2050 Transmission Study

Final Results and Estimated Costs

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Outline of Today's Presentation

- 2050 Transmission Study Overview
- Review of Input Assumptions
- Solution Development Approach
- Cost Estimates: Approach and Final Cost Range
- Key Takeaways
- High-Likelihood Concerns (HLCs)
  - North-South/Boston Import Roadmaps
  - Northwestern Vermont Import Roadmaps
  - Southwest Connecticut Import
  - Miscellaneous HLCs
- Non-High-Likelihood Concerns
- Specific Cost Breakdowns
- Conclusion & Next Steps

2050 TRANSMISSION STUDY OVERVIEW

2050 Transmission Study Overview

- In accordance with a recommendation from NESCOE's October 2020 "New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid," ISO-NE is conducting the 2050 Transmission Study in order to determine:
  - Transmission needs in order to serve load while satisfying NERC, NPCC, and ISO-NE reliability criteria in 2035, 2040, and 2050
  - Transmission upgrade "roadmaps" to satisfy those needs considering both constructability and cost
- ISO-NE has coordinated with NESCOE throughout this study
  - In November 2021, ISO-NE introduced the 2050 Transmission Planning Study Scope of Work, preliminary assumptions, and methodology
  - ISO-NE presented results showing transmission reliability concerns in peak load snapshots in March 2022, April 2022, and July 2022
  - ISO-NE presented updates on proposed solutions in December 2022 and April 2023
  - ISO-NE presented initial key takeaways and roadmap outlines in July 2023
- Under the ISO-NE Tariff, there is no requirement to pursue solutions to the concerns identified
  - This study is meant to evaluate potential transmission scenarios and sample transmission upgrades, and is not a recommendation to develop specific transmission or generation projects
  - Discussions on "Phase 2 of Extended/Longer-Term Planning," which will create a Tariff process for advancing transmission projects from longer-term transmission studies like the 2050 Transmission Study, began at the NEPOOL Transmission Committee on October 17

2050 Transmission Study Scope

- The 2050 Transmission Study examines only the thermal performance of the transmission system under peak load snapshots
- Many other types of analysis are not covered by this study:
  - Voltage
  - Short-Circuit
  - Transient stability
  - Electro-magnetic transient (EMT) analysis
  - Distribution system performance
  - Generator interconnection and deliverability during off-peak hours
- Costs identified by this study will not include any costs associated with these other types of analysis

2050 Transmission Study Status

- Solution development is complete
- Cost estimates are complete
- Report drafting is nearing completion
  - A draft public summary report will be posted for PAC review and comment on November 1, 2023
  - A draft CEII technical appendix will be posted for PAC review and comment on or shortly after November 1, 2023

INPUT ASSUMPTIONS

Review from Previous Presentations

Background on Input Assumptions

- Input assumptions for load and generation totals were provided to ISO-NE from the "All Options" pathway in the "Energy Pathways to Deep Decarbonization" report by Massachusetts (December 2020)
- ISO-NE took the "All Options" input data and created four types of peak load snapshots, creating a set for each of the study years 2035, 2040, and 2050

Snapshot	Months	Hours
Summer Daytime Peak	May – September	9 AM to 5 PM
Summer Evening Peak A (Coincidental NE Peak)	May – September	7 PM to 10 PM
Summer Evening Peak B (Northern NE Peak)	May – September	7 PM to 10 PM
Winter Evening Peak	January – April	4 PM to 10 PM

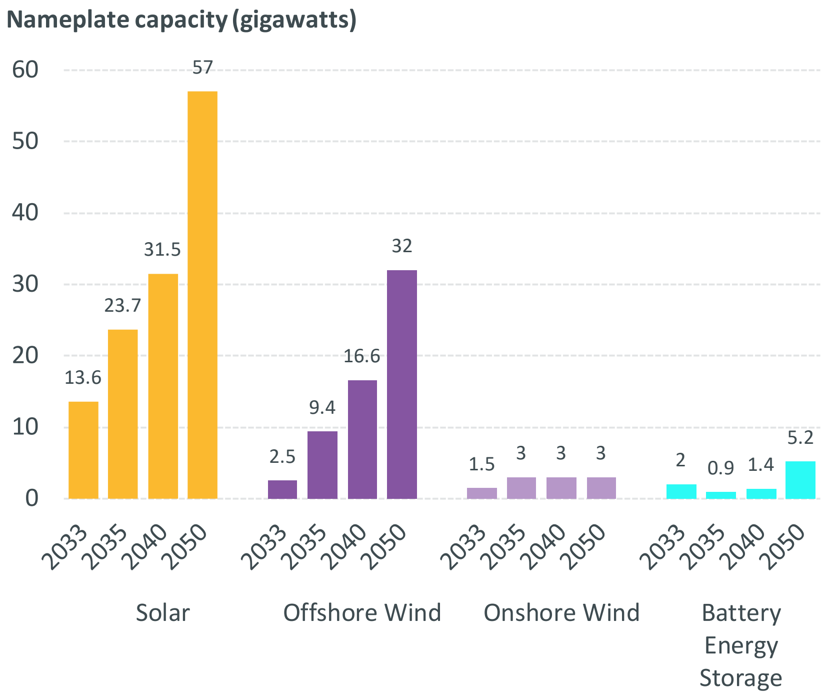
Generation Assumptions

- The All Options Pathway resource data provided nameplate MW values for the study years 2035, 2040, and 2050
  - All oil, coal, diesel, and municipal solid waste (MSW) resources assumed retired by 2035
- The following resource availability profiles on the right were then applied to the totals on the left
  - The renewable availability percentages were conservative estimates obtained from 20 years of historical weather data in New England

Generation Type	Nameplate Capacity (MW)			Availability		
	2035	2040	2050	Summer Daytime Peak	Summer Evening Peak	Winter Peak
Nuclear	3,526	3,526	3,526	100%	100%	100%
Biomass	772	772	772	100%	100%	100%
Natural Gas (CCGT & CT)	15,848	16,548	16,645	100%	100%	100%
Hydro (RoR and Pondage)	1,814	1,814	1,814	Historical	Historical	Historical
Hydro Pumped Storage	1,841	1,841	1,841	Offline	Discharging	Discharging
Battery Energy Storage Systems (BESS)	888	1,395	5,182	Offline	Discharging	Discharging
PV (Rooftop and Ground Mount)	23,714	31,475	56,665	40%	10%/0%*	0%
Onshore Wind	3,006	3,006	3,006	5%	5%	65%
Offshore Wind	9,449	16,633	31,954	5%	5%	40%
Totals	60,858	77,010	121,405			

* Some Evening Peak snapshots occurred before sunset while some occurred after sunset
Note: Several changes were made from the All Options Pathway data. These changes were presented in the November Scope of Work

Generation Assumptions, cont.



Note: The PV and battery numbers include both distribution-connected and transmission-connected generators.

- The 2033 bar represents the latest resource mix in the 10-year case modeled for Needs Assessments
- The 2050 Transmission Study assumes that offshore wind and solar grow significantly from 2033 to 2050
- There is already more battery storage expected to be online by 2033 than the 2050 Transmission Study's input assumption for 2040

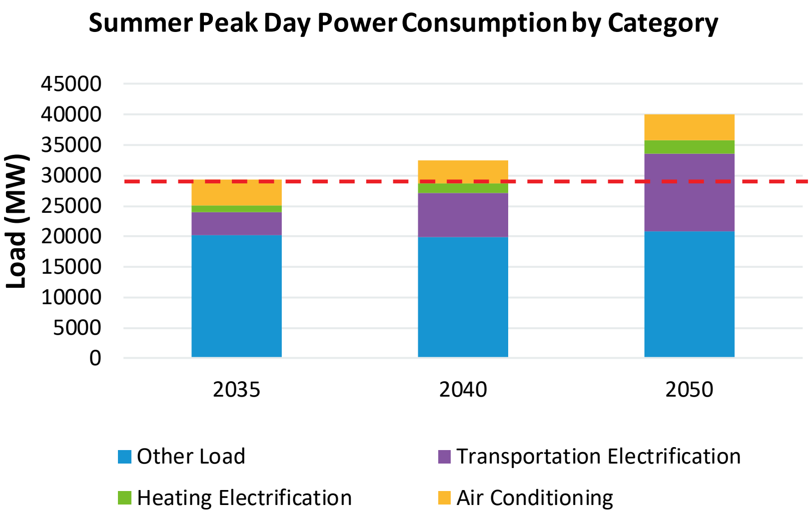
Shortfall Generation

- The input generation assumptions, once they had their generation profiles applied, were not sufficient to meet the load seen in many of the snapshots
- "Shortfall" generators were added to the cases that did not have enough generation in order to reach the load – generation balance that is required to perform a study using power flow analysis
- These "Shortfall" megawatts (shown as red and white stripes on the next four slides) were located at stations containing offshore wind, and can be thought of as being a placeholder in this study that may represent a variety of different generation sources
  - Additional offshore wind generation
  - Battery storage at an offshore wind site that absorbs excess wind and discharges later when wind output is lower
  - Increased imports, possibly through an offshore grid network

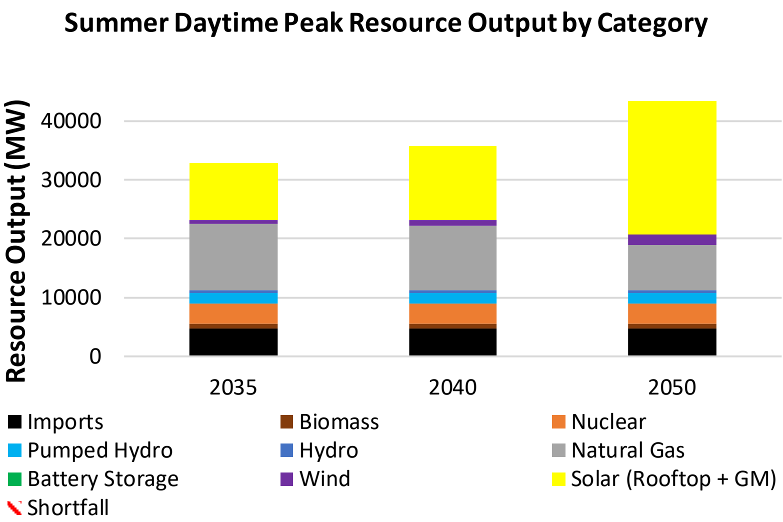
Summer Daytime Peak Snapshots

Application of the Load and Resource Assumptions

Load



Resources



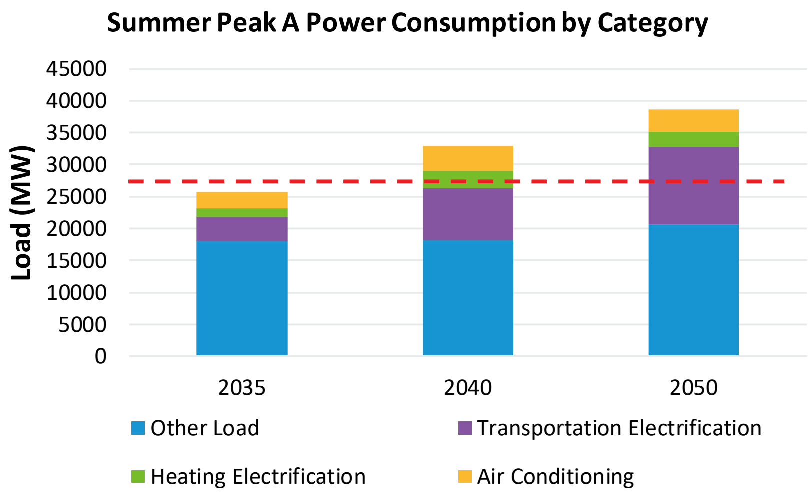
----New England's current record summer peak demand was 28,130 MW on August 2, 2006

Note: Difference between load and generation is due to station service, non-CELT manufacturing loads, and transmission losses

Summer Evening Peak A Snapshots

Application of the Load and Resource Assumptions

Load



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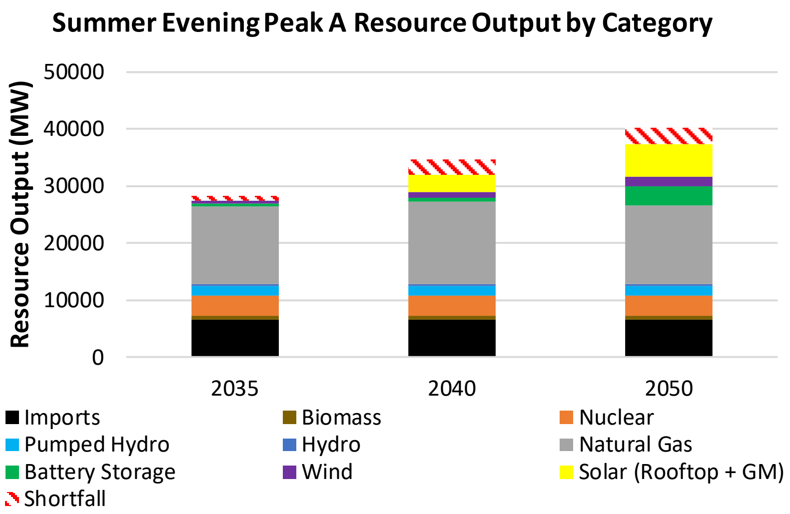


---- New England's current record summer peak demand was 28,130 MW on August 2, 2006

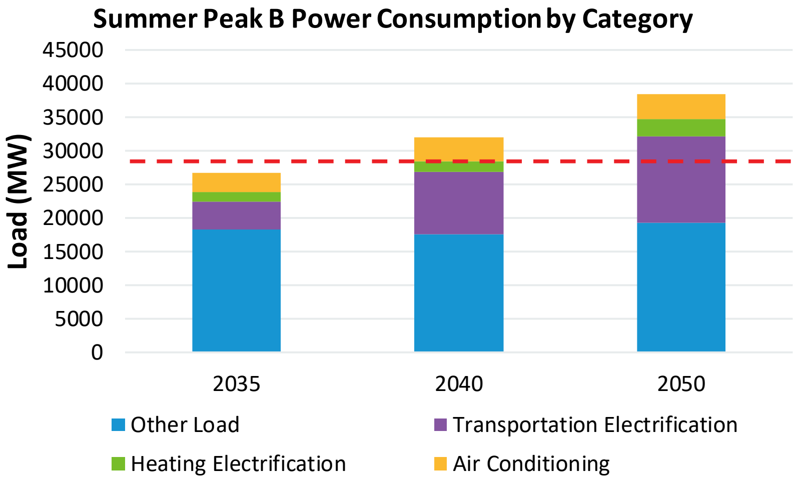
Note 1: Difference between load and generation is due to station service, non-CELT manufacturing loads and transmission losses

Note 2: The 2035 summer evening peak occurred after sunset so 0% solar availability was assumed. Due to differences in load shapes, the 2040 and 2050 summer evening peaks occurred slightly before sunset, so 10% solar availability was assumed.

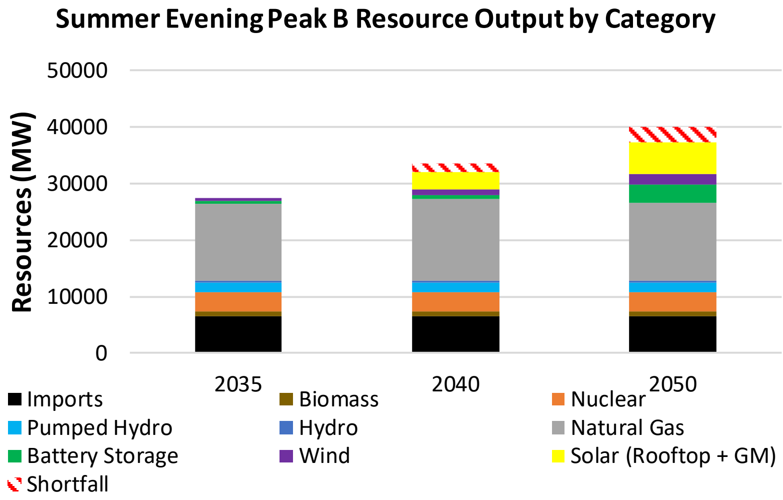
Summer Evening Peak B Snapshots

Application of the Load and Resource Assumptions

Load



Resources



---- New England's current record summer peak demand was 28,130 MW on August 2, 2006

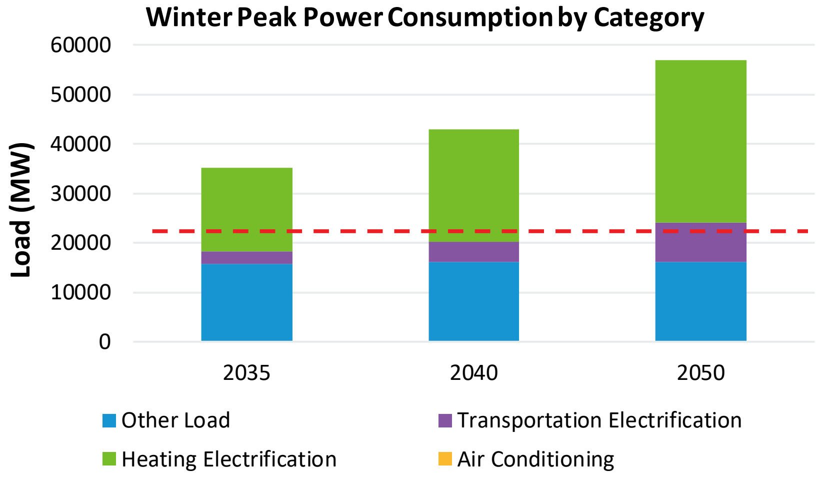
Note 1: Difference between load and generation is due to station service, non-CELT manufacturing loads and transmission losses

Note 2: The 2035 summer evening peak occurred after sunset so 0% solar availability was assumed. Due to differences in load shapes, the 2040 and 2050 summer evening peaks occurred slightly before sunset, so 10% solar availability was assumed.

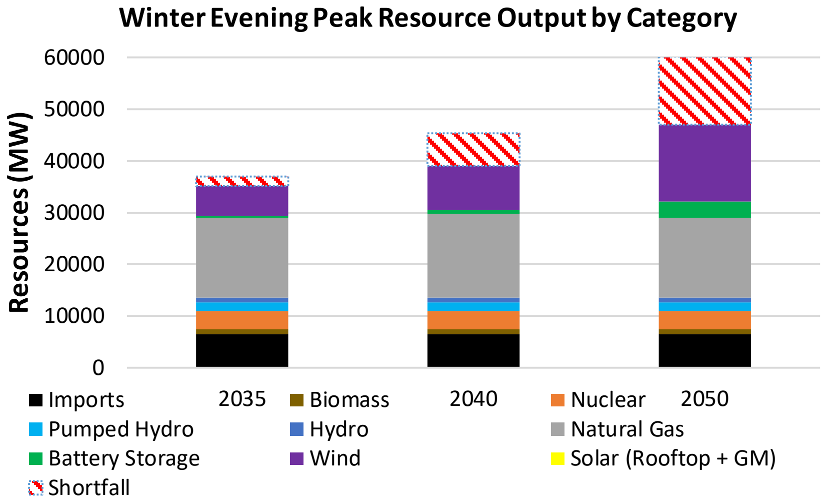
Winter Evening Peak Snapshots

Application of the Load and Resource Assumptions

Load



Resources



---- New England's current record winter peak demand was 22,818 MW on January 15, 2004

Note: Difference between load and generation is due to station service, non-CELT manufacturing loads and transmission losses

51 GW Winter Peak Snapshot

- After obtaining initial results for the 2050 Transmission Study, it was determined that the 2050 57 GW Winter Peak caused the vast majority of the overloads seen in the study
- An additional snapshot, studying a 51 GW winter peak load, was added to the study to investigate how a reduced peak load would affect transmission overloads
- A 57 GW winter load essentially represents New England with 100% transportation and heating electrification
- A 51 GW winter load can be thought of in a couple of different ways:
  - The same 2050 future but with somewhat lower electrification
    - This could mean that fewer people adopt heat pumps and electric vehicles
    - If the full 6 GW reduction in load from 57 GW to 51 GW came from decreased heating electrification, this could represent roughly 80% heating electrification while still maintaining roughly 100% transportation electrification
    - It could also mean that more people use furnace backups during the extremely cold days that this winter peak represents, and use heat pumps the rest of the time
  - 100% electrification but with a significant increase in demand response and energy efficiency programs
    - Better insulation in buildings
    - Smart thermostat programs to keep buildings somewhat cooler during the peak hours
    - Utilizing more efficient ground-source heat pumps rather than air-source heat pumps

SOLUTION DEVELOPMENT APPROACH

Review from Previous Presentations

2050 Transmission Study Solution Development Process

More details were shown at the April 28, 2022 PAC Meeting

2035 & 2040 Solution Subset

- Subsets of primary solution set to fully address needs in 2035 and 2040

Primary Solution Set

- 2050 Winter Evening Sensitivity (51 GW load)
- 2050 Summer Daytime Peak Sensitivity
- 2050 Summer Evening A & B

High Winter Peak Solution Set

- Additional solutions to fully address original 2050 Winter Peak (57 GW load)

“High-Likelihood” Concerns

- NESCOE and other stakeholders have expressed their interest in identifying system concerns that would be most likely to appear, and most helpful to resolve
  - These concerns are those that would appear under a wide variety of conditions, including conditions that do not exactly match those examined in the 2050 Transmission Study
- Not all concerns identified in this study can be or will be “high-likelihood” concerns
  - Some concerns appear only for a very specific set of circumstances

“High-Likelihood” Concerns, cont.

- For each concern identified in the 2050 Transmission study, the following criteria were used to determine whether the concern was “high-likelihood:”
  - The concern must be observed for at least two of the studied snapshots, with these two snapshots needing to be either different seasons from each other or different years (and hence different load levels) from each other
    - Consideration was also given to concerns that exist on today’s system, or those that match other ISO-NE study outcomes, such as the Future Grid Reliability Study or Cluster Regional Planning Studies
  - The concern must not be heavily dependent on load growth in a specific area
    - Additional load-serving substations are likely to be built between 2023 and 2050, and these future substations are not included in the 2050 Transmission Study due to a lack of information on their location
    - This means that a concern related to transporting power between sub-regions within New England would be more likely to be considered a “high-likelihood” concern than one that is only related to feeding radial load
  - The concern must not be solely caused by the injection of power from a specific generator at a specific substation
    - The generation locations chosen in the 2050 Transmission Study are not necessarily where actual future generation will be built
    - A concern related to the delivery of a generator’s power from a specific interconnection point would not be a “high-likelihood” concern, as this generator may in reality be interconnected to a different station, eliminating this concern

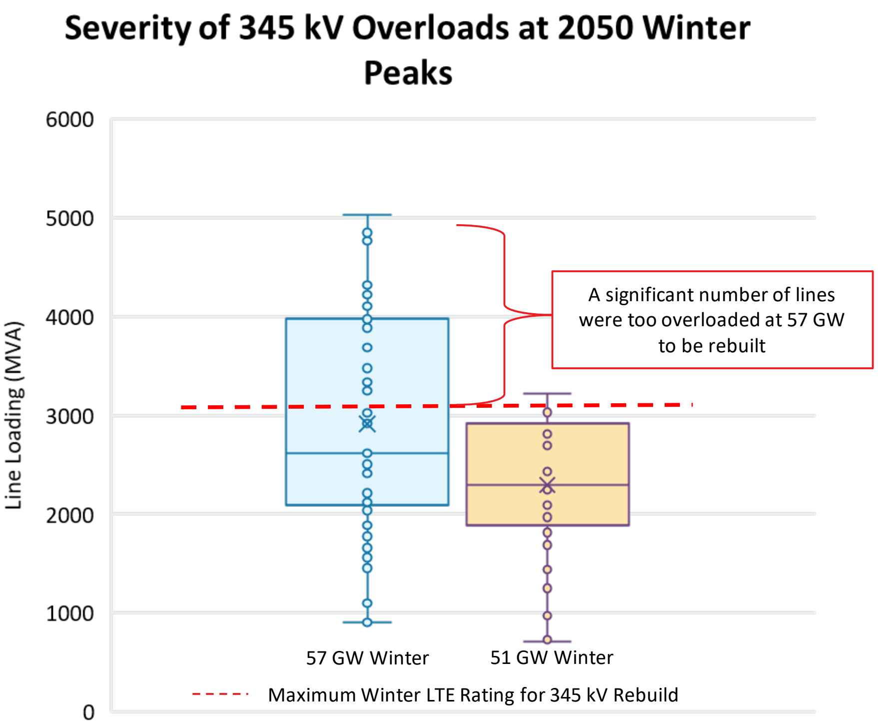
Transmission Development Roadmaps

- A main objective of the 2050 Transmission Study was to develop transmission upgrade "roadmaps" to satisfy anticipated concerns, considering both constructability and cost
  - Roadmaps were developed for regions in New England that saw groupings of high-likelihood concerns
  - Each roadmap consists of several major components, paired with rebuilds of existing lines and other components to form a complete solution for that region
- ISO-NE does not express a preference for any particular roadmap developed in the 2050 Transmission Study due to the following tradeoffs between competing priorities and concerns beyond the study's scope
  - Robustness and performance under off-peak conditions
  - Siting concerns
  - Environmental impact
  - HVDC technology availability and performance
- The intent of including multiple roadmaps for some high-likelihood concerns is to provide a basis of comparison for decision-making by New England stakeholders

Rebuilding Existing Lines

- Many of the overloads observed can be resolved by rebuilding existing lines with larger conductors to increase their ratings
- The 2050 Transmission Study used line rebuilds as a solution provided that the overload was not too severe to make a line rebuild impractical
  - Some of the high-likelihood concern areas were solved with new lines instead of rebuilds because it was found to yield a more cost-efficient solution
- The following ratings were used as the threshold of what could be rebuilt:

Voltage Level	Maximum Summer LTE Rebuild Rating	Maximum Winter LTE Rebuild Rating
115 kV	700 MVA	750 MVA
345 kV	2650 MVA	3050 MVA



COST ESTIMATES

Approach and Final Cost Range

Approach to Estimating Costs

- ISO-NE hired Electrical Consultants Inc. (ECI) to develop detailed cost estimates for some of the more complex solutions that were developed in the 2050 Transmission Study
  - Examples of projects for which ECI provided detailed costs include a Surowiec – Mystic HVDC link and a Stoughton – K St 345 kV underground cable
- For less complex solutions, such as line rebuilds or new overhead lines through less congested locations, ISO-NE used cost assumptions that were developed by looking at a variety of recent projects
  - Recent projects were used as a comparison because there has been a noticeable increase in project costs since the COVID-19 pandemic in 2020
  - The numbers at right were used for cost assumptions

Component	Cost
69/115 kV OH line - rebuild	$5M/mile
69/115 kV OH line - new build	$7M/mile
230/345 kV OH line - rebuild	$6M/mile
230/345 kV OH line - new build	$8M/mile
Autotransformer	$10M
New breaker - 69/115 kV	$2M
New breaker - 230/345 kV	$2M
115 or 345 kV XLPE	$35M/mile

Cost Estimation for Offshore Grid Components

- For one of the solution roadmaps, ISO-NE investigated solving thermal overloads with a small offshore network
  - Much of the technology associated with offshore networks are still relatively new, making accurate cost estimation difficult
  - Due to this, ISO-NE was not able to obtain costs from ECI or from comparing past projects
  - As a rough approximation, the cost estimates used in the Department of Energy (DOE) Atlantic Offshore Wind Transmission Study were used

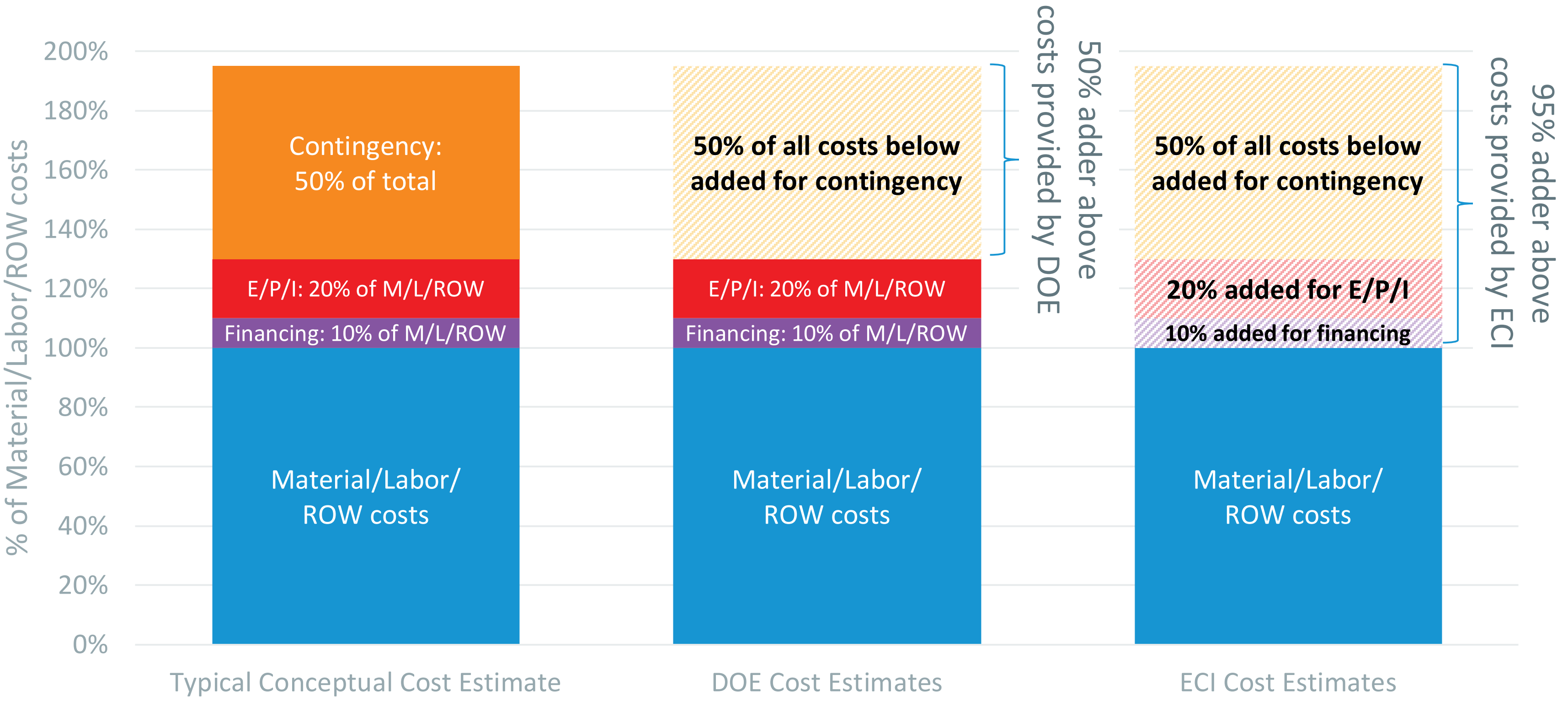
Component	Cost*
HVDC Breaker	$37.5M
End Platform (wind farm connection to one offshore grid link)	$112.5M
Middle Platform (wind farm connection to two offshore grid links)	$142.5M
525 kV Cable	$10.5M/mile

* The costs from the DOE's study include materials, labor, engineering, and financing, but do not include contingency. Due to this, the numbers in the table on this slide include an additional 50% added to the DOE's numbers to reflect contingency.

Cost Estimate Adjustments

- A substantial portion of project costs are outside of direct costs such as materials, labor, and right-of-way (M/L/ROW)
- ISO-NE's review of numerous recent TCA applications revealed the following:
  - Financing costs (interest costs & AFUDC): typically around 10% of M/L/ROW
  - Engineering, permitting (including administrative & legal costs), and indirect costs (E/P/I): typically around 20% of M/L/ROW
  - Contingency (added to allow for unexpected events that may increase costs): for initial "desktop-level" cost estimates, typically around 50% of total (M/L/ROW, E/P/I, and financing)
  - Escalation: not used in this study, since all costs are expressed in 2023 dollars
- Some of these costs were not included in ECI or DOE's estimates
  - ECI: cost estimates included M/L/ROW and some permitting costs only
  - DOE: cost estimates included all categories except for contingency
- To reflect the total cost that will be seen by ratepayers, ECI and DOE's cost estimates were increased to account for all cost categories

Cost Estimate Adjustments



Cost Estimate Caveats

- The 2050 Transmission Study only looked at resolving thermal overloads on the Pool Transmission Facilities (PTF)

- The following additional costs were not considered in any totals:
  – Costs associated with resolving non-PTF overloads that were not associated with PTF overloads
  – Costs for equipment required to solve voltage, short-circuit, transient stability, or electromagnetic transient (EMT) concerns
  – Costs to interconnect any of the new resources assumed in this study
    - As noted earlier, this study assumes that approximately 30 GW of offshore wind and approximately 40 GW of solar are interconnected on to the New England system compared to ISO-NE’s 2033 base cases; the costs to interconnect these resources are not reflected in this study
  – Costs on the distribution system
    - No costs to resolve concerns below 69 kV are included in this study
    - Since many of the overloads in this study were driven by large increases in load, it is reasonable to assume that these distribution costs will be very significant
  – Future inflation was not applied to the cost estimates provided in this study; these cost estimates represent U.S. dollars in 2023

- Given this, the cost estimates from the 2050 Transmission Study should be used for directional guidance as a whole, but should not be used as an exact value for how much any particular project may cost

Range of Final Costs

- The numbers at right represent the cumulative estimated cost to reach the load level shown in the middle column, starting from the present day peak load value
  - This means that it takes approximately $6-9 billion to go from today's peak load of 28,000 MW to 35,000 MW in 2035 and it takes approximately $10-13 billion to go from today's peak load of 28,000 MW to 43,000 MW in 2040
- The costs reflected on this slide only reflect those identified through steady-state thermal analysis; **the total transmission and distribution costs are anticipated to be much higher**

Year/Load Level	Maximum Load Served (MW)	Total Cost Range ($)	Cost Breakdown	
2035	35,000	**$6-9 Billion**	$2.8-5.0 Billion	N-S/Boston
			$0.6-1.1 Billion	NWVT
			$0.5 Billion	SWCT
			$1.7 Billion	Misc. HLC
			$0.4 Billion	Non-HLC
2040	43,000	**$10-13 Billion**	$5.0-6.5 Billion	N-S/Boston
			$0.8-1.3 Billion	NWVT
			$0.7 Billion	SWCT
			$2.8 Billion	Misc. HLC
			$1.4 Billion	Non-HLC
2050 51 GW	51,000	**$15-17 Billion**	$7.5-7.9 Billion	N-S/Boston
			$0.9-1.5 Billion	NWVT
			$0.8 Billion	SWCT
			$3.1 Billion	Misc. HLC
			$3.3 Billion	Non-HLC
2050 57 GW	57,000	**$22-26 Billion**	$10.2-12.8 Billion	N-S/Boston
			$1.2-2.0 Billion	NWVT
			$1.6 Billion	SWCT
			$3.1 Billion	Misc. HLC
			$6.6 Billion	Non-HLC

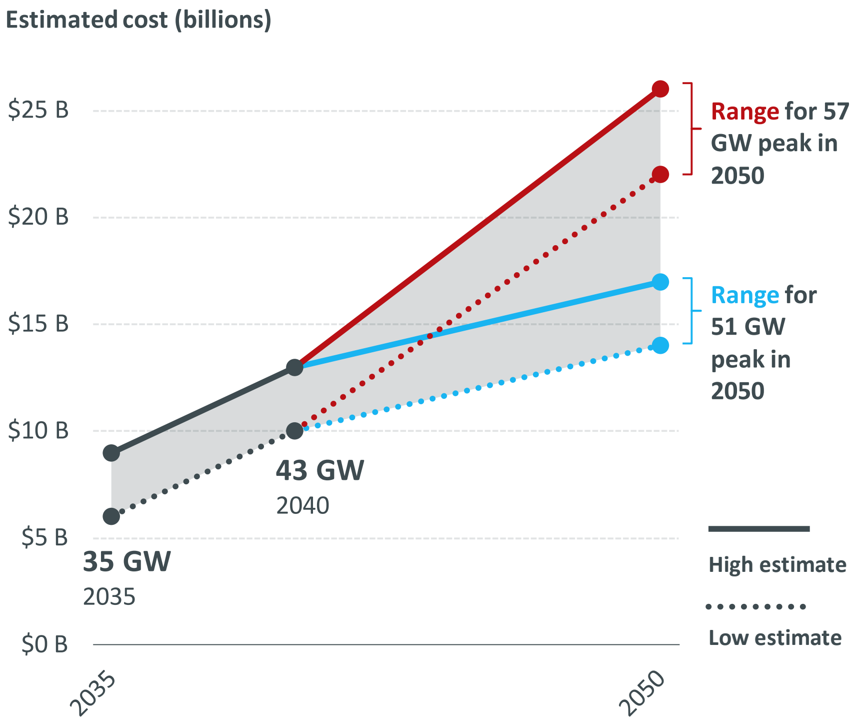
KEY TAKEAWAYS

Key Takeaways from the 2050 Transmission Study

- Reducing Peak Loads Significantly Reduces Transmission Cost
- High-Likelihood Concerns Can Be Prioritized
- Incremental Upgrades Can Be Made As Opportunities Arise
- Generator Location Matters
- A Significant Number of Transformers Need to Be Added

Reducing Peak Loads Significantly Reduces Transmission Cost

- Original 2050 Winter Peak snapshot assumed a 57 GW peak load
- Results presented in [April 2022]() and [July 2022]() introduced the 2050 Winter Peak 51 GW sensitivity, and showed that the total mileage of transmission overloads decreased by 30-40%
- Serving a 57 GW winter peak load costs approximately $8 billion more than serving a 51 GW winter peak load



Reducing Peak Loads Significantly Reduces Transmission Cost

- For the purposes of reducing transmission cost, simply shifting load to another off-peak hour could help avoid upgrades
- Other studies, such as the EPCET study, show that additional capacity and production cost can only be avoided if energy demand is eliminated entirely or shifted seasonally
  - Shifting load to another hour in the same day cannot address multi-day or multi-week needs for stored energy

High-Likelihood Concerns Can Be Prioritized

- As the region looks to transition to a low-emissions, electrified future, certain areas of concern are likely to appear for many possible future scenarios
  - Investment in addressing these concerns may be prudent regardless of exact generator locations and load distribution
- The 2050 Transmission Study has identified a few of these high-likelihood concerns:
  - North-South transfers
  - Boston Import
  - Northwestern Vermont Import
  - Southwest Connecticut Import

Incremental Upgrades Can Be Made As Opportunities Arise

- Much of the investment needed to serve 2050 peak loads is in the form of rebuilding existing transmission lines
- These investments will be somewhat sensitive to generator locations, geographic distribution of load, and locations of new load-serving substations
- It may be prudent to wait for more precise information on future development before pursuing these upgrades

Incremental Upgrades Can Be Made As Opportunities Arise

- Many load-serving concerns do not appear until 2040 or 2050, allowing the region to spread the cost of upgrades over many years rather than addressing issues immediately
- As transmission facilities are replaced for asset condition concerns, increasing capacity may have a relatively small incremental cost
- Addressing these concerns as opportunities arise, rather than upgrading immediately, can make it more likely that lines are not rebuilt unnecessarily

Generator Location Matters

- Throughout the study, generator points of interconnection (POIs) for offshore wind and batteries that were added in the 2050 Transmission Study were gradually optimized, within reason
- As a result, any overloads seen in the 2050 Transmission Study were in spite of these generator POI relocations
- Relocating large offshore wind interconnections from 345 kV to 115 kV was particularly effective at decreasing the number of transformer overloads observed in the study
- Generator POI relocation was less effective at avoiding some of the higher-level upgrades such as the large North-South upgrades because the exact generator location was less critical for these interface-related overloads

A Significant Number of Transformers Need to Be Added

- A large number of transformer overloads were seen throughout the New England system
  - These overloads are seen as the load grows higher, meaning that they are worst in the winter, and in later years, but many also show up in earlier years and sometimes in the summer
- These transformer overloads are often very dependent on the location of generation and load at specific stations
  - This makes it hard to pinpoint exactly where new transformers need to be built
  - Relocating new generators from 345 kV to 115 kV helped to eliminate some of the transformer overloads, but many still persisted
- Ideally the region would wait to order new transformers until closer to when they are definitely needed; however, transformers often have 18-24 month lead times, meaning that physically building/installing the number of transformers needed will be challenging
  - It may be necessary to order a large number of transformers ahead of time, figuring out their exact location later on

HIGH-LIKELIHOOD CONCERN (HLC) #1

North-South/Boston Import Roadmaps

Why is North-South/Boston Import a HLC?

- There are a significant number of very high overloads seen along the major 345 kV lines leading from Maine and New Hampshire south into the Boston area
  - Many of these overloads are seen across both summer and winter peak snapshots
  - Overloads are seen for all three study years
  - The overloads are particularly severe in the 57 GW Winter Peak snapshot, where many of the lines are beyond the threshold of what can be rebuilt without building entirely new lines
- The exact load and generation substation locations have little impact on the overloads
  - As long as generation and load are found in the same general region, overloads similar to those in the 2050 Transmission Study will be observed

Roadmaps for North-South Transfers and Boston Import

AC Roadmap

- New 345 kV overhead transmission

Minimization of New Lines Roadmap

- Prioritize rebuilds of existing lines to the greatest degree possible

DC Roadmap

- New HVDC transmission – overhead, underground, or submarine

Offshore Grid Roadmap

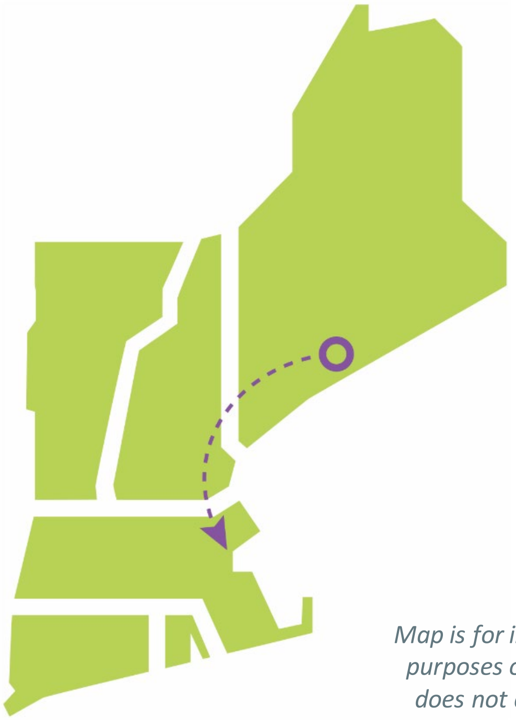
- Connections between offshore wind farms to provide offshore paths for power transfer

Note: ISO-NE is not recommending one roadmap over another; the intent of including multiple roadmaps is to provide a basis of comparison for decision-making by New England stakeholders

AC Roadmap

Summary of Upgrades Required to Serve 51 GW Load
Build new overhead 345 kV line from Surowiec – Timber Swamp – Ward Hill, 110 miles
Build a new partially-overhead/partially-underground 345 kV line from Ward Hill - Wakefield Junction – Mystic, 22.4 miles overhead and 12.8 miles underground
Build third Stoughton - K St 345 kV Underground Cable, 17.5 miles underground
Rebuild 501 miles of overhead 115 kV lines
Rebuild 165 miles of overhead 345 kV lines
Additional Upgrades Required to Serve 57 GW Load
Build a second Timber Swamp – Ward Hill line as described above, 30 miles
Rebuild an additional 181 miles of overhead 115 kV lines
Rebuild an additional 211 miles of overhead 345 kV lines

- This solution option increases transfer capability on Maine-New Hampshire, North-South, and the Boston Import interfaces, bringing energy from northern New England resources to southern New England load centers
- Fully underground/submarine AC transmission lines are likely infeasible due to the long distances involved and lower capacity than overhead transmission lines



Map is for illustrative purposes only, and does not define a route for any transmission project.

Note: The additional upgrades only required to serve the 57 GW load should not be considered High-Likelihood

Minimization of New Lines Roadmap

Summary of Upgrades Required to Serve 51 GW Load
Build a new partially-overhead/partially-underground 345 kV line from Ward Hill - Wakefield Junction – Mystic, 22.4 miles overhead and 12.8 miles underground
Build third Stoughton - K St 345 kV Underground Cable, 17.5 miles underground
Rebuild 558 miles of overhead 115 kV lines
Rebuild 360 miles of overhead 345 kV lines
Additional Upgrades Required to Serve 57 GW Load
A 57 GW peak cannot be served for this roadmap without building additional new transmission

- Two new lines/cables are still required for this option due to a significant number of underground cable overloads in Boston
- Rebuilds alone cannot successfully serve a 57 GW winter peak load along the North-South and Boston Import interfaces
- This roadmap is more likely to require extra upgrades for voltage/stability concerns since fewer new lines are being added

Map is for illustrative purposes only, and does not define a route for any transmission project.

Note: The additional upgrades only required to serve the 57 GW load should not be considered High-Likelihood

DC Roadmap

Summary of Upgrades Required to Serve 51 GW Load
Build new HVDC line from Surowiec – Mystic (assumed to be underwater cable)
Build third Stoughton - K St 345 kV Underground Cable, 17.5 miles underground
Rebuild 459 miles of overhead 115 kV lines
Rebuild 165 miles of overhead 345 kV lines
Additional Upgrades Required to Serve 57 GW Load
Build new HVDC line from South Gorham - Tewksbury
Rebuild an additional 168 miles of overhead 115 kV lines
Rebuild an additional 235 miles of overhead 345 kV lines

Map is for illustrative purposes only, and does not define a route for any transmission project.

- Large portions of the HVDC lines could feasibly be placed overhead, underground, or submarine, leading to more siting flexibility than with AC
- Onshore AC/DC converters at each terminal will add cost, but may bring voltage control and stability benefits to the grid

Note: The additional upgrades only required to serve the 57 GW load should not be considered High-Likelihood

Offshore Grid Roadmap

- Offshore connections are modeled between two or three offshore wind farms, as needed to address onshore overloads
  - Two- and three-terminal offshore networks are common in proposals for offshore networks in Europe
- Offshore networks are modeled to minimize the amount of equipment offshore (HVDC breakers, switching, etc.)
- Any offshore-to-onshore cable capacity not used to bring wind power to shore can be utilized for intra-area transfer capacity
  - For example: in summer daytime peak snapshots, wind is assumed to be at 5% output. The remaining 95% of cable capacity is available to transfer power from one point of interconnection to another

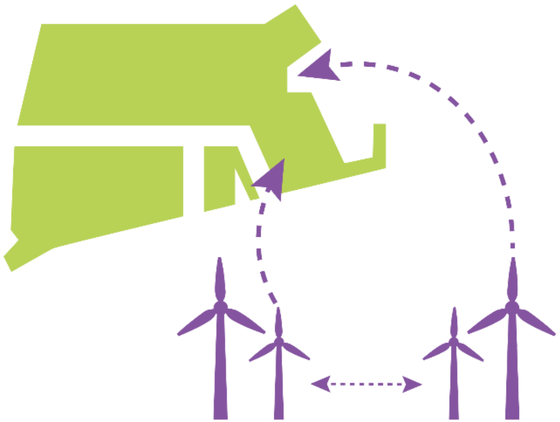
Offshore Grid Roadmap, continued

- Offshore connections between New Hampshire and Maine to Boston were also examined to alleviate North – South overloads
  - These overloads were worse in the winter when wind output is higher, meaning that each additional connection could carry less extra power from the shore, making the connections not as useful in the winter
  - The overloads on North – South were much higher than they were in Boston, meaning that it would have taken roughly 8 – 10 offshore connections to resolve them
    - This was determined to not be cost effective
- The offshore connections were more effective at solving Boston Import issues
  - Overloads occurred mostly in the summer when there was more available capacity on the offshore cables
  - Boston Import overloads were generally less severe than North – South overloads

Offshore Grid Roadmap, continued

Summary of Upgrades Required to Serve 51 GW Load
Build new overhead 345 kV line from Surowiec – Timber Swamp – Ward Hill, 110 miles
Build 3-terminal offshore network by building one HVDC link from Brayton Point Wind – K St Wind and another from K St Wind – Mystic Wind
Build 2-terminal offshore connection with an HVDC link between Montville Wind and Woburn Wind
Build 2-terminal offshore connection with an HVDC link between West Farnum Wind and Brighton Wind
Rebuild 444 miles of overhead 115 kV lines
Rebuild 162 miles of overhead 345 kV lines
Additional Upgrades Required to Serve 57 GW Load
Build a second Timber Swamp – Ward Hill line as described above, 30 miles
Rebuild an additional 220 miles of overhead 115 kV lines
Rebuild an additional 197 miles of overhead 345 kV lines

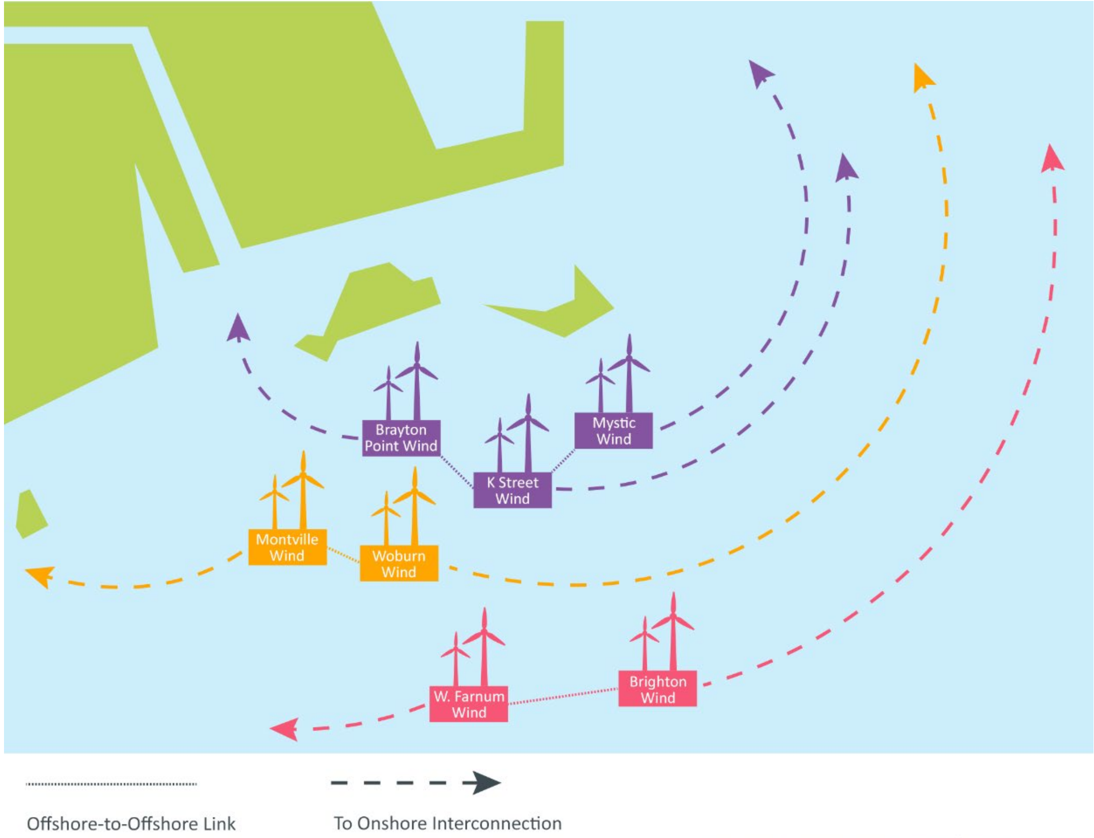
- Primary components are new HVDC connections between offshore wind farms
  - It is assumed that the links from wind farm to shore are already built as part of the generator interconnection
- Each offshore – offshore link was assumed to be 20 miles in length
- During periods of low wind availability, these connections would allow utilization of offshore wind transmission leads for power transfer between points onshore
- Beyond what is modeled in the 2050 Transmission Study, these grids could be expanded to include connections to New York, PJM, or other neighboring areas



Map is for illustrative purposes only, and does not define a route for any transmission project.

Note: The additional upgrades only required to serve the 57 GW load should not be considered High-Likelihood

Offshore Grid Roadmap, continued



Offshore Grid Roadmap Caveats

- While significant research and development towards offshore transmission has been performed in Europe, meshed offshore HVDC systems are not yet in use commercially
  - Many assumptions had to be made in design and modeling for the purposes of the 2050 Transmission Study
  - Costs should be considered to have an order-of-magnitude accuracy only, due to a lack of real-world costs for comparison
  - Technology for HVDC breakers is relatively new, limiting availability
  - ISO-NE is not aware of existing standards that would allow different manufacturers’ HVDC systems to be interconnected together
  - Existing constraints, such as the 1200 MW loss-of-source limit, continued to be observed to provide a fair comparison with AC and DC roadmaps

HIGH-LIKELIHOOD CONCERN (HLC) #2

Northwestern Vermont Import Roadmaps

Why is Northwestern Vermont a HLC?

- There are a significant number of overloads seen on the 115 kV lines that lead into northwestern Vermont, around the city of Burlington
  - These overloads are only seen in the winter peak snapshots, but they are seen across all three study years
- There is almost no utility scale generation located in the area so generator location does not affect these overloads
- The exact load locations at substations have little impact on the overloads
  - As long as generation and load are found in the same general region, overloads similar to those in the 2050 Transmission Study will be observed

Roadmaps for Northwestern Vermont Import

PV-20 Upgrade and Doubling of K-43 Roadmap

- Upgrade the PV-20 tie with NY from 115 kV to 230 kV
- Double the K-43 overhead 115 kV line

Coolidge – Essex Roadmap

- Build new 345 kV overhead line from Coolidge to Essex

New Haven – Essex and Granite – Essex Roadmap

- Build new 345 kV overhead line from New Haven to Essex
- Build a 230 kV overhead line from Granite - Essex

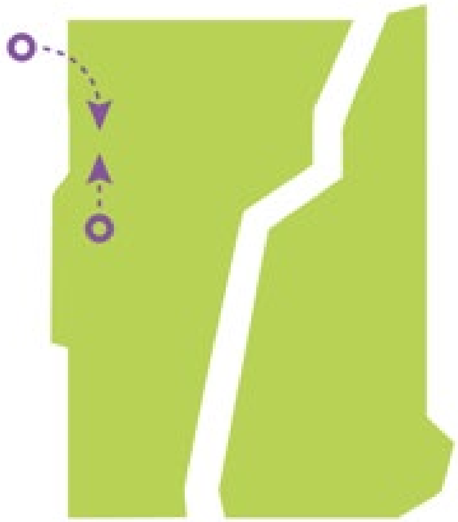
Minimization of New Lines Roadmap

- Prioritize rebuilds of existing lines to the greatest degree possible

Note: ISO-NE is not recommending one roadmap over another; the intent of including multiple roadmaps is to provide a basis of comparison for decision-making by New England stakeholders

PV-20 Upgrade and Doubling of K-43 Roadmap

Summary of Upgrades Required to Serve 51 GW Load
Upgrade the overhead portion of the PV-20 tie with New York from 115 kV to 230 kV
Build new overhead 115 kV line from New Haven – Williston (Doubling the existing K-43 line), 20.8 miles in length
Rebuild 120 miles of overhead 115 kV lines
Three new 345/115 kV Transformers
Additional Upgrades Required to Serve 57 GW Load
Rebuild an additional 31 miles of overhead 115 kV lines
Two additional new 345/115 kV Transformers



Map is for illustrative purposes only, and does not define a route for any transmission project.

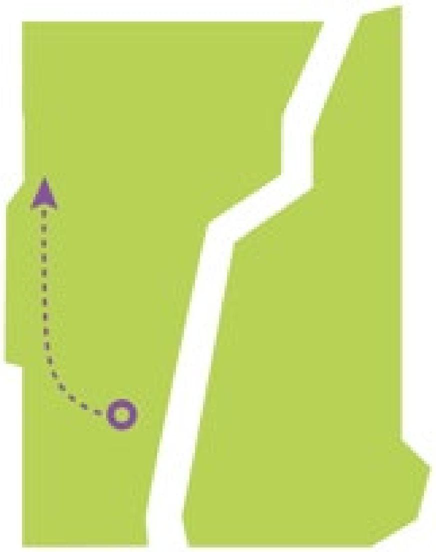
- For the PV-20 Upgrade:
  - Plattsburgh, NY is already connected to an existing 230 kV system in northern NY
  - Underground and underwater segments of PV-20 are already built for 230 kV; only overhead segments would need to be upgraded
  - The PV-20 upgrade could lead to increased NY-NE transfer capability and decreased curtailment of resources in northern NY
  - It would require coordination with New York, and therefore would not be a solution that is purely dependent on New England

Note: The additional upgrades only required to serve the 57 GW load should not be considered High-Likelihood

Coolidge – Essex Roadmap

Summary of Upgrades Required to Serve 51 GW Load
Build new overhead 345 kV line from Coolidge - Essex, 90 miles in length
Rebuild 105 miles of overhead 115 kV lines
Two New 345/115 kV Transformers
Additional Upgrades Required to Serve 57 GW Load
Rebuild an additional 84 miles of overhead 115 kV lines
One additional new 345/115 kV Transformer

- This option requires more miles of new transmission, but is entirely within New England
- The Essex substation is currently only built to 115 kV, so a new 345 kV station with transformer will be required



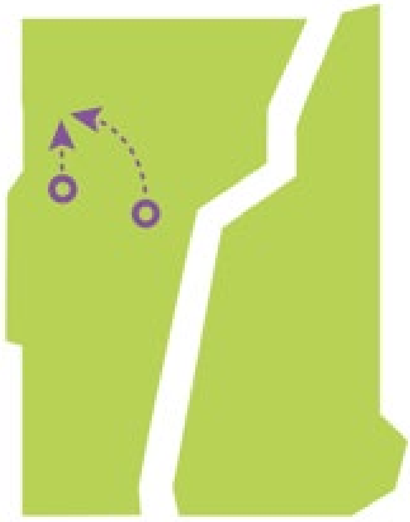
Map is for illustrative purposes only, and does not define a route for any transmission project.

Note: The additional upgrades only required to serve the 57 GW load should not be considered High-Likelihood

New Haven – Essex and Granite – Essex Roadmap

Summary of Upgrades Required to Serve 51 GW Load
Build new overhead 345 kV line from New Haven - Essex, 25 miles in length
Build new overhead 230 kV line from Granite – Essex, 45 miles in length
Rebuild 79 miles of overhead 115 kV lines
Three new 345/115 kV Transformers and one new 230/115 kV Transformer
Additional Upgrades Required to Serve 57 GW Load
Rebuild an additional 42 miles of overhead 115 kV lines
One additional new 345/115 kV Transformer

- This option requires more miles of new transmission than the PV-20 option but fewer than the Coolidge – Essex option
- The Essex substation is currently only built to 115 kV, so a new 345 kV station with transformer and a new 230 kV station with transformer will be required
  - Alternatively, both lines could be built to 345 kV, simplifying the connection at Essex, although two transformers would still be required to avoid the loss of all new feeds into Essex for a single contingency

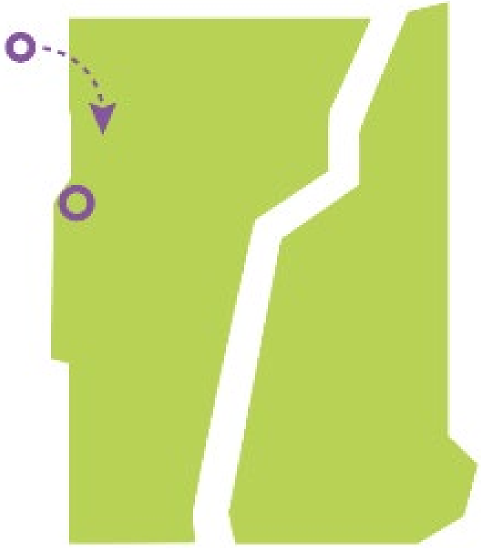


Map is for illustrative purposes only, and does not define a route for any transmission project.

Note: The additional upgrades only required to serve the 57 GW load should not be considered High-Likelihood

Minimization of New Lines Roadmap

Summary of Upgrades Required to Serve 51 GW Load
Upgrade the overhead portion of the PV-20 tie with New York from 115 kV to 230 kV
Double the underground 115 kV cable on the N Ferrisburg – Charlotte line, 0.4 miles in length
Double the underground 115 kV cable on the Shelburne – Queen City line, 1.7 miles in length
Rebuild 142 miles of overhead 115 kV lines
Three new 345/115 kV Transformers
Additional Upgrades Required to Serve 57 GW Load
Rebuild an additional 50 miles of overhead 115 kV lines
Two additional new 345/115 kV Transformers



Map is for illustrative purposes only, and does not define a route for any transmission project.

- Unlike the North-South/Boston Import roadmaps, it is possible to resolve the Vermont overloads without building new overhead transmission, although the following upgrades are required
  - It requires the PV-20 upgrade mentioned in the first roadmap
  - Doubling-up two underground cables near Lake Champlain
  - More miles of rebuilds than the other roadmaps

Note: The additional upgrades only required to serve the 57 GW load should not be considered High-Likelihood

HIGH-LIKELIHOOD CONCERN (HLC) #3

Southwest Connecticut (SWCT) Import

Why is Southwest CT a HLC?

- There were several thermal overloads seen in Southwest Connecticut
  - These overloads were seen starting in 2035 all the way through 2050 with a 57 GW load
- Generation location had some effect on the overloads initially, Norwalk wind was then relocated from 345 kV to 115 kV
  - Any further overloads were not able to be mitigated with generation relocation, without adding generation beyond the input assumptions from the Energy Pathways study
- The exact load locations at substations have little impact on the overloads, as long as they are found in the same general region then the overloads are seen
  - As long as generation and load are found in the same general region, overloads similar to those in the 2050 Transmission Study will be observed

Southwest Connecticut Solutions

Summary of Upgrades Required to Serve 51 GW Load
Build new cables: Norwalk-Glenbrook, Ely Ave-Norwalk Harbor, South End-Cos Cob
Rebuild 96 miles of overhead 115 kV lines
Rebuild 6 miles of overhead 345 kV lines
Two new 345/115 kV Transformers
Additional Upgrades Required to Serve 57 GW Load
Close normally-open 345 kV cable between Archer's Lane and Norwalk Junction
Rebuild an additional 125 miles of overhead 115 kV lines
Rebuild an additional 21 miles of overhead 345 kV lines
Two additional new 345/115 kV Transformers

Map is for illustrative purposes only, and does not define a route for any transmission project.

- Unlike the North-South/Boston Import and northwestern VT solutions, only one solution roadmap was developed for Southwest Connecticut
  - This was due to the fact that there were a much more limited number of ways to address the thermal overloads seen in this area
  - Other solution alternatives investigated would have been far more expensive, and had greater impacts on the environment and local communities
- The Norwalk – Glenbrook cable was able to utilize an existing spare duct bank, somewhat decreasing the cost of this project

Note: The additional upgrades only required to serve the 57 GW load should not be considered High-Likelihood

MISCELLANEOUS HIGH-LIKELIHOOD CONCERNS (HLC)

Miscellaneous High-Likelihood Concerns

- There were a variety of other high-likelihood concerns that were more isolated thermal overloads and did not form a consistent pattern like those in the North-South/Boston Import roadmaps, for example
- These were still high-likelihood concerns because they were seen across at least two different load levels (either different seasons or different years), and were not heavily dependent on specific load/generation locations
- The table on the right summarizes the upgrades required to address these miscellaneous high-likelihood concerns

Upgrades Required to Serve 51 GW Load
Upgrade 298 miles of 69 kV lines to 115 kV
Rebuild 225 miles of overhead 115 kV lines
Rebuild 37 miles of overhead 345 kV lines
Build approximately 13 miles of new 115 kV overhead lines
Build two new overhead 345 kV lines from Brayton Point – Grand Army, 3 miles total
Increase the series capacitor rating on the 3023 line
Install 14 new 345/115 kV Transformers

NON-HIGH-LIKELIHOOD, NON-ROADMAP CONCERNS

Non-High-Likelihood Concerns

- There were a significant number of thermal overloads seen in the 2050 Transmission Study that did not meet the criteria for being a high-likelihood concern
- These are overloads that may be considered lower priority to resolve because they are less likely to occur if the input assumptions to this study do not closely match how the future power system evolves
- However, in order to fully resolve all of the overloads in this study, solutions were still developed for completeness

Non-High-Likelihood Concerns

Upgrades to Address Non-High-Likelihood Concerns
Rebuild approximately 393 miles of overhead 115 kV lines
Rebuild approximately 287 miles of overhead 345 kV lines
Build approximately 103 miles of new 115 kV overhead lines to resolve load loss concerns
Build approximately 48 miles of new 115 kV underground cables to resolve load loss concerns
Build approximately 2 miles of new 115 kV overhead lines to resolve non-load loss concerns
Build approximately 9 miles of new 115 kV underground cables to resolve non-load loss concerns
Replace approximately 10 miles of underground 115 kV cables to XLPE
Install 4 new series reactors throughout New England
Install 10 new 345/115 kV Transformers
Install approximately 300 new circuit breakers throughout New England
Separate 10 sections of double-circuit tower lines

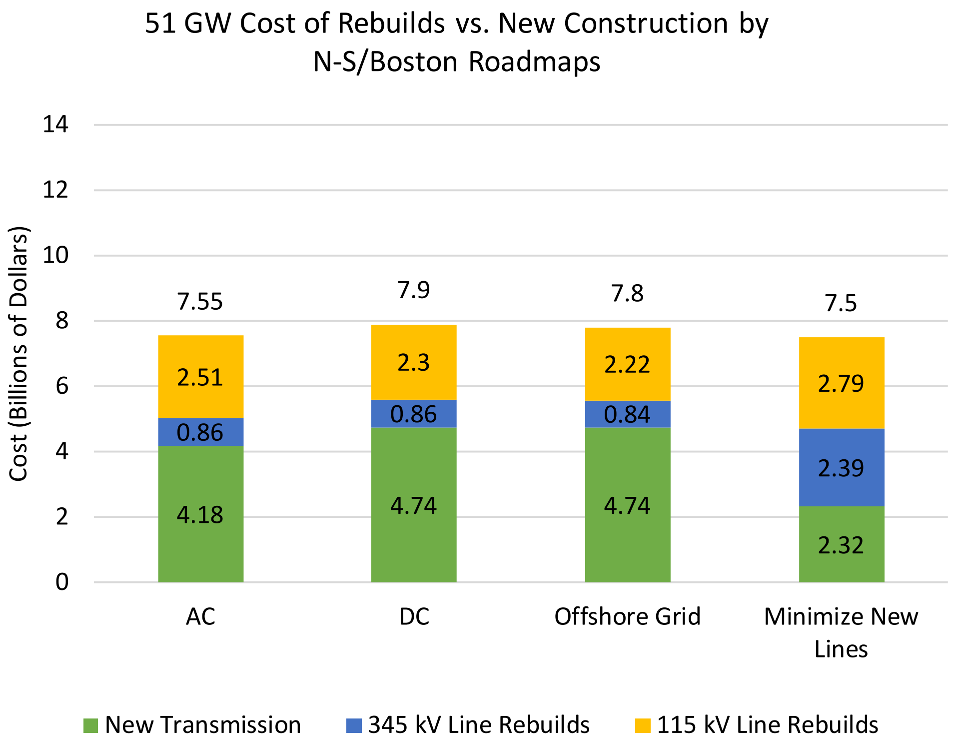
SPECIFIC COST BREAKDOWNS

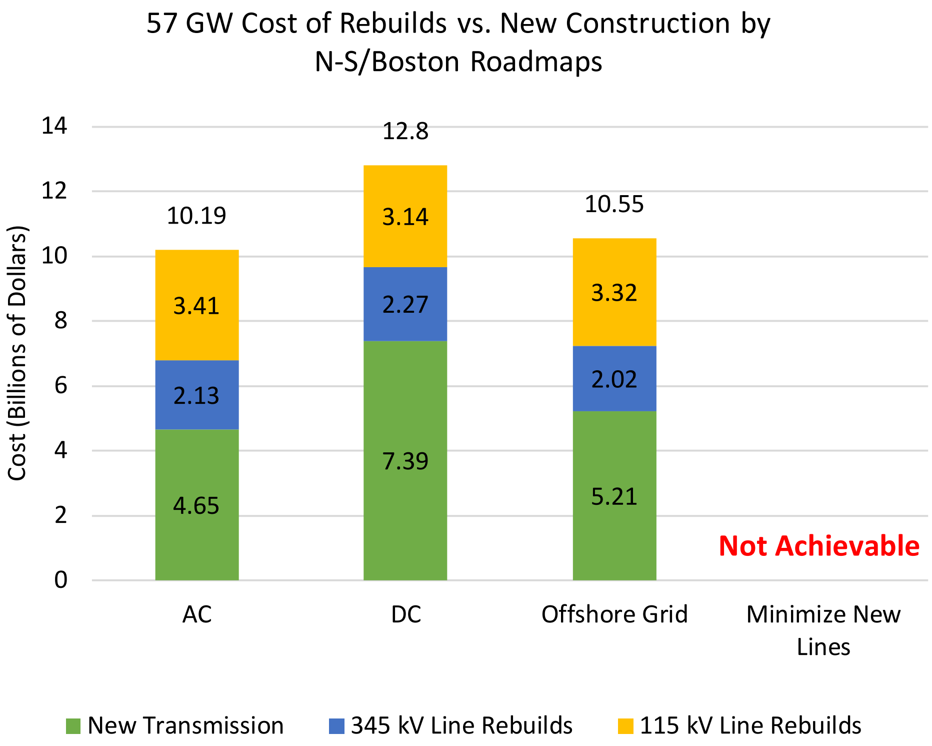
North-South/Boston Import Roadmap Costs

Year/Load Level	AC Roadmap ($)	Minimization of New Lines Roadmap ($)	DC Roadmap ($)	Offshore Grid Roadmap ($)
2035	$4.4 Billion	$2.8 Billion	$5.0 Billion	$4.0 Billion
2040	$6.2 Billion	$5.0 Billion	$6.5 Billion	$5.8 Billion
2050 51 GW	$7.6 Billion	$7.5 Billion	$7.9 Billion	$7.8 Billion
2050 57 GW	$10.2 Billion	Not Achievable	$12.8 Billion	$10.6 Billion

- All estimated costs shown are cumulative, meaning that the 2040 number is the total to reach 2040, starting from the present day peak load value; it is not the amount to go from 2035 to 2040
- The Minimization of New Lines Roadmap starts out cheaper in 2035 and 2040, but ultimately in 2050 for a 51 GW load ends up comparable to the other roadmaps
  – This roadmap also cannot be used to serve a 57 GW load
- The costs reflected on this slide only reflect those identified through steady-state thermal analysis; the total transmission and distribution costs are anticipated to be much higher

North-South/Boston Import Roadmap Costs



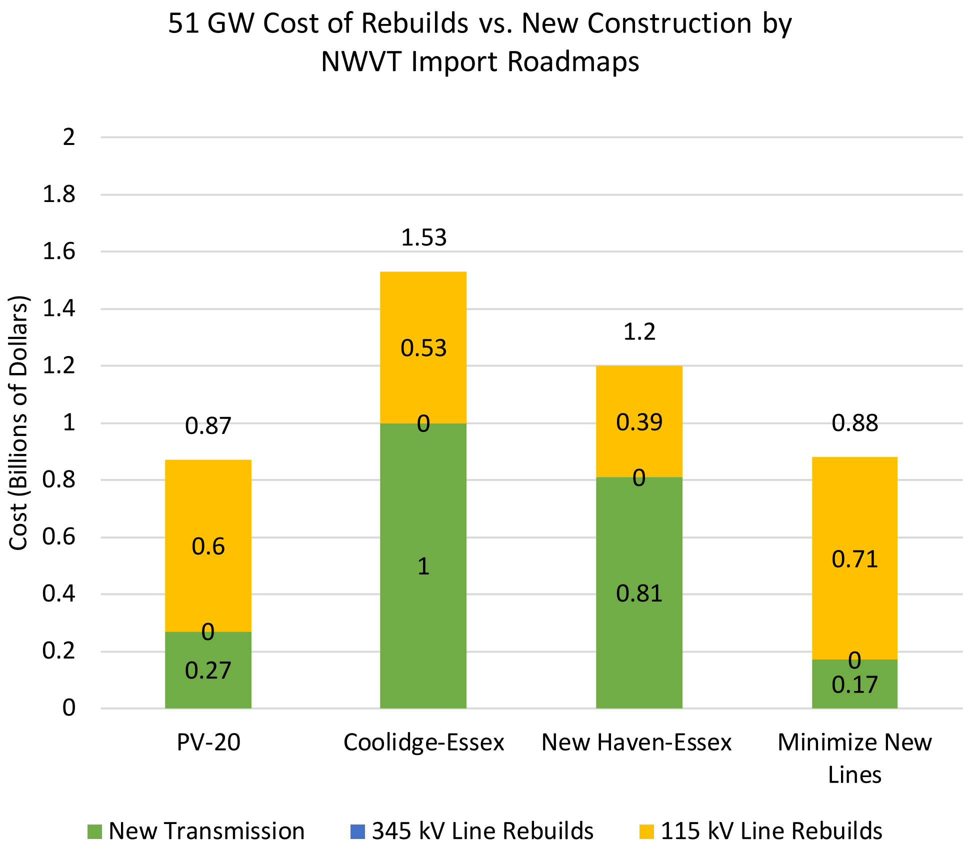


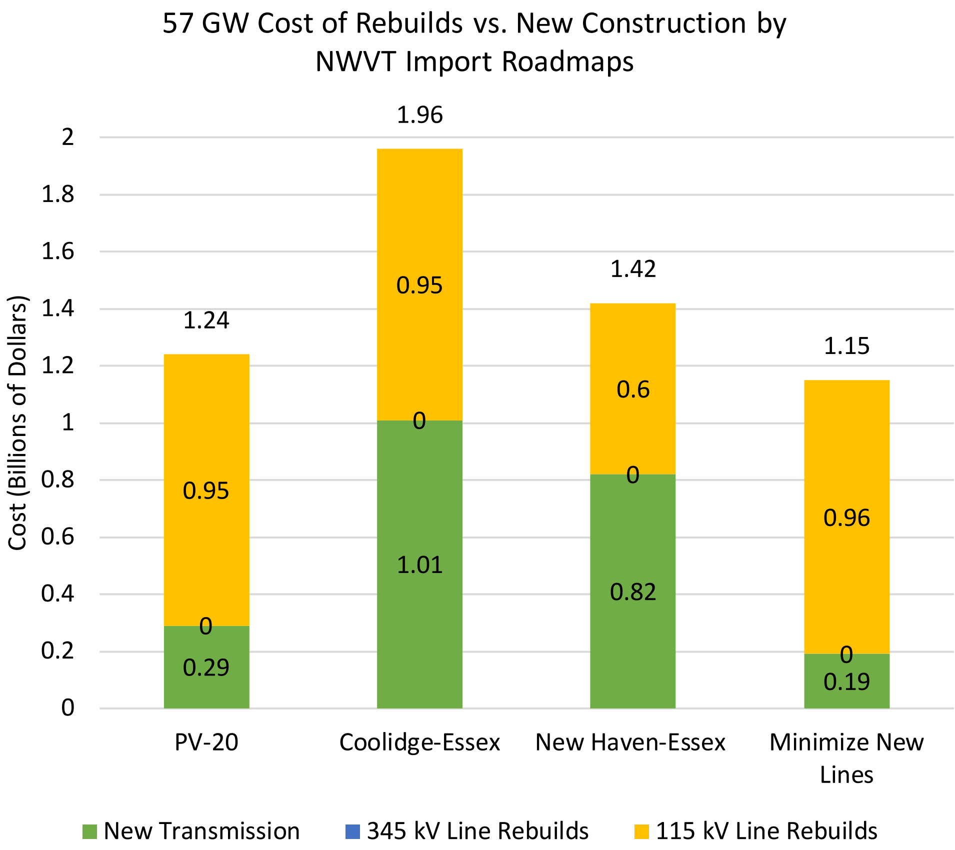
Northwestern Vermont Import Roadmap Costs

Year/Load Level	PV-20 Upgrade and Doubling of K-43 Roadmap ($)	Coolidge – Essex Roadmap ($)	New Haven – Essex and Granite – Essex Roadmap ($)	Minimization of New Lines Roadmap ($)
2035	$0.7 Billion	$1.1 Billion	$1.1 Billion	$0.6 Billion
2040	$0.8 Billion	$1.3 Billion	$1.1 Billion	$0.8 Billion
2050 51 GW	$0.9 Billion	$1.5 Billion	$1.2 Billion	$0.9 Billion
2050 57 GW	$1.2 Billion	$2.0 Billion	$1.4 Billion	$1.2 Billion

- All estimated costs shown are cumulative, meaning that the 2040 number is the total to reach 2040, starting from the present day peak load value; it is not the amount to go from 2035 to 2040
- The costs reflected on this slide only reflect those identified through steady-state thermal analysis; the total transmission and distribution costs are anticipated to be much higher

Northwestern Vermont Import Roadmap Costs





Southwest Connecticut Import Costs

- All estimated costs shown are cumulative, meaning that the 2040 number is the total to reach 2040, starting from the present day peak load value; it is not the amount to go from 2035 to 2040
- The costs reflected on this slide only reflect those identified through steady-state thermal analysis; the total transmission and distribution costs are anticipated to be much higher

Year/Load Level	Southwest CT Import ($)
2035	$0.5 Billion
2040	$0.7 Billion
2050 51 GW	$0.8 Billion
2050 57 GW	$1.6 Billion

Miscellaneous High-Likelihood Concerns Costs

- All estimated costs shown are cumulative, meaning that the 2040 number is the total to reach 2040, starting from the present day peak load value; it is not the amount to go from 2035 to 2040
- The costs reflected on this slide only reflect those identified through steady-state thermal analysis; the total transmission and distribution costs are anticipated to be much higher

Year/Load Level	Miscellaneous HLCs ($)
2035	$1.7 Billion
2040	$2.8 Billion
2050 51 GW	$3.1 Billion
2050 57 GW	$3.1 Billion

Non-High-Likelihood Concerns Costs

- All estimated costs shown are cumulative, meaning that the 2040 number is the total to reach 2040, starting from the present day peak load value; it is not the amount to go from 2035 to 2040
- The costs reflected on this slide only reflect those identified through steady-state thermal analysis; the total transmission and distribution costs are anticipated to be much higher
- While the individual upgrades in this category are non-high-likelihood, some set of upgrades, and associated cost, will be necessary to address load growth and/or generator interconnections at individual substations

Year/Load Level	Non-HLCs ($)	Percent of Total Cost
2035	$0.4 Billion	~5%
2040	$1.4 Billion	~10-15%
2050 51 GW	$3.3 Billion	~20-25%
2050 57 GW	$6.6 Billion	~25-30%

Range of Final Costs

- Totaling up all of the different roadmaps, along with miscellaneous high-likelihood concerns, and non-high-likelihood concerns gives the range of cost totals seen at right

- The numbers above represent the cumulative estimated cost to reach the load level shown in the middle column, starting from the present day peak load value
  - This means that it takes approximately $6-9 billion to go from today's peak load of 28,000 MW to 35,000 MW in 2035 and it takes approximately $10-13 billion to go from today's peak load of 28,000 MW to 43,000 MW in 2040

- The costs reflected on this slide only reflect those identified through steady-state thermal analysis; **the total transmission and distribution costs are anticipated to be much higher**

Year/Load Level	Maximum Load Served (MW)	Total Cost Range ($)	Cost Breakdown	
2035	35,000	**$6-9 Billion**	$2.8-5.0 Billion	N-S/Boston
			$0.6-1.1 Billion	NWVT
			$0.5 Billion	SWCT
			$1.7 Billion	Misc. HLC
			$0.4 Billion	Non-HLC
2040	43,000	**$10-13 Billion**	$5.0-6.5 Billion	N-S/Boston
			$0.8-1.3 Billion	NWVT
			$0.7 Billion	SWCT
			$2.8 Billion	Misc. HLC
			$1.4 Billion	Non-HLC
2050 51 GW	51,000	**$15-17 Billion**	$7.5-7.9 Billion	N-S/Boston
			$0.9-1.5 Billion	NWVT
			$0.8 Billion	SWCT
			$3.1 Billion	Misc. HLC
			$3.3 Billion	Non-HLC
2050 57 GW	57,000	**$22-26 Billion**	$10.2-12.8 Billion	N-S/Boston
			$1.2-2.0 Billion	NWVT
			$1.6 Billion	SWCT
			$3.1 Billion	Misc. HLC
			$6.6 Billion	Non-HLC

Cost of Increasing Load

- There is a significant increase in cost associated with adding each GW of load above 51 GW
  - Roughly $0.75 billion per GW of load to go from 28 GW to 51 GW
    - Increasing load by 23 GW costs roughly $17 billion
  - Roughly $1.5 billion per GW of load to go from 51 GW to 57 GW
    - Increasing load by only an additional 6 GW costs roughly $8 billion

Context for the Final Costs

- It is important to remember that the estimated costs presented today are the approximate costs needed to strengthen the PTF transmission system against thermal overloads over the next 26 years; not all of these upgrades are needed today

- From 2002 to 2023, the region spent approximately $15.3 billion on reliability-based (RSP) projects and asset condition (ACL) projects
  - This is roughly $0.73 billion per year

- The 2050 Transmission Study upgrades, averaged per year in 2023 dollars would come out to
  - $0.58-0.65 billion per year to reach 51 GW
  - $0.85-1.00 billion per year to reach 57 GW

- Some future asset condition costs will likely overlap with some of the rebuild costs needed for the 2050 Transmission Study

- Keep in mind that the 2050 Transmission Study numbers do not include inflation or any of the other caveats previously mentioned, such as distribution costs and non-PTF transmission costs

Year	Average Cost
2002-2023	$0.73 Billion/Year
2024-2050 (51 GW Load)	$0.54-0.65 Billion/Year + Additional ACL and RSP costs*
2024-2050 (57 GW Load)	$0.85-1.00 Billion/Year + Additional ACL and RSP costs*

* These additional costs would consist of asset condition projects not needed in the 2050 Transmission Study, along with reliability projects needed to address voltage, stability, short-circuit, and EMT concerns

CONCLUSION & NEXT STEPS

Conclusion

- Reducing the peak load seen in winter from 57 GW to 51 GW could save New England roughly $8 billion in PTF transmission costs
- Several high-likelihood concerns can be prioritized since these are more likely to occur under a variety of possible futures
- Many of the solutions needed involve rebuilding existing lines
  - This can be done incrementally as the system gradually shifts and as line rebuilds become necessary due to asset condition concerns
- Generation location affects required transmission upgrades
  - This study has attempted to optimize the new generator locations within reason, but where these generators actually interconnect will play a large part in determining how the system needs to evolve
- A large number of new transformers will need to be added to the New England system
  - These devices have long lead times, meaning that the region will need to plan ahead in order to ensure that they can get the number of transformers that are needed

Next Steps

- Feedback on the 2050 Transmission Study presentation may be submitted to pacmatters@iso-ne.com by November 1, 2023
- Next Steps:
  - ISO-NE will post the draft 2050 Transmission Study Report on November 1
  - ISO-NE will post the draft 2050 Transmission Study Technical Appendix on or shortly after November 1
  - Discussions on "Phase 2 of Extended/Longer-Term Planning," which will create a Tariff process for advancing transmission projects from longer-term transmission studies like the 2050 Transmission Study, began at the NEPOOL Transmission Committee on October 17 and will continue

Questions