Longer-Term Proposal Evaluations and Selection of the Preferred Longer-Term Transmission Solution

2025 Longer-Term Transmission Planning RFP

August 14, 2026

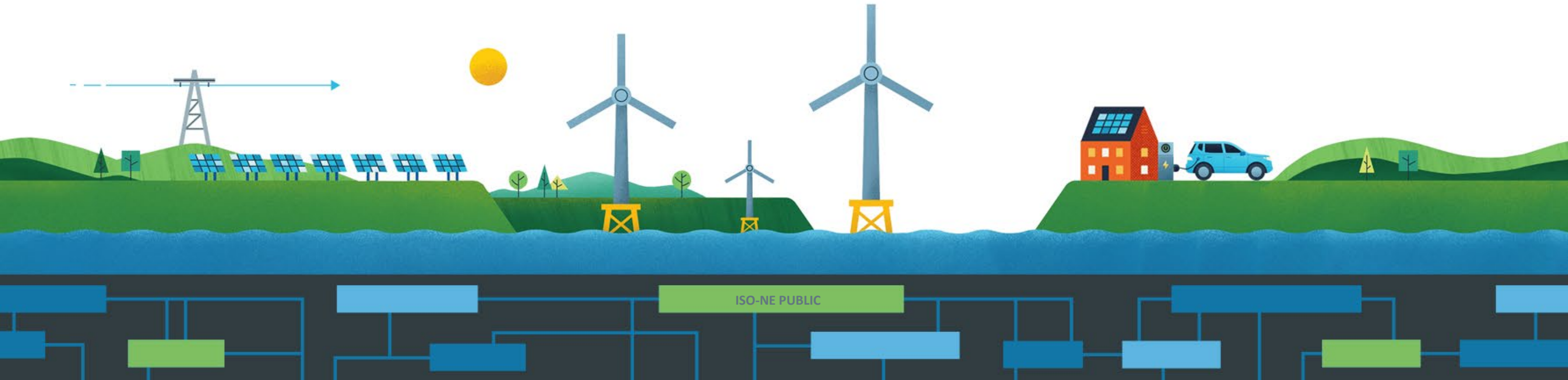


Table of Contents

Figures

Tables

Section 1
Executive Summary

This section summarizes ISO New England's analysis of submissions received in response to the March 2025 Request for Proposals and identifies the preferred Longer-Term Transmission Solution to address longer-term needs on New England's transmission system.

1.1 The Request for Proposals

On March 31, 2025, ISO-NE issued a Longer-Term Transmission Planning (LTTP) Request for Proposals (RFP) (2025 LTTP RFP or RFP) in response to a December 13, 2024 communication from the New England States Committee on Electricity (NESCOE). NESCOE identified three longer-term needs for the Longer-Term Proposals (proposals or LTPs) to address by Dec. 31, 2035. Those needs are shown in Table 1-1. Submissions were due by 11:00 p.m. EDT Sept. 30, 2025.

Table 1-1
2025 LTTP RFP Longer-Term Needs

Unique Identifier	Need Description
LT-1	Increase the Maine-New Hampshire interface capability to at least 3,000 MW
LT-2	Increase the Surowiec-South interface capability to at least 3,200 MW
LT-3	Develop new infrastructure at Pittsfield, Maine, or at an alternate location north of the Albion Road substation, that can accommodate the interconnection of at least 1,200 MW (nameplate) of onshore wind

ISO New England received six Longer-Term Proposals, three of which were primarily AC transmission and three primarily HVDC transmission projects. The projects' installed costs, as provided by the project sponsors, ranged between $0.96B and $4.04B, and the in-service dates ranged between Q4 2032 and Q3 2035. Table 1-2 lists the proposals and costs.[1]

Table 1-2
2025 LTTP RFP Longer-Term Proposal Summary

ID	Lead QTPS	Type	Short Desc	Cost	ISD
A1	Central Maine Power	AC	ME/NH AC #1	$2.20B	Q4 2032
A2	Central Maine Power	AC	ME/NH AC #2	$2.14B	Q4 2032
B1	energyRe Giga-Projects USA	DC	Maine-Mass DC	$4.04B	Q2 2035
C1	[Confidential]	AC	ME/NH AC #3	$0.96B	Q2 2035
D1	NGV US Transmission	DC	Wiscasset-Wakefield DC	$2.60B	Q3 2035
D2	NGV US Transmission	DC	Wiscasset-Everett DC	$2.55B	Q3 2035

[1] Some Longer-Term Proposals included cost estimates for corollary upgrades, which were replaced, as necessary, with cost estimates provided by the applicable Participating Transmission Owner(s) (PTO) for modifications to their existing equipment.

1.2 Evaluation of the Proposals

ISO-NE performed the following review steps for each Longer-Term Proposal consistent with Sections 16.4(f)-(h) of Attachment K of Section II of the ISO New England Inc. Transmission, Markets and Services Tariff (ISO Tariff, the Tariff, or the Open Access Transmission Tariff (OATT)), which specifies the process:

- Initial review – Section 16.4(f)(i), (iii), and (iv) and 16.4(g)
- RFP objectives testing – Section 16.4(f)(ii)
- Benefits calculation – Section 16.4(h) [2]
- Independent review of cost estimates – Section 16.4(f)
- Evaluation of factors – Section 16.4(h)

The ISO also performed a no adverse impact screening.[2]

Two proposals (A1 and A2) met the criteria for the first two steps and proceeded to no adverse impact screening and benefits calculations. Four proposals (B1, C1, D1, and D2) were excluded from future consideration following the initial review and objectives testing:

- C1 did not meet Tariff and RFP requirements during the initial review. The proposal included the installation of two new circuit breakers at an existing PTO facility that was not part of the proposal's interconnection.
- Proposals B1, C1, D1, and D2 failed at least one of the RFP objectives.
    - Proposal B1 failed the steady state thermal and voltage transfer capability testing (LT-1 and LT-2) and the energy and capacity standard tests (LT-3). Stability analysis was not performed on this proposal due to its failures in steady state.
    - Proposals C1, D1, and D2 failed stability testing (LT-1 and LT-2).

ISO-NE performed a preliminary screening for potential significant adverse effect on leading proposals A1 and A2. The screening included steady state, stability, and short-circuit testing. This no adverse impact screening of proposals A1 and A2 flagged potential issues with N-1 thermal overloads, N-1-1 low voltages, and overdutied circuit breakers at two substations. Because both proposals had the same potential to cause a significant adverse effect, this screening was not a deciding factor in selecting the preferred solution.

As required by Section 16.4(h) of Attachment K of the OATT, the ISO calculated a benefit-to-cost ratio (BCR) for proposals A1 and A2. The Tariff requires candidates for the preferred Longer-Term Transmission Solution to have a ratio greater than 1.0. Proposals A1 and A2 each satisfied this requirement, with A1 having a BCR of 2.17 and A2 having a BCR of 2.22. Therefore, the ISO deemed both A1 and A2 eligible for selection as the preferred Longer-Term Transmission Solution.

Independent external consultants reviewed proposals A1 and A2 for construction and financial viability.

[2] The benefits calculation and no adverse impact screening steps were only performed on proposals that passed the initial review and RFP objectives testing.

The construction consultant detailed that both proposals rely on proven technologies and are broadly consistent with ISO-NE, NERC, and NPCC reliability requirements. They have the same constructability strength for rights-of-way (ROW) and procurement planning. Both also rely on conceptual engineering and early-stage design assumptions to develop unit pricing and total project costs, which is appropriate given the current level of project definition.

The financial consultant described that the sponsors for proposals A1 and A2 demonstrate adequate-to-strong overall financial capabilities to support their proposals' equity, debt, and liquidity demands. Differences between proposals A1 and A2 are relatively minor, and their financial performance is similar relative to one another. The primary drivers of cost differences are base capital costs; capital structure and cost containment are identical.

The ISO considered a list of evaluation factors detailed in Attachment A of [NESCOE's RFP Request](#).

Table 1-3 shows NESCOE's priorities for the evaluation factors.

Table 1-3
2025 LTTP RFP Evaluation Factors Provided by NESCOE

A Factors (Highest Priority)	B Factors (Second Highest Priority)	C Factors (Third Highest Priority)
Life-cycle cost	Extreme contingency performance	Project constructability
Cost Cap or Cost Containment Provisions	Impact on Other Interface Limits	Generation and Transmission Facility Outages Required During Construction
Potential Siting/Permitting Issues or Delays	Operational Impacts	Incremental Costs for Potential Resource Retirement
Future Expandability	Winter Reliability Impacts	Consistency with Good Utility Practice
In-Service Date of the Project	Environmental Impact	Design Standards
QTPS Capabilities		Joint Proposals
System Performance		Deployment of Advanced Transmission Technologies
Impact on NPCC BPS Classification		

Table 1-4 gives a comparison of the performance on priority A evaluation factors for A1 and A2.

Table 1-4
Comparison of NESCOE Priority A Evaluation Factors for Proposals A1 and A2

<table>
<tr><th>Evaluation A Factor</th><th>A1</th><th>A2</th></tr>
<tr><td>1. Life-Cycle Cost</td><td></td><td>✓</td></tr>
<tr><td>2. Cost Cap or Cost Containment Provisions</td><td colspan="2">Same</td></tr>
<tr><td>3. Potential Siting/Permitting Issues or Delays</td><td>✓</td><td></td></tr>
<tr><td>4. Future Expandability</td><td colspan="2">Same</td></tr>
<tr><td>5. In-Service Date</td><td colspan="2">Same</td></tr>
<tr><td>6. QTPS Capabilities</td><td colspan="2">Same</td></tr>
<tr><td>7. System Performance</td><td colspan="2">Same</td></tr>
<tr><td>8. Impact on NPCC BPS Classification</td><td colspan="2">Same</td></tr>
</table>

The two proposals were nearly identical for all B and C factors; therefore, these were not a deciding factor in the selection of the preferred Longer-Term Transmission Solution.

Life-cycle cost and siting/permitting were the only two evaluation factors that differed between A1 and A2 due to their design of the right-of-way (ROW) between the ME/NH state border and the Deerfield, NH substation. Proposal A2's 20-year present value revenue requirement (PVRR) is 2.47% lower and its benefit-to-cost ratio is 0.05 higher than proposal A1, giving it a slight edge for the life-cycle cost evaluation factor. For siting/permitting, proposal A2 requires building taller towers at the edge of the ROW, leading to potentially significantly higher siting/permitting risk when compared to proposal A1, which does not need these taller towers.

1.3 The Preferred Solution

Based on the results of the comprehensive evaluation of Longer-Term Proposals A1 and A2, and having taken into consideration the independent construction and financial review of the proposals, as well as NESCOE's evaluation factors, pursuant to Section 16.4(h) of Attachment K of the OATT, ISO-NE selected Longer-Term Proposal A1 as the preferred Longer-Term Transmission Solution for the 2025 LTTP RFP. Despite proposal A2 being slightly less costly and having a slightly higher benefit-to-cost ratio, NESCOE's priority A factor regarding permitting/siting weighed heavily in the ISO's selection.

Section 2
Background & Overview

This section provides background information for the RFP, an overview of each proposal, and a summary of the proposal review process.

2.1 Background

On March 31, 2025, pursuant to Section 16.4 of Attachment K of the OATT, ISO-NE issued an RFP to solicit Longer-Term Proposals from Qualified Transmission Project Sponsors (QTPSs) to:

a) Comprehensively address the identified needs as detailed in Section 2 of Part 1 of the RFP, and
b) Own, operate, and maintain the projects

This request came in response to a December 13, 2024 communication from the New England States Committee on Electricity (NESCOE) to ISO-NE, requesting that the ISO issue an RFP to address certain longer-term needs in connection with the 2050 Transmission Study. This Longer-Term Transmission Study (LTTS) determined the region's transmission needs to serve load under a wide variety of future system conditions, while satisfying reliability criteria of the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and ISO-NE. To this end, the 2050 Transmission Study identified certain "high-likelihood concerns", as well as high-level transmission upgrades designed to address those concerns.

NESCOE requested that the RFP procure transmission to address one such high-likelihood concern: limitations on transfers from northern New England (specifically Maine) to southern New England. In the request, NESCOE required proposals to address three longer-term needs:

- LT-1: A requirement to increase the Maine-New Hampshire interface capability to at least 3,000 MW;
- LT-2: A requirement to increase the Surowiec-South interface capability to at least 3,200 MW; and
- LT-3: A requirement to develop new infrastructure at Pittsfield, Maine, or at an alternate location north of the Albion Road substation, that can accommodate the interconnection of at least 1,200 MW (nameplate) of onshore wind.

Longer-Term Proposals in response to the RFP (proposals or LTPs) were due by 11:00PM EDT September 30, 2025. During the RFP window, QTPSs were able to ask questions to clarify details of the RFP and the associated models. The ISO responded to over 200 questions from QTPSs during the 6-month window.

2.2 The Longer-Term Proposals

In total, six Longer-Term Proposals were submitted by QTPSs to ISO-NE. Each proposal was given a letter-number combination (A1, A2, B1, C1, D1, and D2) to maintain their anonymity throughout the evaluation process. LTPs A1 and A2 were submitted by the same QTPS(s), as were LTPs D1 and D2. Following the completion of the evaluation, permission was given by the Lead QTPS to disclose their name and the names of any joint QTPS(s) involved in the proposal, unless otherwise noted. The six proposals are summarized below, then detailed in the following sections of this report.

2.2.1 Longer-Term Proposal A1

- Lead QTPS: Central Maine Power (CMP)
- Joint Proposal: Yes w/ Public Service New Hampshire (PSNH) and NSTAR Electric Company (NSTAR) (collectively Eversource)
- Type: AC transmission in ME and NH
- Installed Cost as provided by the QTPS: $2.20B
- Cost Containment: Yes
- Construction Start: Q1 2029, In-Service Date: Q4 2032
- Design Summary
  - Wind interconnection POI: Pittsfield
  - New 345 kV lines: Pittsfield-Coopers Mills & Buxton-Deerfield (70 mi total)
  - Rebuild Larrabee Rd-Surowiec 115 kV line to operate at 345 kV
  - Several reconductored 345 & 115 kV lines
  - Retire ME Yankee 345 kV substation, build new adjacent Old Ferry Rd 345 kV
  - New STATCOMs: Eight 400 MVAR @ 345 kV
  - New Phase Angle Regulators: Four 750 MVA @ 345 kV
  - Minor corollary upgrade

2.2.2 Longer-Term Proposal A2

- Lead QTPS: Central Maine Power (CMP)
- Joint Proposal: Yes w/ Public Service New Hampshire (PSNH) and NSTAR Electric Company (NSTAR) (collectively Eversource)
- Type: AC transmission in ME and NH
- Installed Cost as provided by the QTPS: $2.14B
- Cost Containment: Yes
- Construction Start: Q1 2029, In-Service Date: Q4 2032
- Design Summary
  - Wind interconnection POI: Pittsfield
  - New 345 kV lines: Pittsfield-Coopers Mills & Buxton-Deerfield (70 mi total)
  - Rebuild Larrabee Rd-Surowiec 115 kV line to operate at 345 kV
  - Several reconductored 345 & 115 kV lines
  - Retire ME Yankee 345 kV substation, build new adjacent Old Ferry Rd 345 kV
  - New STATCOMs: Eight 400 MVAR @ 345 kV
  - New Phase Angle Regulators: Four 750 MVA @ 345 kV
  - Minor corollary upgrade

2.2.3 Longer-Term Proposal B1

- Lead QTPS: energyRe Giga-Projects USA
- Joint Proposal: No
- Type: HVDC (Maine to Massachusetts)
- Installed Cost as provided by the QTPS: $4.04B
- Cost Containment: Yes
- Construction Start: Q2 2031
- In-Service Date: Q2 2035
- Design Summary

    - Proposal includes work in ME, NH, MA, and CT
    - New High-Voltage Direct Current (HVDC) line (Maine-Massachusetts)
    - Upgrades to 345, 115, & 69 kV lines in ME, NH, and CT

2.2.4 Longer-Term Proposal C1

- Lead QTPS: [Confidential]
- Joint Proposal: No
- Type: AC transmission
- Installed Cost as provided by the QTPS: $0.96B
- Cost Containment: Yes
- Construction Start: Q2 2030
- In-Service Date: Q2 2035
- Design Summary
    - Proposal includes work in ME and NH
    - New/updated 345 & 115 kV AC lines in ME and NH

2.2.5 Longer-Term Proposal D1

- Lead QTPS: NGV US Transmission
- Joint Proposal: Yes w/ New England Power Company (National Grid) and Massachusetts Municipal Wholesale Electric Company (MMWEC)
- Type: HVDC (Wiscasset, ME – Wakefield, MA)
- Installed Cost as provided by the QTPS: $2.60B
- Cost Containment: Yes
- Construction Start Q4 2031
- In-Service Date: Q3 2035
- Design Summary
    - Proposal includes work in ME, NH, and MA
    - New HVDC line (Wiscasset, ME – Wakefield, MA)
    - New/updated 345 & 115 kV lines in ME, NH, and MA

2.2.6 Longer-Term Proposal D2

- Lead QTPS: NGV US Transmission
- Joint Proposal: Yes w/ New England Power Company (National Grid) and Massachusetts Municipal Wholesale Electric Company (MMWEC)
- Type: HVDC (Wiscasset, ME – Everett, MA)
- Installed Cost as provided by the QTPS: $2.55B
- Cost Containment: Yes
- Construction Start: Q4 2031
- In-Service Date: Q3 2035
- Design Summary
    - Proposal includes work in ME, NH, and MA
    - New HVDC line (Wiscasset, ME – Everett, MA)
    - New/updated 345 & 115 kV lines in ME, NH, and MA

2.3 Proposal Review & Analysis

Pursuant to Section 16.4(f) of Attachment K of the OATT, ISO-NE performed an initial review of each proposal to determine whether it met Tariff-specified criteria. The Tariff requires, in part, that the proposal in question:

> *(ii) satisfies the needs identified in the request for proposal;*
> *(iii) is technically practicable and indicates possession of, or an approach to acquiring, the necessary rights of way, property and facilities that will make the proposal reasonably feasible in the required timeframe; and*
> *(iv) is eligible to be constructed only by an existing PTO in accordance with Schedule 3.09(a) of the TOA because the proposed solution is an upgrade to existing PTO facilities*

After this initial review, the ISO performed RFP objective testing to ensure the proposals satisfied all three needs identified in the RFP (LT-1, LT-2, and LT-3). Proposals needed to pass the following tests to move on to further analysis:

- **"Energy Standard" testing**: Does the proposal allow at least 1,200 MW of Northern ME onshore wind to interconnect without further upgrades? (LT-3)
- **"Capacity Standard" testing**: Is the 1,200 MW of new onshore wind, derated to the expected output under various load conditions, useful as new capacity? (LT-3)
- **"Transfer Analysis" testing**: Does the proposal meet the RFP's transfer capability requirements for Maine-New Hampshire and Surowiec-South? (LT-1 and LT-2)

The ISO then performed a preliminary screening for significant adverse effect on leading proposals A1 and A2. While this screening was similar to the Section I.3.9 Proposed Plan Application (PPA) assessment that will follow the selection of the preferred Longer-Term Transmission Solution, it does not supplant the Section I.3.9 requirements. Full Section I.3.9 PPA and approval are required to account for any updates that occurred after the submission of the proposal in response to the RFP.

After the initial screening, and pursuant to Section 16.4(h) of Attachment K of the OATT, the ISO then performed a Benefit-to-Cost Ratio (BCR) analysis to determine the financial benefits associated with the proposals that satisfied the three longer-term needs identified in the RFP. The financial benefits include the following:

- Production cost and congestion savings
- Avoided capital cost of local resources needed to serve demand
- Avoided transmission investment
- Reduction in losses
- Reduction in expected unserved energy

To be eligible for consideration as the preferred Longer-Term Transmission Solution, the proposal needed to provide a BCR of greater than 1.0, where BCR equals financial benefits divided by the project costs. Financial benefits and costs in the BCR calculation were set equal to the present value of the five, financially-quantifiable benefits provided by the project, projected through the first 20 years of the project's life. Project costs were set equal to the present value of the annual revenue requirements for the first 20 years of the project's life.

Proposals with a BCR of greater than 1.0 were then compared using the evaluation factors provided by NESCOE, shown in Table 1-4. Priority A factors were given the most weight, followed by priority B, followed by priority C. The combination of these factors, along with the BCR, were ultimately used to make the selection of the preferred Longer-Term Transmission Solution.

These review steps are described in more detail in the following sections. Figure 2-1 illustrates each step of the review.

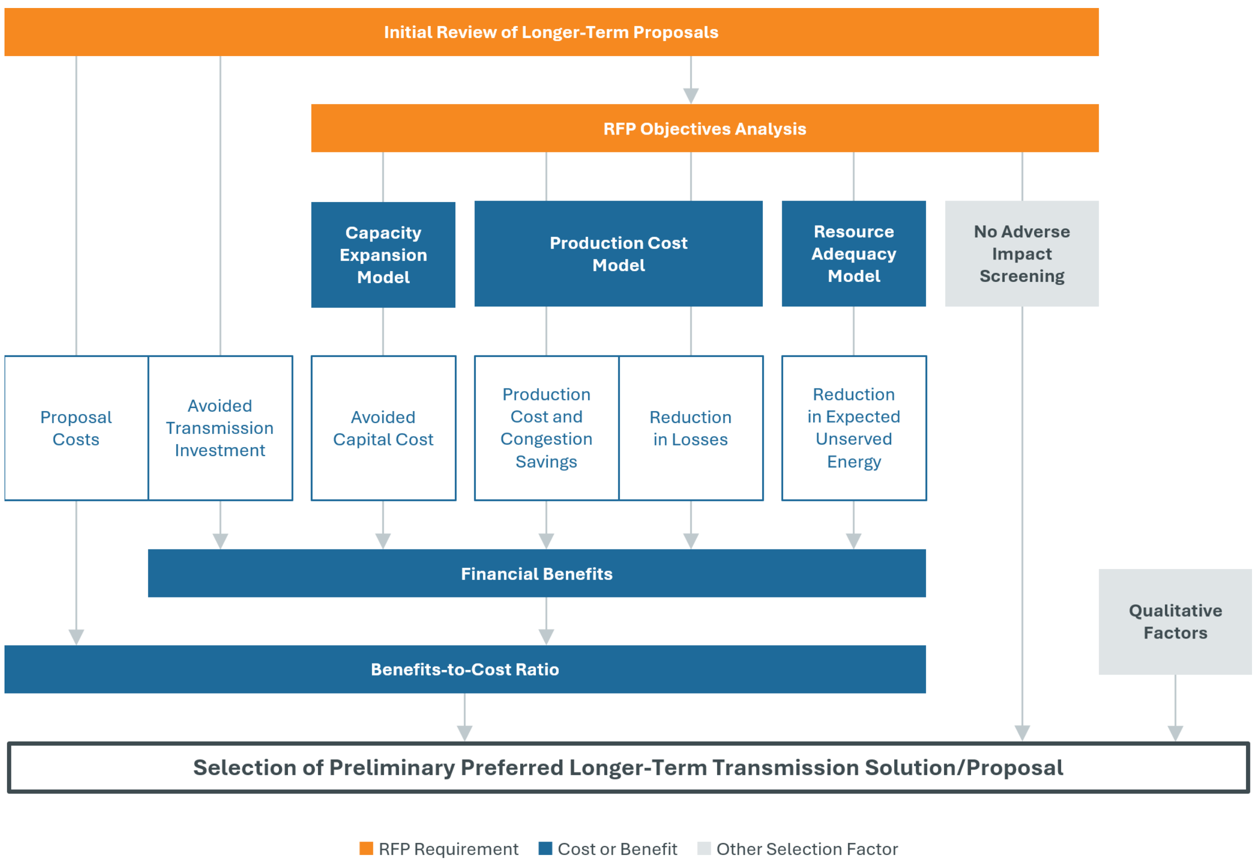


Figure 2-1: Overview of RFP Evaluation and Selection Process

Section 3
Initial Review of Longer-Term Proposals (LTPs)

3.1 Overview of Proposal Review

As part of the initial review of the six Longer-Term Proposals, all joint proposals were required to demonstrate that each non-lead participant was an ISO-qualified QTPS. Not meeting this requirement would be grounds for dismissal for failure to meet the Tariff. All joint proposals met this requirement.

Following verification that each non-lead participant was ISO-qualified, the ISO conducted a high-level screening to confirm each proposal complied with the basic RFP requirements. This review focused on submitted text and attachments only and did not include technical evaluation. The review verified that all QTPSs provided responses to the required questions, all attachments were included, and all necessary modeling information for the proposal was included. Minor deficiencies found in any submitted proposals were handled in accordance with Section 16.4(g) of Attachment K of the OATT, which states:

> *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.*

ISO-NE reached out to the QTPSs for any proposals found to have minor deficiencies and requested clarifications on the deficiencies. Consistent with Section 16.4(g), the ISO only accepted clarifications to the proposals.

The initial review also verified that each proposal claimed to meet all three of the RFP's longer-term needs: LT-1, LT-2, and LT-3. In the RFP objectives testing portion of the evaluation, ISO-NE conducted a thorough technical evaluation of these claims (See Section 4). The in-service dates were compared to the RFP specifications to ensure that the QTPSs planned to complete construction by the December 31, 2035 deadline, or provided an acceptable reason to push completion of the project to a later date.

The ISO also reviewed that each proposal met the requirements in Section 16.4(f), including that the corollary upgrades listed in the proposals were eligible to be considered corollary upgrades. Section 16.4(f) of Attachment K of the OATT states, in part:

> *Upon receipt of Longer-Term Proposals, the ISO shall perform a review of each proposal to determine whether the proposal:*
>
> *(i) provides sufficient data and that the data is of sufficient quality to satisfy Section 16.4(d);*

(ii) satisfies the needs identified in the request for proposal;
(iii) is technically practicable and indicates possession of, or an approach to acquiring, the necessary rights of way, property and facilities that will make the proposal reasonably feasible in the required timeframe; and;
(iv) is eligible to be constructed only by an existing PTO in accordance with Schedule 3.09(a) of the TOA because the proposed solution is an upgrade to existing PTO facilities or because the costs of the proposed solution are not eligible for regional cost allocation under the OATT and will be allocated only to the local customers of a PTO.

3.2 Initial Review of LTP A1

After several rounds of questions and answers during the cure-for-deficiencies period, ISO-NE found that LTP A1 met the Tariff and RFP requirements in the initial review of the proposal. LTP A1 moved on to the technical objectives testing portion of the RFP evaluation.

3.3 Initial Review of LTP A2

After several rounds of questions and answers during the cure-for-deficiencies period, ISO-NE found that LTP A2 met the Tariff and RFP requirements in the initial review of the proposal. LTP A2 moved on to the technical objectives testing portion of the RFP evaluation.

3.4 Initial Review of LTP B1

After several rounds of questions and answers during the cure-for-deficiencies period, ISO-NE found that LTP B1 met the Tariff and RFP requirements in the initial review of the proposal. LTP B1 moved on to the technical objectives testing portion of the RFP evaluation.

3.5 Initial Review of LTP C1

LTP C1 included an upgrade designed to install two new circuit breakers in an existing bay at a Maine substation. These breakers were not related to the interconnection of any other part of the proposal.

During the cure-for-deficiencies period, ISO-NE asked the QTPS for LTP C1 if an agreement had been reached between the QTPS and the PTO of the Maine substation, since the installation of these two circuit breakers did not meet the requirements to be considered corollary upgrades. In response, the QTPS indicated that they did not pursue such an agreement, because the QTPS considered the installation of these two circuit breakers corollary upgrades. Section 16.4(d) of Attachment K of the OATT states:

> *A Qualified Transmission Project Sponsor may submit a proposed solution that includes an **upgrade(s)** located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases, the Qualified Transmission Project Sponsor's proposed solution relating to the upgrade(s) of an existing transmission system element(s) must provide all data available to the Qualified Transmission Project Sponsor as part of its response to the request for proposal. The Qualified Transmission Project Sponsor is not required to procure agreements with the PTO for implementation of such upgrades as the PTO is required to implement the upgrade(s) in accordance with Schedule 3.09(a) of the Transmission Operating*

Agreement if the proposed solution is selected through the competitive process. *(**emphasis added**)*

Per this requirement, only upgrades to existing equipment may be considered a corollary upgrade. Installing new equipment, such as a circuit breaker, is not considered an "upgrade" per the Tariff. This requirement was discussed in a response provided to all QTPSs to a question asked during the RFP window. LTP C1 did not meet the requirements of the ISO Tariff for this RFP.[3]

3.6 Initial Review of LTP D1

After several rounds of questions and answers during the cure-for-deficiencies period, ISO-NE found that LTP D1 met the Tariff and RFP requirements in the initial review of the proposal. LTP D1 moved on to the technical objectives testing portion of the RFP evaluation.

3.7 Initial Review of LTP D2

After several rounds of questions and answers during the cure-for-deficiencies period, ISO-NE found that LTP D2 met the Tariff and RFP requirements in the initial review of the proposal. LTP D2 moved on to the technical objectives testing portion of the RFP evaluation.

3.8 Conclusions from Initial Proposal Review

The initial review demonstrated that five of the six proposals met the RFP requirements, with no Tariff violations. As noted above, LTP C1 did not meet the requirements of the ISO Tariff for this RFP.

While not the primary focus of the initial review, ISO-NE reviewed costs and associated cost documents to determine if they were complete. They were more extensively reviewed by external consultants later in the process. The initial review informed questions posed to the QTPS to ensure costs for parts of the proposals were correctly captured and placed in the correct cost category (Pool Transmission Facilities [PTF] or Other). Additionally, some proposals included their own cost estimates for the corollary upgrades, and the ISO's review ensured those were not captured for a second time in the cost workbooks. Since the PTOs would eventually provide these estimates, ISO-NE needed to prevent double counting.

[3] Despite C1 failing to meet the requirements of the Tariff, the proposal was tested on the technical objectives of the RFP evaluation. This was done because those two workstreams were done in parallel to improve the efficiency of the overall evaluation timeline.

Section 4
RFP Objectives Analysis

The goal of the RFP objective analysis was to evaluate each proposal for their ability to meet the longer-term needs identified in the RFP (LT-1, LT-2, and LT-3). If a proposal failed to meet any of these requirements, it was excluded from further consideration in the RFP. For reference, the longer-term needs were:

- LT-1: A requirement to increase the Maine-New Hampshire interface capability to at least 3,000 MW;
- LT-2: A requirement to increase the Surowiec-South interface capability to at least 3,200 MW; and
- LT-3: A requirement to develop new infrastructure at Pittsfield, Maine, or at an alternate location north of the Albion Road substation, that can accommodate the interconnection of at least 1,200 MW (nameplate) of onshore wind.

4.1 Methodology, Study Assumptions, and Criteria

The RFP objective analysis was performed in accordance with applicable requirements from the following standards and criteria:

- NERC TPL-001: Transmission System Planning Performance Requirements[4]
- NERC NUC-001: Nuclear Plant Interface Coordination[5]
- NPCC Regional Reliability Reference Directory #1: Design and Operation of the Bulk Power System, and
- ISO New England Planning Procedure 3: Reliability Standards for the New England Area Pool Transmission Facilities (PP3)

Additional details on criteria and assumptions for this study are found in Section 4.2, Technical Analysis of the Longer-Term Proposals in Part 1 of the RFP document.

4.2 Areas Studied

The study area spans the states of Maine, New Hampshire, and northeastern Massachusetts. Figure 4-1 highlights the study area, the Maine-New Hampshire (ME-NH) and Surowiec-South interfaces, and other relevant interfaces in the study.

[4] Search for TPL-001 for the latest version of the standard. This study was performed in accordance with TPL-001-5.1

[5] Search for NUC-001.

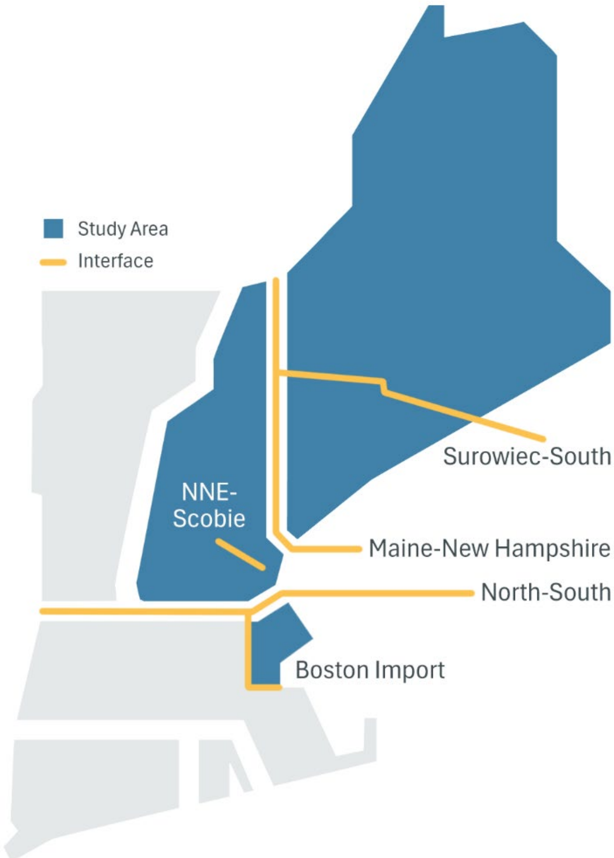


Figure 4-1: RFP Study Area and Interfaces

4.3 Description of Analysis

The study included evaluation of the reliability of the transmission system serving the study area for the projected system conditions in 2035. The system was tested under N-0 (all-facilities-in), N-1 (all-facilities-in, contingency event), and N-1-1 (facility-out, followed by contingency event) conditions for the scenarios described in Section 4.4.

ISO-NE performed the following types of analyses to test if the proposals met the RFP objectives:

- **Steady State Analysis –** Steady state thermal and voltage analysis for N-0, N-1, and N-1-1 contingencies, to ensure no steady state criteria violations were observed with the proposal in-service.[6] This analysis assessed the contingencies included in the RFP, modified to reflect changes in system topology that would be introduced by the proposal (i.e., the contingency list reflecting new, modified, and deleted contingencies). The list of contingencies was adapted depending on the configuration and/or location of the proposal.

[6] For N-1-1 testing, adjustments made between the first and second contingency included generation redispatch, import reductions, HVDC and equipment adjustments, and switching actions. Generation/import reductions and replacement reserves were limited to 1,200 MW.

Steady state testing was one type of analysis used to confirm whether the proposal met the transfer capability objectives (LT-1 and LT-2) and accommodated a minimum of 1,200 MW of onshore wind (LT-3).

- **Stability Analysis –** Analysis applying N-1 contingencies to ensure there were no stability criteria violations observed with the proposal in-service. This analysis assessed the same contingencies included in the RFP, modified to reflect changes in system topology that would be introduced by the proposal (i.e., the contingency list reflecting new, modified, and deleted contingencies). The list of contingencies was adapted depending on the configuration and/or location of the proposal. Stability testing was the other type of analysis used to confirm whether the proposal met the transfer capability objectives (LT-1 and LT-2) and accommodated a minimum of 1,200 MW of onshore wind (LT-3).

These steady state and stability analyses were performed for design contingencies. Extreme contingency testing was not a consideration for a proposal to move on to the next step of review because it is not a requirement to meet reliability standards and criteria. Extreme contingency impacts are one of the evaluation factors for consideration in selecting the preferred solution. If remaining proposals needed additional distinguishing factors to help in the selection of a preferred solution, extreme contingency testing would be completed as a further step in the evaluation.

ISO-NE performed transfer limit analysis for each proposal to confirm whether the required minimum 2035 interface capabilities on the Maine-New Hampshire and Surowiec-South interfaces were met for LT-1 and LT-2. This transfer analysis consisted of thermal, voltage, and stability testing.[7] During this analysis, operating margin is applied to interfaces that are limited by specific reliability phenomena identified through transient stability or steady state voltage analysis. Specifically, a 100 MW operating margin is applied when the limiting condition is system separation, unit instability, or voltage sag identified in transient stability analysis, as well as when the limitation is associated with steady state voltage performance. Operating margin is not applied when the interface limitation is driven by thermal limits or insufficient damping identified in transient stability analysis.

Tests for LT-3, accommodating a minimum of 1,200 MW of onshore wind, included the following:

- An **energy standard** test to determine whether the future onshore wind could produce up to its full output while reducing the output of neighboring resources by a similar amount without compromising reliability. This is comparable to the standard of Network Capability Interconnection Standard. The energy standard test included steady-state and stability testing, as described above.[8]

- A **capacity standard** test to determine whether the future onshore wind would be incrementally useful as capacity in Maine at the output expected during peak load

---

[7] Note stability testing was only completed if a proposal met the thermal and voltage transfer capability objectives.

[8] Stability analysis and associated results for the energy standard testing are included as part of the transfer limit analysis.

conditions. The testing simulated the additional northern Maine wind resources at a given percentage (25% in summer, 65% in winter), with other capacity resources in the area operating at their Capacity Network Resource Capability (CNRC) value.[9] This is comparable to the standard of Capacity Capability Interconnection Standard studies used to qualify new capacity resources. The goal of this test was to determine if the future onshore wind was deliverable to the system regardless of the interface transfer levels. This test assumed Maine-New Hampshire interface flows at the 3,000 MW objective for this RFP. The capacity standard test included only N-0 and N-1 contingencies for thermal testing, as described above, consistent with the approach used by recent overlapping impact analysis.

Figure 4-2 was provided to stakeholders to show a representative set of upgrades needed to accommodate 1,200 MW of wind. Elements in blue are existing elements, those in purple were included in power flow models and did not need to be constructed by RFP participants, and elements in red (or something equivalent) were needed to accommodate the interconnection of 1,200 MW of wind.

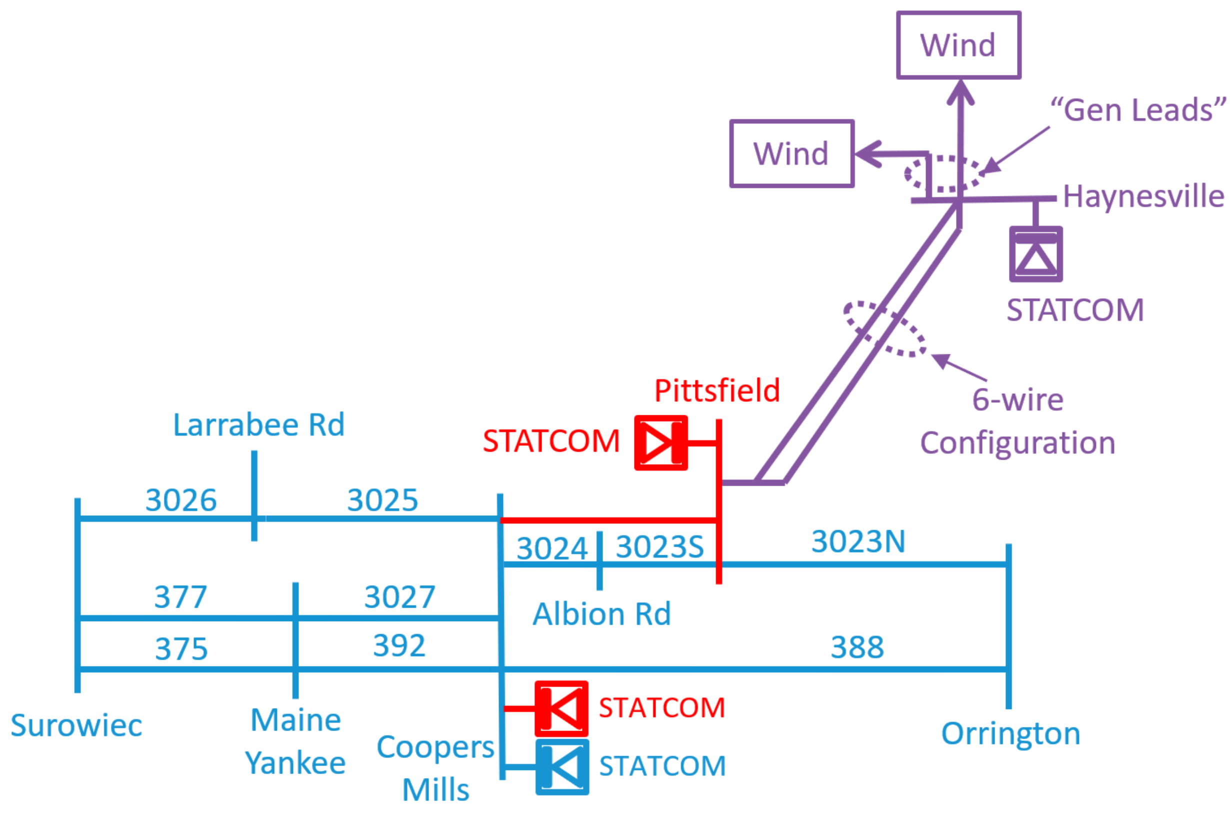


Figure 4-2: Representative Upgrades Needed to Accommodate 1,200 MW of Wind

[9] Based on v8.4 of the Transmission Planning Technical Guide that was current at the time the RFP was issued.

For a proposal to pass the RFP objectives analysis, it must pass both steady state and stability analysis for the transfer analysis and energy standard test, and it must pass steady state analysis for the capacity standard test.

ISO-NE performed steady state transfer limit analysis using PowerGEM TARA v2503 software, for the energy standard and capacity standard tests, and stability analysis using Siemens PTI PSS®E v34.9 software.

4.4 Study Horizon and Scenarios

The 2025 LTTP RFP Transmission Model Reference Document (CEII) details the study horizon, scenarios, and contingencies evaluated for the study year 2035.

The RFP objectives analysis set the starting transfers for the Maine-New Hampshire and Surowiec-South interfaces to the minimum RFP requirement levels of 3,000 MW and 3,200 MW respectively for the energy standard and transfer capability testing. To properly identify transfer capabilities, flows across these interfaces were increased until a transmission system violation occurred.

The three generation dispatches used to set the starting Maine-New Hampshire and Surowiec-South interface flows in each of the Summer Peak, Spring Light, and Winter Peak cases are:

- **Disp D1:** case with central/northern Maine wind (including the 1,200 MW future onshore wind at Haynesville) and NECEC set at 100% output with synchronous generation reduced
- **Disp D2:** case with central/northern Maine wind and synchronous generation set at 100% output with NECEC turned down as low as possible while maintaining the starting transfers
- **Disp D3:** case with NECEC and synchronous generation at 100% output with central/northern Maine wind turned down to maintain the starting transfers

Table 4-1 and Table 4-2 show the nine cases used in RFP objectives analysis. Note that in the Disp D2 for the Summer and Spring Light Load cases (steady state cases shown in Table 4-1 and stability cases shown in Table 4-2), the minimum RFP requirements still needed to be met with NECEC assumed to be out-of-service (OOS) so that any proposal would not be dependent on NECEC needing to be online to meet the minimum RFP requirements. The values in these tables represent pre-project power flows before adding a proposal to the model.

Table 4-1
Study Scenarios: Energy Standard and Transfer Limit Cases (Steady State)

Case Name	NB-NE (MW)	Orrington-South (MW)	Surowiec-South (MW)	Maine-New Hampshire (MW)	NECEC (MW)	NE-NY (MW)	Onshore Wind (MW)
Target	1,100	1,650	3,200	3,000	1,200	No target	1,200
Winter Peak Disp D1	1,100	1,650	3,200	3,000	1,200	-83	1,200
Winter Peak Disp D2	1,100	1,650	3,200	3,000	730	-83	1,200
Winter Peak Disp D3	1,100	1,650	3,200	3,000	1,200	-76	740
Summer Day Peak Disp D1	1,100	1,650	3,200	3,000	1,200	-122	1,200
Summer Day Peak Disp D2	1,100	1,650	3,200	3,000	OOS	-92	1,200
Summer Day Peak Disp D3	1,100	1,650	3,200	3,000	1,200	-92	OOS
Spring Light Load Disp D1	1,100	1,650	3,200	3,000	1,200	-82	1,200
Spring Light Load Disp D2	1,100	1,650	3,200	3,000	OOS	-82	1,200
Spring Light Load Disp D3	1,100	1,650	3,200	3,000	1,200	-82	OOS

Table 4-2
Study Scenarios: Energy Standard and Transfer Limit Cases (Stability)

Case Name	NB-NE (MW)	Orrington-South (MW)	Surowiec-South (MW)	Maine-New Hampshire (MW)	NECEC (MW)	NE-NY (MW)	Onshore Wind (MW)
Target	1,100	1,650	3,200	3,000	1,200	1,200	1,200
Winter Peak Disp D1	1,100	1,650	3,200	3,000	1,200	1,200	1,200
Winter Peak Disp D2	1,100	1,650	3,200	3,000	730	1,200	1,200
Winter Peak Disp D3	1,100	1,650	3,200	3,000	1,200	1,200	740
Summer Day Peak Disp D1	1,100	1,650	3,200	3,000	1,200	1,200	1,200
Summer Day Peak Disp D2	1,100	1,650	3,200	3,000	OOS	1,200	1,200
Summer Day Peak Disp D3	1,100	1,650	3,200	3,000	1,200	1,200	OOS
Spring Light Load Disp D1	1,100	1,650	3,200	3,000	1,200	1,200	1,200
Spring Light Load Disp D2	1,100	1,650	3,200	3,000	OOS	1,200	1,200
Spring Light Load Disp D3	1,100	1,650	3,200	3,000	1,200	1,200	OOS

Only two cases were used in the capacity standard testing, with their interface flows detailed below in Table 4-3.

Table 4-3
Study Scenarios: Capacity Standard Cases (Steady State)

Case Name	NB-NE (MW)	Orrington-South (MW)	Surowiec-South (MW)	Maine-New Hampshire (MW)	NECEC[a] (MW)	NE-NY (MW)	Onshore Wind[b] (MW)
Target	1,000	1,650	No Target	3,000	1,200	No Target	
Winter Peak	1,000	1,650	2,837	3,000	1,200	-83	780
Summer Day Peak	1,000	1,650	3,074	3,000	1,200	-125	300

(a) The assumption of NECEC online at 1,200 MW was used to reasonably stress the downstream northern New England interfaces. It does not denote that NECEC has a Capacity Supply Obligation.

(b) Additional northern Maine wind tested at 25% of nameplate for summer and 65% of nameplate for winter.

For a proposal to satisfy the needs of the RFP, it needs to pass all dispatches for all seasons. If a proposal failed any one case, it would fail the RFP objectives analysis.

4.5 RFP Objectives Analysis for LTPs A1 and A2

A1 and A2 were electrically identical proposals. As such, ISO-NE performed the RFP objectives analysis once to cover both proposals.

4.5.1 Transfer Limit Analysis Results

Table 4-4 summarizes the thermal, voltage, and stability results for transfer analysis testing. Pass indicates the proposal met the minimum transfer capability requirements (LT-1 and LT-2) of this RFP. Fail indicates the proposal did not meet the minimum transfer capability requirements (LT-1 and/or LT-2) of this RFP.

Table 4-4
LTPs A1/A2: Transfer Capability Results

Case Name	Surowiec-South			Maine-New Hampshire			Result
Analysis Type	Thermal	Voltage	Stability	Thermal	Voltage	Stability	-
Winter Peak Disp D1	Pass	Pass	Pass	Pass	Pass	Pass	Pass
Winter Peak Disp D2	Pass	Pass	Pass	Pass	Pass	Pass	Pass
Winter Peak Disp D3	Pass	Pass	Pass	Pass	Pass	Pass	Pass
Summer Day Peak Disp D1	Pass	Pass	Pass	Pass	Pass	Pass	Pass
Summer Day Peak Disp D2	Pass	Pass	Pass	Pass	Pass	Pass	Pass
Summer Day Peak Disp D3	Pass	Pass	Pass	Pass	Pass	Pass	Pass
Spring Light Load Disp D1	Pass	Pass	Pass	Pass	Pass	Pass	Pass
Spring Light Load Disp D2	Pass	Pass	Pass	Pass	Pass	Pass	Pass
Spring Light Load Disp D3	Pass	Pass	Pass	Pass	Pass	Pass	Pass

4.5.2 Wind Accommodation Analysis Results

Table 4-5 summarizes the thermal and voltage results for the energy standard test.

Table 4-6 summarizes the thermal results for the capacity standard test. Pass indicates the proposal met the minimum wind accommodation requirement (LT-3) of this RFP. Fail indicates the proposal did not meet the minimum wind accommodation requirement (LT-3) of this RFP. ISO-NE performed the energy standard test using the most limiting transfer capabilities identified in the transfer limit analysis, or in the case of a proposal failing to meet the minimum RFP transfer capability requirements, these minimum values were then used in the energy standard test. The energy standard test included the assumption that the northern Maine wind resource under evaluation was online at maximum output in the case. Since the base Disp D3 case modeled the northern Maine onshore wind as offline or partially dispatched, Disp D3 cases were not used for the energy standard test.

The Winter Peak Disp D1 and Disp D2 cases for LTPs A1 and A2 were consolidated into a single dispatch case because the identified winter transfer capabilities were sufficiently high that separately dispatching Disp D1 and Disp D2 would have produced very similar results. Given the available resources in Maine for each case, the dispatch outcomes were not expected to materially differ. Therefore, LTPs A1 and A2 were tested at the maximum identified winter transfer capabilities in the Winter Peak (Max) case.

Table 4-5
LTPs A1/A2: Energy Standard Results

Case Name	N-1	N-1	N-1-1	N-1-1	Result
Analysis Type	Thermal	Voltage	Thermal	Voltage	-
Winter Peak (Max)	Pass	Pass	Pass	Pass	Pass
Summer Day Peak Disp D1	Pass	Pass	Pass	Pass	Pass
Summer Day Peak Disp D2	Pass	Pass	Pass	Pass	Pass
Spring Light Load Disp D1	Pass	Pass	Pass	Pass	Pass
Spring Light Load Disp D2	Pass	Pass	Pass	Pass	Pass

Table 4-6
LTPs A1/A2: Capacity Standard Results

Case Name	N-1	Result
Analysis Type	Thermal	-
Winter Peak	Pass	Pass
Summer Day Peak	Pass	Pass

4.6 RFP Objectives Analysis for LTP B1

4.6.1 Transfer Limit Analysis Results

Table 4-7 summarizes the thermal, voltage, and stability results for the transfer analysis testing. Pass indicates the proposal met the minimum transfer capability requirements (LT-1 and LT-2) of this RFP. Fail indicates the proposal did not meet the minimum transfer capability requirements (LT-1 and/or LT-2) of this RFP.

Table 4-7
LTP B1: Transfer Capability Results

Case Name	Surowiec-South			Maine-New Hampshire			Result
Analysis Type	**Thermal**	**Voltage**	**Stability**	**Thermal**	**Voltage**	**Stability**[a]	**-**
Winter Peak Disp D1	Pass	Pass	Not tested	Pass	Fail	Not tested	Fail
Winter Peak Disp D2	Pass	Pass	Not tested	Pass	Pass	Not tested	N/A[b]
Winter Peak Disp D3	Pass	Pass	Not tested	Pass	Fail	Not tested	Fail
Summer Day Peak Disp D1	Fail	Pass	Not tested	Pass	Pass	Not tested	Fail
Summer Day Peak Disp D2	Fail	Fail	Not tested	Pass	Pass	Not tested	Fail
Summer Day Peak Disp D3	Fail	Pass	Not tested	Pass	Fail	Not tested	Fail
Spring Light Load Disp D1	Fail	Fail	Not tested	Pass	Pass	Not tested	Fail
Spring Light Load Disp D2	Fail	Fail	Not tested	Pass	Pass	Not tested	Fail
Spring Light Load Disp D3	Pass	Pass	Not tested	Pass	Pass	Not tested	N/A[b]

(a) Stability analysis was not tested since thermal and/or voltage testing failed objective transfer capabilities for Surowiec-South and/or Maine-New Hampshire

(b) This case did not fail steady -state testing for the objective transfer capabilities, but did not have stability analysis conducted because other cases for B1 did fail steady -state testing

Though one terminal of the HVDC facility was located in the Boston Import area in Everett, MA, ISO-NE did not perform Boston Import, Northern New England (NNE)-Scobie, and North-South thermal transfer limit analyses since the proposal did not meet the objectives of the RFP for the steady state transfer capabilities for the Surowiec-South and Maine-New Hampshire interfaces.

LTP B1 failed to meet the Surowiec-South thermal and voltage transfer capability requirements in at least one study case because it did not resolve N-1 thermal and voltage violations in southern Maine. It also failed to meet the Maine-New Hampshire voltage transfer capability requirement due to an N-1 low-voltage violation in southeastern New Hampshire.

4.6.2 Wind Accommodation Analysis Results

Table 4-8 summarizes the thermal and voltage results for the energy standard test. Table 4-9 summarizes the thermal results for the capacity standard test. Pass indicates the proposal met the minimum wind accommodation requirement (LT-3) of this RFP. Fail indicates the proposal did not meet the minimum wind accommodation requirement (LT-3) of this RFP. ISO-NE performed the energy standard test using the most limiting transfer capabilities identified in the transfer limit analysis, or in the case of a proposal failing to meet the minimum RF transfer capability requirements, these minimum values were then used in the energy standard test. The energy standard test included the assumption that the northern Maine wind resource under evaluation was online at maximum output in the base case. Since Disp D3 modeled the northern Maine onshore wind as offline or partially dispatched, Disp D3 cases were not used for the energy standard test.

Table 4-8
LTP B1: Energy Standard Results

Case Name	N-1	N-1	N-1-1	N-1-1[(a)]	Result
Analysis Type	Thermal	Voltage	Thermal	Voltage	-
Winter Peak Disp D1	Fail	Fail	Not tested	Not tested	Fail
Winter Peak Disp D2	Fail	Pass	Not tested	Not tested	Fail
Summer Day Peak Disp D1	Fail	Fail	Not tested	Not tested	Fail
Summer Day Peak Disp D2	Fail	Fail	Not tested	Not tested	Fail
Spring Light Load Disp D1	Fail	Fail	Not tested	Not tested	Fail
Spring Light Load Disp D2	Fail	Fail	Not tested	Not tested	Fail

(a) N-1-1 contingency analysis was not performed for B1 due to various N-1 contingency violations.

Table 4-9
LTP B1: Capacity Standard Results

Case Name	N-1	Result
Analysis Type	Thermal	-
Winter Peak	Fail	Fail
Summer Day Peak	Pass	Pass

LTP B1 did not include an additional transmission path from the new Pittsfield substation and, as a result, could not accommodate the full 1,200 MW of additional onshore wind generation under the energy standard test. Several post-contingency thermal and voltage violations were identified in the vicinity of the Pittsfield substation. In addition, the absence of an additional transmission path from the Pittsfield substation prevented the proposal from supporting the expected 65% winter wind output under the capacity standard test due to a post-contingency thermal overload.

4.7 RFP Objectives Analysis for LTP C1

4.7.1 Transfer Limit Analysis Results

Table 4-10 summarizes the thermal, voltage, and stability results for the transfer analysis testing. Pass indicates the proposal met the minimum transfer capability requirements (LT-1 and LT-2) of this RFP. Fail indicates the proposal did not meet the minimum transfer capability requirements (LT-1 and/or LT-2) of this RFP.

Table 4-10
LTP C1: Transfer Capability Results

Case Name	Surowiec-South			Maine-New Hampshire			Result
Analysis Type	Thermal	Voltage	Stability	Thermal	Voltage	Stability	-
Winter Peak Disp D1	Pass	Pass	Pass	Pass	Pass	Pass	Pass
Winter Peak Disp D2	Pass	Pass	Pass	Pass	Pass	Pass	Pass
Winter Peak Disp D3	Pass	Pass	Pass	Pass	Pass	Pass	Pass
Summer Day Peak Disp D1	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Summer Day Peak Disp D2	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Summer Day Peak Disp D3	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Spring Light Load Disp D1	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Spring Light Load Disp D2	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Spring Light Load Disp D3	Pass	Pass	Pass	Pass	Pass	Pass	Pass

LTP C1 failed to meet the transient stability transfer capability requirements, with system instability observed in the Summer Peak cases and damping criteria violations identified in the Spring Light Load cases. Preliminary testing indicated that the instability was caused by insufficient dynamic reactive power support on the 345 kV network needed to support the increased power transfers.

4.7.2 Wind Accommodation Analysis Results

Table 4-11 summarizes the thermal and voltage results for the energy standard test. Table 4-12 summarizes the thermal results for the capacity standard test. Pass indicates the proposal met the minimum wind accommodation requirement (LT-3) of this RFP. Fail indicates the proposal did not meet the minimum wind accommodation requirement (LT-3) of this RFP. ISO-NE performed the energy standard test using the most limiting transfer capabilities identified in the transfer limit analysis, or in the case of a proposal failing to meet the minimum RFP transfer capability requirements, these minimum values were then used in the energy standard test. The energy standard test included the assumption that the northern Maine wind resource under evaluation was online at maximum output in the base case. Since Disp D3 modeled the northern Maine onshore wind as offline or partially dispatched, Disp D3 cases were not used for the energy standard test.

Table 4-11
LTP C1: Energy Standard Results

Case Name	N-1	N-1	N-1-1	N-1-1	Result
Analysis Type	Thermal	Voltage	Thermal	Voltage	-
Winter Peak Disp D1	Pass	Pass	Pass	Pass	Pass
Winter Peak Disp D2	Pass	Pass	Pass	Pass	Pass
Summer Day Peak Disp D1	Pass	Pass	Pass	Pass	Pass
Summer Day Peak Disp D2	Pass	Pass	Pass	Pass	Pass
Spring Light Load Disp D1	Pass	Pass	Pass	Pass	Pass
Spring Light Load Disp D2	Pass	Pass	Pass	Pass	Pass

Table 4-12
LTP C1: Capacity Standard Results

Case Name	N-1	Result
Analysis Type	Thermal	-
Winter Peak	Pass	Pass
Summer Day Peak	Pass	Pass

4.8 RFP Objectives Analysis for LTP D1

4.8.1 Transfer Limit Analysis Results

Table 4-13 summarizes the thermal, voltage, and stability results for the transfer analysis testing. Pass indicates the proposal met the minimum transfer capability requirements (LT-1 and LT-2) of this RFP. Fail indicates the proposal did not meet the minimum transfer capability requirements (LT-1 and/or LT-2) of this RFP.

Table 4-13
LTP D1: Transfer Capability Results

Case Name	Surowiec-South			Maine-New Hampshire			Result
Analysis Type	Thermal	Voltage	Stability	Thermal	Voltage	Stability	-
Winter Peak Disp D1	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Winter Peak Disp D2	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Winter Peak Disp D3	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Summer Day Peak Disp D1	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Summer Day Peak Disp D2	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Summer Day Peak Disp D3	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Spring Light Load Disp D1	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Spring Light Load Disp D2	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Spring Light Load Disp D3	Pass	Pass	Fail	Pass	Pass	Fail	Fail

Since one terminal of the HVDC facility was located in the Boston Import area in Wakefield, MA, ISO-NE would have performed Boston Import, NNE-Scobie, and North-South thermal transfer limit analyses to determine the effect the proposal would have on the current N-1 transfer capabilities. Since proposal D1 did not meet the minimum required transfer capabilities from the RFP, additional transfer analyses were not finalized.

LTP D1 failed to meet the transient stability transfer capability requirements, as system instability was observed in all cases. Preliminary testing indicated that the instability resulted from insufficient dynamic reactive power support on the 345 kV network needed to support the increased power transfers.

4.8.2 Wind Accommodation Analysis Results

Table 4-14 summarizes the thermal and voltage results for the energy standard test. Table 4-15 summarizes the thermal results for the capacity standard test. Pass indicates the proposal met the minimum wind accommodation requirement (LT-3) of this RFP. Fail indicates the proposal did not meet the minimum wind accommodation requirement (LT-3) of this RFP. ISO-NE performed the energy standard test using the most limiting transfer capabilities identified in the transfer limit analysis, or in the case of a proposal failing to meet the minimum RFP transfer capability requirements, these minimum values were then used in the energy standard test. The energy standard test included the assumption that the northern Maine wind resource under evaluation was online at maximum output in the base case. Since Disp D3 modeled the northern Maine onshore wind as offline or partially dispatched, Disp D3 cases were not used for the energy standard test.

Table 4-14
LTP D1: Energy Standard Results

Case Name	N-1	N-1	N-1-1	N-1-1	Result
Analysis Type	Thermal	Voltage	Thermal	Voltage	-
Winter Peak Disp D1	Pass	Pass	Pass	Pass	Pass
Winter Peak Disp D2	Pass	Pass	Pass	Pass	Pass
Summer Day Peak Disp D1	Pass	Pass	Pass	Pass	Pass
Summer Day Peak Disp D2	Pass	Pass	Pass	Pass	Pass
Spring Light Load Disp D1	Pass	Pass	Pass	Pass	Pass
Spring Light Load Disp D2	Pass	Pass	Pass	Pass	Pass

Table 4-15
LTP D1: Capacity Standard Results

Case Name	N-1	Result
Analysis Type	Thermal	-
Winter Peak	Pass	Pass
Summer Day Peak	Pass	Pass

4.9 RFP Objectives Analysis for LTP D2

4.9.1 Transfer Limit Analysis Results

Table 4-16 summarizes the thermal, voltage, and stability results for the transfer analysis testing. Pass indicates the proposal met the minimum transfer capability requirements (LT-1 and LT-2) of this RFP. Fail indicates the proposal did not meet the minimum transfer capability requirements (LT-1 and/or LT-2) of this RFP.

Table 4-16
LTP D2: Transfer Capability Results

Case Name	Surowiec-South			Maine-New Hampshire			Result
Analysis Type	Thermal	Voltage	Stability	Thermal	Voltage	Stability	-
Winter Peak Disp D1	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Winter Peak Disp D2	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Winter Peak Disp D3	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Summer Day Peak Disp D1	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Summer Day Peak Disp D2	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Summer Day Peak Disp D3	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Spring Light Load Disp D1	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Spring Light Load Disp D2	Pass	Pass	Fail	Pass	Pass	Fail	Fail
Spring Light Load Disp D3	Pass	Pass	Fail	Pass	Pass	Fail	Fail

Since one terminal of the HVDC facility was located in the Boston Import area in Everett, MA, ISO-NE would have performed Boston Import, NNE-Scobie, and North-South thermal transfer limit analyses to determine the effect the proposal would have on the current N-1 transfer capabilities. Since proposal D2 did not meet the minimum required transfer capabilities from the RFP, additional transfer analyses were not finalized.

LTP D2 failed to meet the transient stability transfer capability requirements, as system instability was observed in all cases. Preliminary testing indicated that the instability resulted from insufficient dynamic reactive power support on the 345 kV network needed to support the increased power transfers.

4.9.2 Wind Accommodation Analysis Results

Table 4-17 summarizes the thermal and voltage results for the energy standard test. Table 4-18 summarizes the thermal results for the capacity standard test. Pass indicates the proposal met the minimum wind accommodation requirement (LT-3) of this RFP. Fail indicates the proposal did not meet the minimum wind accommodation requirement (LT-3) of this RFP. ISO-NE performed the energy standard test using the most limiting transfer capabilities identified in the transfer limit analysis, or in the case of a proposal failing to meet the minimum RFP transfer capability requirements, these minimum values were then used in the energy standard test. The energy standard test included the assumption that the northern Maine wind resource under evaluation was online at maximum output in the base case. Since Disp D3 modeled the northern Maine onshore wind as offline or partially dispatched, Disp D3 cases were not used for the energy standard test.

Table 4-17
LTP D2: Energy Standard Results

Case Name	N-1	N-1	N-1-1	N-1-1	Result
Analysis Type	Thermal	Voltage	Thermal	Voltage	-
Winter Peak Disp D1	Pass	Pass	Pass	Pass	Pass
Winter Peak Disp D2	Pass	Pass	Pass	Pass	Pass
Summer Day Peak Disp D1	Pass	Pass	Pass	Pass	Pass
Summer Day Peak Disp D2	Pass	Pass	Pass	Pass	Pass
Spring Light Load Disp D1	Pass	Pass	Pass	Pass	Pass
Spring Light Load Disp D2	Pass	Pass	Pass	Pass	Pass

Table 4-18
LTP D2: Capacity Standard Results

Case Name	N-1	Result
Analysis Type	**Thermal**	**-**
Winter Peak	Pass	Pass
Summer Day Peak	Pass	Pass

4.10 Summary of RFP Objective Analysis Results

4.10.1 Maine-New Hampshire Results (LT-1)

Table 4-19 summarizes the pass/fail results of each proposal for the Maine-New Hampshire interface minimum transfer capability requirement. If a proposal passed all the tests, the final MW values for the transfer capabilities are listed.

Table 4-19
Maine-New Hampshire Summary

Proposal	Season	Thermal (MW)	Voltage[b] (MW)	Stability[b] (MW)	Result[c] (MW)
A1/A2	Summer	3,525	3,625	**3,200**[a]	**3,100**
	Winter	3,950	**3,525**[a]	>3,650	**3,425**
B1		Pass	Fail	Not Studied[d]	Fail
C1		Pass	Pass	Fail	Fail
D1		Pass	Pass	Fail	Fail
D2		Pass	Pass	Fail	Fail

(a) **Bold text** = most limiting result for season

(b) Voltage and stability capabilities displayed are un-margined

(c) Final interface capabilities include 100 MW margin where applicable (voltage/stability limited)

(d) Stability analysis was not tested since thermal and/or voltage testing failed objective transfer capabilities for Surowiec-South and/or ME-NH

4.10.2 Surowiec-South Results (LT-2)

Table 4-20 summarizes the pass/fail results of each proposal for the Surowiec-South interface minimum transfer capability requirement. If a proposal passed all the tests, the final MW values for the transfer capabilities are listed.

Table 4-20
Surowiec-South Summary

Proposal	Season	Thermal (MW)	Voltage[b] (MW)	Stability[b] (MW)	Result[c] (MW)
A1/A2	Summer	3,500	4,075	**3,400**[a]	**3,300**[a]
	Winter	**3,825**[a]	>4,300	>3,850	**3,725**[e]
B1		Fail	Fail	Not Studied[d]	Fail
C1		Pass	Pass	Fail	Fail
D1		Pass	Pass	Fail	Fail
D2		Pass	Pass	Fail	Fail

(a) **Bold text** = most limiting result for season

(b) Voltage and stability capabilities displayed are un-margined

(c) Final interface capabilities include 100 MW margin where applicable (voltage/stability limited)

(d) Stability analysis was not tested since thermal and/or voltage testing failed objective transfer capabilities for Surowiec-South and/or ME-NH

(e) The Winter capability was set based on flow across Surowiec-South when ME-NH is set to its 3,525 MW capability

4.10.3 Wind Accommodation Results (LT-3)

Table 4-21 summarizes the pass/fail results of each proposal for the requirement to accommodate the interconnection of at least 1,200 MW (nameplate) of onshore wind.

Table 4-21
Wind Accommodation Summary

Proposal	Energy Standard	Capacity Standard
A1	Pass	Pass
A2	Pass	Pass
B1	Fail	Fail
C1	Pass	Pass
D1	Pass	Pass
D2	Pass	Pass

4.10.4 Objectives Analysis Determination

Table 4-22 summarizes the pass/fail results of each proposal for each of the requirements of this RFP.

Table 4-22
Combined Summary

Proposal	Maine-New Hampshire (LT-1)	Surowiec-South (LT-2)	Energy Standard (LT-3)	Capacity Standard (LT-3)
A1	Pass	Pass	Pass	Pass
A2	Pass	Pass	Pass	Pass
B1	Fail	Fail	Fail	Fail
C1	Fail	Fail	Pass	Pass
D1	Fail	Fail	Pass	Pass
D2	Fail	Fail	Pass	Pass

LTP A1 and LTP A2 met all requirements for the RFP objectives analysis and proceeded to the no adverse impact screening and benefits calculation portions of the RFP analysis.

The other four proposals did not meet all the requirements for the RFP objectives analysis and were not considered further in the selection of the preferred Longer-Term Transmission Solution for the 2025 LTTP RFP. Each of these proposals are listed below, along with a summary of which portions of the RFP objectives analysis they failed:

LTP B1

LTP B1 failed to meet the Surowiec-South thermal and voltage transfer capability requirements in at least one study case because it did not resolve N-1 thermal and voltage violations in southern Maine. It also failed to meet the Maine-New Hampshire voltage transfer capability requirement due to an N-1 low-voltage violation in southeastern New Hampshire.

The proposal did not include an additional transmission path from the new Pittsfield substation and, as a result, could not accommodate the full 1,200 MW of additional onshore wind generation under the energy standard test. Several post-contingency thermal and voltage violations were identified in the vicinity of the Pittsfield substation. In addition, the absence of an additional transmission path from the Pittsfield substation prevented the proposal from supporting the expected 65% winter wind output under the capacity standard test due to a post-contingency thermal overload.

LTP C1

LTP C1 failed to meet the transient stability transfer capability requirements, with system instability observed in the Summer Peak cases and damping criteria violations identified in the Spring Light Load cases. Preliminary testing indicated that the instability was caused by insufficient dynamic reactive power support on the 345 kV network needed to support the increased power transfers.

LTP D1

LTP D1 failed to meet the transient stability transfer capability requirements, as system instability was observed in all cases. Preliminary testing indicated that the instability resulted from insufficient dynamic reactive power support on the 345 kV network needed to support the increased power transfers.

LTP D2

LTP D2 failed to meet the transient stability transfer capability requirements, as system instability was observed in all cases. Preliminary testing indicated that the instability resulted from insufficient dynamic reactive power support on the 345 kV network needed to support the increased power transfers.

Section 5
No Adverse Impact Screening

5.1 Screening Analysis Objective

The objective of the no adverse impact screening portion of the 2025 LTTP RFP was to evaluate if a proposal would potentially have a "significant adverse effect" on the stability, reliability, or operation of the New England transmission system to identify any differences between competing proposals to aid in selection of the preferred Longer-Term Transmission Solution. Listed below are the types of potential impacts assessed to determine whether a significant adverse effect may exist under Section I.3.9 of the ISO Tariff and ISO-NE Planning Procedure No. 5-3, *Guidelines for Conducting and Evaluating Proposed Plan Application Analyses* (PP5-3):

- **Thermal impact**: a change that increases flow in an element by at least two percent (2%) of the element's rating and that causes the flow to exceed that element's appropriate thermal rating by more than two percent (2%).[10]
- **Voltage impact**: a change that increases or decreases the voltage on the transmission system by at least one percent (1%) and causes a voltage level that is higher or lower than the appropriate rating.[10]
- **Short circuit impact**: A change that causes at least a 1% change in the short circuit current experienced by an element and that causes a short circuit stress that is higher than an element's interrupting or withstand capability. [10]

The no adverse impact screening does not supplant future Section I.3.9 testing after the selection of the preferred Longer-Term Transmission Solution.

5.2 Methodology, Study Assumptions, and Criteria

The goal of the no adverse impact screening was to identify any differences between competing proposals to aid in selection of the preferred Longer-Term Transmission Solution. The requirements in the following NERC, NPCC, and ISO-NE standards and criteria were applied for the conduct of the no adverse impact screening:

- NERC TPL-001: Transmission System Planning Performance Requirements[11]
- NERC NUC-001: Nuclear Plant Interface Coordination[12]
- NPCC Regional Reliability Reference Directory #1: Design and Operation of the Bulk Power System, and
- ISO New England Planning Procedure 3: Reliability Standards for the New England Area Pool Transmission Facilities

[10] https://www.iso-ne.com/static-assets/documents/100028/tptg_rev8_4.pdf Section 5 Appendices

[11] Search for TPL-001 for the latest version of the standard. This study was performed in accordance with TPL-001-5.1

[12] Search for NUC-001.

Additional details on criteria applied for the no adverse impact screening are found in Section 4 of the Technical Analysis of the proposals in Part 1 of the RFP document.

The future 1,200 MW (nameplate) onshore wind and the connections between the wind and the proposed substation were not included in the no adverse impact screening because these portions would not be built by the QTPS.

5.3 Areas Studied

The study area used for the no adverse impact screening was the same used for the RFP objectives analysis detailed in Section 4.

5.4 Description of Screening Analysis

Only LTPs A1 and A2 moved on to the no adverse impact screening, because they were the only proposals that passed the initial review and the RFP objectives analysis portion of the RFP testing. Since LTPs A1 and A2 are electrically identical, ISO-NE performed the no adverse impact screening once to cover both proposals.

ISO-NE performed the following types of analysis for the no adverse impact screening:

Thermal analysis to determine the level of steady state power flows on transmission circuits under the following conditions:

- N-0 (all-facilities-in)
- N-1 (all-facilities-in, contingency event)
- N-1-1 (facility out, followed by contingency event)

Voltage analysis to determine steady state voltage levels and performance under the following conditions:

- N-0 (all-facilities-in)
- N-1 (all-facilities-in, contingency event)
- N-1-1 (facility out, followed by contingency event)

Stability analysis to determine transient performance under the following conditions:

- N-0 (all-facilities-in)
- N-1 (all-facilities-in, contingency event)
- N-1-1 (facility out, followed by contingency event)

Short circuit analysis to determine the ability of substation equipment to withstand and interrupt fault current.

ISO-NE performed the steady state and stability analyses described above for design contingencies only. Extreme contingencies were not evaluated. Extreme contingency impacts are one of the evaluation factors for consideration in selecting the preferred solution. If remaining proposals needed additional distinguishing factors to help in the selection of the preferred solution, extreme contingency testing would be completed as a further step in the evaluation.

ISO-NE performed thermal, voltage, and stability analyses using Siemens PTI PSS®E v34.9 and PowerGEM TARA v2503 software, and short circuit analysis using Aspen OneLiner 15.9.

The base cases used for the no adverse impact screening for LTPs A1 and A2 were modified to adjust the phase-angle regulators (PARs) added by the proposals for the Summer Day Peak Disp D2 case. This reduced flows to secure the base case to avoid any N-1 thermal overloads post-A1/A2.

5.5 Screening Analysis Horizon and Scenarios

The RFP Document details the no adverse impact screening horizon and scenarios.

The no adverse impact screening focused on the year 2035 based on the requested in-service date of the RFP. The steady state and stability analysis cases were performed assuming the following specific generation dispatch scenarios, in addition to removing the proposed 1,200 MW of onshore wind generation from service:

- **Disp D1**
  - Wind on at 100%[13]
  - NECEC at 100%
  - Synchronous Generation reduced to achieve Surowiec-South at 2,900 MW
- **Disp D2**
  - Wind on at 100%[13]
  - NECEC OOS
  - Synchronous Generation at 100% to achieve Surowiec-South at 2,900 MW
- **Disp D3**
  - Wind generation reduced to achieve Surowiec-South at 2,900 MW
  - NECEC at 100%
  - Synchronous Generation at 100%

All three generation dispatch scenarios (Disp D1 – Disp D3) were applied to all Summer Peak Load and Spring Light Load scenarios. The Winter Peak case included higher local loads and reduced generation from distributed energy resources (DER) and hydroelectric resources, which limited the ability to stress the Surowiec-South interface to the 2,900 MW target. Accordingly, only Disp D1 was applied to the Winter Peak, as it represented the most limiting conditions for the study objective.

The goal of the no adverse impact screening was to assess a proposal's effect on the existing transmission system, not on future transfer levels. Therefore, the Surowiec-South and Maine-New Hampshire Interface flows were reduced (from 3,200 MW and 3,000 MW, respectively) to the unmargined post-NECEC transfer capabilities (2,900 MW and 2,300 MW, respectively).[14] Note that the unmargined values were used for the no adverse impact screening, rather than the margined

[13] Wind generation in the New England system except for the new onshore wind in Northern Maine which was offline.

[14] https://markets.iso-ne.com/operations-services/ceii/pac/2025/06/ceii_maine_transfer_capabilities_report_final.zip (CEII), or https://www.iso-ne.com/static-assets/documents/100022/a05_2025_04_29_pac_me_capacity_transfer_capability.pdf (Non-CEII)

post-NECEC transfer capabilities (2,800 MW and 2,200 MW, respectively), to ensure that the required margin is maintained.

A total of seven cases (one Winter Peak, three Summer Day Peak, and three Spring Light Load cases) were used for the analysis. The Summer Day Peak Disp D2 Case Surowiec-South interface transfer could not meet the target post-NECEC, pre-proposal interface capability since the NECEC project was assumed to be out-of-service (OOS).

Table 5-1 shows the interface flows studied in each case during the no adverse impact screening.

Table 5-1
Summary of Interface Flows used for the No Adverse Impact Screening

Case Name	NB-NE (MW)	Orrington-S (MW)	Surowiec-S (MW)	ME-NH (MW)	Boston Import (MW)	NECEC (MW)
Target	**1,100**	**1,650**	**2,900**	**2,300**	**5,250**	**1,200**
Winter Peak Disp D1	1,099	1,649	2,669	2,314	5,228	ON
Summer Day Peak Disp D1	1,100	1,650	2,890	2,287	5,232	ON
Summer Day Peak Disp D2	1,100	1,650	2,451	2,327	5,148	OOS
Summer Day Peak Disp D3	1,100	1,650	2,899	2,360	5,123	ON
Spring Light Load Disp D1	1,096	1,649	2,804	2,310	2,317	ON
Spring Light Load Disp D2	1,094	1,649	2,516	2,306	2,482	OOS
Spring Light Load Disp D3	1,096	1,651	2,768	2,324	2,404	ON

5.6 Overview of Results

The no adverse impact screening monitored only the PTF system. The assessment compared the pre-proposal thermal, voltage, and stability results with the post-proposal results for LTPs A1 and A2. As such, this report only details PTF violations. ISO-NE did not screen for non-PTF violations or conduct further analysis (e.g., generator re-dispatch) to mitigate potential concerns.

Additionally, ISO-NE did not perform system adjustments between the first and second contingencies to prevent thermal and voltage violations on non-NPCC BPS PTF facilities if the violation only occurred for multi-element contingencies as a second contingency.[15] These were excluded because they are not valid for second contingencies per NERC TPL-001 and ISO-NE PP3.

The overall N-1 approach was the same for the stability analysis as for the steady state analysis. However, instead of performing N-1-1 analysis for stability, ISO-NE initially performed N-2 testing without any system adjustments between the first element out and the second contingency events. If stability performance criteria were not met in this combined step, system adjustments were evaluated to test N-1-1. System adjustments were restricted to those that operators could reasonably accomplish, including addressing thermal violations through generation re-dispatch,

[15] The excluded multi-element contingencies are breaker failure contingencies, double-circuit tower contingencies, and bus section contingencies.

reflecting differences between N-1 and N-1-1 transfer capabilities, and respecting generation output restrictions based on existing ISO-NE Transmission Operating Guides.

5.7 Steady State Results

Steady state analysis evaluated N-0, N-1, and N-1-1 conditions for Winter Peak, Summer Peak, and Spring Light Load conditions.

5.7.1 Steady State Results

5.7.1.1 N-0 Thermal and Voltage Violation Summary

The Peak Load cases were all N-0 (also known as “all-lines-in”) secured. There were no thermal or voltage violations for either pre-LTP A1/A2 or post-LTP A1/A2.

5.7.1.2 N-1 Thermal and Voltage Violation Summary

ISO-NE observed no significant adverse effect in the N-1 post-LTP A1/A2 N-1 thermal results. Results showed one thermal violation at Section 83-2 (between Wyman Hydro and Section 83C tap) pre-LTP A1/A2 and post-LTP A1/A2, with negligible change in magnitude. This violation is a known pre-existing condition and is not expected to be a significant adverse effect of LTPs A1 and A2 due to the small change in flow (<2%) as a result of the proposal.

Table 5-2
N-1 Thermal Summary

Element	Dispatch	Pre-Proj (% LTE)	Pst-Proj (% LTE)	Delta
S83-2	Disp D1	111.0	111.1	+0.1%

ISO-NE observed no significant adverse effect in the N-1 post-LTP A1/A2 voltage results.

5.7.1.3 N-1-1 Thermal and Voltage Violation Summary

ISO-NE observed no significant adverse effect in the N-1-1 post-LTP A1/A2 N-1-1 thermal results. Initial results showed several thermal overloads in the Boston area facilities; however, these overloads were mitigated when the Waltham and Baker St. PARs were permitted to adjust post-N-1 contingency.

ISO-NE observed several N-1-1 low voltage violations both before and after the inclusion of LTPs A1 and A2. Table 5-3 shows the Summer Peak Portland Area voltage violations in both the pre-LTP A1/A2 and post-LTP A1/A2 cases.

Table 5-3
N-1-1 Voltage Summary

Substation	Worst Dispatch	Pre-Proj (pu)	Pst-Proj (pu)	Delta
Fore River 115 kV	Disp D1	0.918	0.907	-1.20%
Moshers 115 kV	Disp D1	0.933	0.922	-1.18%
Sewall 115 kV	Disp D1	0.919	0.907	-1.31%
Cape 115 kV	Disp D1	0.918	0.907	-1.20%
Pleasant Hill 115 kV	Disp D1	0.912	0.901	-1.21%
Hinkley Pond 115 kV	Disp D1	0.916	0.905	-1.20%

The local PTO has a pending project, the Greater Portland Project, that proposes a significant reconfiguration of the system in the region. ISO-NE conducted a sensitivity to include the Greater Portland Project upgrades. Table 5-4 shows these results with either LTPs A1 or A2 in service. LTPs A1 and A2 showed no significant adverse effects from N-1-1 low voltages in this sensitivity.

Table 5-4
Summer Peak Greater Portland Area Voltage Sensitivity Study

Element	Dispatch	Pst-LTP A1/A2 Pst-LSP (pu)
Fore River 115 kV	Disp D1	1.011
Moshers 115 kV	Disp D1	1.009
Cape 115 kV	Disp D1	1.012
Sewall 115 kV	Disp D1	1.011
Pleasant Hill 115 kV	Disp D1	1.009
Hinkley Pond 115 kV	Disp D1	1.011

5.7.2 Non-Convergence Scenarios

5.7.2.1 N-1 Non-Convergence Scenarios

Three contingencies caused non-convergence pre-LTP A1/A2, but these are known, pre-existing conditions that remain unaffected by LTPs A1 and A2.

5.7.2.2 N-1-1 Non-Convergence Scenarios

The ISO observed non-convergent contingencies under N-1-1 conditions. Multiple contingencies did not converge under N-1-1 conditions in the Summer and Winter Peak load scenarios. The anticipated loss of load for these contingencies was below the 300 MW guideline used to identify unacceptable loss of load for an initial element out, followed by a contingency event. The contingencies and impact were local, reflect the underlying weakness of the local sub-transmission system, and are not attributable to LTPs A1 or A2.

The additional identified non-convergent contingencies represent known, pre-existing issues. None are attributable to LTPs A1 or A2.

5.8 Stability Results

ISO-NE observed no significant adverse effects in the stability screening for N-0, N-1, and N-1-1 conditions across Summer Peak, Winter Peak, and Spring Light Load conditions.

The initial N-2 stability study identified LTE thermal violations. ISO-NE performed additional N-1-1 analysis to include generation re-dispatches based on the steady state analysis results to confirm that these violations could be mitigated. As a result, these thermal violations do not constitute a significant adverse effect on the system.

5.8.1 N-0 Stability Violation Summary

ISO-NE observed no stability violations for N-0.

5.8.2 N-1 Stability Violation Summary

ISO-NE observed no stability violations for N-1.

5.8.3 N-1-1 Stability Violation Summary

ISO-NE observed no stability violations for N-1-1.

5.8.4 Other Observed Stability Criteria Exceedances for Neighboring Systems

ISO-NE observed no stability violations in neighboring systems.

5.9 Short Circuit Results

Several recent changes to the system in the study area have occurred since the models were provided for the RFP, including:

- Fall 2025 – NECEC provided their 'as-purchased' model
- March 2026 – DER update
- April 2026 – Greene Apple Solar (QP #1097) withdrew from the interconnection queue
    - Proposed to interconnect at Larrabee Rd 115 kV substation
    - Required upgrade of nine circuit breakers at Larrabee Rd, which are no longer moving forward due to the QP #1097 withdrawal

While these changes were not known nor could have been predicted by any proposal, the analysis was run to screen for any changes that could be seen during the Section I.3.9 PPA analysis for LTPs A1 and A2.

Short circuit study results for the no adverse impact screening indicated two West Medway 345 kV circuit breakers would be overdutied for the 2030 system model pre-LTP A1/A2 and post-LTP A1/A2. These circuit breakers were also seen as overdutied in the 2036 Short Circuit Needs Assessment.[16] Although LTPs A1 and A2 increase fault current at West Medway, the solution to be

[16] https://www.iso-ne.com/static-assets/documents/100037/a2.0_2036_new_england_short_circuit_needs_assessment.pdf

identified in the 2036 Solutions Study for the Needs Assessment may address any concerns related to LTPs A1 and A2.

With the changes listed above, all 15 remaining 40 kA circuit breakers at Larrabee Road are not overdutied before the addition of any proposal. With the changes, the 15 circuit breakers become overdutied and >1% increase when LTPs A1 or A2 are added. See Table 5-5 for details.

Table 5-5
Larrabee Rd 115 kV Short Circuit Results

Breaker[a]	Previous Project	2036 NA SC Case			Post-A1/A2		
		DUTY [%]	DUTY [A]	Rating	DUTY [%]	DUTY [A]	Δ DUTY [%]
Larrabee CB01	2028 ME SC SS	96.4	38562.8	40000	**105.8**	40000	**9.4**
Larrabee CB02	QP 1097	98.7	39479.8	40000	**108.2**	40000	**9.5**
Larrabee CB03	QP 1097	99.3	39723.4	40000	**108.7**	40000	**9.4**
Larrabee CB04	QP 1097	97.8	39106.2	40000	**107.0**	40000	**9.2**
Larrabee CB05	QP 1097	99.3	39723.4	40000	**108.7**	40000	**9.4**
Larrabee CB06	2028 ME SC SS	99.3	39723.4	40000	**108.7**	40000	**9.4**
Larrabee CB07	2028 ME SC SS	99.3	39723.4	40000	**108.7**	40000	**9.4**
Larrabee CB08	QP 1097	98.3	39337.8	40000	**107.6**	40000	**9.2**
Larrabee CB09	QP 1097	99.3	39723.4	40000	**108.7**	40000	**9.4**
Larrabee CB10	QP 1097	99.3	39723.4	40000	**108.7**	40000	**9.4**
Larrabee CB11	QP 1097	99.3	39723.4	40000	**108.7**	40000	**9.4**
Larrabee CB12	CMP-20-T02 rev1	63.2	39805.7	63000	69.2	63000	7.0
Larrabee CB13	2028 ME SC SS	99.3	39723.4	40000	**108.7**	40000	**9.4**
Larrabee CB14	2028 ME SC SS	96.2	38494.4	40000	**108.7**	40000	**12.5**
Larrabee CB15	QP 1097	99.3	39723.4	40000	**108.7**	40000	**9.4**
Larrabee CB16	2028 ME SC SS	99.3	39723.4	40000	**108.7**	40000	**9.4**

(a) To keep the report non-CEII, the circuit breaker names have been replaced with generic IDs.

5.9.1 Treatment of No Adverse Impact Screening

The no adverse impact screening performed as part of the 2025 LTTP RFP evaluation sought to identify whether the proposal would have a potential significant adverse effect on the system that might be found in a future Section I.3.9 PPA study for the proposal, to further inform the identification of the preferred Longer-Term Transmission Solution. The system is continuously evolving; changes that occurred after the issuance of the RFP introduced issues that were unknown or could not have been predicted from the system models provided as part of the RFP document.

In the case of Larrabee Road, it was assumed that, at the time of the RFP issuance, other proposed projects would provide those replacements. A QTPS, therefore, could not have included the necessary circuit breaker replacements as corollary upgrades in an LTP. According to the Tariff, if ISO-NE determines an upgrade need from the later, post-selection Section I.3.9 PPA process, that need would be addressed as part of the Selected QTPS Agreement (SQTPSA).

As such, the relevant changes to the duty-levels of the Larabee Road breakers, and the associated update in the indication of a potential adverse effect resulted from changes to the model that occurred after the RFP models were provided to the QTPSs. When the PPA study for the preferred Longer-Term Transmission Solution begins, such an adverse effect will be assessed to determine if it persists and the need for additional circuit breaker replacements will be evaluated.

5.10 Summary of No Adverse Impact Screening

The results of the no adverse impact screening for LTPs A1 and A2 identified steady state PTF thermal and voltage violations, which are not expected to be issues. The stability analysis did not identify any issues. However, the short circuit analysis demonstrated that all 15 remaining 40 kA circuit breakers at Larrabee Road became overdutied and increased over 1% when LTPs A1 or A2 were added.

The no adverse impact screening was performed to further inform the identification of the preferred Longer-Term Transmission Solution. This screening showed LTPs A1 and A2 had the same potential to have a significant adverse effect on the system, so this was not a deciding factor in the selection of the preferred solution.

Section 6
Benefit-to-Cost Ratio (BCR) Determination

6.1 Overview of BCR Calculation

To be eligible for consideration as the preferred Longer-Term Transmission Solution, a Longer-Term Proposal needed to have a BCR of greater than 1.0, where the BCR is determined by dividing the financial benefits by the project costs. This section details the quantitative benefits and costs for Longer-Term Proposals A1 and A2. It also provides the resulting BCR for each proposal.

6.1.1 Benefits

Section 16.4(h) of Attachment K of the OATT requires ISO-NE to calculate the financial benefits associated with the proposals that meet the needs identified in the RFP. The five benefits categories that comprise the total project benefits used to determine the benefit-to-cost ratio are:

- Production cost and congestion savings
- Avoided capital cost of local resources needed to serve demand
- Avoided transmission investment (ATI)
- Reduction in losses
- Reduction in expected unserved energy (EUE)

ISO-NE used PLEXOS capacity expansion software in this step of the RFP evaluation. Each of the above metrics, except for ATI, were determined as the difference between values in the pre-project PLEXOS model and the post-project PLEXOS model. Each benefit was then present-valued to the year 2025 to provide all numbers in a "common dollar year". Equation 1 shows the formula used for this present-valuing:

Equation 1: Present Value

$$Present\ Value\ (P.V.) = \sum_{n=in-service\ year}^{n+20} \frac{Total\ Fixed\ Costs_n}{(1+r)^{(n-2025)}}$$

The first year the projects are in service (n) for LTPs A1 and A2 is 2033, and the discount rate (r) for this RFP was assumed to be 8.2%. The first year of earned benefits for the projects start in 2033, so the 20-year period of analysis used for the benefits calculation was January 1, 2033, to December 31, 2052. The results for 2035 were repeated for 2033 and 2034 and the results for 2050 were repeated for 2051 and 2052. ISO-NE then calculated the remaining years of benefits by interpolating the production cost results between years 2035 and 2050. The difference between these values was then present-valued to the year 2025 using Equation 1. Each benefit is described in detail in Sections 6.2 through 6.6.

LTPs B1, C1, D1, and D2 did not pass the initial review and/or meet the objectives of the RFP, and therefore ISO-NE did not calculate their benefits.

6.1.2 Costs

All costs, including both QTPS and corollary upgrade costs, were summed and present-valued to 2025. Those costs are detailed in Section 6.8.

6.2 Production Cost and Congestion Savings Benefit Calculation

The production cost and congestion savings benefit calculation compared production cost model results between a pre-project model and a post-project model for years 2035 and 2050. The pre-project production cost models used the pre-RFP, post-NECEC transfer capabilities for all months of the year. The pre-project interface limits relevant to this RFP are:

- Maine-New Hampshire: 2,200 MW
- Surowiec-South: 2,800 MW

The post-project production cost models included all new transmission topology associated with the proposed project and used the existing interface transfer capabilities, along with the following transfer capabilities updated by the project with winter ratings applied in months 1-4 and 11-12 (Nov through Apr) and summer ratings applied for all other months (May through Oct):

- Maine-New Hampshire:
  - Summer Capability: 3,100 MW
  - Winter Capability: 3,425 MW
- Surowiec-South:
  - Summer Capability: 3,300 MW
  - Winter Capability: 3,725 MW

All production cost models monitored the BHE, Boston, CMA/NEMA, ME, NH, and SME RSP subareas at 115 kV and above. The RSP subareas of CT, NOR, RI, SEMA, SWCT, VT, and WMA were monitored at 345 kV and above.

ISO-NE simulated the 2035 production cost models with 1,200 MW of land-based wind added to the Pittsfield bus in the ME RSP subarea in the post-project production cost model. ISO-NE simulated the 2050 production cost models with the new generation buildouts from the results of the capacity expansion runs. For both models, production cost was the sum of all positive total generator costs plus an adder for any EUE equal to $3,500/MWh. The final production cost and congestion savings benefit was $1.420 billion for both LTPs A1 and A2.

Table 6-1 and Figure 6-1 show the numbers used in the production cost and congestion benefit.

Table 6-1
Production Cost and Congestion Benefit Results

Year[(a)]	PC Base ($M)	PC Pst-LTPs A1/A2 ($M)	Difference ($M)	Difference (2025$M)
2033	$3,514.64	$3,210.24	$304.40	$162.04
2034	$3,514.64	$3,210.24	$304.40	$149.76
2035	$3,514.64	$3,210.24	$304.40	$138.41
2036	$3,394.97	$3,100.09	$294.88	$123.92
2037	$3,275.31	$2,989.95	$285.36	$110.83
2038	$3,155.65	$2,879.81	$275.84	$99.01
2039	$3,035.98	$2,769.67	$266.31	$88.35
2040	$2,916.32	$2,659.53	$256.79	$78.74
2041	$2,796.66	$2,549.39	$247.27	$70.07
2042	$2,676.99	$2,439.25	$237.75	$62.27
2043	$2,557.33	$2,329.10	$228.22	$55.24
2044	$2,437.66	$2,218.96	$218.70	$48.93
2045	$2,318.00	$2,108.82	$209.18	$43.25
2046	$2,198.34	$1,998.68	$199.66	$38.15
2047	$2,078.67	$1,888.54	$190.13	$33.58
2048	$1,959.01	$1,778.40	$180.61	$29.48
2049	$1,839.34	$1,668.25	$171.09	$25.81
2050	$1,719.68	$1,558.11	$161.57	$22.53
2051	$1,719.68	$1,558.11	$161.57	$20.82
2052	$1,719.68	$1,558.11	$161.57	$19.24
Totals	**$52,343.19**	**$47,683.49**	**$4,659.70**	**$1,420.43**

(a) The cost for 2035 was repeated for the years 2033 and 2034 and the cost for 2050 was repeated for 2051 and 2052 to align with the project in-service year of 2033 to give a full 20 years of results.

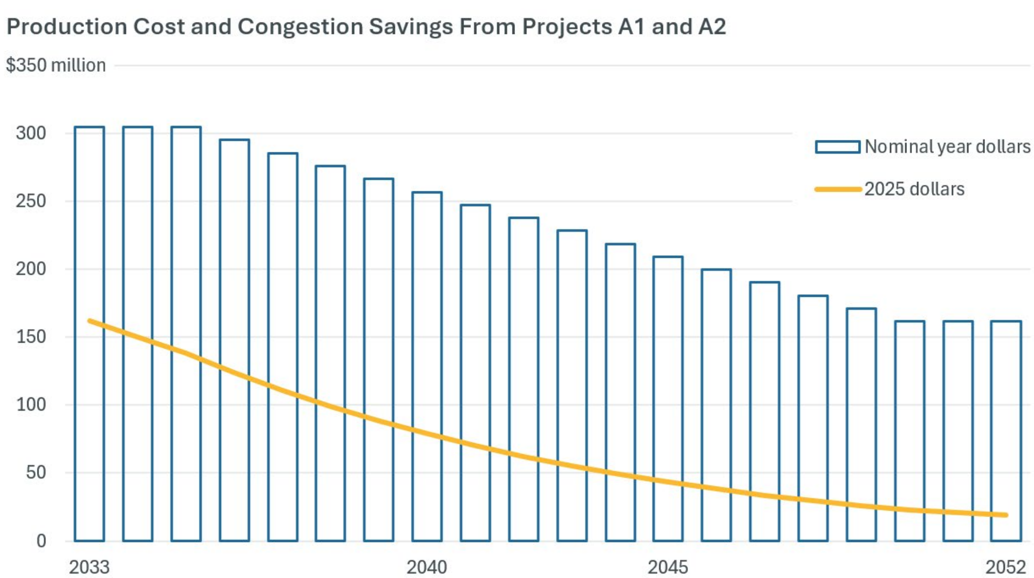


Figure 6-1: Production Cost and Congestion Benefit Results for LTPs A1 and A2

6.3 Reduction in Losses Benefit Calculation

ISO-NE determined the reduction-in-losses benefit from the results of the production cost model. Resistance and hourly flows from the model result were queried for every line and transformer 115 kV and above. To calculate the hourly losses, first the hourly production cost per MWh was determined by taking an hourly sum of all generator costs (fuel, emissions, variable costs, and start costs) divided by the net load (load minus behind-the-meter photovoltaics [BTM-PV]). This was done to determine how costly a MWh of losses were at each point in time. Then, the hourly flow was squared for each element and multiplied by the resistance. Finally, the hourly losses were multiplied by the hourly production cost for each element. Equation 2 shows the formula used for this calculation.

Equation 2: Calculation of Reduction in Losses

$$Losses\ (MWh) = \sum_{h=1}^{8760}\left(\frac{Flow\ (MW)^2}{MVA\ Base} * Resistance\ (pu)\right)$$

The final reduction-in-losses benefit was $12.77 million for both LTPs A1 and A2. The numbers used in the loss reduction benefit calculation are summarized in Table 6-2.

Table 6-2
Reduction in Losses Benefit Calculation

Year	Loss Base ($M)	Loss Pst-LTPs A1/A2($M)	Difference ($M)	Difference (2025$M)
2033	$57.92	$61.42	-$3.49	-$1.86
2034	$57.92	$61.42	-$3.49	-$1.72
2035	$57.92	$61.42	-$3.49	-$1.59
2036	$57.04	$59.42	-$2.38	-$1.00
2037	$56.15	$57.41	-$1.27	-$0.49
2038	$55.26	$55.41	-$0.15	-$0.05
2039	$54.37	$53.41	$0.96	$0.32
2040	$53.48	$51.41	$2.07	$0.64
2041	$52.60	$49.41	$3.19	$0.90
2042	$51.71	$47.41	$4.30	$1.13
2043	$50.82	$45.41	$5.42	$1.31
2044	$49.93	$43.40	$6.53	$1.46
2045	$49.05	$41.40	$7.64	$1.58
2046	$48.16	$39.40	$8.76	$1.67
2047	$47.27	$37.40	$9.87	$1.74
2048	$46.38	$35.40	$10.98	$1.79
2049	$45.50	$33.40	$12.10	$1.82
2050	$44.61	$31.40	$13.21	$1.84
2051	$44.61	$31.40	$13.21	$1.70
2052	$44.61	$31.40	$13.21	$1.57
Totals	**$1,025.31**	**$928.14**	**$97.17**	**$12.77**

6.4 Avoided Capital Cost Benefit Calculation

ISO-NE determined the avoided capital costs benefit by comparing PLEXOS capacity expansion (CapEx) model cost results between a pre-project model and a post-project model. The pre-project capacity expansion model ran from 2035-2050 using the pre-RFP, post-NECEC transfer capabilities for all months of the year. The pre-project transfer capabilities relevant to this RFP are:

- Maine-New Hampshire: 2,200 MW
- Surowiec-South: 2,800 MW

The model simulated the pre-project capacity expansion solution's region-wide fixed costs for each year of the simulation horizon. Fixed costs included fixed operation and maintenance costs as well as the annualized build cost of new resources. The pre-project capacity expansion model produced costs for 2035-2050, with 2035 data used to represent 2033 and 2034, and 2050 data being used to represent 2051 and 2052 to achieve a full 20 years from 2033 to 2052.

The pre-project capacity expansion solution dictated a resource mix that was subsequently used in the pre-project 2050 production cost and expected unserved energy (EUE) models. In addition to the resources selected by the capacity expansion engine, a local sourcing screen was performed to identify RSP subareas that did not have a 10% margin of generation capacity over peak net load minus import capability. In the pre-project 2050 production cost and EUE models, four-hour batteries were added to subareas with capacity shortages until they achieved the 10% margin. The costs of the additional batteries were recorded and added to the fixed costs, which is reflected in Table 6-4.

ISO-NE ran the post-project capacity expansion model from 2035 to 2050 using the existing interface transfer capabilities, along with the following transfer capabilities updated by the project with winter ratings applied in months 1-4 and 11-12 (Nov through Apr) and summer ratings applied to all other months (May through Oct):

- Maine-New Hampshire:
  - Summer Capability: 3,100 MW
  - Winter Capability: 3,425 MW
- Surowiec-South:
  - Summer Capability: 3,300 MW
  - Winter Capability: 3,725 MW

The model simulated the post-project capacity expansion solution's region-wide fixed costs for each year of the simulation horizon. For post-project models, the fixed and capital costs of the accommodated wind were reduced to only include turbine costs and transmission to deliver the energy to Pittsfield. This was because the transmission to deliver that wind from Pittsfield to the rest of the New England grid, as well as the Pittsfield station itself, was already included in the RFP proposal's costs. In the pre-project capacity expansion model, the costs of wind included the additional cost of the Pittsfield substation and transmission costs south of Pittsfield according to the Third Maine Resource Integration Study (MRIS). The post-project capacity expansion model produced costs for 2035-2050, with 2035 data used to represent 2033 and 2034, and 2050 data being used to represent 2051 and 2052 to achieve a full 20 years from 2033 to 2052.

The post-project capacity expansion solution dictated the resource mix that was subsequently used in the post-project 2050 production cost and EUE models. The local sourcing requirement (LSR) screen was repeated for the post-project capacity expansion results, and four-hour batteries were added to the post-project 2050 production cost and EUE models as needed. Table 6-3 summarizes the capacity expansion solution and local sourcing requirement resource additions for the pre-project and post-project models.

Table 6-3
Capacity Expansion Buildouts

Resource Type	Pre-Proj Capacity Built (MW)	Post-Proj Capacity Built (MW)
Solar	45,000	45,000
Land-Based Wind	2,400	3,600
Offshore Wind	15,600	14,400
4-Hr Battery (CapEx)	16,820	17,485
4-Hr Battery (LSR[17])	1,935	2,021
8-Hour Battery	5,209	3,571
Total	**86,964**	**86,077**

ISO-NE then calculated the avoided capital cost benefit by finding the difference between the pre-project and post-project total fixed costs and converting the result to a dollar year of 2025 using Equation 1.

The avoided capital cost benefit for both LTPs A1 and A2 was $1.302 billion.

Table 6-4 summarizes the numbers from the avoided capital cost benefit calculation.

[17] LSR = Local Sourcing Requirement

Table 6-4
Avoided Capital Cost Benefit Results

Year	CapEx Base ($M)	CapEx Pst-A1/A2 ($M)	Difference ($M)	Difference (2025$M)
2033	$258.66	$112.21	$146.46	$77.96
2034	$258.66	$112.21	$146.46	$72.05
2035	$258.66	$112.21	$146.46	$66.59
2036	$1,018.31	$847.24	$171.07	$71.89
2037	$1,573.66	$1,428.77	$144.89	$56.27
2038	$3,540.54	$3,364.92	$175.62	$63.04
2039	$4,037.38	$3,808.90	$228.49	$75.80
2040	$5,049.93	$4,770.02	$279.91	$85.82
2041	$6,276.15	$6,369.63	-$93.48	-$26.49
2042	$7,566.67	$7,501.76	$64.91	$17.00
2043	$8,299.92	$8,155.10	$144.82	$35.05
2044	$9,470.67	$9,338.18	$132.49	$29.64
2045	$12,010.64	$11,464.76	$545.89	$112.86
2046	$12,610.60	$12,036.06	$574.54	$109.79
2047	$15,318.70	$14,745.85	$572.85	$101.17
2048	$16,566.93	$16,169.84	$397.09	$64.81
2049	$16,570.47	$16,174.23	$396.24	$59.77
2050	$17,796.16	$17,205.17	$590.99	$82.39
2051	$17,796.16	$17,205.17	$590.99	$76.15
2052	$17,796.16	$17,205.17	$590.99	$70.38
Totals	**$174,075.04**	**$168,127.40**	**$5,947.65**	**$1,301.97**

6.5 Reduction in Expected Unserved Energy (EUE) Benefit Calculation

ISO-NE calculated the reduced EUE benefit by comparing the modeled EUE between a pre-project model and a post-project model. In the post-project model, the transfer capabilities on Maine-New Hampshire and Surowiec-South were upgraded to the following limits with winter ratings applied in months 1-4 and 11-12 (November through April) and summer ratings applied for all other months (May through October):

- Maine-New Hampshire:
  - Summer Capability: 3,100 MW
  - Winter Capability: 3,425 MW
- Surowiec-South:
  - Summer Capability: 3,300 MW
  - Winter Capability: 3,725 MW

Additionally, in the 2035 model, 1,200 MW of new land-based wind was sited in the ME RSP subarea.

For the 2050 models (both pre-project and post project), the results of the capacity expansion runs (new generation buildouts) were sited in the EUE model. Each of the Monte Carlo models were run for 20 weather years, and the average unserved energy was collected from each model. Then, the unserved energy was multiplied by a penalty price of $3,500/MWh.

ISO-NE then calculated the reduction in EUE benefit by finding the difference between the pre-project and post-project EUE costs and then converting to a dollar year of 2025 using Equation 1.

Table 6-5 shows the numbers used in the reduction in EUE benefit calculation.

Table 6-5
Reduction in EUE Benefit Results

Year	EUE Base ($M)	EUE Pst-A1/A2 ($M)	Difference ($M)	Difference (2025$M)
2033	$0.01	$0.02	-$0.01	$0.00
2034	$0.01	$0.02	-$0.01	$0.00
2035	$0.01	$0.02	-$0.01	$0.00
2036	$10.61	$12.03	-$1.42	-$0.60
2037	$21.21	$24.05	-$2.84	-$1.10
2038	$31.80	$36.06	-$4.26	-$1.53
2039	$42.40	$48.08	-$5.67	-$1.88
2040	$53.00	$60.09	-$7.09	-$2.17
2041	$63.60	$72.11	-$8.51	-$2.41
2042	$74.20	$84.12	-$9.92	-$2.60
2043	$84.80	$96.14	-$11.34	-$2.75
2044	$95.40	$108.15	-$12.76	-$2.85
2045	$106.00	$120.17	-$14.17	-$2.93
2046	$116.59	$132.19	-$15.59	-$2.98
2047	$127.19	$144.20	-$17.01	-$3.00
2048	$137.79	$156.22	-$18.42	-$3.01
2049	$148.39	$168.23	-$19.84	-$2.99
2050	$158.99	$180.25	-$21.26	-$2.96
2051	$158.99	$180.25	-$21.26	-$2.74
2052	$158.99	$180.25	-$21.26	-$2.53
Totals	**$1,589.98**	**$1,802.63**	**-$212.65**	**-$41.06**

The reduction in EUE benefit for both LTPs A1 and A2 was -$41.06 million, which means that EUE actually slightly increased. While the benefits metric for the EUE was negative, this negative metric is significantly outweighed by the improvement in avoided capital costs, production costs, and congestion. All benefits should be seen as complementary to one another — e.g., the capacity expansion model could decide to build another unit to reduce EUE — but this would drive a higher capital cost. The capacity expansion model may opt for a slightly higher EUE to gain a greater reduction in capital cost. The capacity expansion model was set to only add solar, wind, four-hour batteries, and eight-hour batteries, which limited the optimization options for the PLEXOS models.

The capacity expansion model contains simplified models for production cost and resource adequacy, and as a result, under-reports EUE compared to a more detailed resource adequacy model used to calculate the EUE numbers. Therefore, it cannot truly optimize all parameters.

6.6 Avoided Transmission Investment (ATI) Calculation

ISO-NE determined the avoided transmission investment benefit using a combination of information submitted by the QTPS, information from Asset Condition Projects (ACPs) presented at the Planning Advisory Committee (PAC), and per-mile cost estimates that the ISO provided in slides 8-9 of the February 2025 PAC presentation. Information from PAC ACP presentations was given preference in determining what numbers should be used for calculating avoided transmission investment. After that, any additional transmission structures to be replaced with an age of 40 or more years as of December 31, 2035 (i.e., installed prior to December 31, 1995) were used to calculate avoided transmission investment using per-mile costs.

Table 6-6 details the elements that were deemed eligible to receive avoided transmission investment benefit for LTPs A1 and/or A2, with the component's inclusion in a particular proposal indicated by X:

Table 6-6
Elements Considered for Avoided Transmission Investment

Project Component	A1	A2	kV	Len (mi)	Total Strs	PTO
Rebuild Maine Yankee Substation as Old Ferry Road	X	X	345	N/A	N/A	CMP
Partial Rebuild of Line 374	X	X	345	26.50	237	CMP
Partial Rebuild of Line 3038	X	X	345	26.55	242	CMP
Full Rebuild of Line 391-ME	X	X	345	30.60	259	CMP
Upgrade Line 64 to 345 kV	X	X	115	16.10	241	CMP
Partial Rebuild of Line 67	X	X	115	17.40	158	CMP
Full Rebuild of Line 257	X	X	115	20.84	228	CMP
Full Rebuild of Line 258	X	X	115	21.07	234	CMP
Partial Rebuild of Line 81	X	X	115	28.51	307	CMP
Partial Rebuild of Line 200-1	X	X	115	13.80	166	CMP
Partial Rebuild of Line 167-1	X	X	115	16.30	217	CMP
Full Rebuild of Line 391-NH	X		345	18.50	175	ES
Partial Rebuild of Line 373	X	X	345	18.60	178	ES
Partial Rebuild of Line N133-2	X	X	115	4.50	58	ES

Note that the only difference in elements considered for avoided transmission investment between LTPs A1 and A2 involved Eversource's portion of the 391 line between Buxton and the ME/NH state border. For LTP A1, line 391 would be rebuilt to accommodate the proposal's new Buxton-Deerfield line and a rebuilt 391 line in the same space containing the existing 391 line structures. For LTP A2, line 391 would not be rebuilt because the new Buxton-Deerfield line would be built at the edge of the ROW without needing to fully rebuild the 391 line. Based on an identified future ACP involving

Eversource's portion of the 391 line, LTP A1 is credited with avoided transmission investment for that element, while LTP A2 is not.

Table 6-7 details the elements for LTPs A1 and A2 that had relevant ACP presentations for the PAC. This information was used as part of the calculation of avoided transmission investment for these elements.

Table 6-7
Asset Condition Project (ACP) Summary

Project Component	A1	A2	PTO	PAC Date	ACP List #	Total Strs	ACP # of Strs Rpl	ACP Cost (ISD$M)
Partial Rebuild of Line 374	X	X	CMP	9/17/25	499	237	28	11.19
Partial Rebuild of Line 3038	X	X	CMP	9/17/25	505	242	46	18.56
Partial Rebuild of Line 200-1	X	X	CMP	9/17/25	497	166	19	5.95
Full Rebuild of Line 391-ME	X	X	CMP	9/17/25	503	259	19	7.75
Full Rebuild of Line 391-NH	X		ES	6/16/25	495	175	59[a]	17.12
Partial Rebuild of Line 373	X	X	ES	6/16/25	493	178	27	9.25
							Total Cost A1 (ISD$M)	**69.82**
							Total Cost A2 (ISD$M)	**52.71**

(a) This project replaces 89 structures, however only 59 were needed for the proposal so ACP cost shown was original cost multiplied by 59/89

The avoided transmission investment for all other transmission lines from Table 6-6 was determined using per-mile numbers from the February 2025 PAC presentation, with the categories reproduced and clarified in Table 6-8:

Table 6-8
Per-Mile Cost Assumptions

Component	Cost (2025$)
Partial Rebuild (115 kV Overhead)	$5.50M/mi
Total Rebuild (115 kV Overhead)	$8.00M/mi
Partial Rebuild (345 kV Overhead)	$6.50M/mi
Total Rebuild (345 kV Overhead)	$9.00M/mi

Note that the February 2025 PAC presentation listed the categories as either "Rebuild" or "New Build." Table 6-8 has clarified the definitions such that the "Rebuild" numbers listed in the PAC presentation were interpreted as being either a reconductoring of a line or a partial rebuild — essentially, a line needing some amount of replacement but not a complete rebuild. The "New Build" category listed in the PAC presentation was interpreted as a complete rebuild, where every structure on the line would be replaced and new siting may be required.

Table 6-9 summarizes the number of structures being replaced by LTPs A1 and A2 and shows the number of structures that ultimately used per-mile cost estimates to calculate avoided transmission investment after subtracting out the number of structures that were replaced as part of an ACP:

Table 6-9
LTPs A1 and A2 Structures Replaced

Project Component	A1	A2	Total Str	Str Repl	Str Repl (40+Yr)	ACP # of Str Repl	Strs Elig for /Mi Est.
Full Rebuild of Line 67	X	X	158	158	100	0	100
Full Rebuild of Line 257	X	X	228	228	99	0	99
Full Rebuild of Line 258	X	X	234	234	71	0	71
Upgrade Line 64 to 345 kV	X	X	241	241	101	0	101
Partial Rebuild of Line 374	X	X	237	164	157	28	129
Partial Rebuild of Line 3038	X	X	242	123	97	46	51
Partial Rebuild of Line 81	X	X	307	176	138	0	138
Partial Rebuild of Line 200-1	X	X	166	127	91	19	72
Partial Rebuild of Line 167-1	X	X	217	74	41	0	41
Full Rebuild of Line 391-ME	X	X	259	259	234	19	215
Full Rebuild of Line 391-NH	X		175	175	59	59	0
Partial Rebuild of Line 373	X	X	178	30	30	27	3
Partial Rebuild of Line N133-2	X	X	58	14	14	0	14

Table 6-10 summarizes the structures that LTPs A1 and A2 would replace that were not part of an ACP but are eligible for the per-mile estimate of the avoided transmission investment:

Table 6-10
LTPs A1 and A2 ATI From Per-Mile Estimates

Project Component	A1	A2	Total Str	Strs Eligible for Per-Mi Est.	% of Line Eligible for Per-Mi Est.	Length (mi)	Miles Used in Per-Mi Est.	Per-Mile Cost Used (2025$M)	ATI Benefit/mi (2025$M)
Full Rebuild of Line 67	X	X	158	100	63.29%	17.40	11.01	8.00	88.10
Full Rebuild of Line 257	X	X	228	99	43.42%	20.84	9.05	8.00	72.39
Full Rebuild of Line 258	X	X	234	71	30.34%	21.07	6.39	8.00	51.14
Upgrade Line 64 to 345 kV	X	X	241	101	41.91%	16.10	6.75	8.00	53.98
Partial Rebuild of Line 374	X	X	237	129	54.43%	26.50	14.42	6.50	93.76
Partial Rebuild of Line 3038	X	X	242	51	21.07%	26.55	5.60	6.50	36.37
Partial Rebuild of Line 81	X	X	307	138	45.00%	28.51	12.82	5.50	70.49
Partial Rebuild of Line 200-1	X	X	166	72	43.37%	13.80	5.99	5.50	32.92
Partial Rebuild of Line 167-1	X	X	217	41	18.89%	16.30	3.08	5.50	16.94
Full Rebuild of Line 391-ME	X	X	259	215	83.01%	30.58	25.38	9.00	228.46
Full Rebuild of Line 391-NH	X		175	0	0.00%	18.50	0.00	9.00	0.00
Partial Rebuild of Line 373	X	X	178	3	1.69%	18.60	0.31	6.50	2.04
Partial Rebuild of Line N133-2	X	X	58	14	24.14%	4.50	1.09	5.50	5.97
								Total Cost A1 (2025$M)	**752.56**
								Total Cost A2 (2025$M)	**752.56**

The total avoided transmission investment benefit for each transmission line was then determined by adding together the per-mile estimates and the ACP estimates, giving the totals for LTPs A1 and A2, shown in Table 6-11.

Table 6-11
LTPs A1 and A2 Total Avoided Transmission Investment for Lines

Project Component	A1	A2	ATI Benefit from Per-Mi (2025$M)	ATI Benefit from ACP (ISD$M)	Total ATI Benefit (2025$M)
Full Rebuild of Line 67	X	X	88.10	0.00	88.10
Full Rebuild of Line 257	X	X	72.39	0.00	72.39
Full Rebuild of Line 258	X	X	51.14	0.00	51.14
Upgrade Line 64 to 345 kV	X	X	53.98	0.00	53.98
Partial Rebuild of Line 374	X	X	93.76	11.19	104.95
Partial Rebuild of Line 3038	X	X	36.37	18.56	54.93
Partial Rebuild of Line 81	X	X	70.49	0.00	70.49
Partial Rebuild of Line 200-1	X	X	32.92	5.95	38.87
Partial Rebuild of Line 167-1	X	X	16.94	0.00	16.94
Full Rebuild of Line 391-ME	X	X	228.46	7.75	236.21
Full Rebuild of Line 391-NH	X		0.00	17.12	17.12
Partial Rebuild of Line 373	X	X	2.04	9.25	11.29
Partial Rebuild of Line N133-2	X	X	5.97	0.00	5.97
				Total Cost A1 (2025$M)	**822.38**
				Total Cost A2 (2025$M)	**805.26**

Avoided transmission investment was also counted for the proposal's replacement of the Maine Yankee substation with a new substation named Old Ferry Road. This replacement was the same for both LTPs A1 and A2, and the cost estimate was provided by the QTPS, shown in Table 6-12.

Table 6-12
ATI For Maine Yankee Substation Replacement

Project Component	Total ATI Benefit (2025$M)
Rebuild Maine Yankee Substation as Old Ferry Road	67.82

The total avoided transmission investment benefit for LTPs A1 and A2 was determined by summing the ATI from the lines and the Maine Yankee substation replacement, summarized in Table 6-13:

Table 6-13
LTPs A1 and A2 Total Avoided Transmission Investment Benefit

Project Component	A1	A2	Total ATI Benefit (2025$M)
Full Rebuild of Line 67	X	X	88.10
Full Rebuild of Line 257	X	X	72.39
Full Rebuild of Line 258	X	X	51.14
Upgrade Line 64 from 115 kV to 345 kV	X	X	53.98
Partial Rebuild of Line 374	X	X	104.95
Partial Rebuild of Line 3038	X	X	54.93
Partial Rebuild of Line 81	X	X	70.49
Partial Rebuild of Line 200-1	X	X	38.87
Partial Rebuild of Line 167-1	X	X	16.94
Full Rebuild of Line 391-ME	X	X	236.21
Full Rebuild of Line 391-NH	X		17.12
Partial Rebuild of Line 373	X	X	11.29
Partial Rebuild of Line N133-2	X	X	5.97
Rebuild Maine Yankee Substation as Old Ferry Road	X	X	67.82
Total Avoided Transmission Investment A1 (2025$M)			**890.21**
Total Avoided Transmission Investment A2 (2025$M)			**873.09**

The avoided transmission investment number was then net-present-valued (NPV) over the first 20 years of the project's life (2033-2052) using a carrying cost factor of 14% applied to the depreciated book value of the transmission and then a discount rate of 8.2%. Transmission assets are assumed to have a 40-year book life, so they were depreciated by 2.5% per year. The annual amount for each of the 20 years was determined by multiplying the book value of the total avoided transmission investment value by 14% and then each year's value was present-valued back to 2025 using the 8.2% discount rate. Table 6-14 shows the results of this calculation.

Table 6-14
Annual Carrying Cost (ACC) from Avoided Transmission for LTPs A1 and A2

Year	A1 Book Value (CY$M)	A1 ACC (CY$M)	A1 ACC (2025$M)	A2 Book Value (CY$M)	A2 ACC (CY$M)	A2 ACC (2025$M)
2033	$890.21	$124.63	$66.34	$873.09	$122.23	$65.07
2034	$867.95	$121.51	$59.78	$851.26	$119.18	$58.63
2035	$845.69	$118.40	$53.84	$829.43	$116.12	$52.80
2036	$823.44	$115.28	$48.45	$807.61	$113.06	$47.51
2037	$801.18	$112.17	$43.56	$785.78	$110.01	$42.73
2038	$778.93	$109.05	$39.14	$763.95	$106.95	$38.39
2039	$756.67	$105.93	$35.14	$742.12	$103.90	$34.47
2040	$734.42	$102.82	$31.53	$720.30	$100.84	$30.92
2041	$712.16	$99.70	$28.25	$698.47	$97.79	$27.71
2042	$689.91	$96.59	$25.30	$676.64	$94.73	$24.81
2043	$667.65	$93.47	$22.63	$654.82	$91.67	$22.19
2044	$645.40	$90.36	$20.21	$632.99	$88.62	$19.82
2045	$623.14	$87.24	$18.04	$611.16	$85.56	$17.69
2046	$600.89	$84.12	$16.07	$589.33	$82.51	$15.77
2047	$578.63	$81.01	$14.31	$567.51	$79.45	$14.03
2048	$556.38	$77.89	$12.71	$545.68	$76.40	$12.47
2049	$534.12	$74.78	$11.28	$523.85	$73.34	$11.06
2050	$511.87	$71.66	$9.99	$502.03	$70.28	$9.80
2051	$489.61	$68.55	$8.83	$480.20	$67.23	$8.66
2052	$467.36	$65.43	$7.79	$458.37	$64.17	$7.64
Totals		**$1,900.59**	**$573.20**		**$1,864.04**	**$562.18**

The numbers in bold at the bottom of Table 6-14, $573.20 million for LTP A1 and $562.18 million for LTP A2, are the final avoided transmission investment benefit numbers used to determine each proposal's BCR.

6.7 Summary of Financial Benefits

Table 6-15 summarizes the total benefits for LTPs A1 and A2:

Table 6-15
LTPs A1 and A2 Benefits Summary

Benefit (2025$M)	A1	A2
Production Cost & Congestion Savings	$1,420.43	$1,420.43
Reduction in Losses	$12.77	$12.77
Avoided Capital Cost	$1,301.97	$1,301.97
Reduction in Expected Unserved Energy	-$41.06	-$41.06
Avoided Transmission Investment	$573.20	$562.18
Total Project Benefits[18]	**$3,267.32**	**$3,256.30**

Figure 6-2 and Figure 6-3 illustrate the total financial benefits of LTPs A1 and A2, respectively.

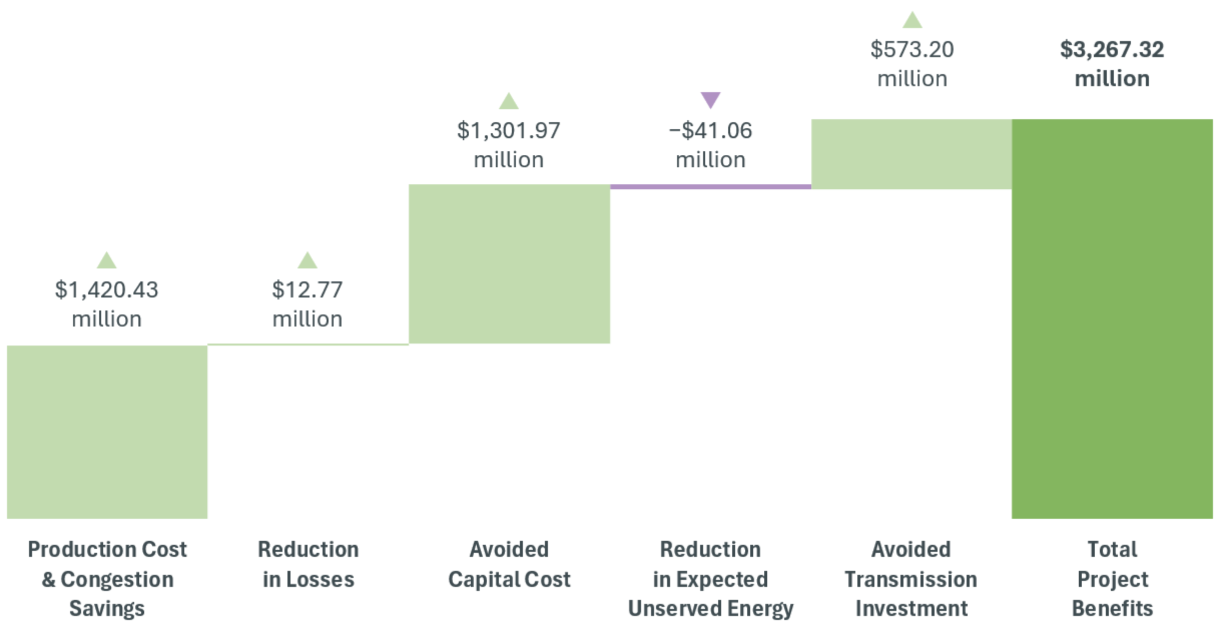


Figure 6-2: LTP A1 Total Financial Benefits

[18] Totals may not sum exactly due to rounding.

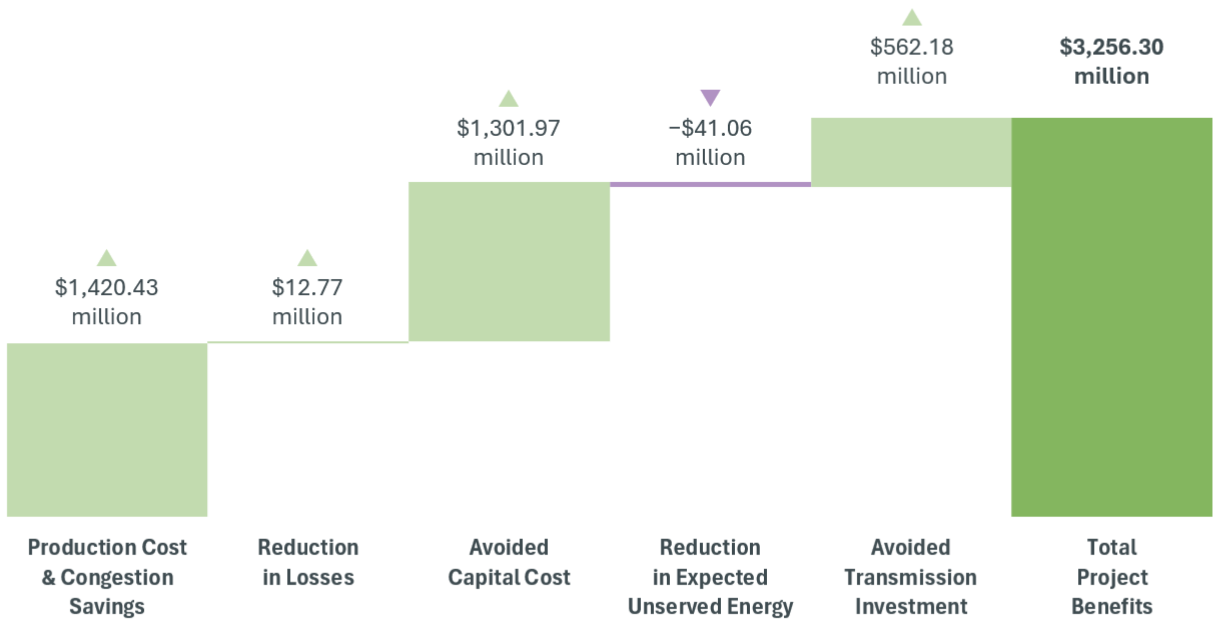


Figure 6-3: LTP A2 Total Financial Benefits

6.8 Longer-Term Proposal Costs

Proposals A1 and A2 had installed costs of $2.20 billion and $2.14 billion, respectively (nominal dollars). These costs represent the total capital costs required to build each proposal. The annual revenue requirement (ARR) for each proposal was then determined over the first 20 years of each proposal's life to be $4.726 billion for A1 and $4.590 for A2. The ARR represents the yearly amount that a transmission owner must collect to recover the initial investment (via depreciation) plus return on equity and debt, taxes, and O&M. The sum of the first 20 years of nominal ARRs is significantly higher than the installed cost because it includes the initial investment (depreciation), the return on equity and debt, taxes, and O&M across two decades. Table 6-16 summarizes the ARR values calculated by the financial consultant:

Table 6-16
Annual Revenue Requirement (ARR) for LTPs A1 and A2

Year	A1 ARR ($M)	A2 ARR ($M)
2033	$304.75	$296.12
2034	$297.25	$288.84
2035	$287.69	$279.52
2036	$279.20	$271.26
2037	$271.20	$263.47
2038	$264.63	$257.10
2039	$257.48	$250.14
2040	$250.59	$243.43
2041	$243.37	$236.40
2042	$236.35	$229.57
2043	$230.89	$224.30
2044	$223.12	$216.72
2045	$216.07	$209.85
2046	$209.30	$203.28
2047	$202.03	$196.20
2048	$196.29	$190.61
2049	$197.37	$191.81
2050	$189.02	$183.53
2051	$185.91	$180.50
2052	$183.04	$177.72
Total ARR	**$4,725.54**	**$4,590.36**
Total PVRR	**$1,556.39**	**$1,517.83**

The QTPS costs for LTPs A1 and A2 that were ultimately used to calculate the BCR were the present value revenue requirement (PVRR) for each proposal. The PVRR discounts the ARR back to 2025 dollars using an 8.2% discount rate. This converts the costs to the same time basis for the benefits, allowing for a direct comparison of costs and benefits. The ISO's financial consultant determined LTP A1's PVRR was $1.556 billion, and LTP A2's was $1.518 billion.

Table 6-17 summaries the costs related to the QTPS's portion of their proposals:

Table 6-17
LTPs A1 and A2 QTPS Costs

Proposal	Installed Costs (Nominal $M)	ARR (Nominal $M)	PVRR (2025$M)
A1	$2,201.42	$4,725.54	$1,556.39
A2	$2,138.79	$4,590.36	$1,517.83

Proposals A1 and A2 each contained corollary upgrades to replace several circuit breakers; these were common to both proposals. The installed cost estimate from the PTO to replace the breakers was $2.91 million. This number was then depreciated 2.5% per year, converted into the ARR, and then into the PVRR amount, detailed in Table 6-18:

Table 6-18
Costs for A1 and A2 Corollary Upgrades

Year	Book Value (CY$M)	ARR (CY$M)	PVRR (2025$M)
2033	$2.91	$0.41	$0.22
2034	$2.83	$0.40	$0.20
2035	$2.76	$0.39	$0.18
2036	$2.69	$0.38	$0.16
2037	$2.62	$0.37	$0.14
2038	$2.54	$0.36	$0.13
2039	$2.47	$0.35	$0.11
2040	$2.40	$0.34	$0.10
2041	$2.32	$0.33	$0.09
2042	$2.25	$0.32	$0.08
2043	$2.18	$0.31	$0.07
2044	$2.11	$0.29	$0.07
2045	$2.03	$0.28	$0.06
2046	$1.96	$0.27	$0.05
2047	$1.89	$0.26	$0.05
2048	$1.82	$0.25	$0.04
2049	$1.74	$0.24	$0.04
2050	$1.67	$0.23	$0.03
2051	$1.60	$0.22	$0.03
2052	$1.53	$0.21	$0.03
Total		**$6.20**	**$1.87**

Table 6-19 summarizes the total costs for LTPs A1 and A2, including the costs that come from the QTPS and the costs that come from corollary upgrades to be performed by the incumbent TO on the QTPS's behalf.

Table 6-19
Costs for A1 and A2

Cost (2025$M)	A1	A2
QTPS Project Costs PVRR	$1,556.39	$1,517.83
PTO Corollary Upgrade PVRR	$1.87	$1.87
Total Project Costs	**$1,558.26**	**$1,519.70**

6.9 Final Benefit-to-Cost Ratio (BCR) Calculation

Table 6-20 summarizes the BCRs for LTPs A1 and A2:

Table 6-20
Calculation of BCR for LTPs A1 and A2

BCR Components (2025$M)	A1	A2
Total Project Benefits	$3,267.32	$3,256.30
Total Project Costs	$1,558.26	$1,519.70
Project BCR	**2.10**	**2.14**

Both LTPs A1 and A2 exceeded the BCR requirement of 1.0, which means that the remainder of the RFP follows the LTTP's process detailed in Section 16.5 of Attachment K of the OATT rather than the process detailed in Section 16.8 of Attachment K of the OATT.[19]

[19] Section 16.4(i) of Attachment K describes the selection process to be used when at least one of the Longer-Term Proposal(s) has a benefit to cost ratio greater than 1.0. In such instances, the ISO reports the preliminary preferred Longer-Term Transmission Solution to the PAC. Following receipt of stakeholder comments, the ISO identifies the preferred Longer-Term Transmission Solution. In instances where all of the Longer-Term Proposal(s) do not meet the greater than 1.0 benefit to cost ratio threshold, Section 16.4(j) of Attachment describes the process whereby NESCOE may identify the preferred Longer-Term Proposal.

Section 7
Evaluation of Proposals

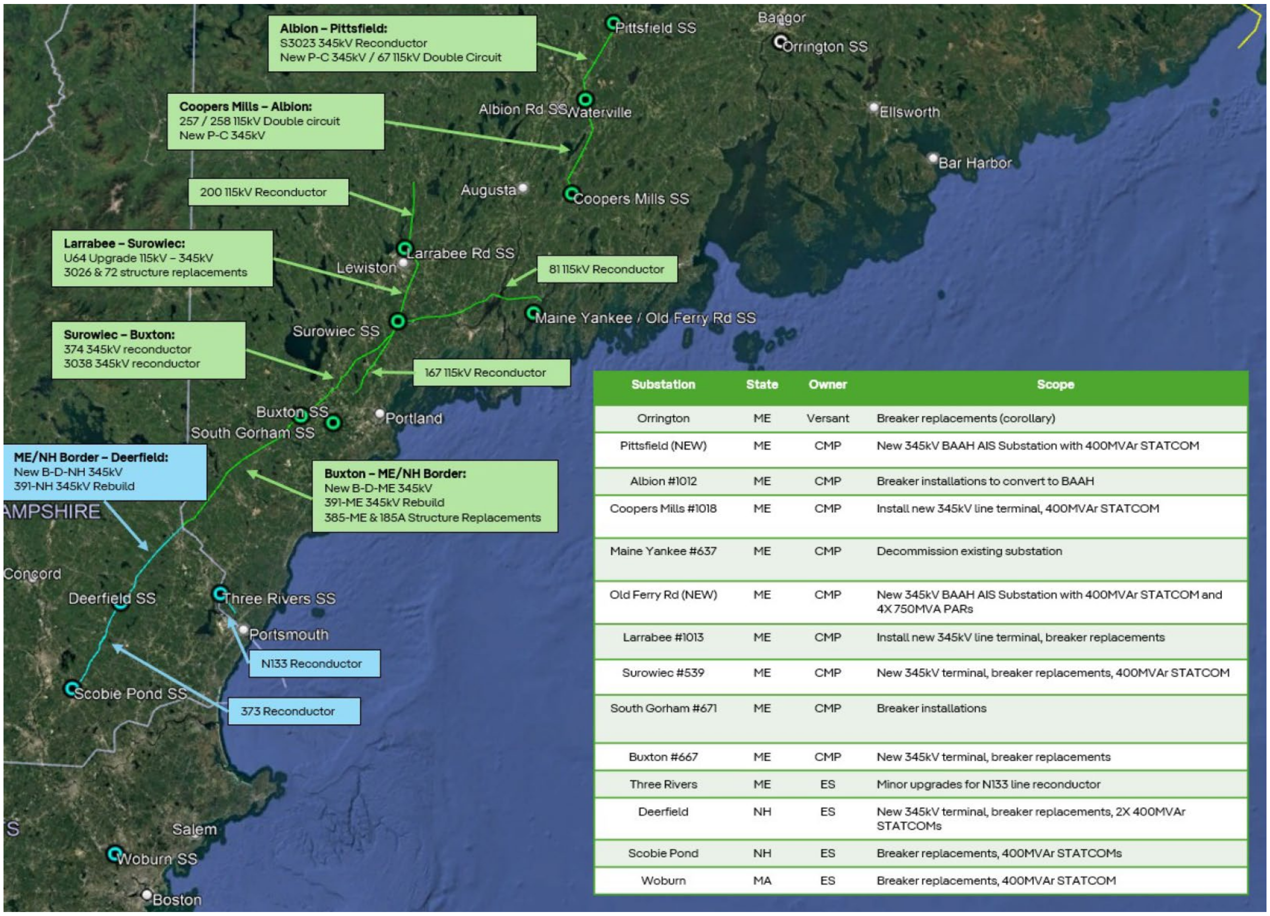
The goal of the evaluation was to consider all quantitative and qualitative factors provided and provided by NESCOE to select the preferred Longer-Term Transmission Solution.

7.1 Detailed Design of LTPs A1 and A2

Proposals A1 and A2 are identical in electrical performance (i.e., from a power flow perspective they have no differences in topology, impedances, and ratings). The two proposals only differ in overall capital costs, ROW design for one line segment in NH, and avoided transmission investment benefits.

7.1.1 LTP A1 Details

- Lead QTPS: Central Maine Power (CMP)
- Joint Proposal: Yes w/ Public Service New Hampshire (PSNH) and NSTAR Electric Company (NSTAR) (collectively Eversource)
- Type: AC transmission in ME and NH
- Cost Containment: Yes
- Construction Start: Q1 2029, In-Service Date: Q4 2032
- Design Summary
    - Wind interconnection POI: Pittsfield
    - New 345 kV lines: Pittsfield-Coopers Mills & Buxton-Deerfield (70 mi total)
    - Rebuild Larrabee Rd-Surowiec 115 kV line to operate at 345 kV
    - Several reconductored 345 & 115 kV lines
    - Retire ME Yankee 345 kV substation, build new adjacent Old Ferry Rd 345 kV
    - New STATCOMs: Eight 400 MVAR @ 345 kV
    - New Phase Angle Regulators: Four 750 MVA @ 345 kV
    - Minor corollary upgrade

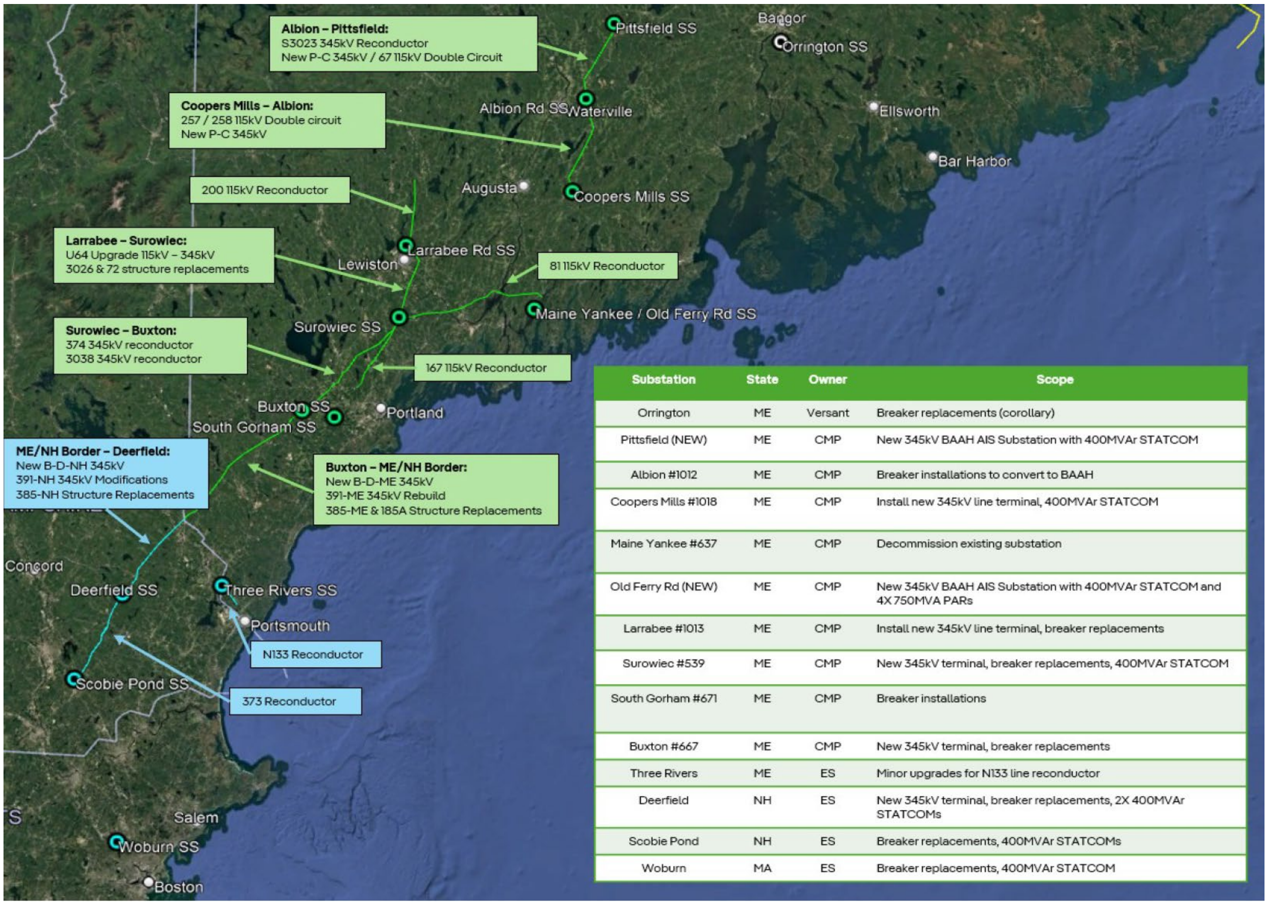


Substation	State	Owner	Scope
Orrington	ME	Versant	Breaker replacements (corollary)
Pittsfield (NEW)	ME	CMP	New 345kV BAAH AIS Substation with 400MVAr STATCOM
Albion #1012	ME	CMP	Breaker installations to convert to BAAH
Coopers Mills #1018	ME	CMP	Install new 345kV line terminal, 400MVAr STATCOM
Maine Yankee #637	ME	CMP	Decommission existing substation
Old Ferry Rd (NEW)	ME	CMP	New 345kV BAAH AIS Substation with 400MVAr STATCOM and 4X 750MVA PARs
Larrabee #1013	ME	CMP	Install new 345kV line terminal, breaker replacements
Surowiec #539	ME	CMP	New 345kV terminal, breaker replacements, 400MVAr STATCOM
South Gorham #671	ME	CMP	Breaker installations
Buxton #667	ME	CMP	New 345kV terminal, breaker replacements
Three Rivers	ME	ES	Minor upgrades for N133 line reconductor
Deerfield	NH	ES	New 345kV terminal, breaker replacements, 2X 400MVAr STATCOMs
Scobie Pond	NH	ES	Breaker replacements, 400MVAr STATCOMs
Woburn	MA	ES	Breaker replacements, 400MVAr STATCOM

Figure 7-1: LTP A1 Diagram

7.1.2 LTP A2 Details

- Lead QTPS: Central Maine Power (CMP)
- Joint Proposal: Yes w/ Public Service New Hampshire (PSNH) and NSTAR Electric Company (NSTAR) (collectively Eversource)
- Type: AC transmission in ME and NH
- Cost Containment: Yes
- Construction Start: Q1 2029, In-Service Date: Q4 2032
- Design Summary
  - Wind interconnection POI: Pittsfield
  - New 345 kV lines: Pittsfield-Coopers Mills & Buxton-Deerfield (70 mi total)
  - Rebuild Larrabee Rd-Surowiec 115 kV line to operate at 345 kV
  - Several reconductored 345 & 115 kV lines
  - Retire ME Yankee 345 kV substation, build new adjacent Old Ferry Rd 345 kV
  - New STATCOMs: Eight 400 MVAR @ 345 kV
  - New Phase Angle Regulators: Four 750 MVA @ 345 kV
  - Minor corollary upgrade



Substation	State	Owner	Scope
Orrington	ME	Versant	Breaker replacements (corollary)
Pittsfield (NEW)	ME	CMP	New 345kV BAAH AIS Substation with 400MVAr STATCOM
Albion #1012	ME	CMP	Breaker installations to convert to BAAH
Coopers Mills #1018	ME	CMP	Install new 345kV line terminal, 400MVAr STATCOM
Maine Yankee #637	ME	CMP	Decommission existing substation
Old Ferry Rd (NEW)	ME	CMP	New 345kV BAAH AIS Substation with 400MVAr STATCOM and 4X 750MVA PARs
Larrabee #1013	ME	CMP	Install new 345kV line terminal, breaker replacements
Surowiec #539	ME	CMP	New 345kV terminal, breaker replacements, 400MVAr STATCOM
South Gorham #671	ME	CMP	Breaker installations
Buxton #667	ME	CMP	New 345kV terminal, breaker replacements
Three Rivers	ME	ES	Minor upgrades for N133 line reconductor
Deerfield	NH	ES	New 345kV terminal, breaker replacements, 2X 400MVAr STATCOMs
Scobie Pond	NH	ES	Breaker replacements, 400MVAr STATCOMs
Woburn	MA	ES	Breaker replacements, 400MVAr STATCOM

Figure 7-2: LTP A2 Diagram

7.1.3 Corollary Upgrades for LTPs A1 & A2

A1 and A2 had the same corollary upgrades: three new circuit breakers at the Orrington 115 kV substation in Maine. The corollary upgrades require the following work:

- New SF_6 circuit breakers: 3,000 A (43 kA interrupting)
- Upgrade foundations and communications for new circuit breakers

The PTO installed cost estimate for the corollary upgrades is \$2.91M (-50%, +100%).

7.2 Independent Review of Proposals

Both LTPs A1 and A2 were reviewed by the ISO's independent external consultants for construction and financial viability.

7.2.1 Construction Consultant Review

From an electrical and physical design perspective, LTPs A1 and A2 rely on proven technologies and are broadly consistent with ISO-NE, NERC, and NPCC reliability requirements. An important constructability strength of LTPs A1 and A2 is their use of existing, previously acquired rights-of-way (ROW) and QTPS-owned properties to route new and upgraded 345 kV facilities in Maine, New Hampshire, and Massachusetts. Procurement planning is another notable strength, with complementary strategies between the joint QTPSs that appropriately address long-lead equipment risks. Overall, the ISO's construction consultant found that LTPs A1 and A2 represent conservative, execution-focused transmission solutions with a strong feasibility baseline driven by corridor reuse, conventional overhead infrastructure, standardized substations, and experience.

To improve execution certainty and reduce exposure to schedule, cost, and stakeholder-driven risk, the consultant recommended additional refinement during early-phase surveying and real estate validation, temporary access planning, adaptive community and political engagement strategies, and schedule and risk governance prior to project advancement.

Consistent with Section 16.4(f) of Attachment K of the OATT, the construction consultant performed an independent cost estimate to validate the cost estimate provided by LTPs A1 and A2. Overall, the estimating approaches described by LTPs A1 and A2 align with what the consultant would expect for an Association for the Advancement of Cost Engineering (AACE) Class 3 estimate at this stage of project development, representing the highest level of accuracy reasonably achievable given the available information. LTPs A1 and A2 both rely on conceptual engineering and early-stage design assumptions to develop unit pricing and total project costs, which is appropriate given the current level of project definition.

7.2.2 Financial Consultant Review

The QTPSs for LTPs A1 and A2 demonstrate adequate-to-strong overall financial capabilities to support the equity, debt, and liquidity demands of their proposals. All QTPSs (or their parent sponsors) maintain:

- Investment-grade credit ratings or equivalent indicators of creditworthiness
- Sufficient balance sheet strength to support large capital commitments
- Direct access to internal liquidity, intercompany credit facilities, commercial paper (CP) programs, or project-specific equity and debt financing sources
- Demonstrated experience financing and delivering large transmission or infrastructure projects

All QTPSs for LTPs A1 and A2 possess sufficient equity capacity, either directly or via parent entities, to meet the highest equity requirement scenario tested. Both LTPs A1 and A2 benefit from strong parent backing, with the financial consultant finding that the parent sponsors provide deep retained earnings, large equity bases, and multi-billion-dollar liquidity programs.

The QTPSs for LTPs A1 and A2 have the financial capability to construct the proposals, and neither proposal exhibits material weaknesses that would impede their ability to fund or execute the proposed transmission projects. Liquidity is strong across all developer groups, supported by substantial cash balances, retained earnings, intercompany facilities, and established capital markets access. Credit ratings are uniformly investment grade, with only two entities carrying Negative Outlooks, and these outlooks do not represent immediate barriers, but merit continued monitoring post-award. Insurance coverage proposals are broadly adequate, but require specific clarifications during negotiations (e.g., Owner's Pollution Liability, General Liability overlap with corporate program). Debt financing structures are appropriate to each developer type, as investor-owned utilities rely on corporate debt and CP programs.

LTP A2 has the lower cost of the two proposals with a Base Case Present Value Revenue Requirement (PVRR) of approximately $1.518B, which is approximately 2.5% lower than LTP A1's PVRR. Cost containment is weak for both LTPs A1 and A2, as each proposal includes a soft cap on capital costs. Across the consultant's modeled scenarios, these mechanisms perform poorly, with PVRR growing by an average of 167% in the 'Downside' scenario,[20] indicating limited customer protection. Significant cost containment exclusions further weaken cost containment, and one QTPS of LTPs A1 and A2 allows cost cap increases tied to various indices. These provisions substantially dilute the binding nature of the caps. Differences between LTPs A1 and A2 are relatively minor. Relative to each other, LTPs A1 and A2 perform financially similarly. The primary drivers of differences in costs are base capital costs, as capital structure and cost containment are identical.

7.3 Consideration of RFP Evaluation Factors

Pursuant to Section 16.4(h) of Attachment K of the OATT, the ISO is required to:

> *"…identify the Longer-Term Transmission Solution that offers the best combination of electrical performance, cost, future system expandability and feasibility to comprehensively address all of the needs in the timeframes specified in the request for proposal(s) as the preliminary preferred Longer-Term Transmission Solution in response to each request for proposal. The ISO will consider several factors during the evaluation process for identification of the preliminary preferred Longer-Term Transmission Solution."*

As part of the RFP evaluation, the ISO also considered a list of evaluation factors provided in Attachment A of NESCOE's RFP Request. The evaluation factors listed in Attachment A are also identified in the subsequent three sections. Table 7-1 shows NESCOE's LTTP Non-Economic Evaluation Factors Prioritization Groupings.

[20] The purpose of the "Downside" scenario is to combine the "worst case" of all other univariate scenarios and stress test the effectiveness of the full suite of cost containment measures using a single scenario. As such, the "Downside" scenario does not indicate a probable outcome. Stakeholders should not infer that this increase in cost is an expected outcome from its inclusion in the testing. See memo posted on August 3, 2026 for more details.

Table 7-1
2025 LTTP RFP Evaluation Factors

A Factors (Highest Priority)	B Factors (Second Highest Priority)	C Factors (Third Highest Priority)
Life-cycle cost	Extreme contingency performance	Project constructability
Cost Cap or Cost Containment Provisions	Impact on Other Interface Limits	Generation and Transmission Facility Outages Required During Construction
Potential Siting/Permitting Issues or Delays	Operational Impacts	Incremental Costs for Potential Resource Retirement
Future Expandability	Winter Reliability Impacts	Consistency with Good Utility Practice
In-Service Date of the Project	Environmental Impact	Design Standards
QTPS Capabilities		Joint Proposals
System Performance		Deployment of Advanced Transmission Technologies
Impact on NPCC BPS Classification		

7.3.1 Comparison of Priority A Factors

7.3.1.1 Life-cycle cost

Life-cycle cost, including all costs associated with corollary upgrades, ROW acquisition, easements, and associated real estate:

- A1 20-Year PVRR: $1.558B, BCR = 2.10
- A2 20-Year PVRR: $1.519B, BCR = 2.14

LTP A2 has 1.87% lower cost and 0.04 higher BCR than LTP A1, giving a slight edge to LTP A2 for this evaluation factor.

7.3.1.2 Cost Containment or Cost Containment Provisions

Cost cap or cost containment provisions, including considerations to manage consumer bill impacts (e.g., smoothing or other mechanisms to mitigate rate impacts) are another priority A factor considered in the evaluation. As supported by findings of the financial consultant, the cost containment provisions for both LTPs A1 and A2 are weak and include significant exclusions that further weaken the proposal. Since LTPs A1 and A2 have the same cost containment proposals, this was not a deciding factor in the selection process.

7.3.1.3 Potential Siting/Permitting Issues or Delays

Potential siting/permitting issues or delays and consideration of whether the bidder has demonstrated a clear plan to obtain support through engagement (assess experience, engagement strategy) are also a priority A factor. The scopes of LTPs A1 and A2 are identical except for work proposed along an existing transmission right-of-way (ROW) between the NH/ME State line and the existing Deerfield Substation. This section of ROW passes through Rochester, Strafford, Northwood, and Deerfield, all in NH, running north to south. Within this ROW segment, at present, there are two existing 345 kV transmission lines, the 385 line and the 391 line. Both lines are constructed in a horizontal conductor configuration, on H-frame structures. Both LTPs A1 and A2 include construction of a new 345 kV line along this same length of ROW. The difference between the proposals is related to how the new line would be constructed in this ROW and how that construction may impact the existing 391 line.

Figure 7-3 shows the existing ROW configuration for the 385 and 391 lines.

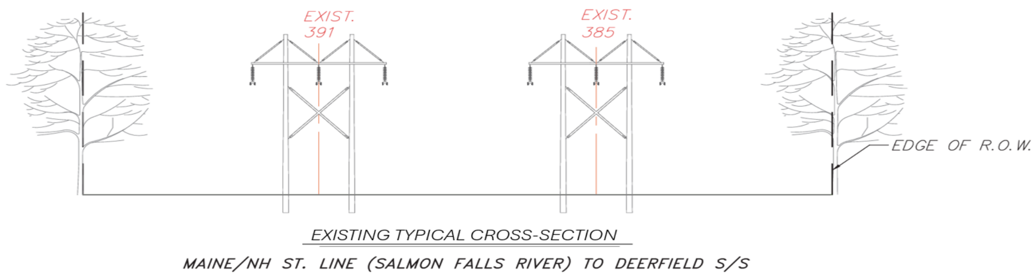


Figure 7-3: Existing ROW Layout of the 385 and 391 Lines

The QTPS for LTP A1 proposed reconstructing the existing 391 line between the ME/NH state line and the existing Deerfield substation to place this circuit in a vertical conductor arrangement on steel monopole structures. Modifying the configuration of the 391 line will free up space within the existing ROW to build the new 345 kV line without further encroachment toward the edge of the ROW. The new line will be built adjacent to the modified 391 line, and the two circuits will, in effect, "mirror" one another. Figure 7-4 shows the ROW configuration of the 385 and 391 lines for LTP A1.

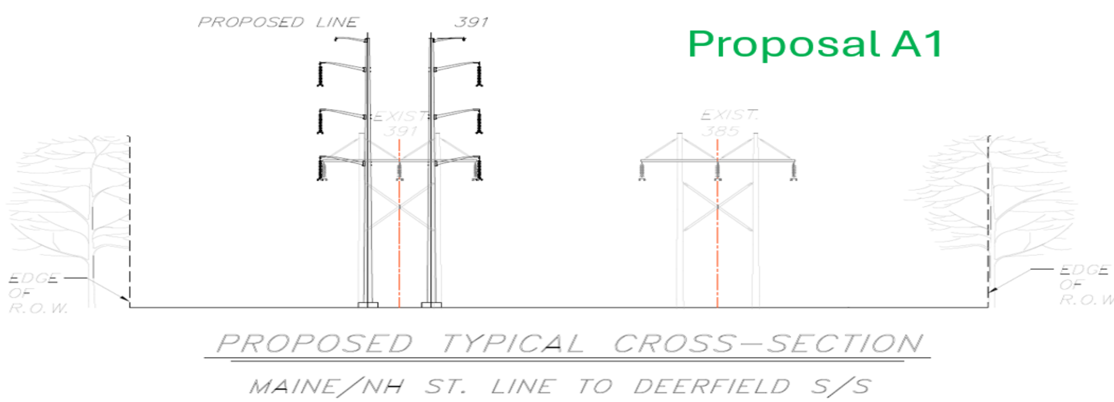


Figure 7-4: Post-LTP A1 ROW Layout of the 385 and 391 Lines

The QTPS for LTP A2 would not significantly reconstruct the existing 391 line or alter its current configuration. The new 345 kV line will be located in the space that exists between the existing 391 line and the eastern edge of the existing ROW. The new 345 kV line will be built in a vertical conductor configuration on steel monopole structures. To maintain adequate clearance between the new and existing circuits, the new line and its structures will be taller than the steel monopoles illustrated in LTP A1. Some existing structures on the 391 line will be removed and replaced to ensure that clearances between the new and existing lines are adequate. Additionally, LTP A2 includes two new "mid-span" H-frame structures on the existing 385 line to help maintain adequate clearance between the existing 385 line and the new structures proposed on the 391 line. Note that these new mid-span structures on the 385 line are not included (nor are they necessary) in LTP A1. Figure 7-5 shows the ROW configuration for the 385 and 391 lines for LTP A2.

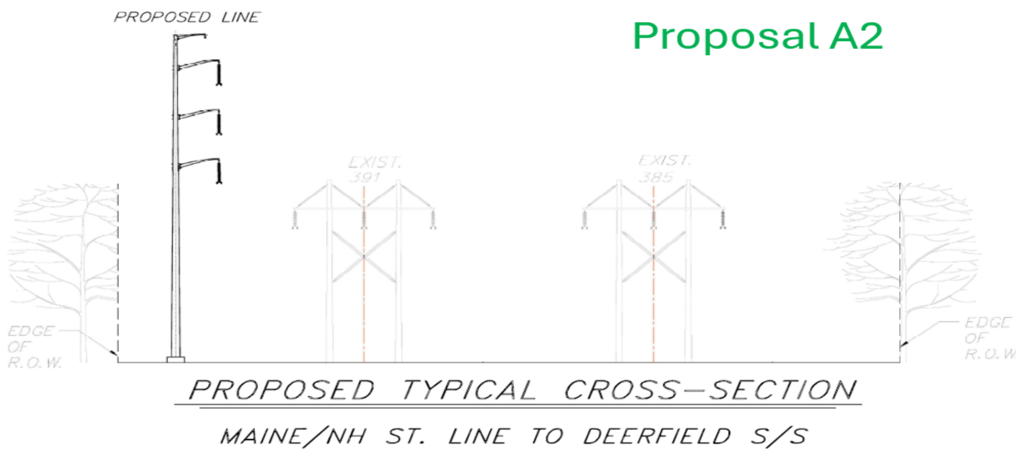


Figure 7-5: Post-LTP A2 ROW Layout of the 385 and 391 Lines

It is also important to note that portions of the 391 line will be greater than 40 years old by December 31, 2035, and would be part of a future asset condition project. LTP A1 eliminates the need for the future asset condition project by rebuilding a section of the existing 391 line in NH as part of the proposal, making it qualified to be counted as part of the avoided transmission investment benefit of the project. Taller towers for LTP A2 will likely lead to more risk during siting and permitting than compared to LTP A1. The ISO's construction consultant also noted there could be clearance concerns that close to the edge of the ROW that would require further review during the detailed design of the project. For these reasons, the siting/permitting factor for LTP A1 exceeds LTP A2.

7.3.1.4 Future Expandability

Future expandability — meaning whether the proposal enables the interconnection of additional future resources — was also a priority A evaluation factor. Both proposals are electrically identical and enable the interconnection of the same amount of additional future resources. Both proposals allow for the addition of another 345 kV line (beyond what LTPs A1 and A2 propose) on the right half of the congested ROW mentioned earlier between the ME/NH state line and Deerfield substation by converting the 385 line H-frame structures into two monopole structures, similar to the conversion of the 391 line in LTP A1. Since LTPs A1 and A2 have the same future expandability, this was not a deciding selection factor.

7.3.1.5 In-Service Date of the Project

Both LTPs A1 and A2 have the same In-Service Date (ISD) of Q4 2032. Since LTPs A1 and A2 have the same ISD, this was not a deciding selection factor.

7.3.1.6 QTPS Capabilities

The same QTPS is the lead for both LTPs A1 and A2. The external financial and construction consultants determined the QTPSs for each proposal had the capability to construct and ability to finance the project. Since LTPs A1 and A2 have the same QTPS, this factor was not a deciding selection factor.

7.3.1.7 System Performance

Both LTPs A1 and A2 have the same electrical characteristics and performance. Both proposals met the RFP Objectives, they accommodate the same amount of onshore wind, and they have the same transfer capabilities on the Surowiec-South and ME-NH interfaces. Since LTPs A1 and A2 have the same system performance, this was not a deciding selection factor.

7.3.1.8 Impact on NPCC BPS Classification

Both LTPs A1 and A2 have the same electrical characteristics and performance and, therefore, both would have the same impact on NPCC BPS classification. Because the proposals were the same, BPS testing was not completed during the evaluation period. Because proposals A1 and A2 would have the same impact on NPCC BPS classification, this was not a deciding selection factor.

7.3.1.9 Summary of Priority A Factors

Table 7-2 shows a comparison of LTPs A1's and A2's performance on the priority A factors.

Table 7-2
Performance Comparison of LTPs A1 and A2 for Priority A Factors

Evaluation Factor	A1	A2
1. Life-Cycle Cost		✓
2. Cost Cap or Cost Containment Provisions	Same	
3. Potential Siting/Permitting Issues or Delays	✓	
4. Future Expandability	Same	
5. In-Service Date	Same	
6. QTPS Capabilities	Same	
7. System Performance	Same	
8. Impact on NPCC BPS Classification	Same	

7.3.2 Comparison of Priority B Factors

Since LTPs A1 and A2 are very similar if not identical for all the priority B factors shown in Table 7-1, these were not deciding selection factors.

7.3.3 Comparison of Priority C Factors

LTP A1 would have a slightly more complex outage schedule to rebuild the 391 line in the ROW described earlier, but LTP A2 would still require outages on the 391 line and the 385 line for replacement and addition of structures. Since LTPs A1 and A2 are very similar, if not identical, for all the priority C factors shown in Table 7-1, these were not deciding selection factors.

7.4 Reduction in Carbon Emissions

While not an evaluation factor for this RFP, in the NESCOE RFP Request, NESCOE requested that the ISO quantify any carbon reductions associated with Longer-Term Proposals. The ISO quantified carbon reductions for only LTPs A1 and A2, as these were the only proposals that met the RFP objectives and for which the benefit calculation was performed. Due to the very similar design of LTPs A1 and A2, their carbon reductions were identical. These reductions are shown in Table 7-3.

Table 7-3
Reduction in Carbon Emissions for LTPs A1/A2

Year	Pre-Project CO2 (Tons)	Post-Project CO2 (Tons)	Reduction in CO2 (Tons)
2033	27,758,194	25,001,500	2,756,694
2034	27,758,194	25,001,500	2,756,694
2035	27,758,194	25,001,500	2,756,694
2036	26,673,060	24,015,860	2,657,200
2037	25,587,926	23,030,220	2,557,705
2038	24,502,791	22,044,580	2,458,211
2039	23,417,657	21,058,940	2,358,717
2040	22,332,523	20,073,300	2,259,223
2041	21,247,389	19,087,660	2,159,728
2042	20,162,254	18,102,020	2,060,234
2043	19,077,120	17,116,380	1,960,740
2044	17,991,986	16,130,740	1,861,245
2045	16,906,852	15,145,100	1,761,751
2046	15,821,717	14,159,461	1,662,257
2047	14,736,583	13,173,821	1,562,763
2048	13,651,449	12,188,181	1,463,268
2049	12,566,315	11,202,541	1,363,774
2050	11,481,180	10,216,901	1,264,280
2051	11,481,180	10,216,901	1,264,280
2052	11,481,180	10,216,901	1,264,280
Total	**392,393,744**	**352,184,008**	**40,209,736**

The estimated carbon emissions were determined using the production cost models. In the production cost model, emitting fuel types (gas, oil, municipal solid waste, landfill gas, and wood) were each given a carbon production rate in lbs/MMBtu. The carbon production rates were sourced from Energy Information Administration (EIA) data. During the course of the simulation, each MMBtu of fuel consumed was tracked and multiplied by the production rate. The model then summed the carbon emissions across all hours and reported annual values.

In line with how other benefits were treated, production cost models were run for the years 2035 and 2050 with and without the projects in service. For years before 2035, the 2035 emission numbers were repeated. For years after 2050, the 2050 emission numbers were repeated. For years between 2035 and 2050, modeled emission values were linearly interpolated.

LTPs A1 and A2 are both estimated to reduce carbon emissions in New England by 40.21 million tons over the 20-year period of 2033-2052.

7.5 Selection of the Preferred Longer-Term Transmission Solution

Based on all the evaluation factors described in the previous sections, pursuant to Section 16.4(h) of Attachment K of the OATT, ISO New England selects **Longer-Term Proposal A1** as the preferred Longer-Term Transmission Solution for the 2025 LTTP RFP. Despite LTP A2 being slightly less costly and having a slightly higher BCR than LTP A1, the priority A factor of permitting/siting weighed heavily in the ISO's selection.

Section 8
Conclusion and Next Steps

ISO-NE has selected LTP A1 as the preferred Longer-Term Transmission Solution for the 2025 LTTP RFP.

Stakeholder input on the draft report was submitted to ISO-NE via the PACMatters@iso-ne.com email address by August 12, 2026. Pursuant to Section 16.4(i) of Attachment K of the OATT, following the receipt of stakeholder input, the ISO identified the preferred Longer-Term Transmission Solution and posted this report on the ISO's website.

Within 30 days of the ISO's posting of the final report, NESCOE may submit to the ISO a written communication requesting that either:

a. The ISO terminate the 2025 LTTP RFP process, or
b. The ISO continue the process, but specifying an alternative allocation for the recovery of the incremental costs to address longer-term needs.

If the ISO does not receive a written communication within 30 days of the publishing of the final report requesting that the ISO terminate the 2025 LTTP RFP process, the ISO will proceed in accordance with Section 16.5 of Attachment K of the OATT. If the ISO does receive a communication requesting to terminate the RFP process, the ISO shall terminate the 2025 LTTP RFP process pursuant to Section 16.6 of Attachment K of the OATT.