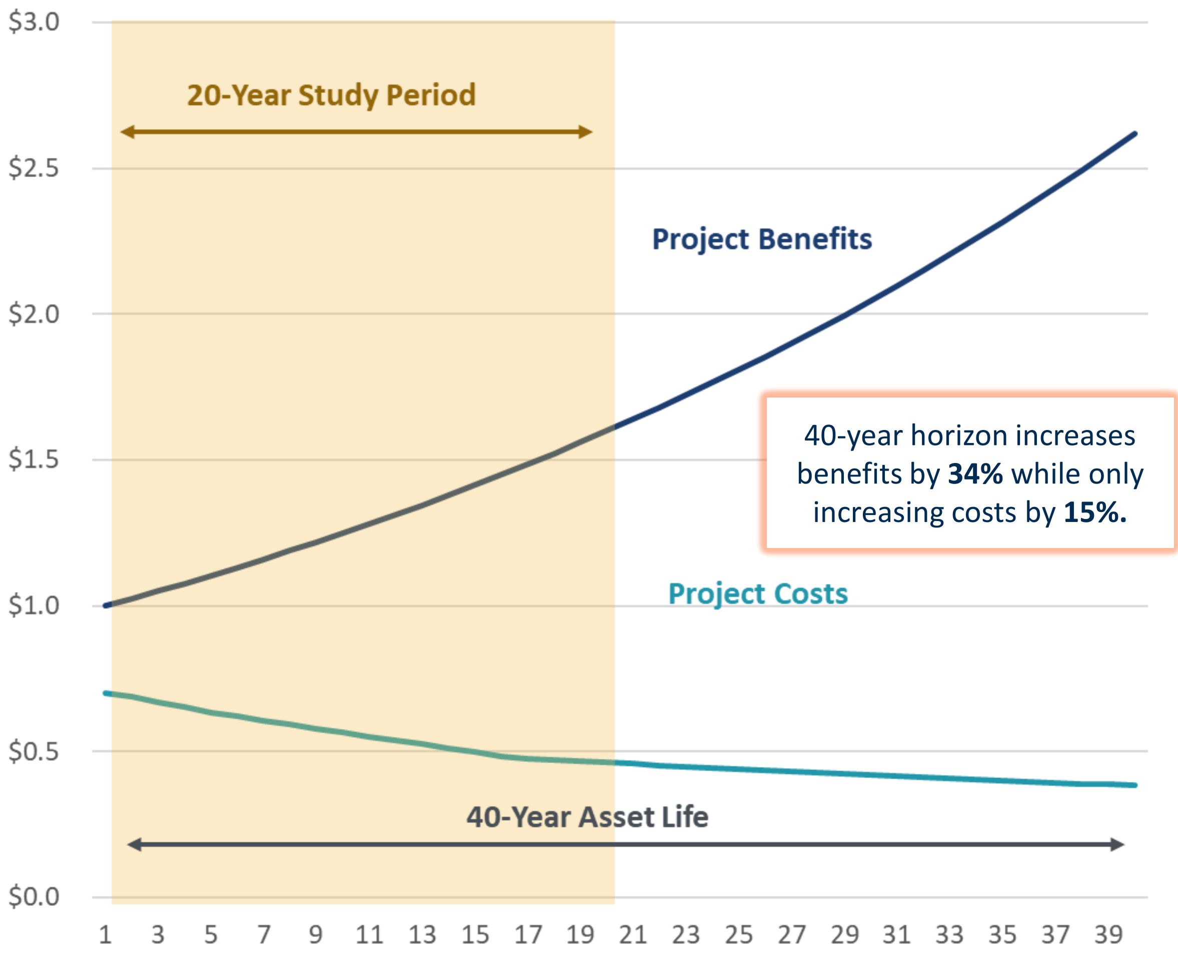
ISO-NE's BCR Methodology uses:

- 20-year evaluation horizon
- 8.2% discount rate

This places disproportionate weight on early-year costs relative to later-year benefits. A sensitivity of **40 years** would align the expected asset life (conservatively). Additionally, ATWACC of transmission owners is typically 6.5 – 7%, which would increase the present value of benefits.

For example, MISO evaluates benefits over both 20- and 40-year horizons and reports results both a 7.1% transmission-owner WACC and a 3% societal discount rate.

The combined effect of testing a longer benefit horizon (40 years) and lower discount rate (7%) would **increase value the true long-term BCR by over 20%.**



Importance of Additional Evaluation Factors

Relevant “Evaluation Factors” to Capture Broader System Value

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

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 evaluation factors when selecting the preferred transmission solution.

Several of these factors are particularly relevant to capture the broader system value of the LTTP proposals, specifically those with expanded scope; however, they are second- and third-tier priority.

Advanced HVDC Benefits May Not be Captured

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.

Some benefits, particularly those associated with advanced HVDC technology, are difficult to fully capture in traditional BCR metrics; therefore, consideration of their value in the additional evaluation factors is required.

Even if a HVDC project is not ultimately the chosen highest-value solution, these benefits should be assessed to ensure that potentially higher-value projects are not overlooked.

Case Study: Ontario IESO Toronto IRRP

Evaluated two conventional onshore AC expansion options (CAD $800–900 million) and an underwater HVDC option (CAD $1.5 billion); selected the **HVDC solution despite higher upfront cost.**

Decision based on benefits not fully captured:

- Largest long-term load serving capability
- New geographically diverse transmission corridor
- Improved resilience and restoration capability
- Dynamic reactive power and voltage control
- Operational flexibility and increased stability
- Avoidance of future transmission upgrades

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.

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."

Sources: IESO Toronto IRRP; 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.

Recommendations for Enhancing the LTTP Selection Process

Supplementing the Specified Evaluation Criteria

Under the current modeling assumptions, benefit metrics, and evaluation criteria established for this RFP, we recommend the ISO-NE supplement the specified evaluation criteria in two ways.

Sensitivity Analyses

Sensitivity analyses can be used to estimate the value of unquantified or understated benefit metrics using updated assumptions to more fully capture actual project benefits.

These sensitivities should be incorporated into future LTTP solicitations to more accurately assess the benefits that proposals could provide New England.

Sufficient Weighting of Factors

The additional evaluation factors should be given sufficient weight to capture their likely importance in terms of long-term consumer benefits.

The likely importance of additional factors can be informed by the sensitivity analyses performed. Unquantified benefits should have their importance considered qualitatively.

Understanding the magnitude of understated or not quantified benefits helps to ensure the evaluation process selects a solution that offers the highest net benefits and overall cost savings to consumers in New England.

Sensitivity Analyses for a Robust Selection Process

1. Identify avoidable transmission costs beyond RSP list
2. Value the resilience benefit of additional transmission corridor
3. Update capacity expansion model zonal capital costs
4. Update capacity expansion model zonal build Limits
5. Calibrate production cost model (or use multiplier)
6. Optimize HVDC dispatch in production cost model
7. Simulate challenging market & weather conditions
8. Consider longer-term value in benefit-cost analysis
9. Consider congestion during construction outages
10. Consider the value of facilitating future expansions

Conclusion

The objective of the LTTP solicitation should be to identify the transmission solution that maximizes long-term consumer savings and system value for New England.

ISO-NE is taking a major step forward with the first LTTP solicitation

- 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

Enhanced benefit calculation methods and sufficient weighting of additional factors will help to select the project with highest value to the region

- 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

To keep future solicitations competitive, ISO-NE should engage with bidders and allow minor changes to resolve identified concerns (particularly if modifications do not require change in bid price)

- Solicitations for a given need, rather than a specific project, require flexibility to fully design around hundreds of screening analyses. Bidders may not be able to run all of these analyses and mirror ISO-NE assumptions fully
- Excluding 4 of 6 proposals and 3 of 4 bidders now risks even less interest in the next competitive process

Questions?

(Additional Slides)

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Appendix

Summary of LTTP Benefits, Eval Criteria, and Extent to Which 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.

Detailed Sensitivity Analyses for a Robust Selection Process

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 NS/Boston interfaces that address the 2035-2040 transmission system needs identified in the 2050 study.

2

Value the Resilience Benefit of 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.

Detailed Sensitivity Analyses for a Robust Selection Process (cont.)

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 & 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.

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.

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