Revision 1

AGENDA
JOINT MEETING
NEPOOL MARKETS & RELIABILITY COMMITTEES
TUESDAY, AUGUST 4, 2020

Location: Teleconference
Call-in Number: 1-866-803-2146 / Access Code: 7169224
WebEx: WebEx Link
WebEx Password: nepool

Item	Description	Time Allotted
1*	CHAIRS' OPENING REMARKS	9:30-9:35
	(A) Approval of Minutes [66.67% MC vote] [66.67% RC vote] • Joint MC/RC Meeting Date: July 1, 2020	
2*	TRANSITION TO THE FUTURE GRID STUDY	
	(A) OVERVIEW OF E3/EFI DEEP DECARBONIZATION STUDY FOR NEW ENGLAND (E3: Arne Olson) (Calpine: William Fowler) (1st MC/RC Mtg) Overview of results of the "Electric Reliability under Deep Decarbonization Pathways in New England" study conducted jointly by Energy+Environmental Economics (E3) and Energy Futures Initiative (EFI).	9:35-11:00
	(B) OVERVIEW OF STUDY FOR OFFSHORE TRANSMISSION (The Brattle Group: Johannes Pfeinfengerger & Walter Graf; GE Energy Consulting: Ken Wei; Anbaric Development Partners: Lawrence Mott) (1st MC/RC Mtg) Overview of results of a study conducted by The Brattle Group, GE Energy Consulting, and CHA Consulting to inform how the future grid plans for offshore wind.	11:00-12:15
	LUNCH	12:15-12:45
	(C) OVERVIEW SUMMARY OF STUDY REQUEST PROPOSALS (Day Pitney: Eric Runge) (1st MC/RC Mtg) Overview of NEPOOL Counsel summary of the study proposal submittals for the Transition to Future Grid Study.	12:45-1:00
	(D) OBJECTIVE OF FUTURE GRID STUDY REQUEST PROPOSALS	
	(i) Discussion of Eversource's analysis request proposal objective. (20 min)	1:00-1:20
	(ii) Discussion of National Grid's analysis request proposal objective. (20 min)	1:20-1:40
	(iii) Discussion of Energy Market Advisors' analysis request proposal objective. (20 min)	1:40-2:00
	(iv) Discussion of FirstLight Power Management's analysis request proposal objective. (20 min)	2:00-2:20
	(v) Discussion of NextEra/Dominion's analysis request proposal objective. (20 min)	2:20-2:40

* Material distributed for this agenda item
AGENDA ITEMS with BOLD & ITALICIZED FONT: MC ACTION and RC ACTION Requested
WMPP: Wholesale Markets Project Plan

(vi)	Discussion of American Petroleum Institute's analysis request proposal objective. (20 min)	2:40-3:00
(vii)	Discussion of Multi-Sector Group A's (Acadia Center, Advanced Energy Economy, Brookfield Renewables, Energy New England, NRDC, PowerOptions, and Conservation Law Foundation) analysis request proposal objective. (20 min)	3:00-3:20
(viii)	Discussion of Multi-Sector Group B's (Acadia Center, Advanced Energy Economy, Brookfield Renewables, Energy New England, NRDC, PowerOptions, and Conservation Law Foundation) analysis request proposal objective. (20 min)	3:20-3:40
(ix)	Discussion of Anbaric Development Partners, LLC's analysis request proposal objective. (20 min)	3:40-4:00
(x)	Discussion of NESCOE analysis request proposal objective.	

(E) COORDINATOR ROLE — 4:00-4:30

(Participants Committee Chair: Nancy Chafetz)

Discussion of utilizing a coordinator for the Transition to the Future Grid Study.

3 OTHER BUSINESS — 4:30-4:35

* Material distributed for this agenda item

AGENDA ITEMS with BOLD & ITALICIZED FONT: MC ACTION Requested

WMPP: Wholesale Markets Project Plan

Energy+Environmental Economics

Study performed in partnership with Energy Futures Initiative

ENERGY FUTURES INITIATIVE

Electric Reliability under Deep Decarbonization in New England

Presentation at NEPOOL Meeting

August 4, 2020

Draft/Preliminary Results

EFI:
Alex Kizer
Alex Breckel
Sam Savitz
Anne Canavati

E3:
Arne Olson
Liz Mettetal, PhD
Saamrat Kasina, PhD
Clea Kolster, PhD
Manohar Mogadali
Vignesh Venugopal
Zach Ming
Sharad Bharadwaj

Agenda

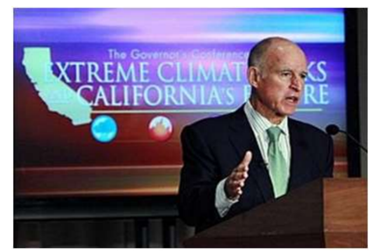
+ Introduction
+ Economy-Wide Decarbonization Results
+ Electricity Resource Portfolios
+ Illustration of 2050 Electricity Sector Reliability Challenge
+ Key Findings

Energy+Environmental Economics

Introduction

E3 has worked with a wide range of clients to understand the challenges of deep carbon reductions and high renewable penetration

- **United Nations Deep Decarbonization Pathways Project**
- **California:**
  - Carbon Reduction Pathways studies
  - Landmark 2014 study of 50% RPS goal for PG&E, SDG&E, SCE, LADWP, SMUD, CAISO
  - 100% RPS studies for LADWP, SMUD, Calpine, The Nature Conservancy
  - Support for California CPUC IRP process
- **Deep carbon reduction and 100% renewables planning in a diverse group of regions:**
  - **New York:** NYSERDA, NYPSC
  - **Hawaii:** HECO
  - **Canada:** Nova Scotia Power, Atlantic provinces
  - **Upper Midwest:** Xcel Energy
  - **Pacific NW & Desert SW:** numerous utilities
- **Asset valuation and strategy support for resource developers in multiple jurisdictions**



About the Energy Futures Initiative (EFI)

EFI is a nonprofit clean energy think tank founded by former Secretary of Energy Ernest Moniz dedicated to harnessing the power of innovation to create clean energy jobs, grow economies, enhance national and global energy security, and address the imperatives of climate change.

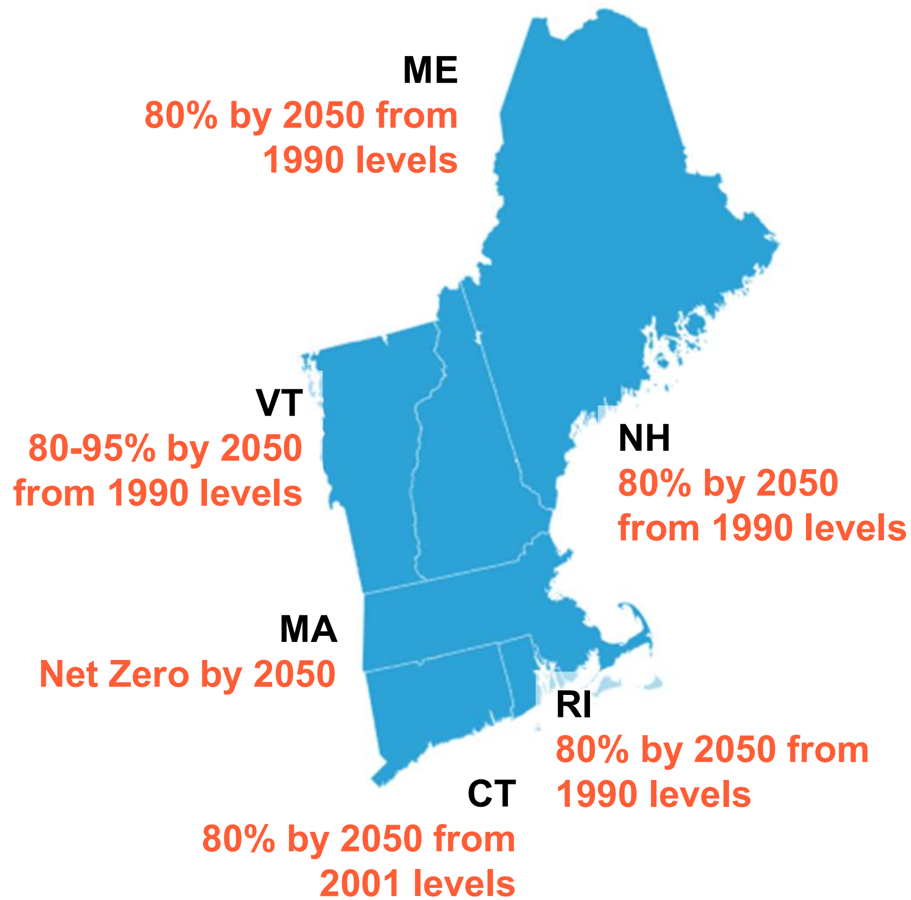
Some of EFI's work:

- Optionality, Flexibility, and Innovation: Pathways to Deep Decarbonization in California (May 2019): Identified 33 pathways for California to meet its 2030 low-carbon energy goals, and outlined a California-specific innovation agenda for midcentury.
- Advancing the Landscape of Clean Energy Innovation (February 2019): Co-produced with IHS Market and sponsored by Breakthrough Energy, assesses energy technologies based on four criteria—technical merit, market viability, compatibility with other energy systems and consumer value.
- Clearing the Air: A Federal RD&D Initiative and Management Plan for Carbon Dioxide Removal Technologies (September 2019): Outlines a 10-year RD&D initiative to bring innovative CDR technologies to commercial readiness at a gigaton scale, at technology-specific cost targets, with minimal ecological impacts. Sponsored by the Linden Trust for Conservation and ClimateWorks.
- Regional Clean Energy Innovation (February 2020): Analyzes how state-level policy efforts to accelerate local clean energy technology innovation can complement federal activity on climate and energy while creating local economic development opportunities.

Study Motivation

+ **The six New England states are pursuing efforts aimed at increasing renewable energy generation and reducing carbon emissions**
  – Notable recent "net zero" mandate signed in Massachusetts
+ **The electricity sector will play a key role by providing low-carbon energy to power the New England economy under economy-wide deep decarbonization**
  – Economy-wide decarbonization will require significant renewable build-out
  – Open questions remain around how much firm capacity is needed in the medium to long-term, and how substitutable renewable generation is for firm dispatchable capacity in "keeping the lights on"

Mid-Century Economy-wide GHG Emission Reduction Targets in New England



Key Study Questions

Study Question: How can New England provide affordable, reliable electric power under future scenarios that achieve net zero economy-wide greenhouse gas emissions by 2050?

Corollary Questions:

+ What **decarbonization technologies and strategies** are most likely to be successful in New England, given weather, policy, economics, etc.?
+ How much must **electricity sector emissions** be reduced by 2050?
+ How much **new electric load** will materialize due to electrification of end-uses in other sectors by 2050?
+ What is the **optimal electricity resource mix** to meet's NE energy and resource adequacy needs through 2050 while achieving economy-wide GHG goals?
+ What roles do various supply resources play in achieving **resource adequacy**?

Today's discussion focuses on the initial electricity sector resource portfolio results and reliability findings.

Study Approach is a Coordinated E3-EFI Effort

Modeling Steps

1. PATHWAYS
Economy-wide GHG Scenarios

New England PATHWAYS model develops scenarios for meeting 2050 economy-wide decarbonization goals (E3)

- Electric sector carbon budgets and electrification loads passed to RESOLVE

2. RESOLVE
Electricity Capacity Expansion

New England RESOLVE model develops least-cost resource portfolios to meet GHG targets (E3)

- Electricity resource portfolio passed to RECAP

3. RECAP
Electricity Resource Adequacy

New England RECAP model tests the resource adequacy of the portfolios (E3)

- Calculates Loss-of-Load Expectation

iteration

Parallel Research

Carbon Dioxide Removal Potential (EFI)

Innovation Portfolio (EFI) informed by rest of study

Study sponsored by Calpine Corp.

CALPINE®

Technical Advisory Group provided advice and feedback across the study components

Preview: Key Study Findings

1. **Electricity demand will increase significantly in New England over the next three decades under all plausible low-carbon scenarios**
   - Electricity demand grows by 66 - 97 percent
2. **A significant quantity of renewable generation is selected in every case, particularly solar and offshore wind**
   - Land and transmission availability will likely be constraining factors
3. **The New England system requires 30-37 GW of thermal capacity through 2050 in all cases**
   - Thermal resources operated at increasingly low capacity factors over time
   - It is expected that some form of low-carbon fuel will be available to reduce the carbon intensity of this use
4. **Cases with broader sets of available solutions have lower costs and lower technology risks**
   - Firm, low-carbon technologies such as advanced nuclear, CCS or hydrogen could play a significant role
   - Increasing the availability of land-based wind and solar also reduces cost

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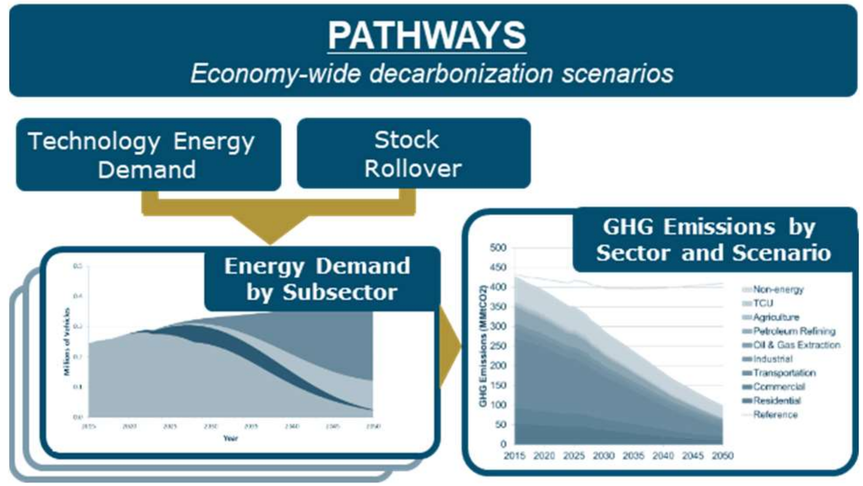
Economy-Wide Decarbonization

Step 1: E3 PATHWAYS model used to identify economy decarbonization strategies

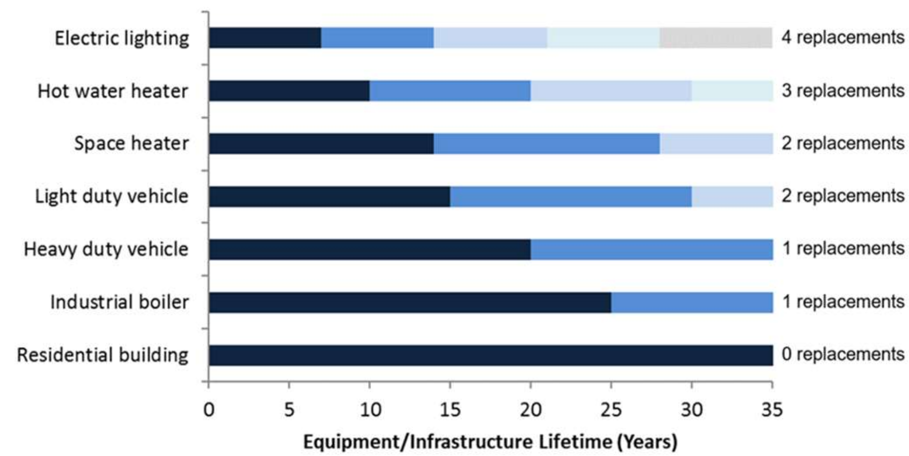
+ **Economy-wide infrastructure-based GHG analysis**
  - Driven by user-defined scenarios (i.e., not an optimization)
  - Stock rollover captures "infrastructure inertia" reflecting lifetimes and vintages of buildings, vehicles, equipment



E3 modeled two economy-wide scenarios to reflect a range of load implications

- **High Electrification:** Relies heavily on electrification to decarbonize end-uses, given assumption of somewhat more limited market development of advanced low carbon fuels
- **High Fuels:** Large-scale market development of advanced biofuels and hydrogen result in somewhat lower electrification rates and greater reliance on low-carbon fuels

Illustrative PATHWAYS Lifetimes



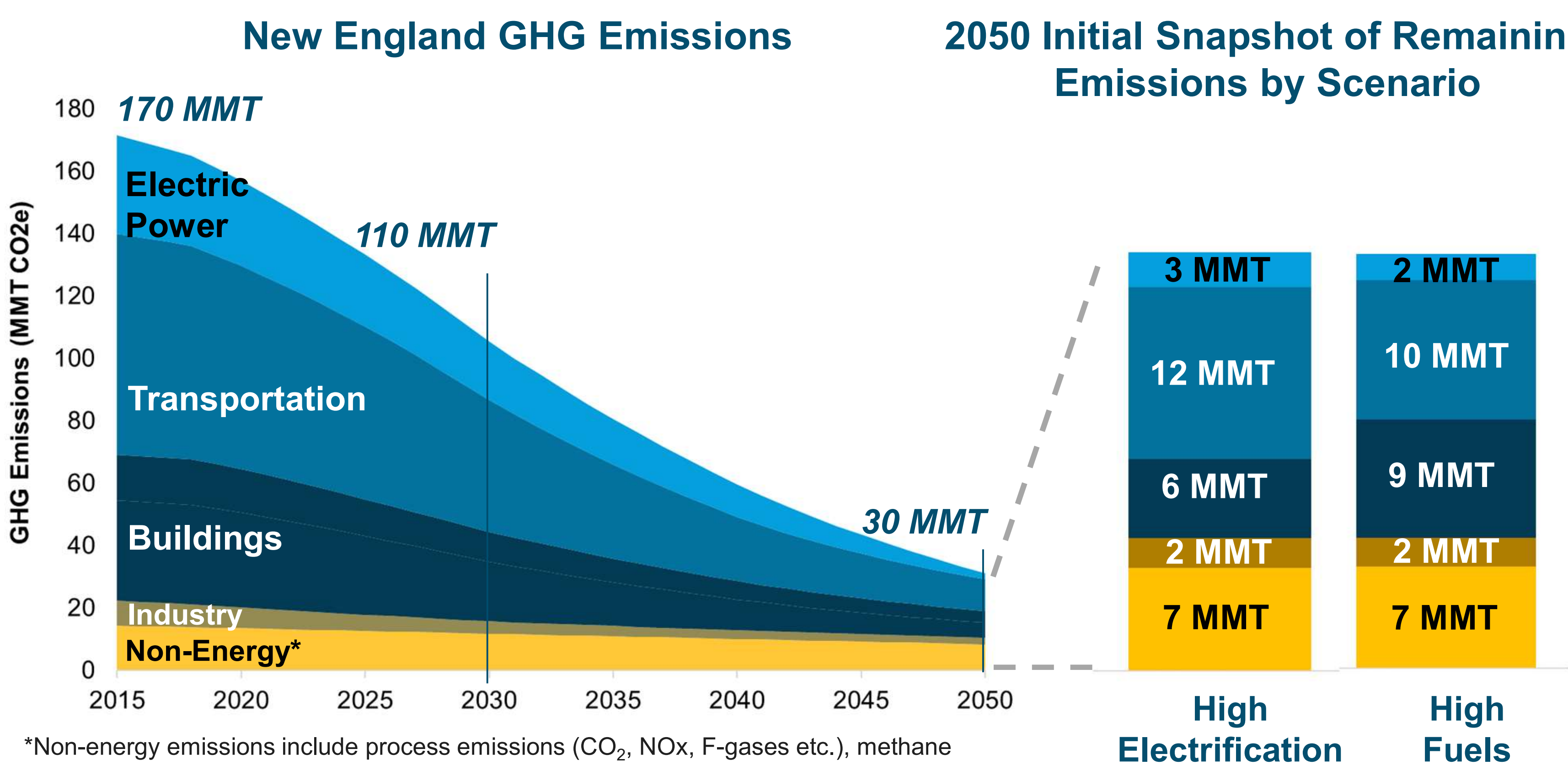
Assumptions regarding key decarbonization measures in 2050

- Both scenarios assume deeply decarbonized electric grid (90-100% zero-carbon generation scenarios)
- Both scenarios also include significant energy efficiency, including technological improvements resulting in efficiency gains, switching to high efficiency appliances, energy reductions due to behavioral conservation, and smart transportation growth.

Sector	Key 2050 Measure	High Electrification	High Fuels
Buildings	Building efficiency	**100%** Energy Star + Grade Appliances **60%** of buildings have efficient shells	
	Building energy consumption	**About 80%** electricity, based on 80% of building space heating stock being heat pumps	**About 60%** electricity, based on 52% of building space heating stock being heat pumps; **13%** low carbon fuels (hydrogen and RNG).
Transportation	Light-duty vehicles and efficiency	**100%** sales are battery electric or plug-in hybrid electric **7%** reduction in VMT	
	Medium and heavy-duty vehicles	**90%** MDV sales are electric; **10%** sales hydrogen FC **50%** HDV sales are electric, and **50%** are hydrogen FC	**70%** MDV sales are electric; **30%** MDV sales hydrogen FC **100%** HDV sales are hydrogen FC
	Aviation	**40%** efficiency gain (FAA CLEEN 2); No renewable fuel adoption	**40%** efficiency gain (FAA CLEEN 2); **30%** of fuel use is renewable fuel
Industry	Industry efficiency	**25% decrease** in industry energy demand relative to no-increased-efficiency reference	
	Industry energy consumption	**53%** electric **34%** biomass**,** hydrogen, and natural gas with CCS	**39%** electric **48%** biomass**,** renewable fuels, hydrogen, and natural gas with CCS
Low-Carbon Fuels	Fuel utilization	**34 TBtu** of hydrogen, used in transportation (no hydrogen in natural gas distribution pipeline), and no advanced biofuels	**140 TBtu** of advanced biofuels; About **80 TBtu** of hydrogen, in transportation and within pipeline (7% H_2 by energy blended in natural gas distribution pipeline; 20% by volume)

Direct emissions are reduced 85% below 1990 levels by 2050 in both scenarios

+ Study assumes New England achieves "net zero" target, consistent with 85% direct emissions reductions relative to 1990 emissions
+ Last 15% achieved through CO_2 removal strategies (not shown)

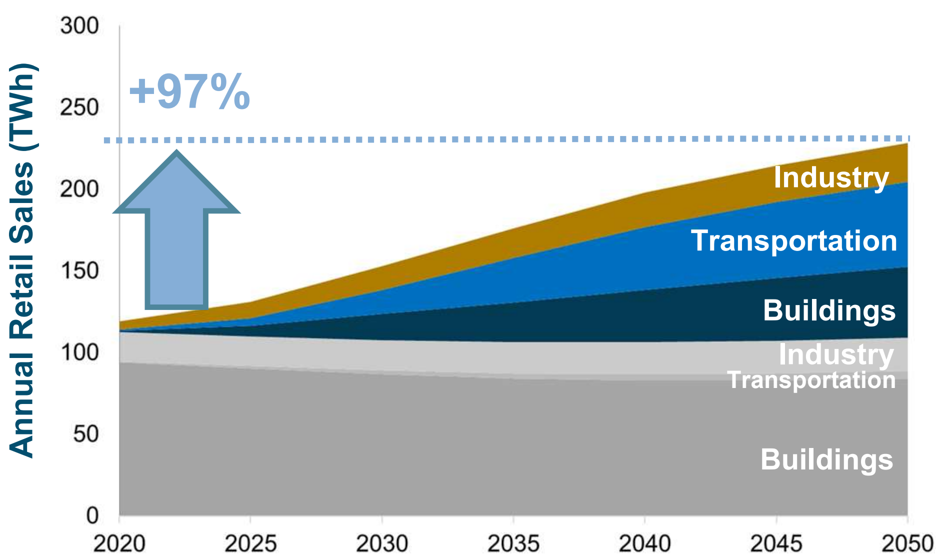


*Non-energy emissions include process emissions (CO_2, NOx, F-gases etc.), methane leakage, GHG emissions from agriculture and waste.

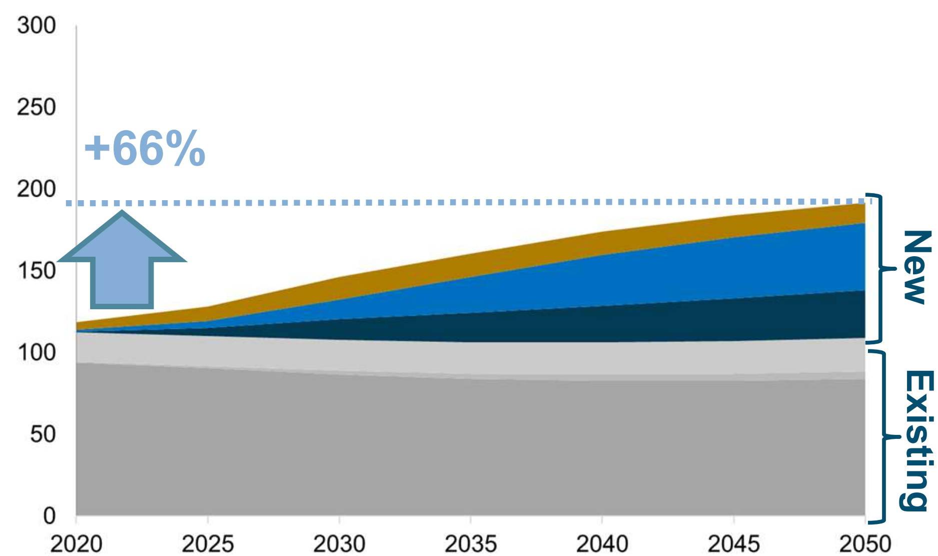
Electricity demand grows significantly under deep decarbonization

+ **Both scenarios see significant load growth, particularly from electrification of space heating and light-duty vehicles, compared to reference load demand (BAU)**
  - **High Electrification** scenario has high electrification of all building service demands, vehicles, and industry resulting in about 230 TWh of annual load in 2050
  - **High Fuels** scenario utilizes higher reliance on fuel blends and fuel switching to hydrogen and biofuels, thus has lower peak demand and a total electric load of about 192 TWh by 2050

High Electrification Scenario Load



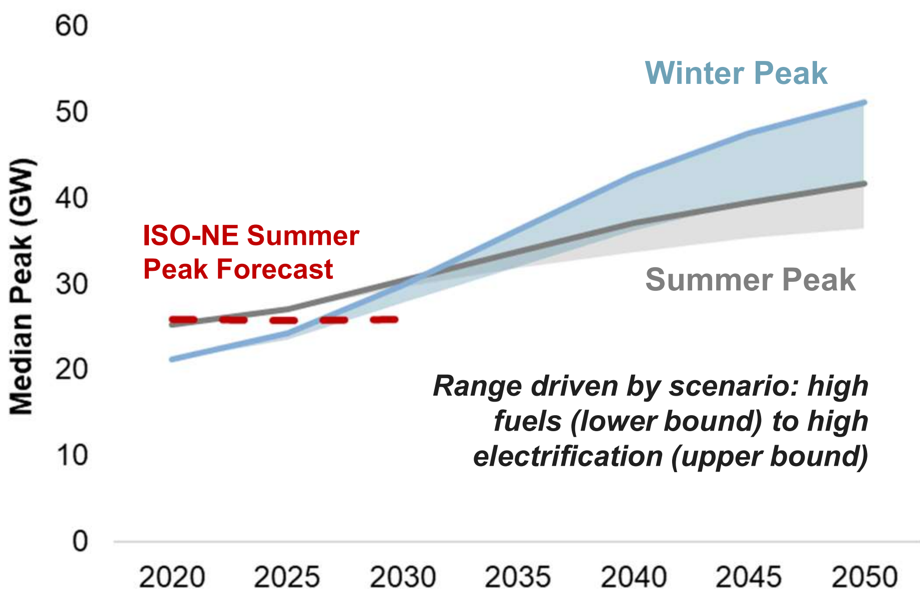
High Fuels Scenario Load



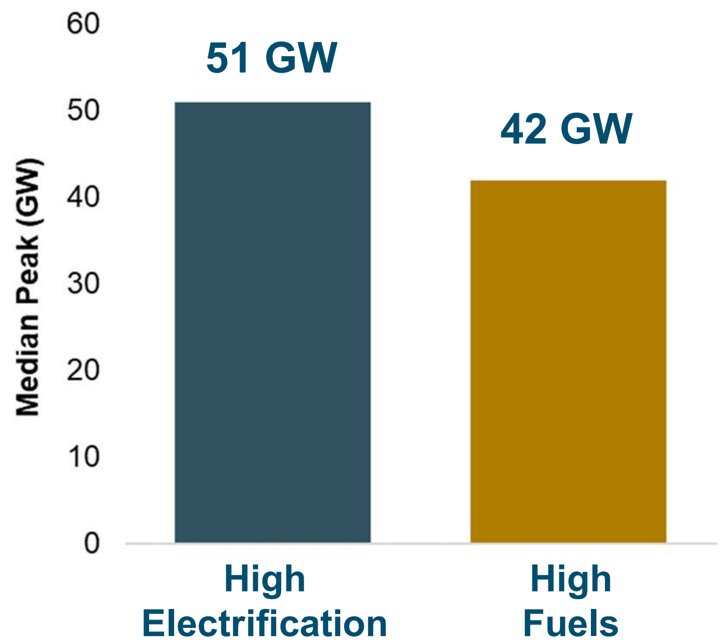
New England electricity system becomes winter-peaking in the 2030s

- **Median gross load peak (net of EE) assumed to increase from 25 GW in 2019 to 42-51 GW by 2050**
  - Winter peak exceeds summer in early to mid 2030s under both scenarios
  - 2050 peak impacts of electrification load mitigated by assuming diverse portfolio of heat pump technologies and sizing

Seasonal Peak Load Change

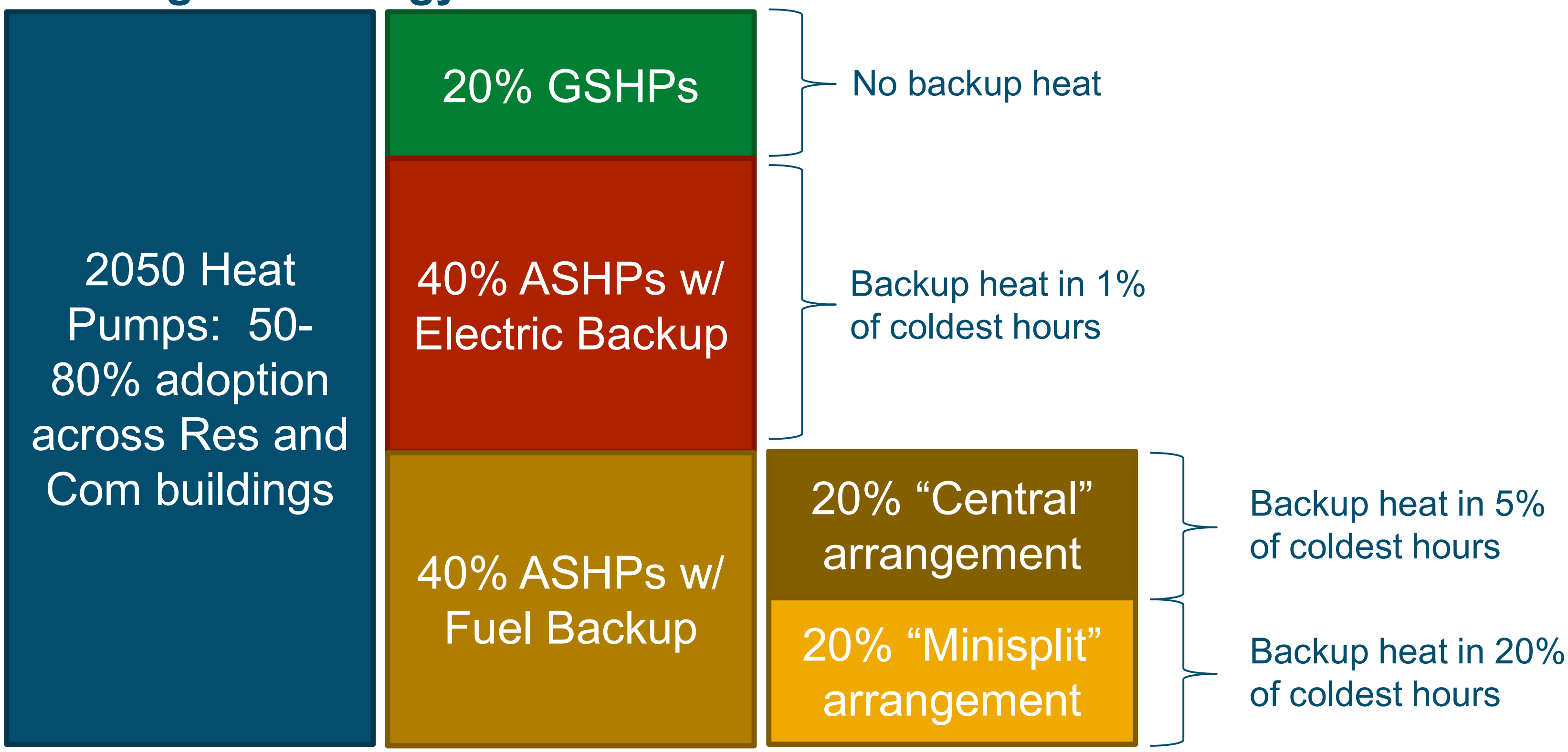


2050 Peak Load Snapshot



A mix of heat pump technologies is assumed to be adopted throughout New England

Heating Technology Mix Assumed



- **Mix of heat pump technologies is a key issue**
- **Encouraging oversizing or fuel backup to mitigate electric peak impacts will need to be a policy focus**

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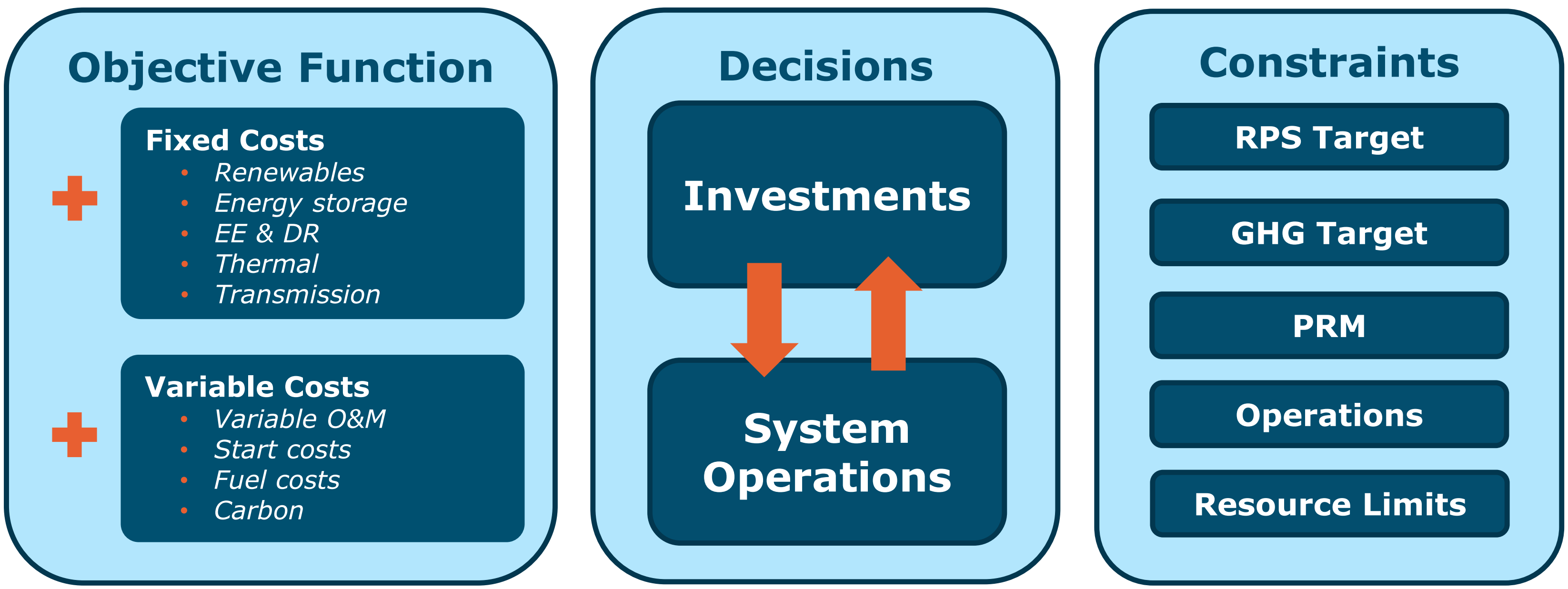
Electricity Resource Portfolios

Step 2: E3's RESOLVE model calculates optimal portfolio subject to GHG constraints

- **RESOLVE co-optimizes investments and operations to minimize total net present value of the electric system cost through 2050**
  - Optimization directly captures linkages between investment decisions and system operations
  - RESOLVE is designed for systems with high levels of renewables and storage



Step 3: E3's RECAP model used to test resource adequacy in detail (iterative w/ 2)

+ **RECAP simulates thousands of years with different weather conditions to derive parameters for RESOLVE modeling**
  - Determines PRM needed to meet reliability standard of 1 day in 10 years
  - Calculates ELCC of different resources at varying penetrations and combinations
+ **Optimal RESOLVE portfolio tested for resource adequacy in RECAP**

Inputs

Load
- *Hourly load for many weather years*

Dispatchable Generation
- *Capacity*
- *FOR*
- *Maintenance*

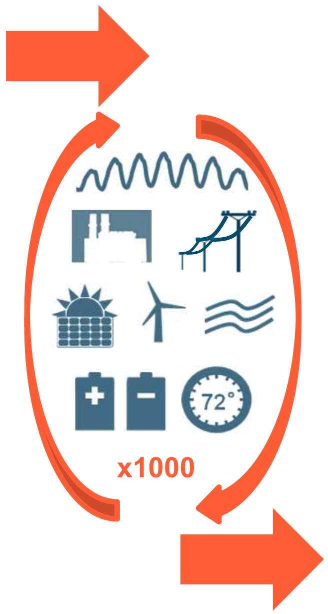
Renewables
- *Capacity*
- *Hourly generation profiles for many weather years*

Hydro
- *Hydro availability for many hydro years*
- *Max/min constraints*

Storage
- *Capacity*
- *Duration*
- *Roundtrip efficiency*
- *FOR*

Demand Response
- *Capacity*
- *Max # of calls*
- *Duration of each call*

Flexible Load
- *Capacity*
- *Max hours of shift*



Outputs

LOLH
- *Loss of load hours*
- *Hrs/yr of total expected lost load per year*

LOLE
- *Loss of load expectation*
- *Days/yr of total expected lost load per year*

ALOLP
- *Annual loss of load probability*
- *% probability of having a single loss of load in any given year*

EUE
- *Expected unserved energy*
- *MWh/yr of energy that cannot be served*

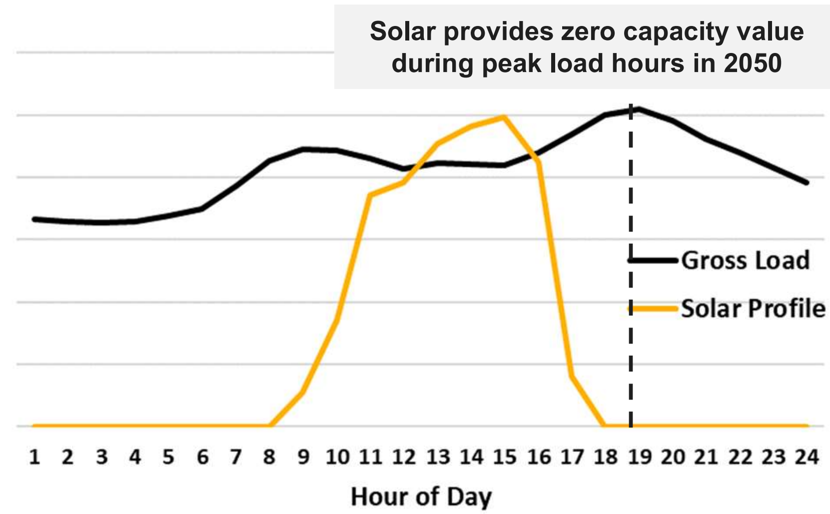
ELCC
- *Effective load carrying capability*
- *Equivalent quantity of 'perfect capacity' for a variable or energy-limited resource*

TPRM
- *Target planning reserve margin*
- *PRM required to achieve a specified reliability threshold (i.e. LOLH, LOLE, ALOLP, or EUE)*

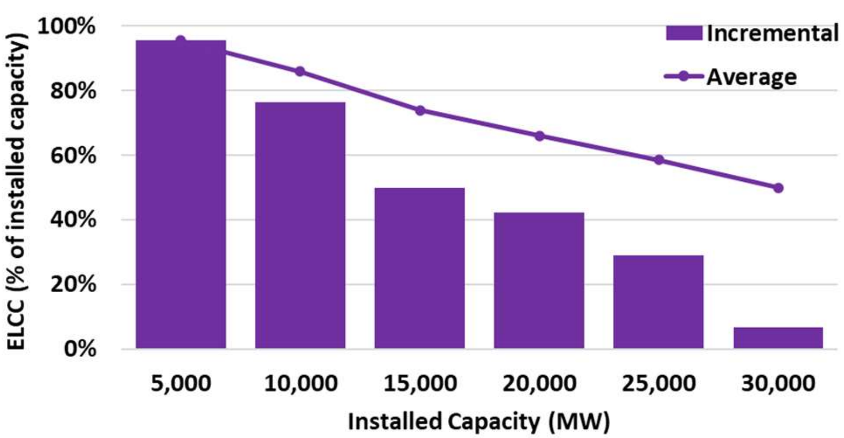
E3 estimated ELCCs for candidate wind, solar and storage resources

- **ELCC is the amount of perfect capacity a resource can replace while providing the same reliability**
- **ELCCs from RECAP used as input parameters to RESOLVE**
  - Standalone solar provides zero ELCC after 2035 due to non-coincidence with wintertime peaks

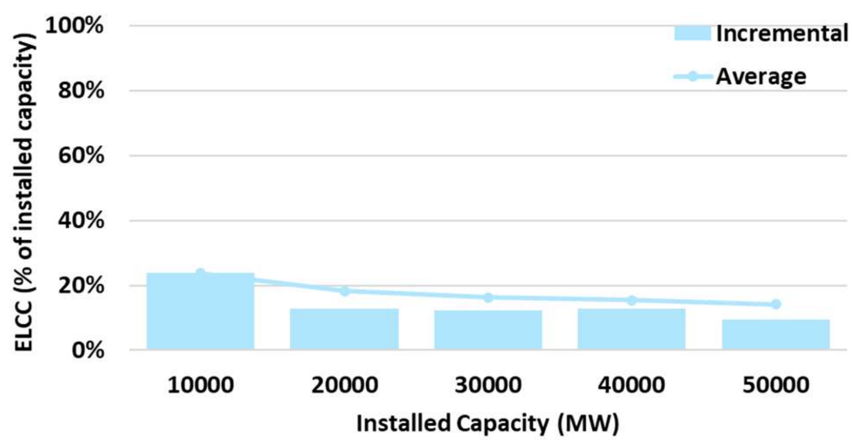
Typical day with high loads in 2050



2050 ELCC, 4-hour Storage

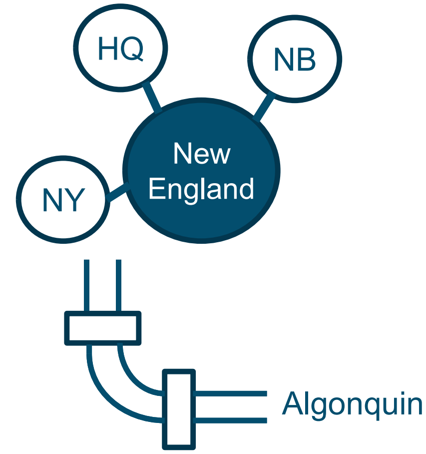


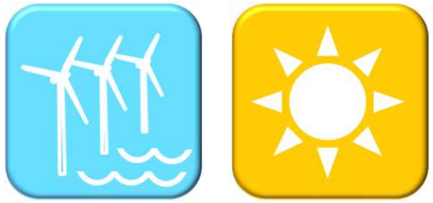
2050 ELCC, mix of NE Wind



Key Electricity Sector Assumptions

1. **Load:** Based on economy-wide decarbonization modeling.
2. **Candidate Resources:** Various combinations of renewables (onshore/offshore wind, solar), Canadian hydro, hydrogen/zero carbon fuel combustion, gas with CCS, nuclear SMR.
3. **Candidate Resource Costs:** Latest public estimates for resource costs based on NREL Annual Technology Baseline (ATB) 2019 and Lazard 5.0, with local adjustments.
4. **Fuel Prices:** Single natural gas price (Algonquin) assumed throughout New England, with seasonal variation reflecting fuel constraints. Zero-carbon fuel prices based on E3 research.
5. **Transmission:** Single load zone within NE, several internal and external resource zones with transmission needs.
6. **Imports:** Three external zones (Hydro Quebec, New Brunswick and New York) which can contribute to planning reserve margin using existing transmission.



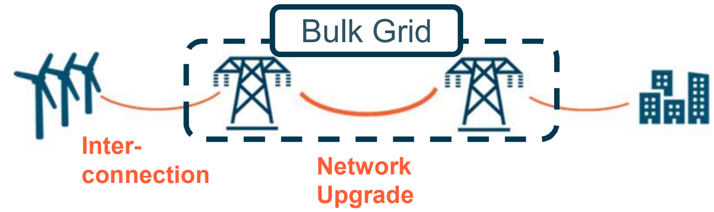


NREL NATIONAL RENEWABLE ENERGY LABORATORY LAZARD

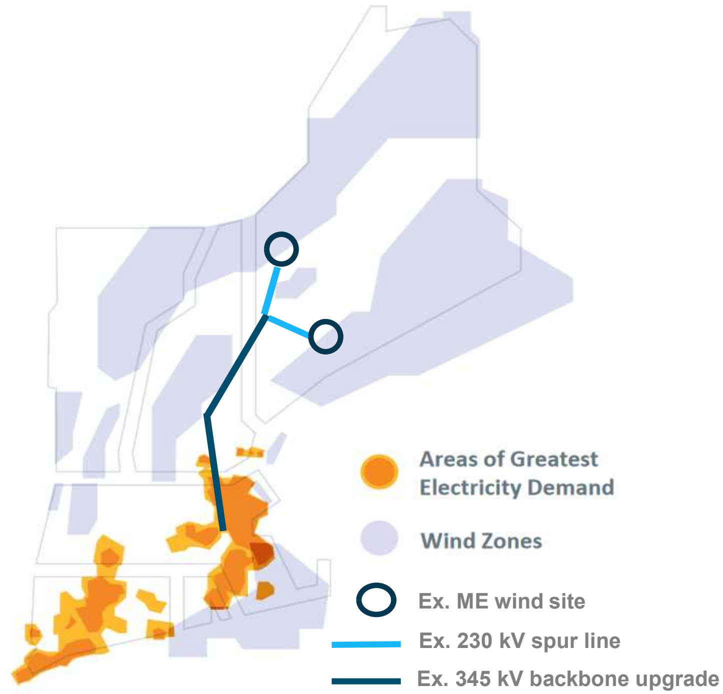
Transmission costs required to integrate renewables

+ **Types of modeled transmission costs**
  1. 230 kV interconnection (spur line) cost
     - Incurred by all new renewable projects (except distributed); based on NREL ReEDS
  2. 345 kV network (backbone) upgrade cost
     - Required once available headroom on existing transmission is exhausted
  3. 115k kV line
     - Incurred only by second tier of distributed solar
+ **Available headroom to serve load without 345 kV network upgrades**
  - Interstate headroom: 800 MW for NH+VT, 4 GW each for CT, MA, RI
  - Local headroom for utility solar: Utility-scale solar can be built up to 50% of the projected 2050 peak load (by state)
  - Offshore wind headroom estimated at 8 GW
  - DG solar: Up to 50% of technical potential; first tier (half) requires no transmission and the second tier (other half) requires 115 kV line

Transmission Components



Ex. ME onshore wind costs & associated transmission costs

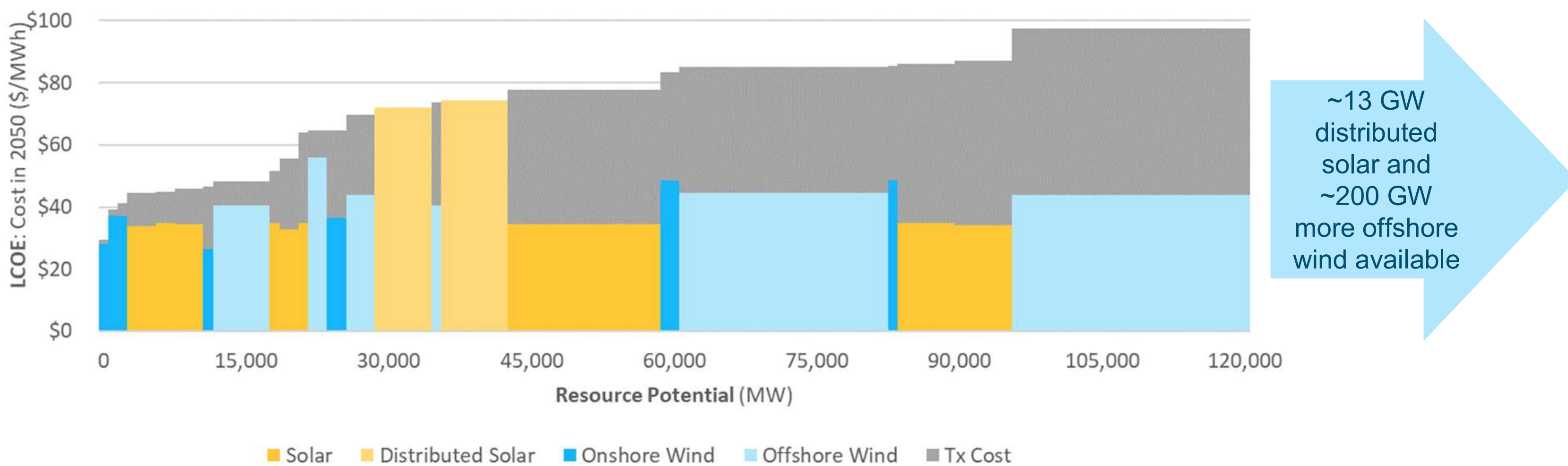


Source: Base map of demand and wind zones from ISO-NE

New England renewable supply curve developed from NREL data sources

+ **Supply curves for wind and solar from NREL**
  - New England has limited low cost onshore wind and solar, with significant offshore wind potential available with network upgrades
+ **E3 applied screens based on land use**
  - Land use screens: land equal to 4% of farmland for solar, 2% of farm + forest for wind in base case
  - Land restricted case with 2%/1% modeled as sensitivity
+ **Renewable supply curves provide useful indication of available resources and relative costs (RESOLVE selects resources based on value to portfolio)**

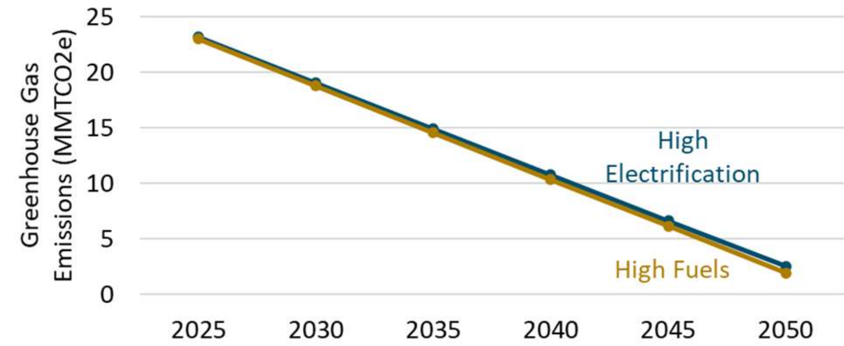
Renewable Supply Curve for New England in 2050 (includes Base Case Land Screen)



Resource availability in the Base Case and sensitivities

+ **Base Case developed for both High Electrification and High Fuels load scenarios**
+ **Several sensitivities test changes in technology and land availability**
+ **Sensitivities also vary carbon targets, from 2x Base Case emissions to zero emissions by 2050**

Emissions Target

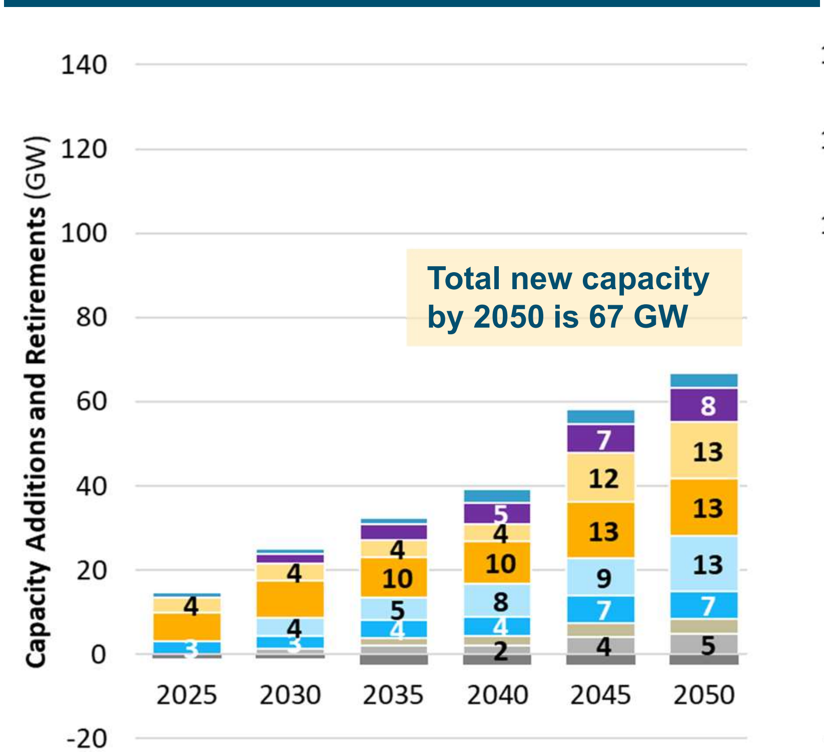


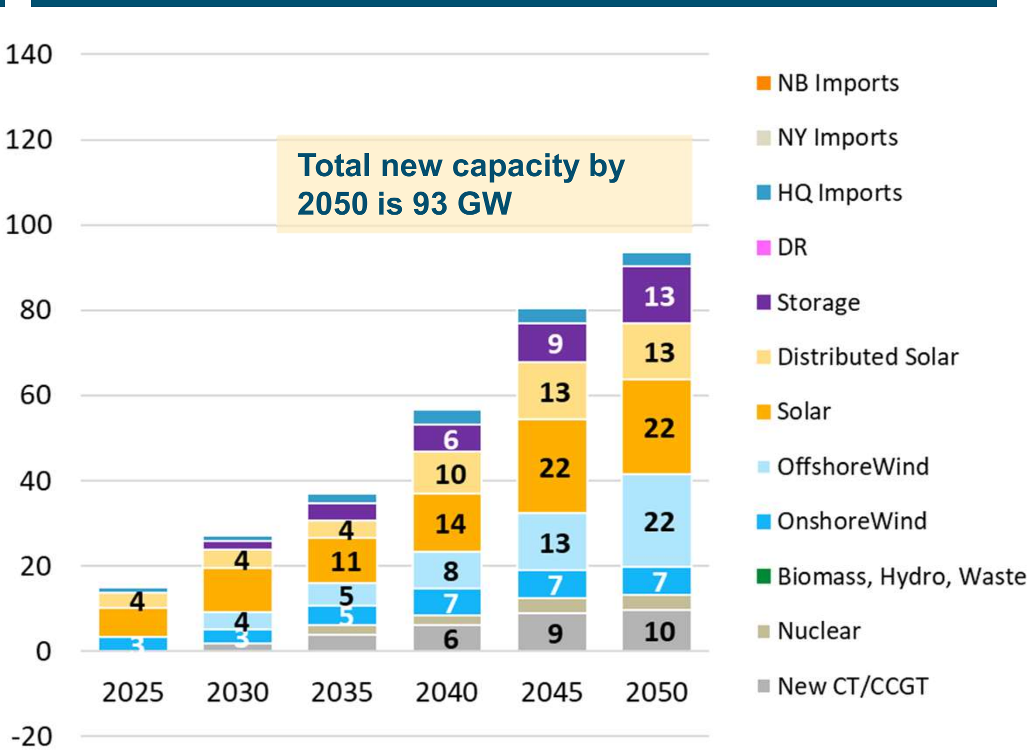
Resource Option	Available Options in New England Base Case	Range/Changes Evaluated in Sensitivities
Natural Gas Generation	• Simple cycle gas turbines • Combined cycle gas turbines	• No new gas units allowed • No new gas and retire all existing fossil
Renewable Generation	• Solar PV (4% farm) • Distributed solar (50% tech potential) • Onshore wind (2% forest + farm) • Offshore wind	• Solar PV: range from half base (2% farm area) to NREL technical potential • Onshore wind: range from half base (1% forest + farm) to NREL technical potential
Energy Storage	• Batteries (> 4 hr): model chooses duration	
Imports*	• Quebec hydro tier 1: turbine upgrades • Quebec hydro tier 2: new impoundments • New Brunswick: new onshore wind	
Clean Firm Generation	• Nuclear SMR up to amount such that total nuclear doesn't exceed about 3.5 GW in given model year	• Unlimited SMR • Unlimited CCS (with 90% capture) • Unlimited SMR + CCS
Demand Response**	• 740 MW + flexible EV charging load	

* In addition to new imports, existing imports from New York, Quebec and New Brunswick are modeled.
** Model includes load flexibility that acts as 'shift' DR, i.e., allowing about 4 GW to move in/out of each hour.

Results: Capacity Additions

+ New capacity additions are dominated by renewables and energy storage, particularly offshore wind and solar
+ Although loads and resulting builds vary, both scenarios achieve over 95% zero emissions electric generation by 2050

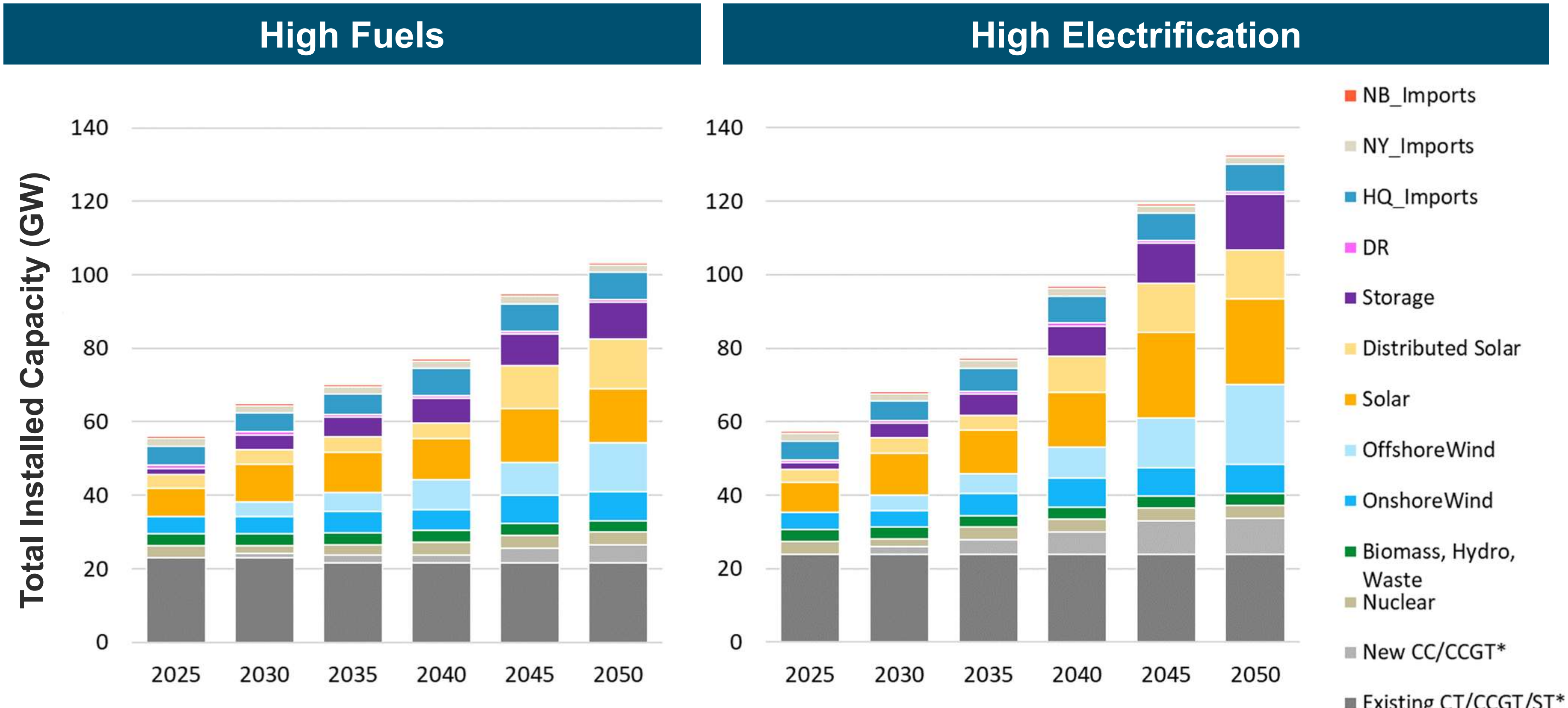




*CT/CCGT can burn natural gas and/or hydrogen blend

Results: Total Installed Capacity

- Most capacity is non-emitting by 2050, with wind, solar and batteries reflecting about 60% of capacity (slightly less in HF, slightly more in HE)
- Existing fossil and new gas is utilized to meet reliability needs and PRM; nuclear is also maintained/built to its model-imposed limit of ~3.5 GW

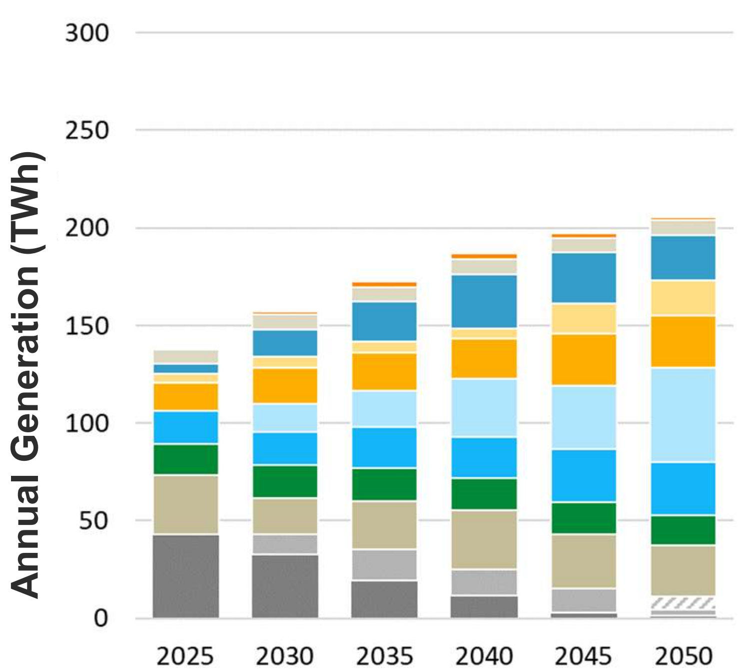


*CT/CCGT can burn natural gas and/or hydrogen.

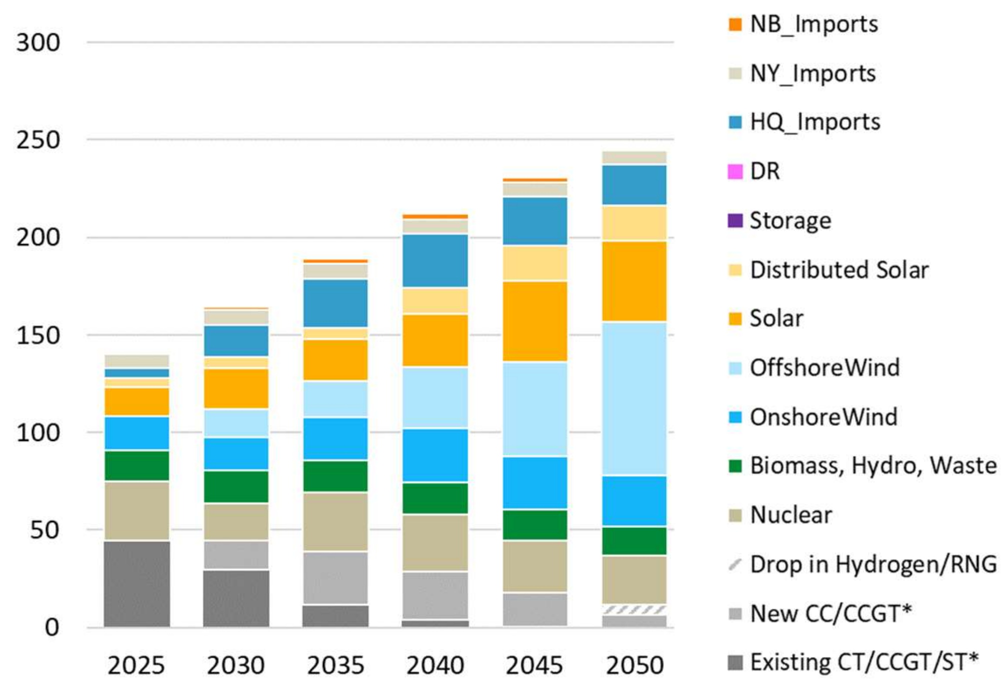
Results: Total Energy Generation

+ **Generation becomes dominated by renewables, with additional low/no carbon generation from nuclear, imports, hydrogen/zero-carbon fuel, and biomass, hydro and waste**

High Fuels



High Electrification

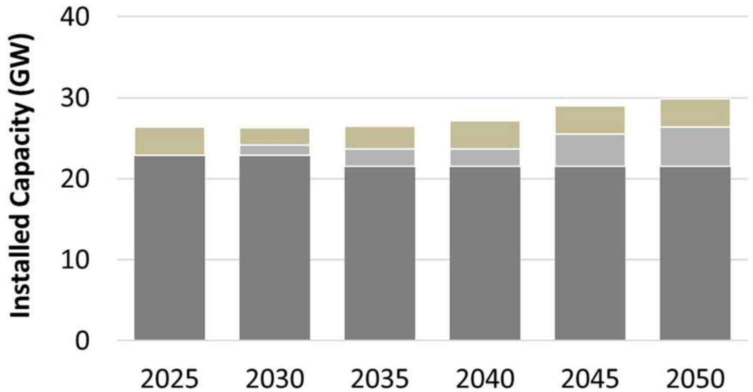


*CT/CCGT (new or existing) can burn natural gas and/or a zero-carbon fuel (assumed hydrogen in model)

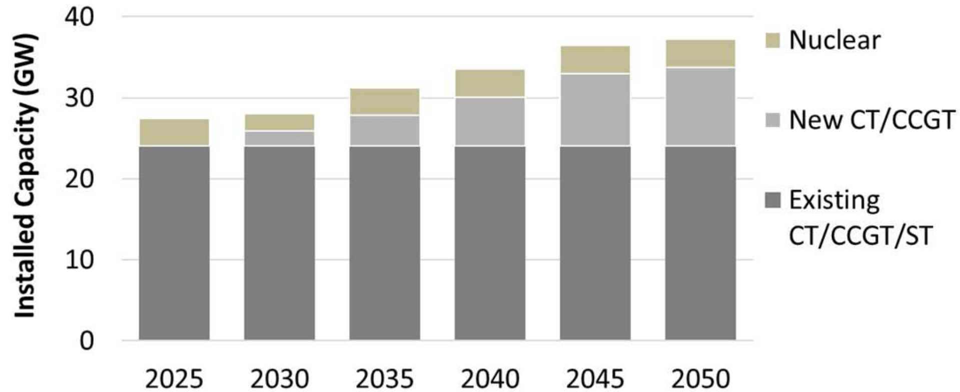
Role of Firm Generation

- The model retains significant gas and other fossil resources for reliability, but capacity factors decline substantially, with limited gas quantities burned by 2050
- In the future, firm generation can be provided by combustion-based generation, nuclear, or emerging long-duration storage technologies
  - Low-carbon firm generation may be achieved through reliance on zero-carbon fuels (hydrogen or biogas), nuclear, or by coupling generation with carbon-capture and storage

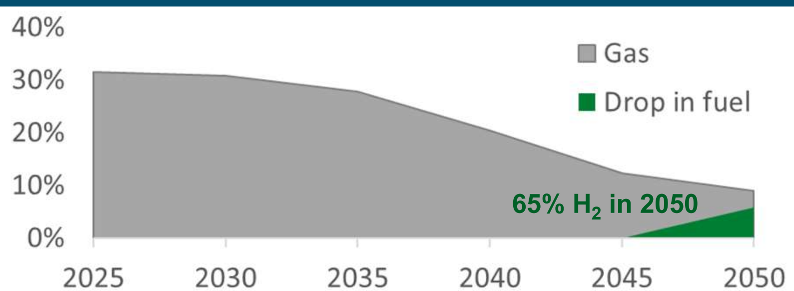
High Fuels Scenario – Firm Capacity (Existing and New Fossil and Nuclear)



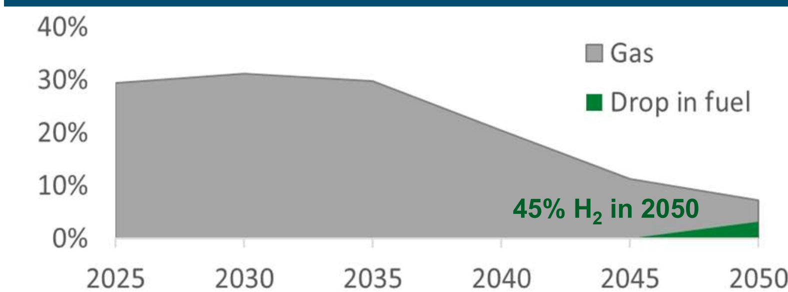
High Electrification Scenario – Firm Capacity (Existing and New Fossil and Nuclear)



High Fuels Scenario - Gas Capacity Factor (%)

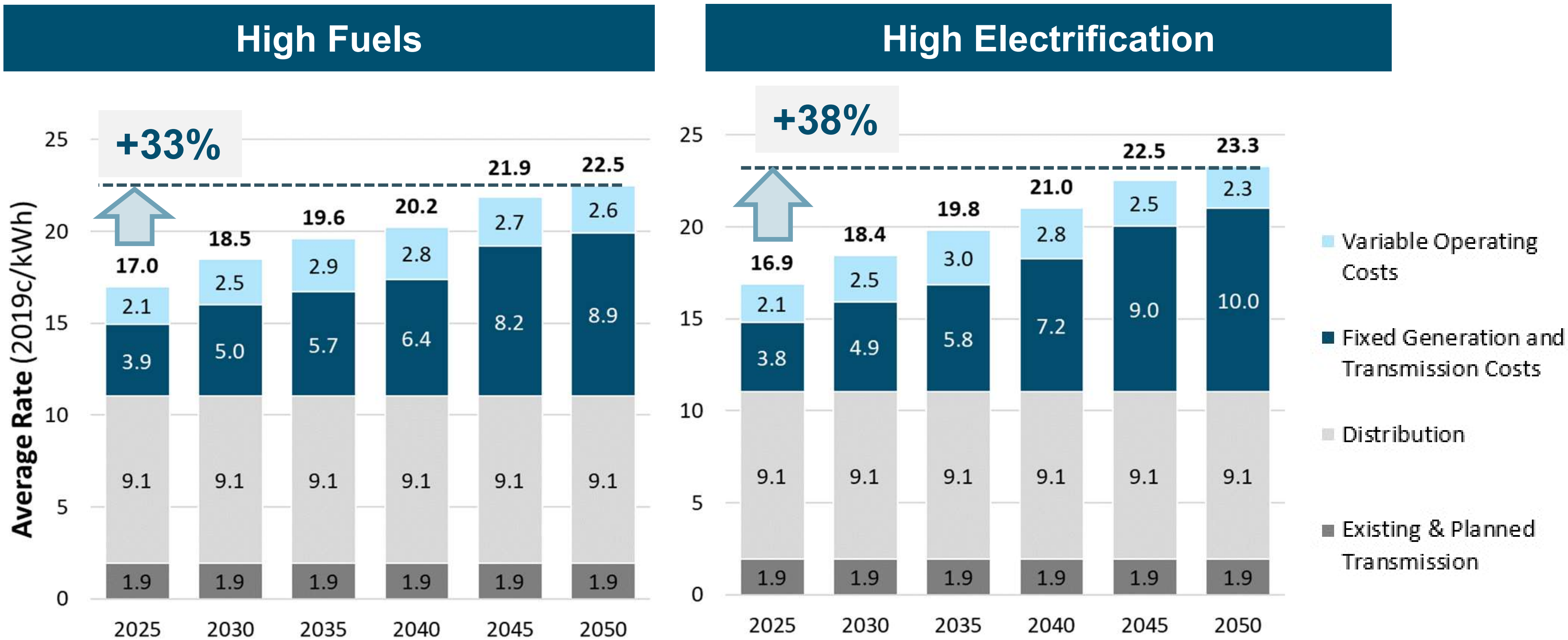


High Electrification Scenario - Gas Capacity Factor (%)

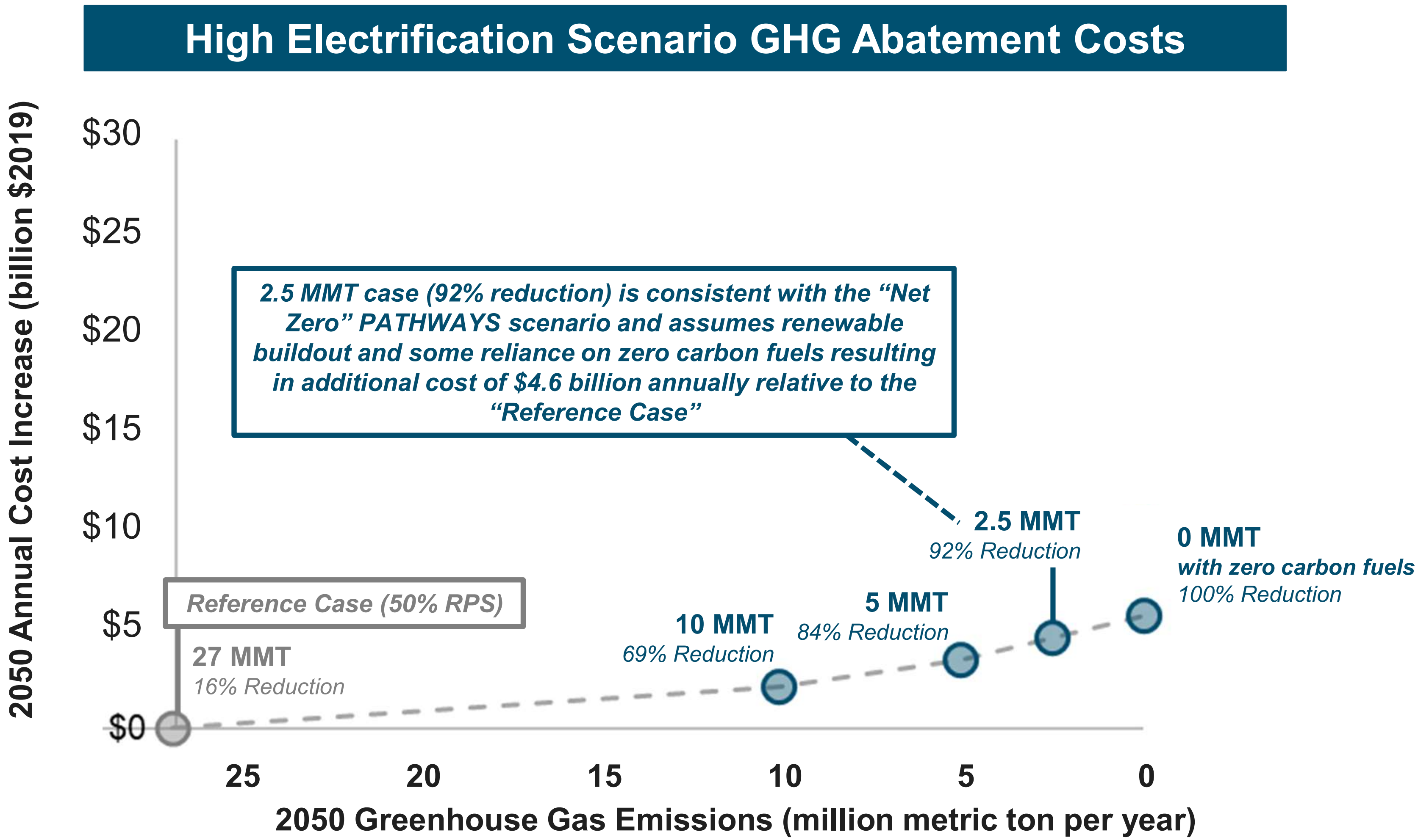


Results: System Cost/Rate

- **Average electric rates increase with significant infrastructure build for new generation, which includes transmission upgrades and spur line costs, and slightly increasing variable costs resulting in a CAGR of 1.3% to 1.5% by 2050**
  - About 60% of the rate increase results from load growth and about 40% from the deep decarbonization resource mix (assuming reference 2050 resource mix of about 50% renewables)
- **Retail rates will differ based on customer class**



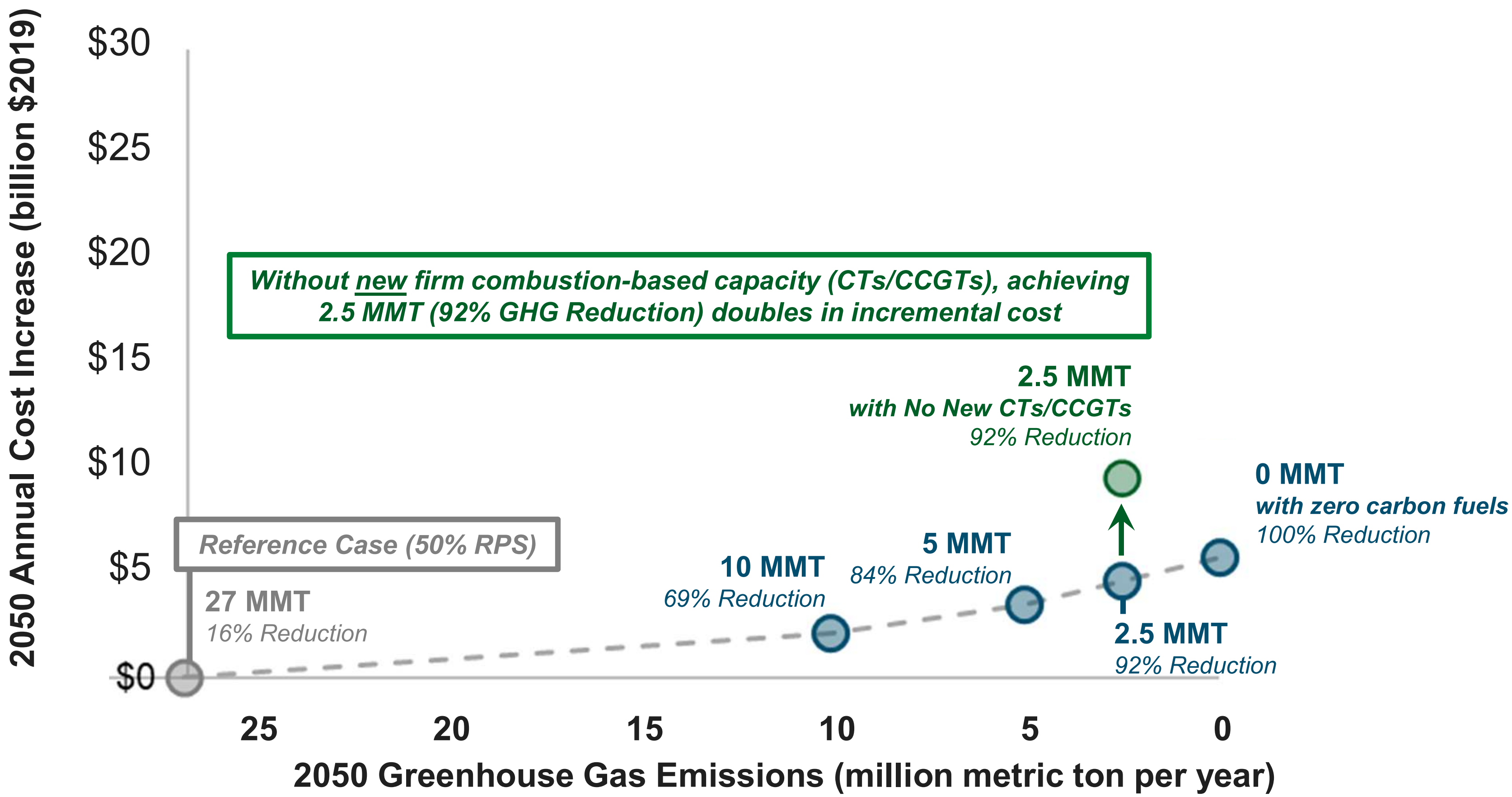
2050 Electricity Sector Abatement Costs under High Electrification Loads



Cost increases are reported relative to the hypothetical Reference Case (50% RPS).
Reductions relative to 2016 emissions of 32 MMT estimated based on EPA SIT database and import emissions for all New England States.

2050 Electricity Sector Abatement Costs under High Electrification Loads

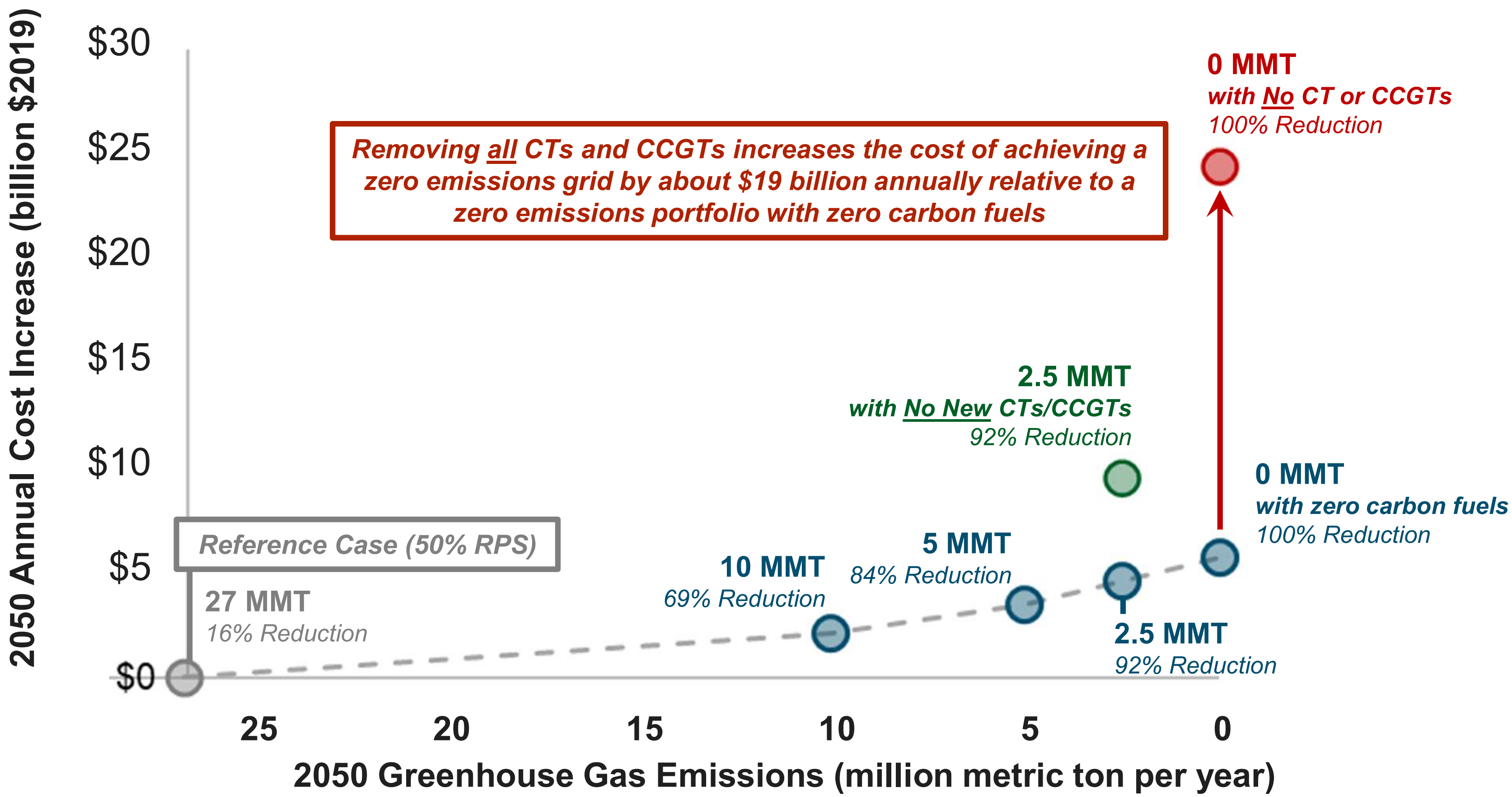
High Electrification Scenario GHG Abatement Costs



Cost increases are reported relative to the hypothetical Reference Case (50% RPS).
Reductions relative to 2016 emissions of 32 MMT estimated based on EPA SIT database and import emissions for all New England States.

2050 Electricity Sector Abatement Costs under High Electrification Loads

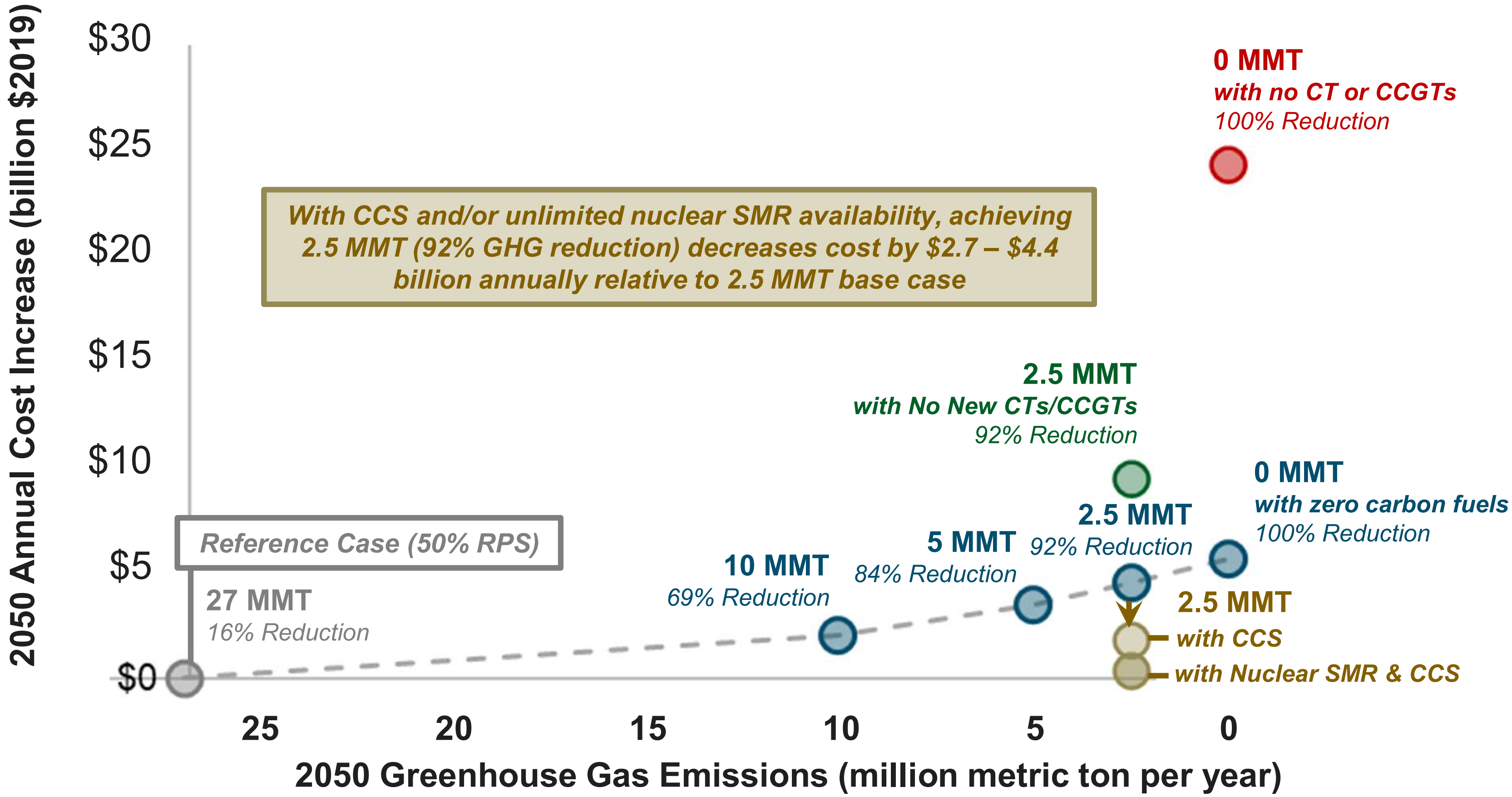
High Electrification Scenario GHG Abatement Costs



Cost increases are reported relative to the hypothetical Reference Case (50% RPS).
Reductions relative to 2016 emissions of 32 MMT estimated based on EPA SIT database and import emissions for all New England States.

2050 Electricity Sector Abatement Costs under High Electrification Loads

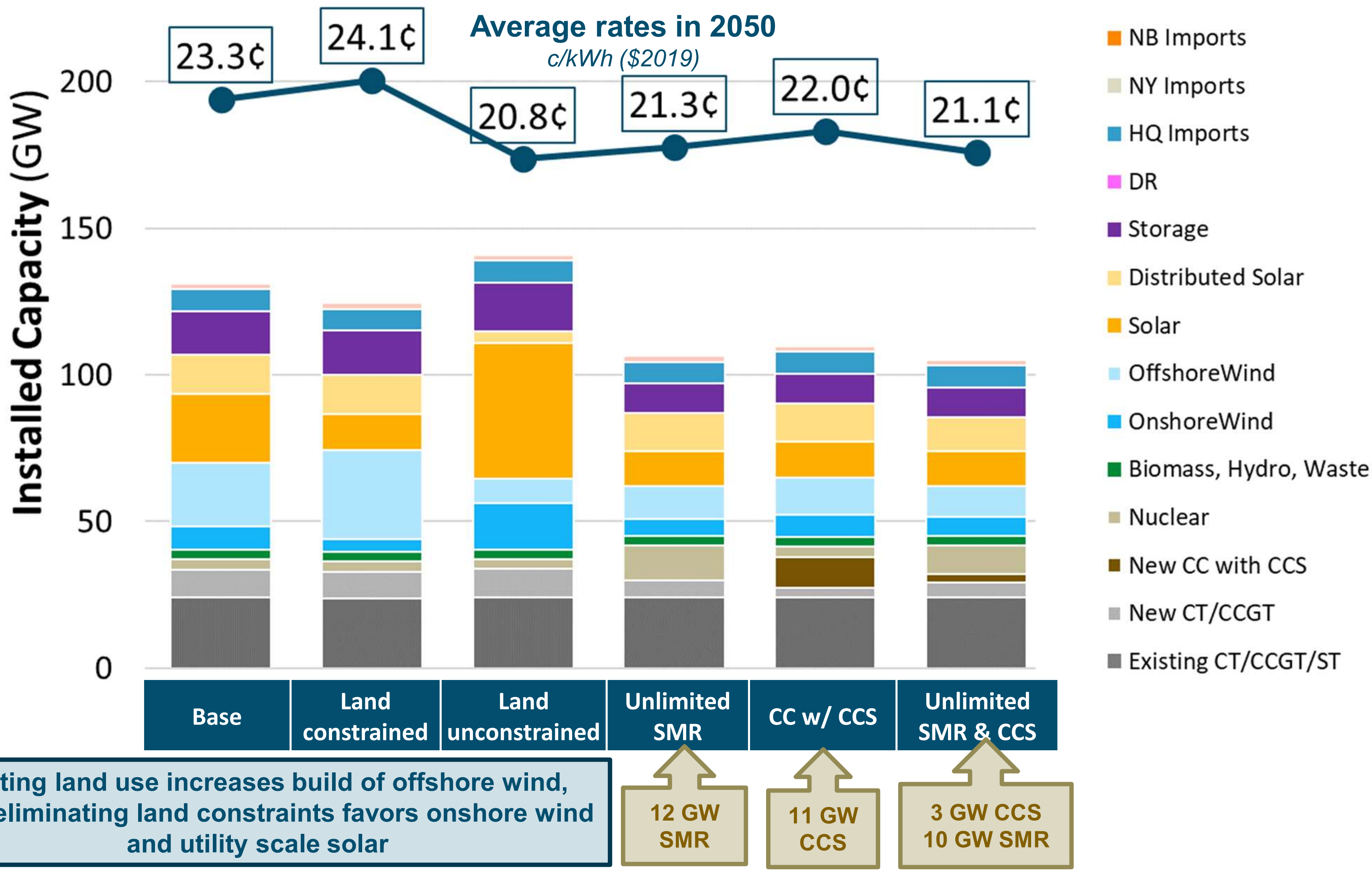
High Electrification Scenario GHG Abatement Costs



Cost increases are reported relative to the hypothetical Reference Case (50% RPS).
Reductions relative to 2016 emissions of 32 MMT estimated based on EPA SIT database and import emissions for all New England States.

2050 Sensitivity Comparison of Installed Capacity and Rates (High Electrification)

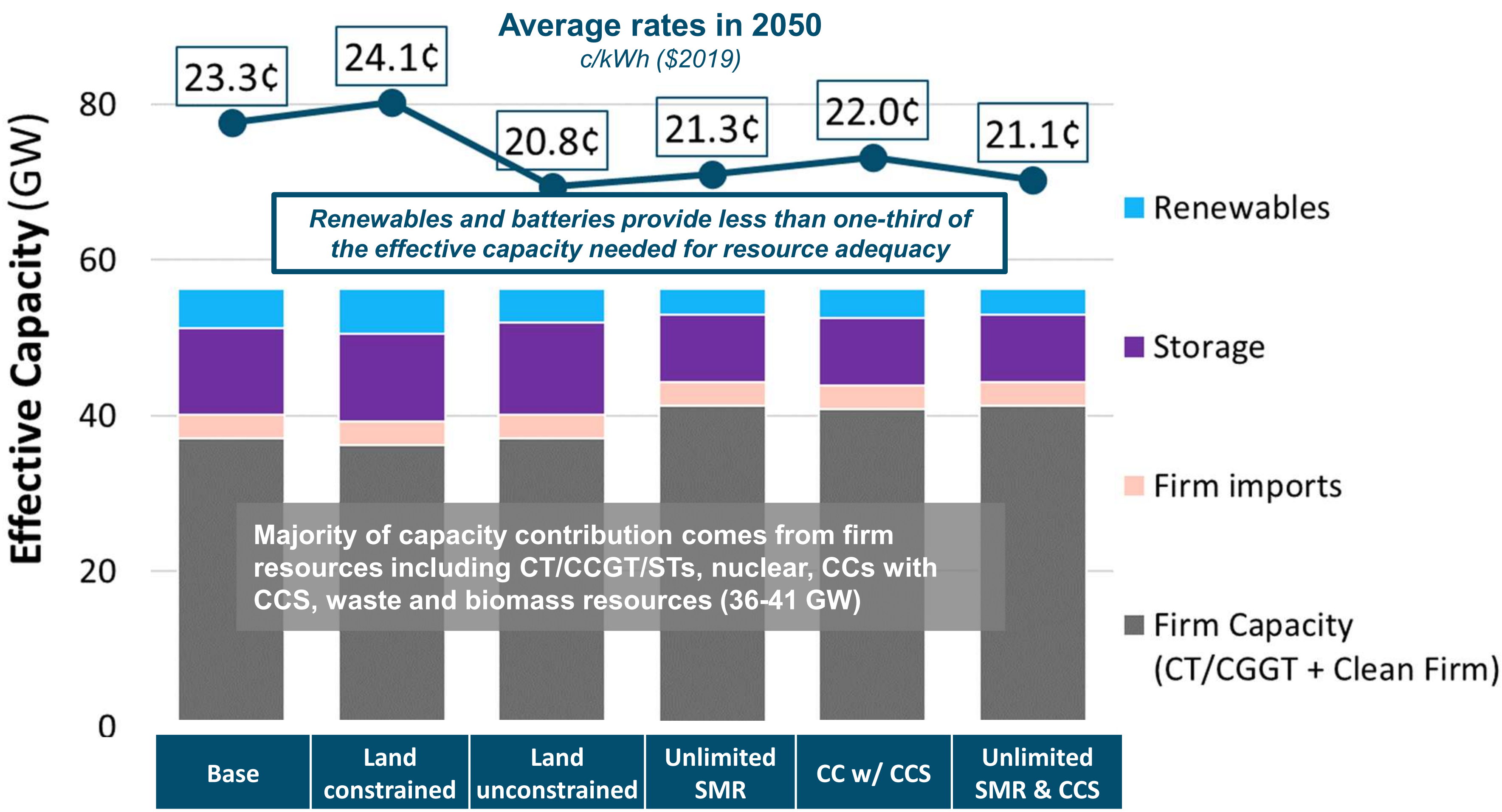
All cases achieve 2.5 MMT/y 2050 GHG electricity sector emissions, consistent with economy-wide "Net Zero"



Limiting land use increases build of offshore wind, while eliminating land constraints favors onshore wind and utility scale solar

High Electrification - 2050 Sensitivity Comparison: Effective Capacity

All cases achieve 2.5 MMT/y 2050 GHG electricity sector emissions, consistent with economy-wide "Net Zero"



Energy+Environmental Economics

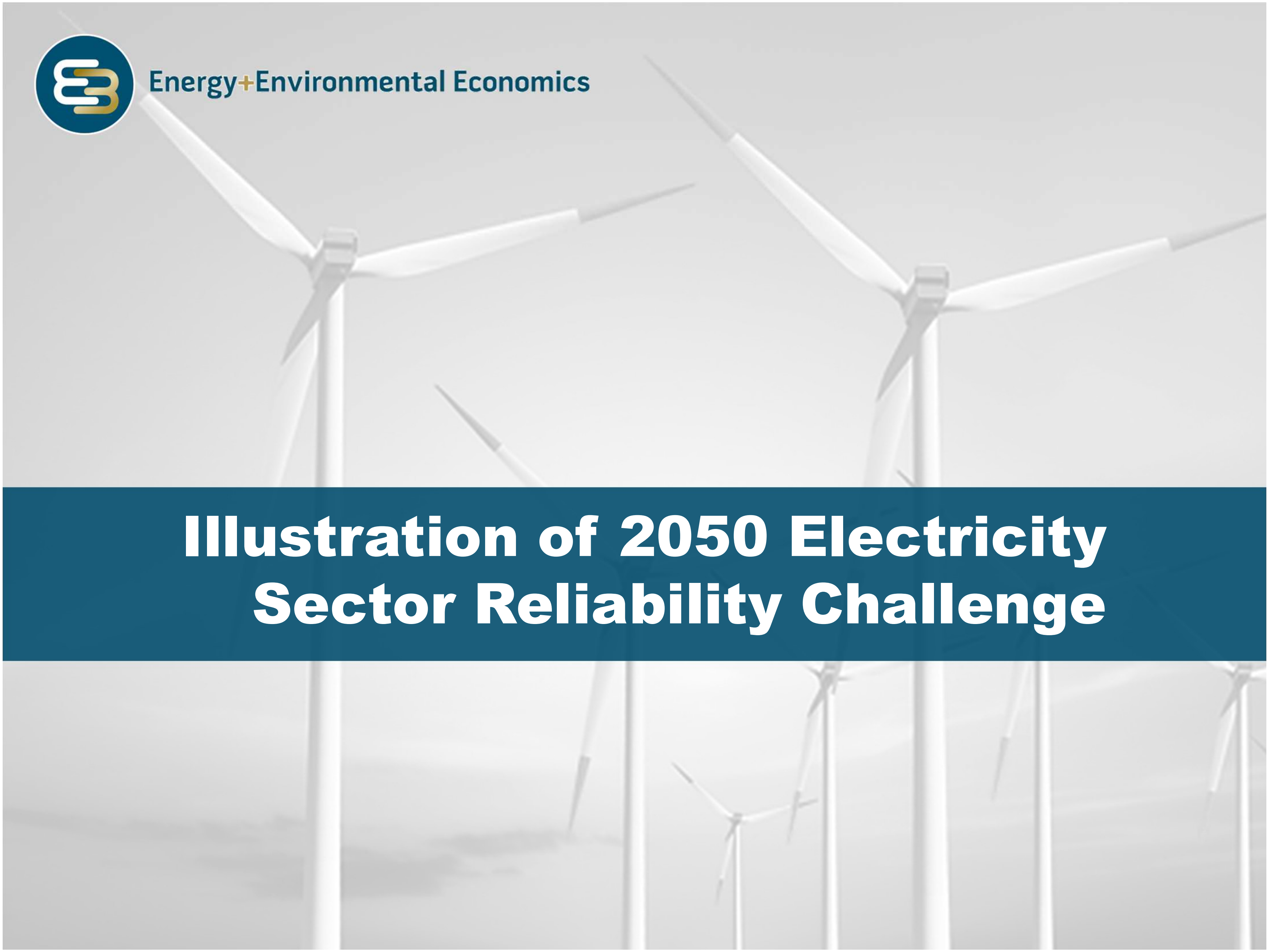
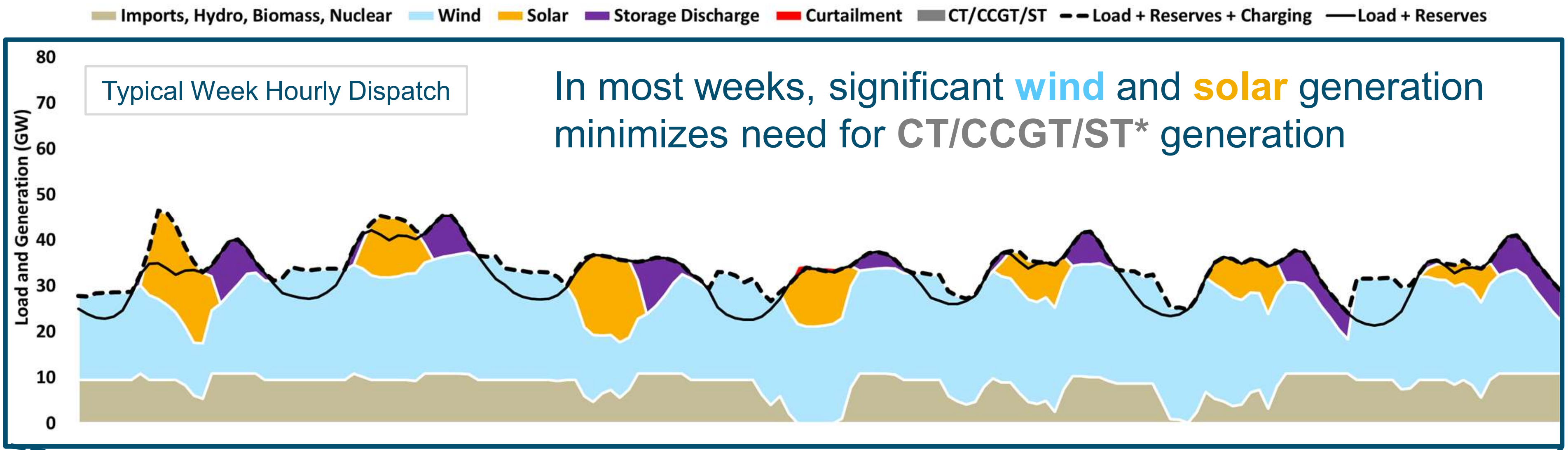
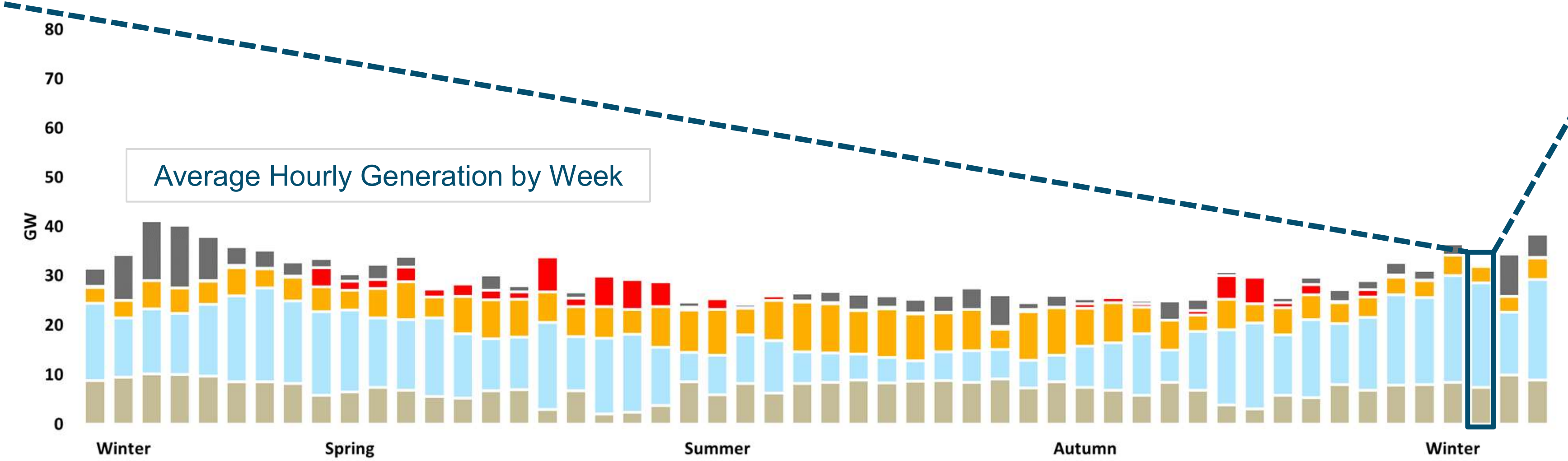


Illustration of 2050 Electricity Sector Reliability Challenge

Typical Week Dispatch in High Electrification Base Case

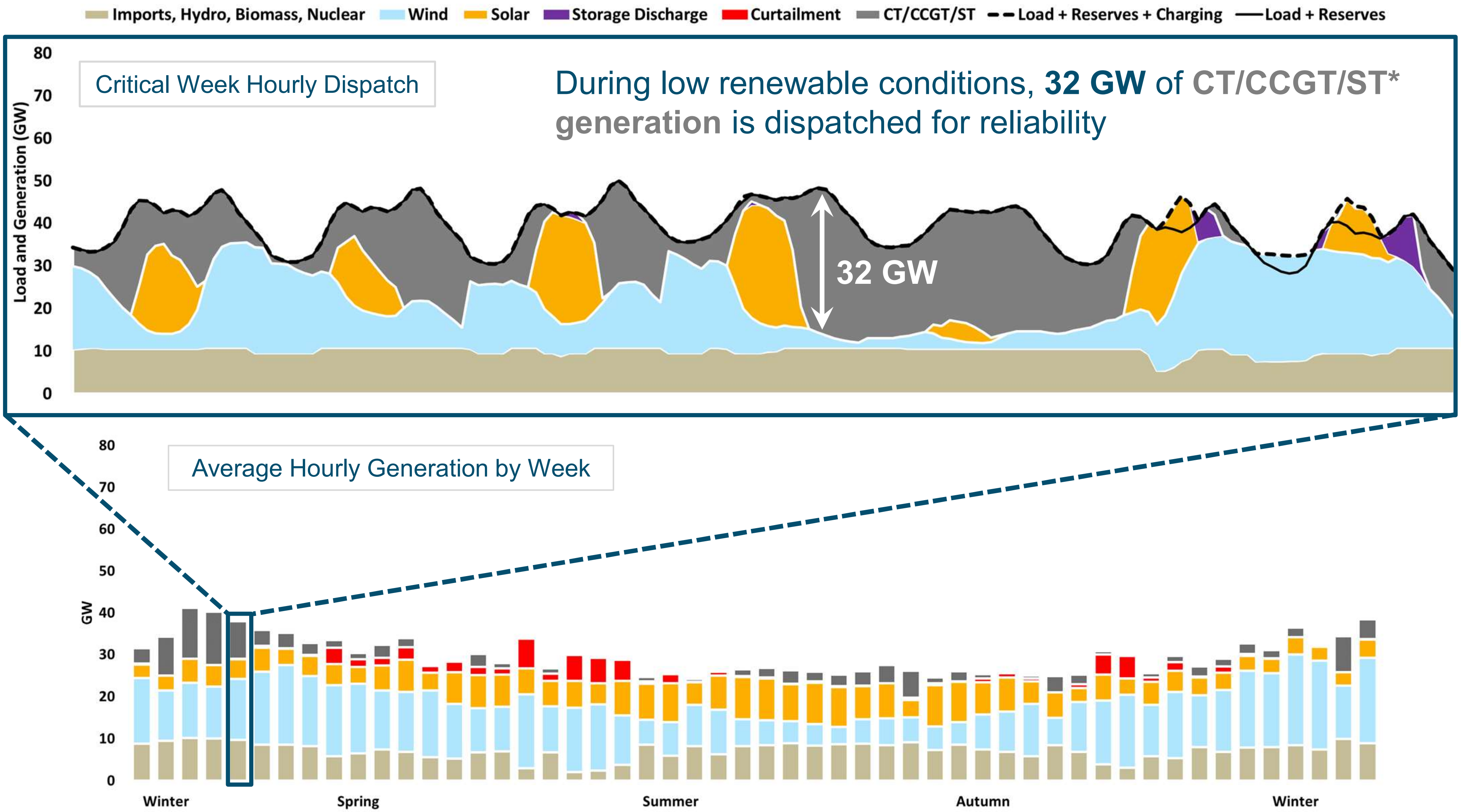




High Electrification Base Case

* Could represent natural gas, hydrogen, or other zero-carbon fuel blend burned in CT/CCGT, or dispatchable long-duration storage if viable technology emerges. More generally, this could represent any firm capacity, e.g. nuclear SMRs and Gas with CCS could also play this role.

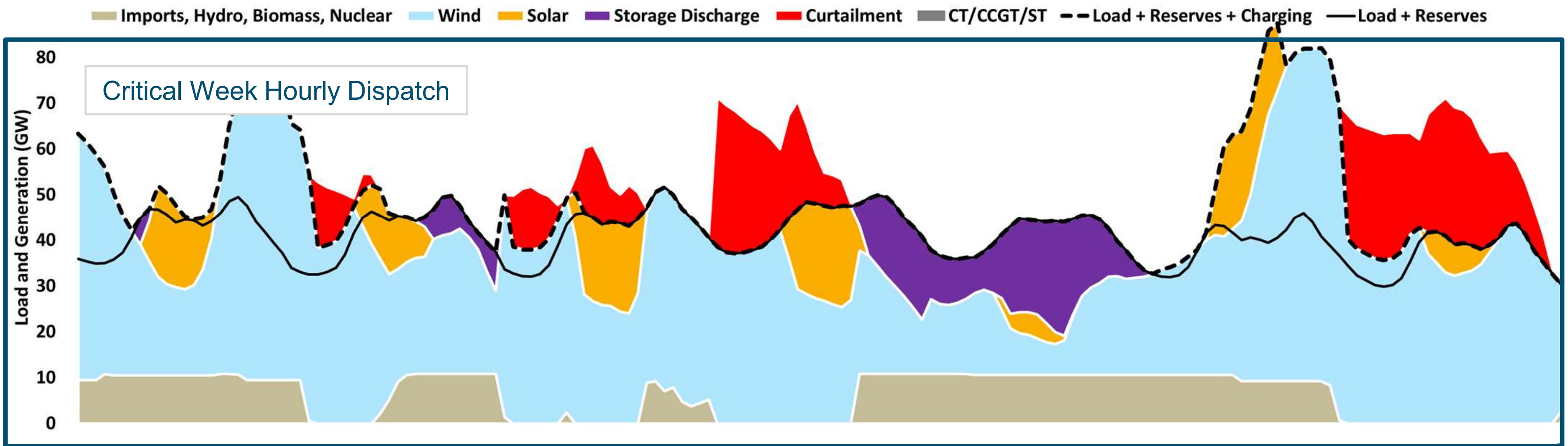
Critical Week Dispatch in High Electrification Base Case

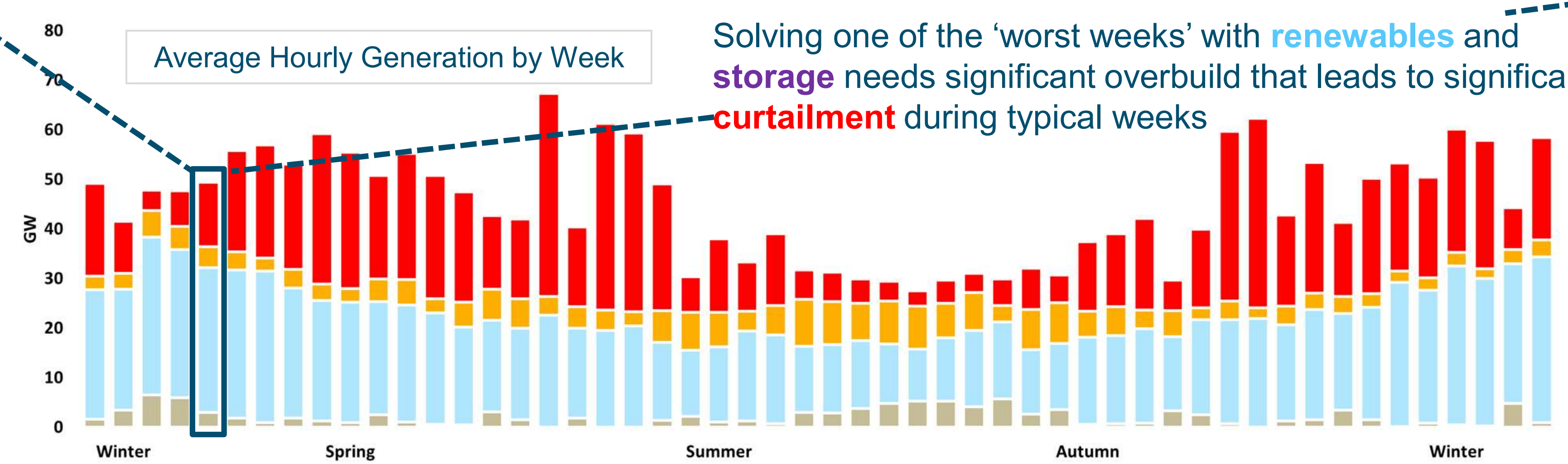


High Electrification Base Case

** Could represent natural gas, hydrogen, or other zero-carbon fuel blend burned in CT/CCGT, or dispatchable long-duration storage if viable technology emerges. More generally, this could represent any firm capacity, e.g. nuclear SMRs and Gas with CCS could also play this role.*

Critical Week Dispatch With No Gas/ Hydrogen (High Electrification Scenario)





Solving one of the 'worst weeks' with **renewables** and **storage** needs significant overbuild that leads to significant **curtailment** during typical weeks

No CTs, CCGTs or STs Available

Key Findings

Key Findings

1. **Electricity demand will increase significantly in New England over the next three decades under all plausible low-carbon scenarios**
   - Electricity demand grows by 66 - 97 percent
2. **A significant quantity of renewable generation is selected in every case, particularly solar and offshore wind**
   - Land and transmission availability will likely be constraining factors
3. **The New England system requires 30-37 GW of thermal capacity through 2050 in all cases**
   - Thermal resources operated at increasingly low capacity factors over time
   - It is expected that some form of low-carbon fuel will be available to reduce the carbon intensity of this use
4. **Cases with broader sets of available solutions have lower costs and lower technology risks**
   - Firm, low-carbon technologies such as advanced nuclear, CCS or hydrogen could play a significant role
   - Increasing the availability of land-based wind and solar also reduces cost

Thank You

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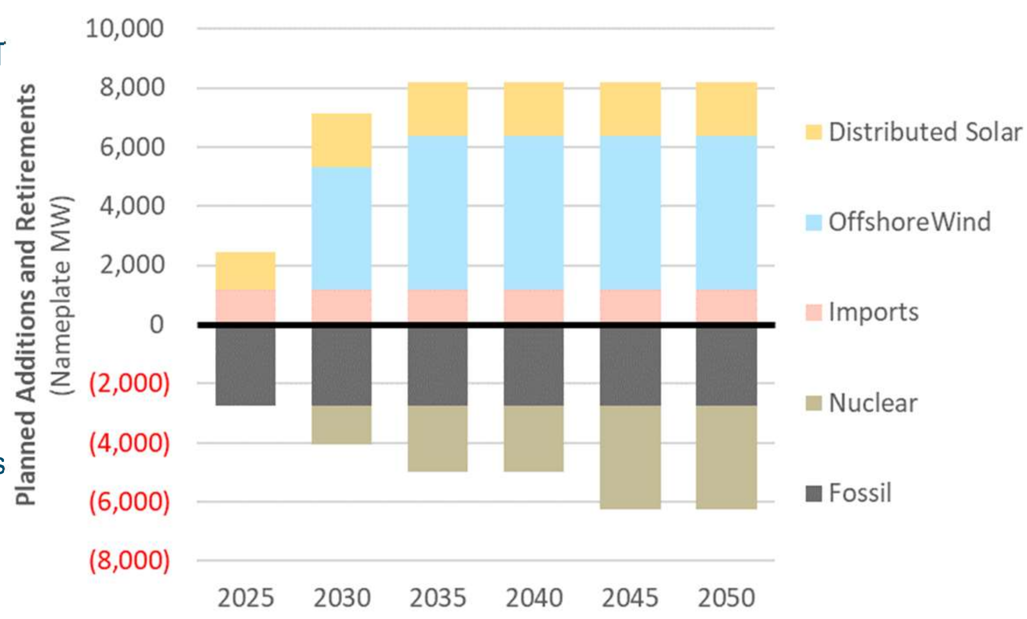
Energy+Environmental Economics

Appendix

Planned Additions and Retirements

- **Modeling incorporates planned builds and retirements in New England**
- **Planned additions**
  - Distributed solar per ISO NE PV forecast from CELT report
  - Offshore wind:
    - MA target: 3.2 GW by 2035
    - CT target: 2 GW by 2030
  - Imports: 1,200 MW of NECEC line (1,090 firm)
- **Planned retirements**
  - Announced fossil plants per ISONE announcements (post-2020)
    - Mystic (1,744 MW)
    - Mystic Dual Unit (617 MW)
    - Bridgeport (700 MW)
  - Nukes are assumed to retire at end of current contract, but builds could reflect license extension*
    - 2030: Seabrook (1,250 MW)
    - 2035: Millstone Unit 2 (870 MW)
    - 2045: Millstone Unit 3 (1,230 MW)

Planned Additions and Retirements (MW)



* Model allows new nuclear builds -- which could reflect license extensions, repowering, or actual new builds -- but limits total nuclear capacity in all model years to about 3.5 GW.

4 AUGUST 2020

Offshore Transmission in New England:

THE BENEFITS OF A BETTER-PLANNED GRID

STUDY AUTHORS

Johannes Pfeifenberger
Sam Newell
Walter Graf

PREPARED FOR

ANBARIC®

THE Brattle GROUP

Project Scope and Approach

Anbaric retained Brattle to compare the potential costs of various offshore transmission options and recommend the most competitive and cost-effective options to enable offshore wind development in New England

We qualitatively and quantitatively examined two approaches to developing offshore transmission and associated onshore upgrades to reach New England's offshore wind (OSW) development goals

1. The **current approach** wherein OSW developers compete primarily on cost to develop incremental amounts of offshore generation and associated project-specific generator lead lines (GLLs)
2. An **alternative "planned" approach** wherein transmission is developed independently from generation. Offshore transmission and onshore upgrades are planned to minimize overall risks and costs.

We conduct analyses of potential OSW-interconnection configurations for two levels of future offshore wind development. While other transmission configurations are possible, those captured here are representative of likely outcomes

- The analyses reflect current trends in how and where developers cite generator lead lines
- We highlight an alternative outcome that is unlikely to occur without a planning process

Executive Summary

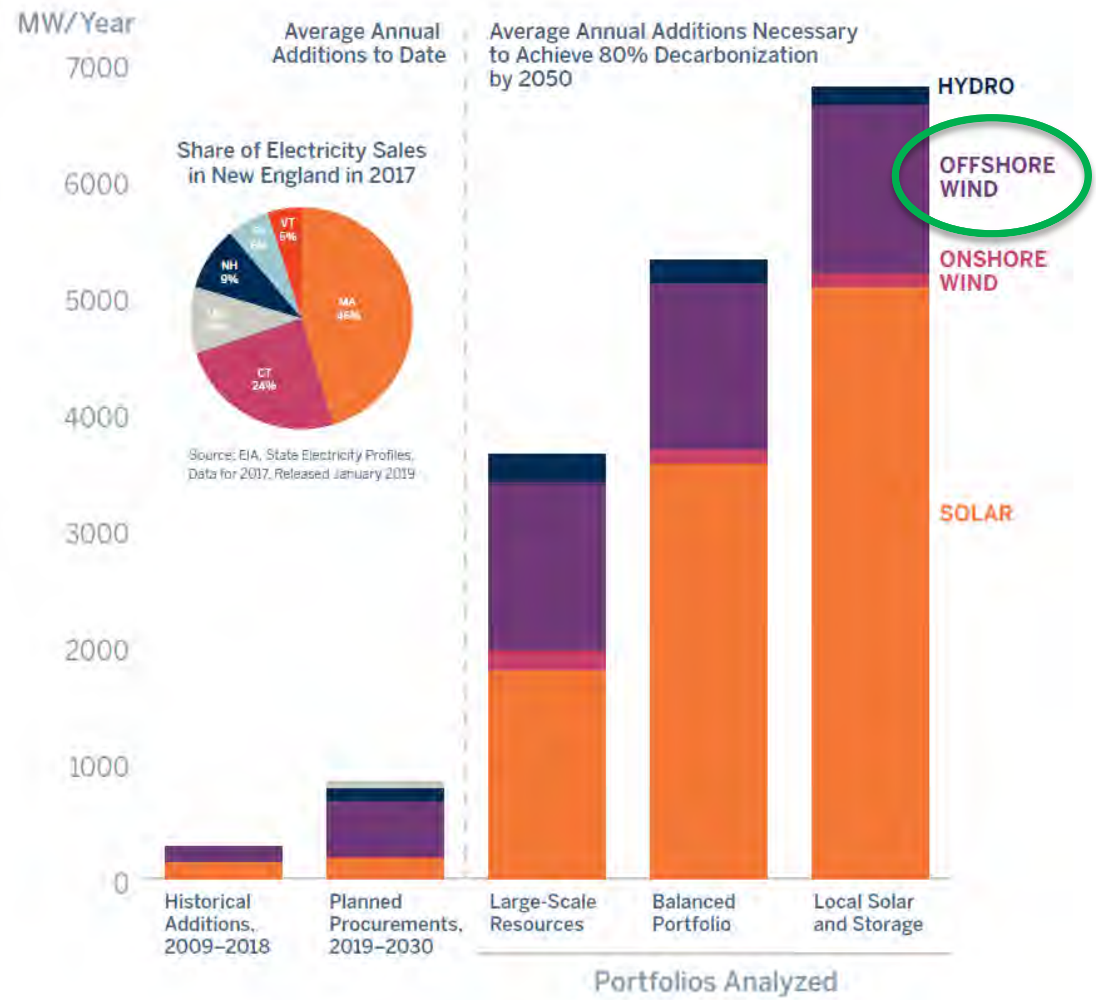
Motivation and policy goals

Thousands of MW of new clean resources would need to be built every year to meet decarbonization goals in New England – **possibly over 40,000 MW of OSW by 2050**

Developing these resources and associated transmission efficiently is essential for controlling customer costs

A key policy challenge is ensuring a pathway to enable the lowest-cost solutions for delivering new clean energy from source to population centers

New England Likely Needs 1,500 MW+ of OSW Additions Every Year to Achieve "80% by 2050" Decarbonization Goals



Source: Brattle Study by Jurgen Weiss and Michael Hagerty, "Achieving 80% GHG Reduction in New England by 2050," September 2019.

EXECUTIVE SUMMARY

The current approach to offshore transmission will incur high costs

New England has already contracted for 3,112 MW of OSW. The next 3,600 MW* of OSW could still be developed under the status quo: with each developer constructing a GLL to an onshore point of interconnection (POI)

- To date, OSW developers have focused on identifying landing sites with the closest access to onshore grid

However, **this existing approach is likely to lead to substantial onshore upgrade needs far sooner than assumed**: already selected projects connecting to Cape Cod face up to $787 million in onshore transmission upgrades and continuing this approach in the next procurements could lead to an additional $1.7 billion in onshore upgrades**

Given the high cost and difficulty of building onshore transmission, **a planned approach to developing the offshore grid can significantly reduce the need and costs for onshore upgrades**, where there is a history of delays and budget overruns in New England

- Since 2002 major onshore transmission projects in New England have on average exceeded budgets by 79% with project duration exceeding five years***

A planned approach is likely to result in lower costs in both the near- and longer-term, by lowering risks and costs of onshore upgrades and increasing competition for both offshore transmission and generation

Estimated Offshore Transmission and Onshore Upgrade Costs Under Current Approach

* Corresponds to currently-authorized procurement authority in MA and CT and potential demand from other states and 3rd parties, beyond the OSW that has already been procured in New England.
**See slides 15-17
*** New Hampshire Transmission, "Greater Boston Cost Comparison," January 2015

Anticipatory planning will lead to lower and more predictable costs

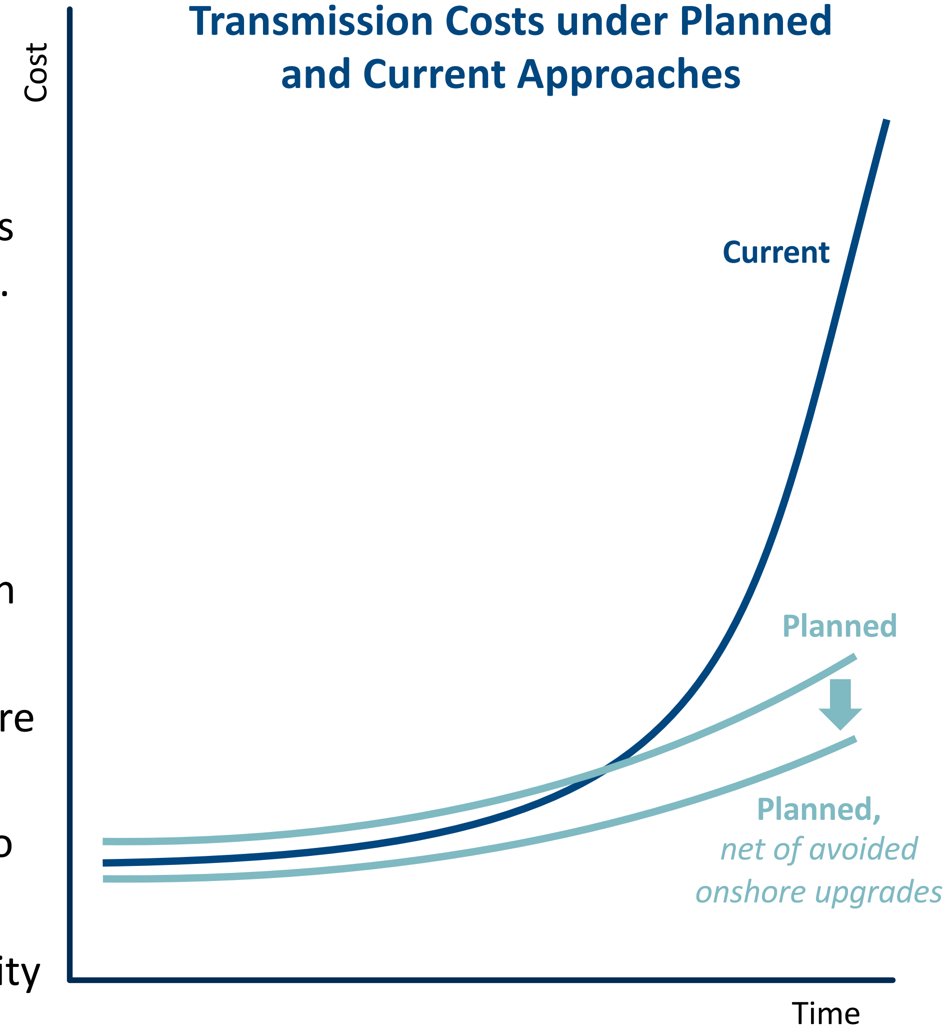
With a well-planned offshore grid, the overall transmission costs can be more closely estimated and phased-in over time

The current GLL approach may appear to have low initial costs but those will likely increase substantially after the "low hanging fruit" is picked, when real costs are revealed through costly onshore system upgrades.

Lack of well-planned transmission to achieve states' objectives has already created barriers for the deployment of clean energy in New England:

- Less than half of the 2,000 MW target Maine established for onshore wind resources have been built, largely due to transmission constraints
- While major new transmission projects for onshore wind were proposed, none have been built
- Five wind projects in Maine were cancelled due to prohibitive transmission upgrade costs
- Lack of a regional plan also imperils hydroelectricity imports from Canada

***Illustration* of Potential Incremental Transmission Costs under Planned and Current Approaches**



Source: Maine Governor's Office of Energy Independence and Security, "Maine Wind Energy Development Assessment," 2012.

Role of public policy in informing regional transmission planning

The growth in offshore wind in New England is driven by state public policy goals and will be achieved through policy mechanisms.

When considering the transmission network needed to support offshore wind deployment, system planning for New England should consider current cumulative goals and a high-OSW future.

Individual states or groups of states can proactively plan for and procure portions of the needed transmission network; such a state-led procurement framework is provided in later slides.

Broader regional coordination among New England states and ISO-NE could help meet the policy objectives of the participating states, including planning and procurement of offshore and onshore transmission systems.

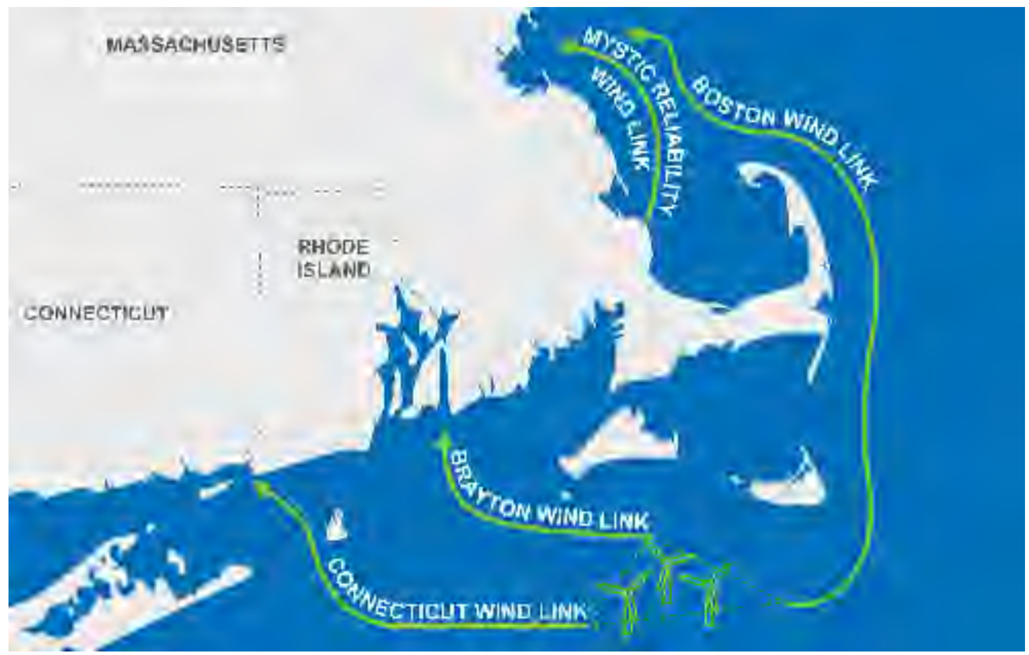
There is precedent for planned development of offshore transmission

Other U.S. jurisdictions have planned transmission infrastructure to develop large-scale onshore renewables. Examples include Texas (CREZ), California (Tehachapi Wind), MISO (Regional Multi-Value Projects), and several European countries. **New England could adopt a similar approach to planning transmission infrastructure to support offshore wind.**

As an example, Anbaric has proposed developing a southern New England OceanGrid that includes a vision to:

- Connect offshore wind directly to load centers and robust grid connections
- Meet needs identified by ISO-NE for new paths for offshore wind to integrate with existing system
- **Avoid more than $1 billion in onshore transmission upgrades**

Schematic of Anbaric OceanGrid Proposal



Source: Anbaric, "Southern New England OceanGrid."

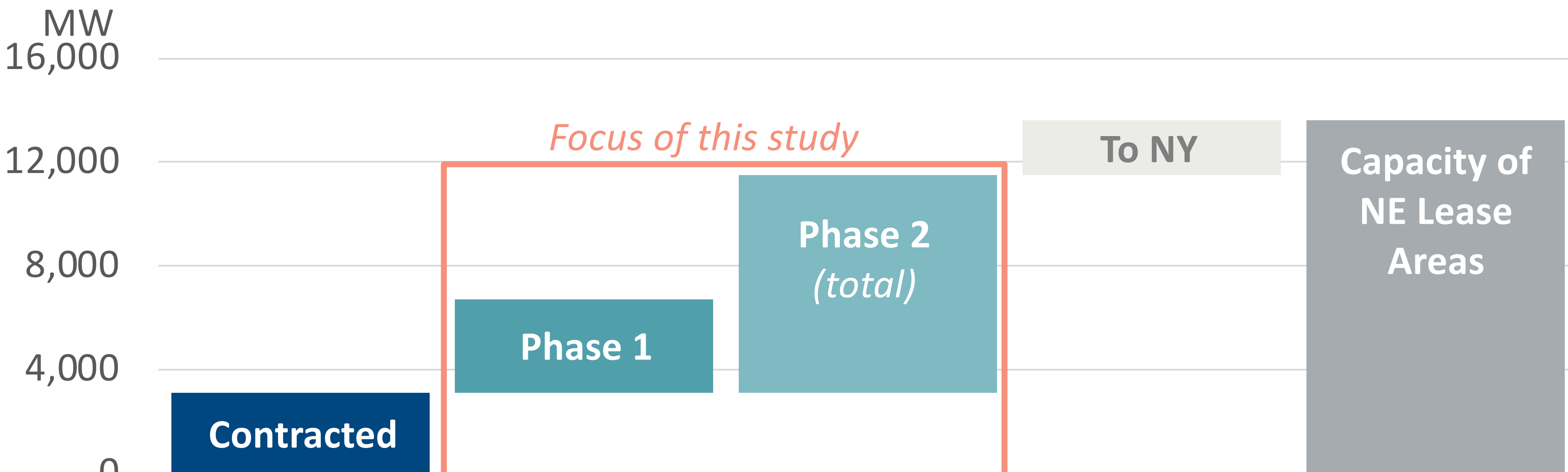
Benefits of a planned offshore transmission approach

A planned transmission approach that jointly coordinates onshore and offshore transmission investments to serve New England's offshore wind needs provides significant benefits for the growing industry and electric customers.

Elements we examine	Our analysis indicates…	*Slides*
Total onshore + offshore transmission costs • Onshore transmission upgrade costs (more risk) • Offshore transmission costs (less risk)	10% lower under planned approach • 65% lower under planned approach • 22% higher under planned approach	*16 & 17*
Losses over offshore transmission	40% lower under planned approach	*12*
Impact to fisheries and environment	49% less marine cable under planned approach	*22*
Generation-related production costs	Reach ~$1 million/yr lower for 3,600 MW of OSW under planned approach	*19*
Customer costs of energy, excluding transmission	Reach $20 million/yr lower for 3,600 MW of OSW under planned approach	*19*
Effect on generation and transmission competition	Increased competition under planned approach	*18 & 20*
Utilization of constrained landing points	Improved under planned approach	*21*
Utilization of existing lease areas	Improved under planned approach	*23*
Enabling third-party customers	Improved under planned approach	*24*

Analytical Approach

We compare transmission configurations for two additional OSW expansion phases



3,112 MW of projects already procured in New England, using gen-ties to interconnect Vineyard Wind, Mayflower Wind, Revolution Wind, and Park City Wind

3,600 MW of new OSW in Phase 1, currently authorized procurement authority for MA (1,600 MW), CT (1,200 MW), and 800 MW of assumed procurements from other states and third-parties

8,200-8,600 MW evaluated as Phase 2, with ~4,800 MW of OSW in addition to Phase 1

~2,110 MW of New England lease areas interconnected to NY, including Sunrise Wind, South Fork Wind, and an assumed additional 1100 MW project

~14,000 MW assumed total capacity of New England lease areas based on Anbaric analysis of public announcements from BOEM and leaseholders

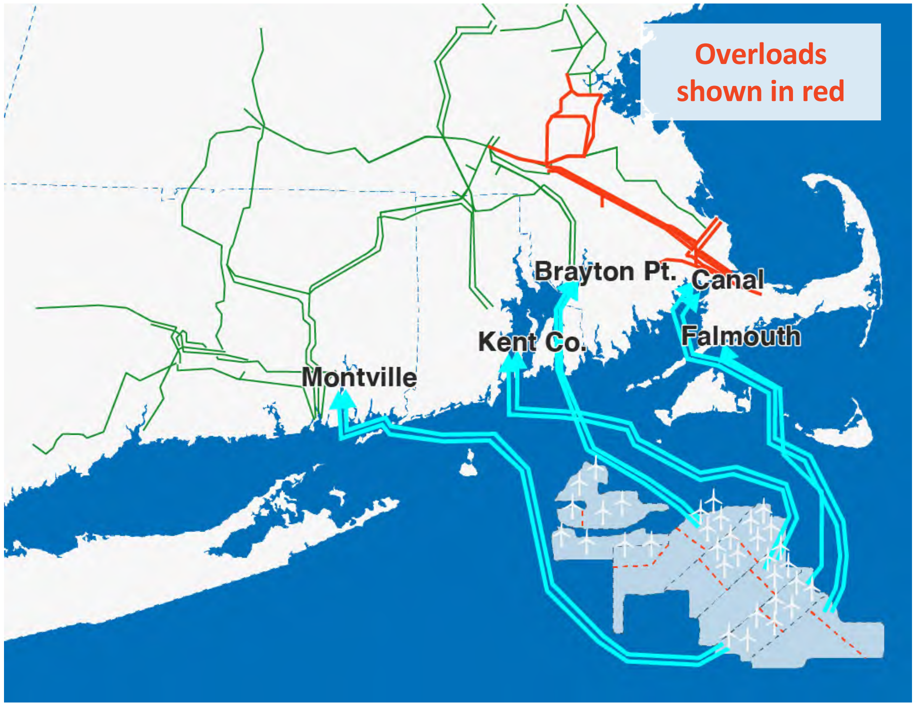
Phase 1 (add 3,600 MW): Summary of the two transmission approaches

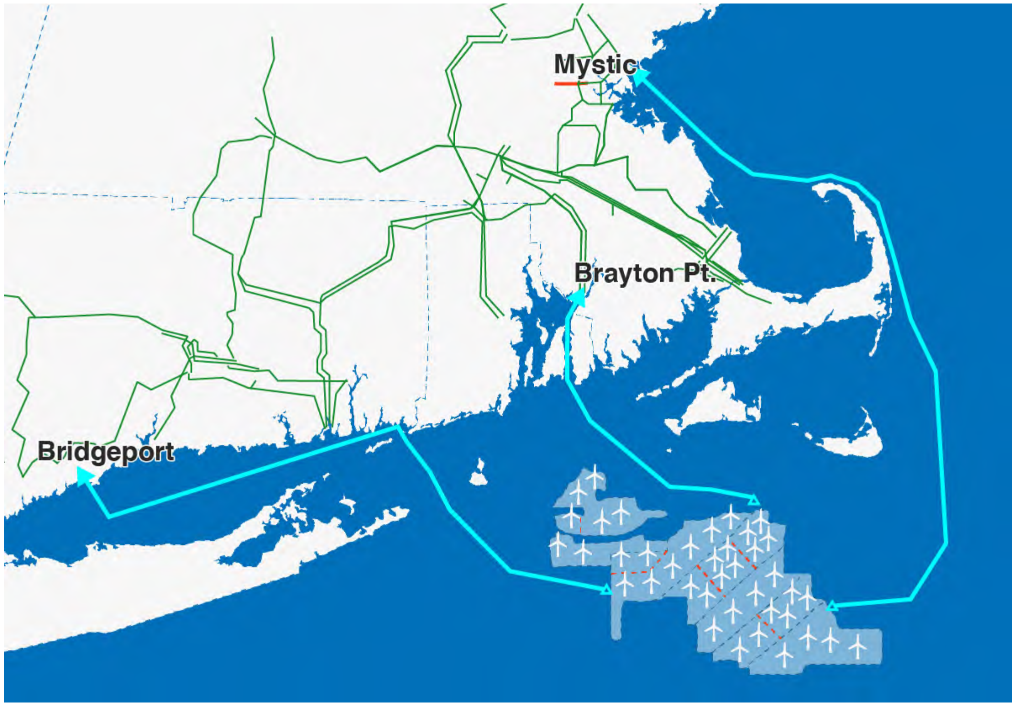
Current GLL Approach

- 9 x 400 MW High Voltage Alternating Current (HVAC) cable bundles:
  - 800 MW each at Montville, Kent Co. Brayton Pt. & Canal
  - 400 MW at Falmouth
- 694 miles of marine cabling
- 4.0% losses
- Significant onshore transmission overloads

Planned Offshore-Grid Approach

- 3 x 1,200 MW High Voltage Direct Current (HVDC) cable bundles
  - 1,200 MW each at Bridgeport, Brayton Pt. & Mystic
- 356 miles of marine cabling
- 2.4% losses
- Minimal onshore transmission overloads





Sources: Overloads based on GE analysis for Anbaric (Appendix B), which identified numerous within-zone overloads not identified in ISO-NE zonal analysis. Loss estimates based on vendor specifications and third-party sources

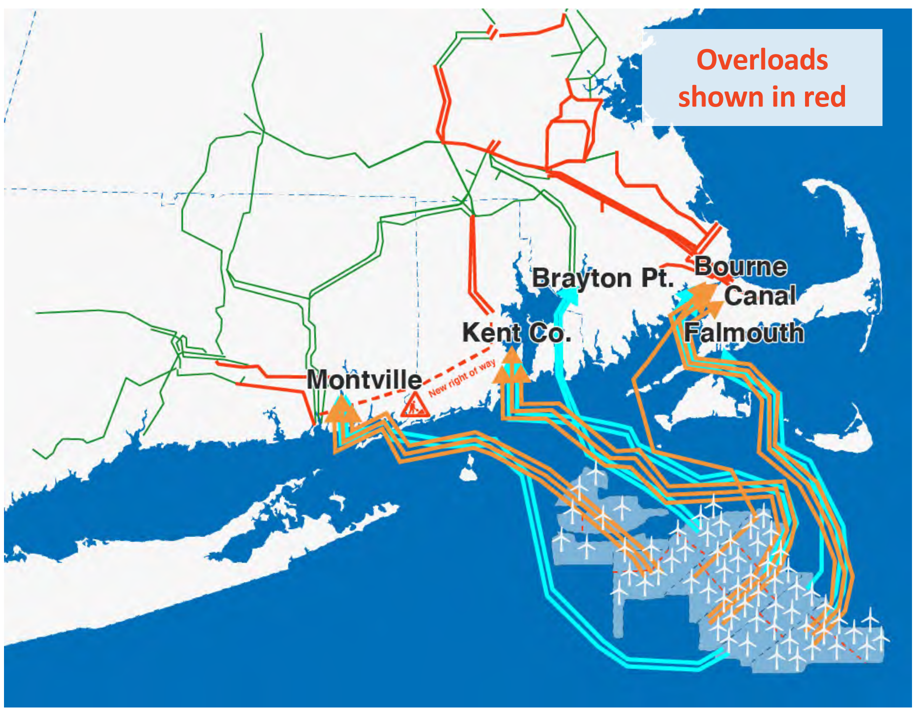
Phase 2 (add 8,000+ MW): Summary of the two transmission approaches

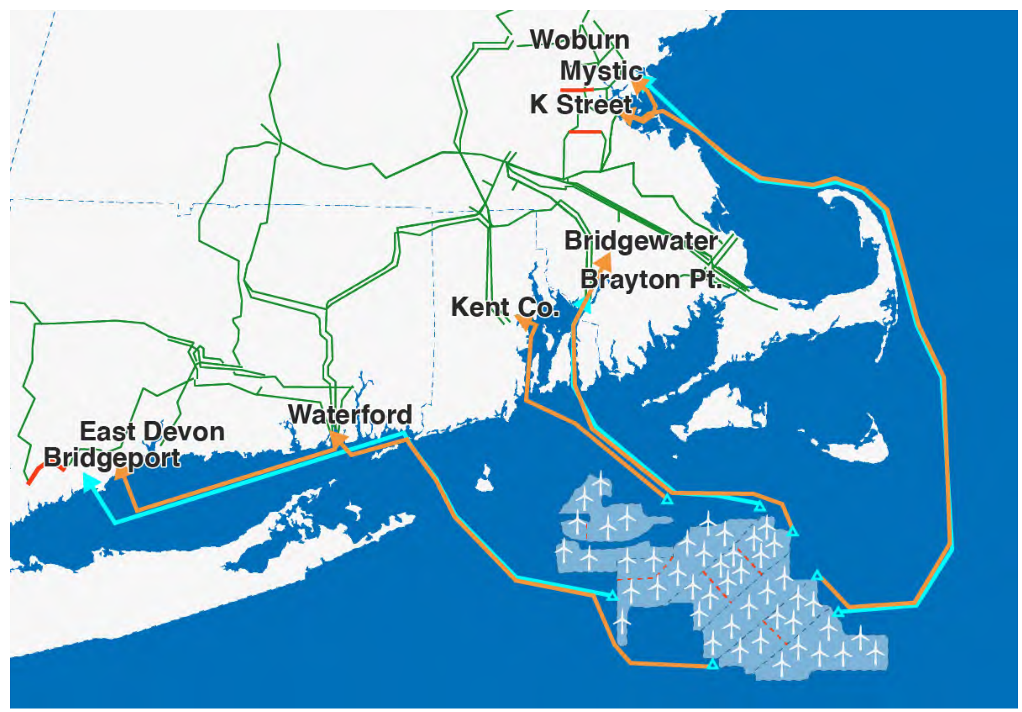
Phase 2, Current Approach (add 8,200 MW)

- 9 x 466 MW HVAC cable bundles
  - 1,400 MW each at Montville, Kent Co., & Canal
- 1 x 400 MW HVAC project
  - 400 MW at Bourne
- 926 miles of marine cabling *(1,620 through Phase 2)*
- Major onshore transmission overloads

Phase 2, Planned Approach (add 8,600 MW)

- 3 x multiterminal HVDC projects
  - 2,000 MW to Waterford (1200 MW) & East Devon (800 MW)*
  - 1,600 MW to K St. (800 MW) & Woburn (800 MW)*
  - 1,000 MW to Bridgewater
  - 400 MW HVAC project to Kent Co. RI
- 474 miles of marine cabling *(831 through Phase 2)*



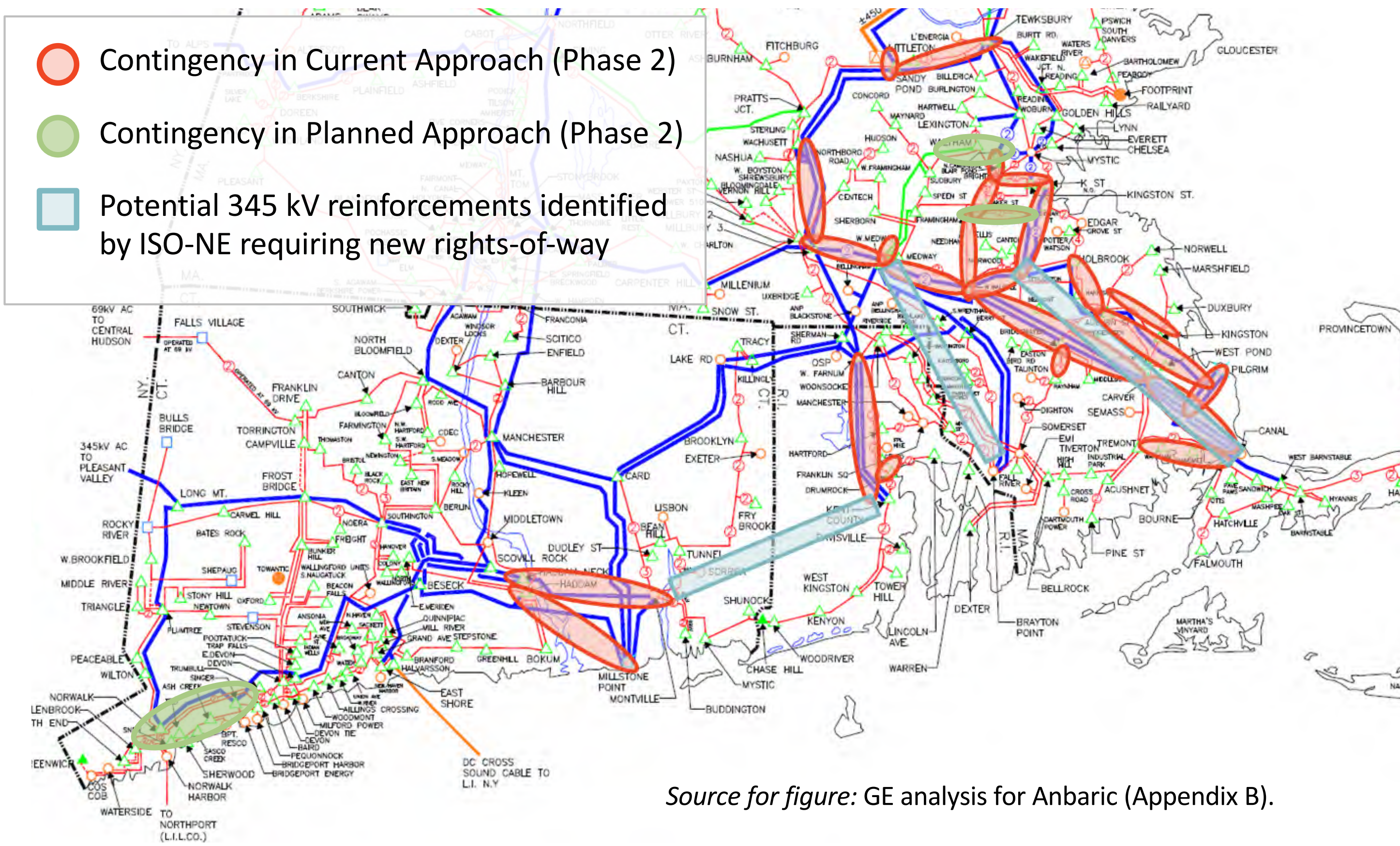


*Multiterminal HVDC injecting at two locations

Benefits of Planned Offshore Transmission

Avoid major overloads of the onshore grid resulting from current gen-tie approach

- To date, OSW developers have focused on landing sites with the closest access to onshore grid
- Already-procured projects connecting to Cape Cod face up to $787 million in onshore upgrades*
- Regional procurement targets exceed available near-shore landing sites**
- Onshore upgrade costs should be included in a generator's bid, but we anticipate that costs are underestimated, in which case the additional costs could lead to problems completing the projects or increased costs for customers



Source for figure: GE analysis for Anbaric (Appendix B).

* ISO-NE's Feasibility Study for interconnecting three projects totaling 2,400 MW to Cape Cod (QP 828) identifies $227M in upgrade costs with a -50% to +200% range ($113M to $681M). Interconnecting an additional 400 MW associated with one of these projects (QP829) is estimated to cost an additional $36M with a -50% to +200% range ($18M to $106M).

** ISO-NE has identified 5,800 MW of injection capability in SEMA, RI, and SECT, and existing state procurement targets already equal 5,900 MW

Planning ahead avoids onshore transmission upgrades that otherwise would be needed

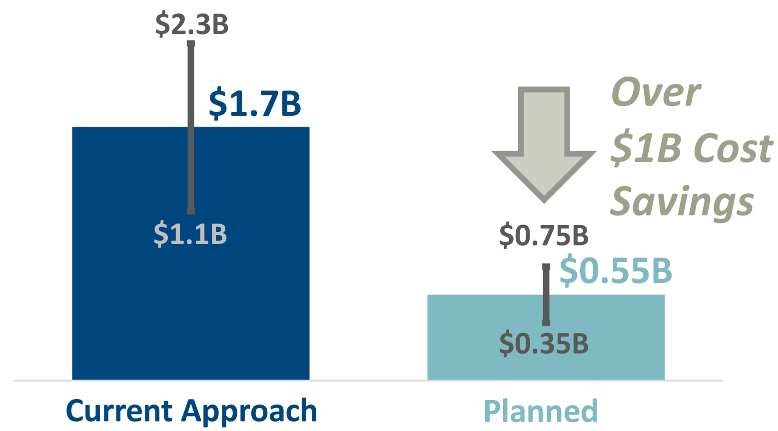
Given the high cost and difficulty of building onshore transmission, a planned offshore grid can significantly reduce need and costs for onshore upgrades, where there is a history of delays and budget overruns in New England

- Major transmission projects in New England since 2002 have averaged budget overruns of 79% with average development times of over five years*
- One recent project in Southern New England – the New England East-West Solution Interstate Reliability Project – took 9 years to complete

Customers benefit from better-planned off-shore transmission through reduced cost and risk of onshore transmission upgrades

- Previous analysis indicates that delays of even one or two years could cost ratepayers $350 to $700 million*
- These uncertainties add substantial risks to the feasibility of the current approach; potentially adding $1.1 billion in costs

The Current GLL Approach Would Require Onshore Upgrade Costs $1.1B Higher Than a Planned Approach in Phase 1
(3,600 MW additional OSW)



Sources: CHA analysis of "Phase 1" transmission upgrade costs for Anbaric included in Appendix C.
*New Hampshire Transmission, "Greater Boston Cost Comparison," January 2015.

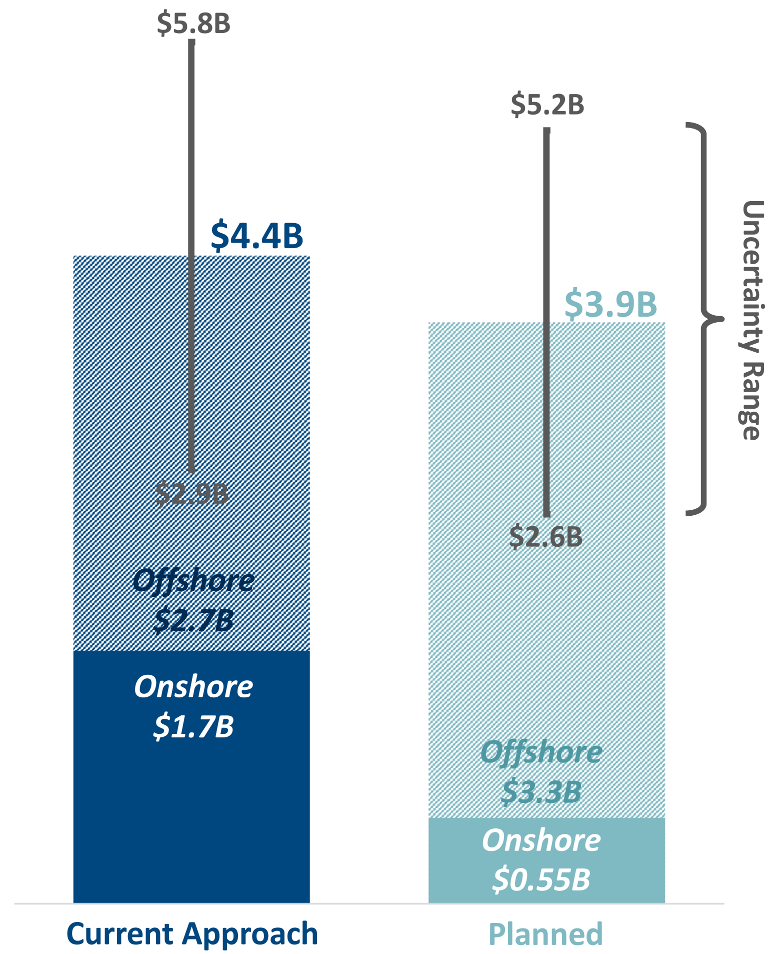
Total costs of transmission are expected to be lower under a planned approach

Even including the more costly offshore transmission equipment ($3.3B vs $2.7B for Phase 1), total costs of onshore upgrades plus offshore transmission to enable the next 3,600 MW of OSW are estimated to be lower under a planned than the current gen-tie approach

- Onshore upgrade costs of $0.55B under planned approach vs $1.7B under current approach)

The planned approach to building offshore transmission can enable significant long-term cost savings and avoid some of the higher risks associated with onshore upgrades

Comparison of Total Onshore Plus Offshore Transmission Costs in Phase 1
(3,600 MW additional OSW)



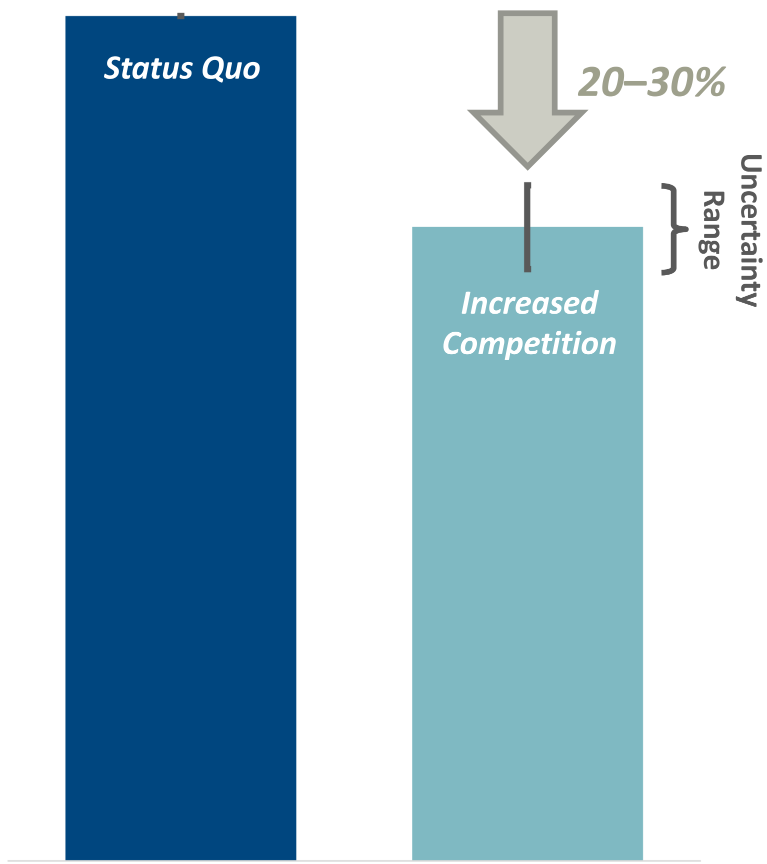
Source for cost data: Onshore upgrade cost estimates based on GE and CHA analysis of "Phase 1" scenarios for Anbaric included in Appendices B and C. Estimate for offshore transmission equipment based on proprietary supplier information provided to Anbaric.

Increased competition among offshore transmission developers

Offshore transmission developers would compete to build planned transmission. This direct competition would put downward pressure on costs to ratepayers (further lowering costs beyond that described on previous slides)

- Studies of onshore transmission indicate that competitive procurement enables "significant innovation and cost savings of 20–30%" relative to the costs incurred by incumbent transmission companies; the costs of conducting the competitive processes are small compared to the savings*
- Studies of offshore transmission costs in the U.K. similarly indicate that competition across independent offshore transmission owners reduced costs 20–30% compared to generator-owned transmission (driven by lower operating costs and financing costs from improved allocation of risk and reduced risk premium)**

Anticipated Cost Impact of Competition to Develop Offshore Transmission



Sources: * The Brattle Group, "Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value," April 2019, Produced for LSP Transmission.
** Cambridge Energy Policy Associates, "Evaluation of OFTO Tender Round 2 and 3 Benefits," March 2016, Produced for Ofgem.

Lower total system-wide generation costs and savings to customers

Based on analyses conducted by GE, the planned approach will yield system-wide generation cost savings, primarily from reduced transmission losses and reduced offshore wind curtailments

- After Phase 2 with an additional 8 GW of OSW in service, curtailments would be reduced from 13% in the current approach to 4% in the planned: equivalent to ~700 MW
- This yields generation cost savings that reach **$55 million** per year-under the planned approach relative to the current approach for Phase 2

The planned approach would inject more of the OSW into higher-priced locations on the grid, further reducing customer costs

- GE's estimated customer savings of the planned approach reach ~$20 million per year in Phase 1 and over **$300 million** per year in Phase 2 in 2028
- Part of this is a value transfer from conventional generators to customers, not necessarily a reduction in total system costs (so is not shown in the chart)

One Year System-wide Generation Cost Savings of Planned Approach Compared to Current Approach

Source: GE analysis for Anbaric included in Appendix B

Increased competition among OSW generation developers

Competition among developers of OSW generation would be enhanced, yielding a range of potential cost savings

Minimum savings

The planned, competitive approach would simplify a major strategic decision for developers

Today, developers must bid before they have accurate information about their transmission upgrade costs. Removing these risks from the offshore generation procurement should lead to lower bids because of the reduced risk premium alone

Higher potential savings

Ultimately, it could increase participation and competition in OSW solicitations.

In Europe, planned transmission approaches have enhanced head-to-head competition leading to **zero-subsidy bids** in recent procurements (see case study details in appendix)

We anticipate more willing bidders and more competition with increased access to transmission (though overall still limited by number of leaseholders)

More efficient use of constrained "cable-approach" routes

There are a limited number of landing sites for offshore wind transmission lines in New England

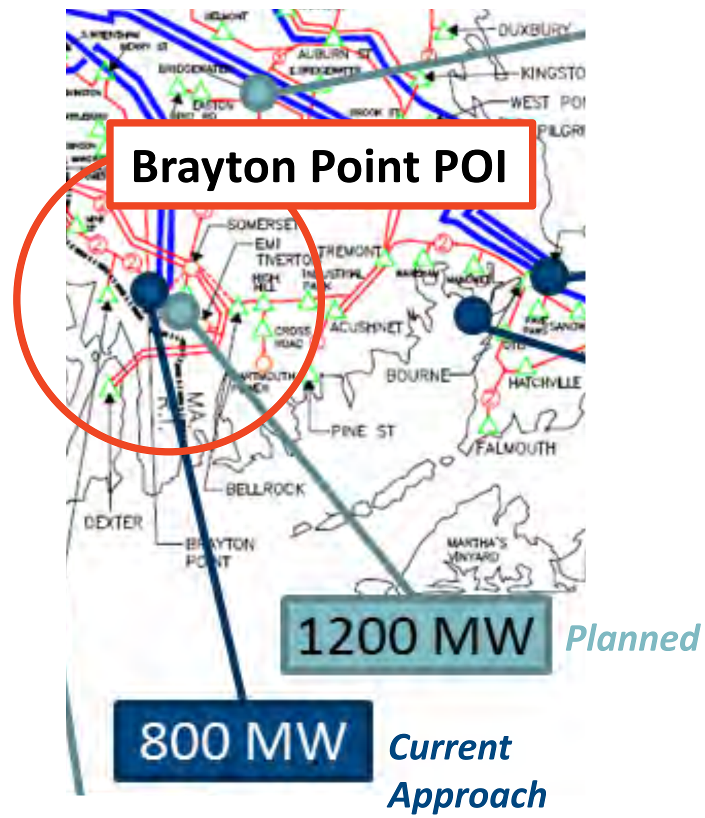
In the longer term, if each OSW project requires a separate cable connection to the onshore transmission system, viable cabling routes become constrained

A planned transmission approach can make better use of limited landing sites.

For example:

- Anbaric's analysis indicates that access routes to Brayton Point have space for only 2 physical cable bundles. Under the current gen-tie approach this would accommodate 2 x 400 MW HVAC interconnection cable bundles
- A planned approach utilizing HVDC cable bundles can deliver 1,200MW to Brayton Point with room for an additional HVDC cable bundle before reaching spacing constraints

Example: Interconnection Capacity under the Current and Planned Approaches



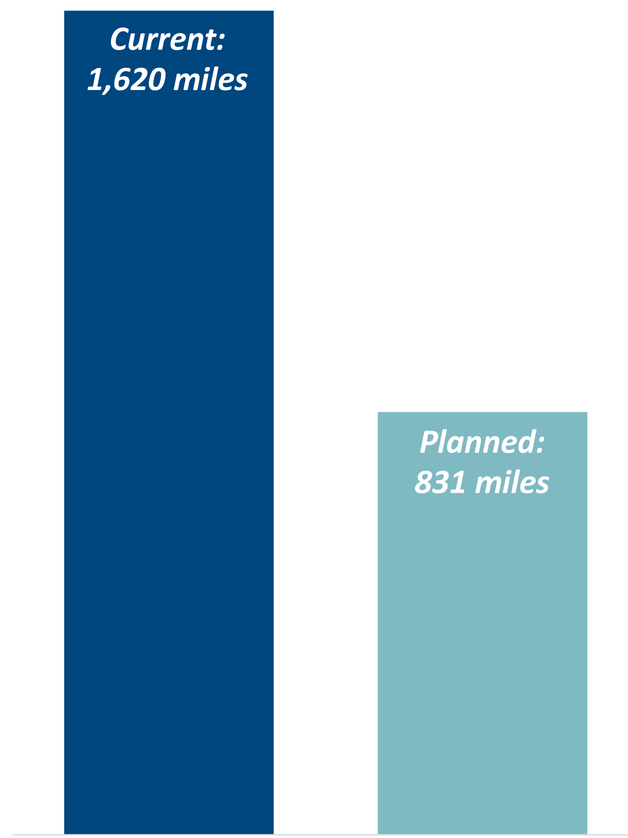
Reduced impacts to fisheries and the environment

Better planning can reduce the cumulative effects of offshore transmission on fisheries and the environment

- Under a planned off-shore-grid approach, marine trenching can be reduced by almost 50% (based on Anbaric proposed cable routing)
- Offshore cables can be grouped in transmission corridors to minimize impact; this is not possible to enforce under the current (one-off, unplanned) approach

Minimizing the number of offshore platforms, cabling, and seabed disturbance reduces impacts on existing ocean uses and marine environments to the greatest practical extent

Comparison of Total Length of Undersea Transmission Under Current and Planned Approaches by Phase 2
(8,000 MW + additional OSW)



Source: Slide 13.

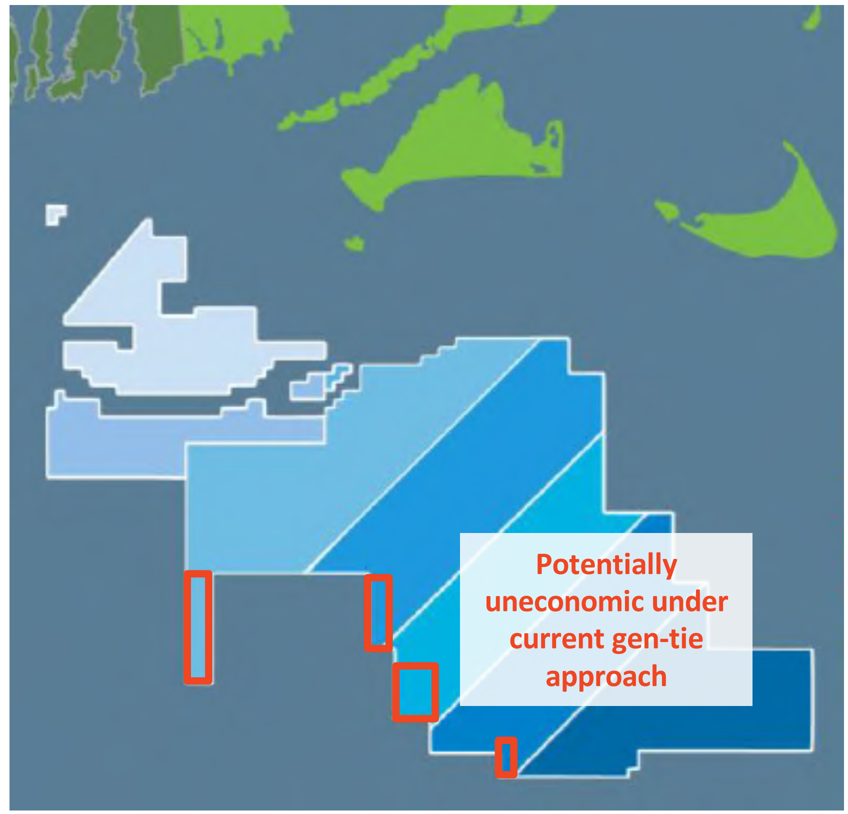
Realize the full potential of existing lease areas

Without a well-planned offshore grid, some of the existing offshore lease sites may not be economic to develop

- After developers interconnect the bulk of their lease sites, it may be cost prohibitive to interconnect the residual areas (of perhaps 50 MW to 250 MW each) using AC generator lead lines sized to carry ~400 MW each
- This increases the risk of inefficient use of lease sites and stranded assets

An offshore grid with well-located offshore collector stations would increase the likelihood that residual lease areas could be developed cost-effectively, and that the full potential of all lease areas can be realized

Developers May Find Residual Areas Uneconomic to Interconnect With Generator Lead Lines



Map Source: Massachusetts CEC, "Massachusetts Offshore Wind Initiatives," EBC Sixth Annual Offshore Wind Conference.

Improved reliability and reduced OSW curtailments

Designing and building the offshore grid with networking capability preserves the option to create a meshed configuration to improve reliability and reduce curtailments in case of transmission outages

- For example: If three 1,200 MW HVDC converter stations were networked offshore, an outage of one line would still allow flowing full power in all hours when the total generation is less than 2,400 MW, resulting in only 4% of energy curtailed relative to no outages
- Under the current (non-meshed) gen-tie approach, an outage in any one of three lines would results in 33% reduction in delivered energy to the onshore system, causing significantly more curtailments than under a meshed configuration

Source: Anbaric analysis.
Notes: Several European countries are studying meshed DC configurations for use interconnecting OSW in the North Sea. Reference materials compiled by Curis et al., "Synthesis of available studies on offshore meshed HVDC grids," 2016.

Enabling third-party customers

An independent, open-access offshore grid can create opportunities for additional (non-mandated) OSW resources to be built at lower cost

- As OSW generation costs decrease, third-party customers have expressed interest in purchasing offshore wind, but even large individual customers are unlikely to purchase sufficient OSW to fully utilize an export cable sized to carry 400 MW of offshore wind. Developing smaller projects with larger export cables would be uneconomical
- An open access transmission system could serve as a platform for individual offshore-wind procurements of smaller sizes, enabling OSW development without state-sponsored contracts
- A generation developer could build surplus transmission capacity into a project but would then likely have market power in selling to third parties, whereas independent transmission would require OSW generators to compete against each other to utilize independent transmission.

Case examples:

Microsoft and Google purchased 90 MW and 92 MW of OSW over independent transmission in the Netherlands and Belgium

The Texas CREZ served as a platform for third-party power purchase agreements (PPAs), enabling over 2 GW of onshore wind PPAs from 22 corporate buyers

In the Southwest Power Pool, ISO-planned transmission investment enabled 2.5 GW of corporate PPAs

Sources: Wind Solar Alliance, "Corporate Renewable Procurement and Transmission Planning," October 2018.

Procurement Approach

We recommend a planned approach to offshore transmission

A planned approach leverages competition among transmission developers to build out a New England offshore transmission grid in a staged manner, enhances competition between off-shore wind generators, and leads to lowest costs

Utilizing GLLs has distinct disadvantages over planned offshore transmission. While the GLL approach may appear to offer* lower costs in the short run, it is not aligned with the public interest in the long run, leading to:

- Poorer use of limited onshore POIs
- Increased seabed disturbance
- Reduced competition for transmission and off-shore wind generation
- Higher onshore transmission upgrade costs and higher overall costs in the long run

Under the planned approach, OSW generation developers still will be able to participate in transmission procurements,** but must be willing to develop open-access transmission for other leaseholders when participating in the transmission procurement (even if their generation bid is unsuccessful in the generation procurement)

* Costs of transmission in bundled generation + transmission bids could also appear artificially low if bidders can shift costs from transmission to generation within projects
** This would require functional or physical business separation

Implementing planned transmission procurements

The planned approach can be implemented through joint procurement of transmission and generation. The solicitation can build on prior New England state procurements of transmission for renewable energy, including the 2015 "Three State RFP" issued by MA, CT and RI, which included a Transmission Service Agreement model. The procurement can be initiated immediately, with selection of winning projects by 2021.

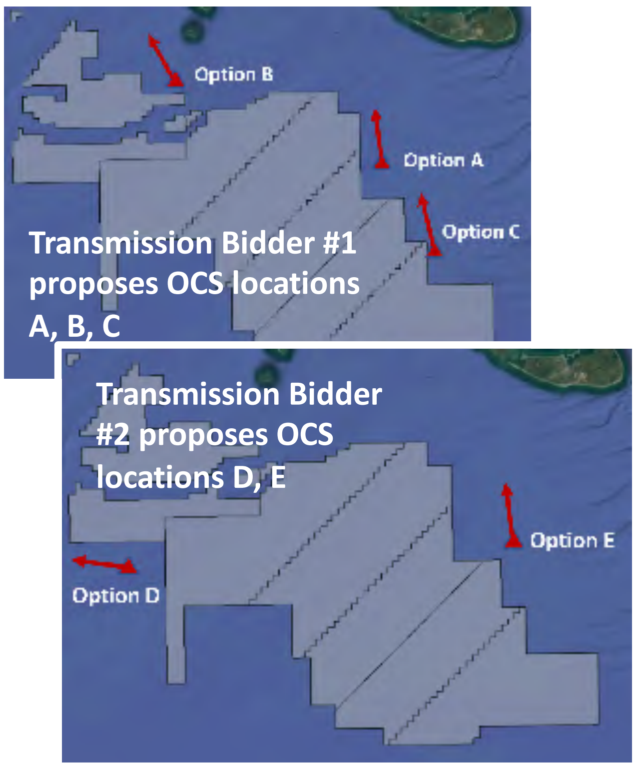
Example Implementation of Transmission and Generation Procurement

1. **Identify preferred onshore POIs** based on long-term plan
2. **Solicit transmission** developers to propose multiple fixed-price options for (bidder-determined) offshore collector station (OCS) locations and POIs
3. Evaluate transmission (Tx) bids considering cost, accessibility to lease areas, impacts on fisheries & environment and select a single winning bidder – but do not yet select final OCS location or POI
4. **Solicit generation** developers to bid to interconnect to any of the OCS locations provided by winning Tx bidder
5. Evaluate OSW generation bids, considering total cost (generation + transmission) and other factors to select generation developer and OCS location

Example of transmission and generation procurement

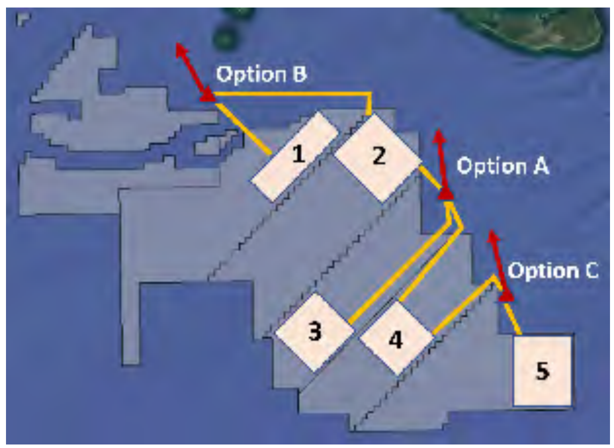
<u>Transmission</u> developers propose collector station locations A - E

Each transmission developer bids a fixed price for one or more collector station locations



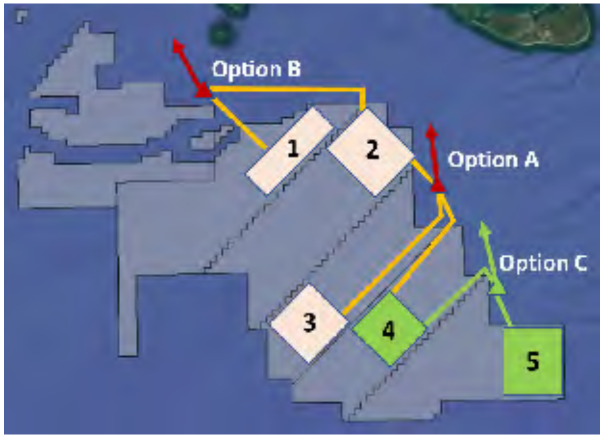
Transmission developer #1 selected; leaseholders bid <u>wind generation</u> 1-5 to collector stations A, B, C

Each generation developer bids a fixed price for one or more collector station locations



Selection of winning configuration

Wind farms 4 and 5 connecting to collector station C minimize costs of procuring specified MW quantity of offshore wind



Mitigating risk with separate generation and transmission procurements

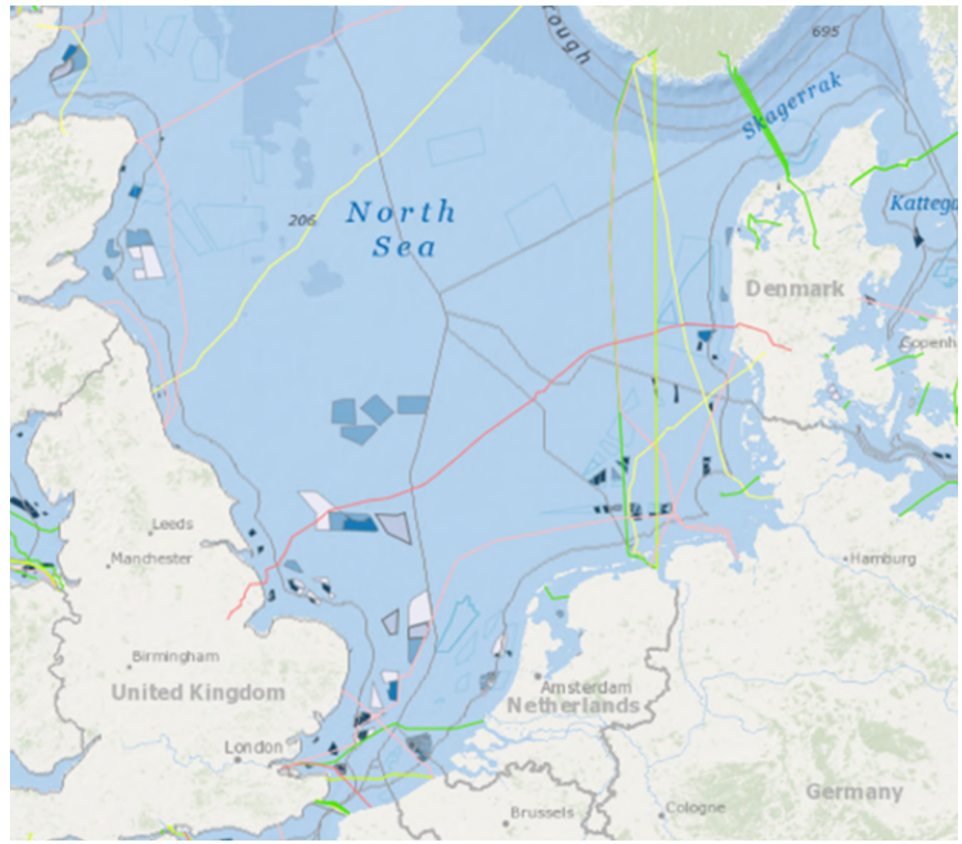
- The current GLL approach places development of generation and offshore transmission under a single developer, but leaves onshore upgrades with incumbent (onshore) transmission owners
  - This approach reduces coordination risk between OSW and offshore transmission, but there remains project-on-project risk related to the completion of onshore upgrades
  - Furthermore, the misalignment between generation developer incentives and public policy objectives increase risks to the overall offshore wind development effort (significant onshore upgrades, higher curtailment risk, less competition, and higher long-term costs)
- The planned offshore grid model reduces risks that could inhibit achievement of overall OSW development goals, and can also address individual project-on-project risk through:
  - Strong performance and completion incentives (rewards or penalties) for both transmission and generation developers to meet project deadlines
  - Allowing generation developer to participate in transmission procurement, with the condition that the transmission will be open access
  - Staggered transmission and generation project completion timelines (e.g., scheduling transmission project completion before generation)

Appendix A:
Case Studies

Offshore transmission network in Europe

- Both Germany and the Netherlands have implemented a planned transmission approach, with offshore transmission developed separately and in anticipation of new OSW generation
- Offshore transmission developed by TSO and paid for by electric ratepayers (as with other transmission infrastructure)
- This approach has already enabled 8,600 MW of OSW connected to Germany and the Netherlands to date
- Approach has increased competition among OSW developers. Project costs have declined by over 50% in the last five years, leading to "subsidy free" PPAs for recent OSW in both Germany and the Netherlands

Existing Offshore Transmission Development in the North Sea



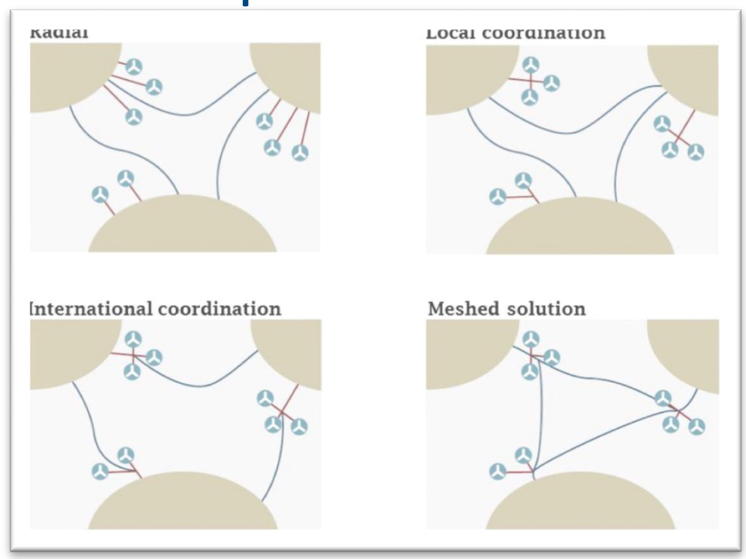
Source: NY Power Authority, "Offshore Wind: A European Perspective," August 2019.
Wind Europe, "Offshore Wind in Europe," February 2020.

CASE STUDIES

Planning in the North Sea of Europe

- Planning ahead in the North Sea included analyses of "Radial" versus "Meshed" offshore grid
  - The North Seas Countries' Offshore Grid initiative (NSCOGI), formed in 2010, evaluated and facilitated coordinated development of a possible offshore grid that maximizes the efficient and economic use of renewable resources and infrastructure investments
  - Ten countries were represented by their energy ministries, supported by their Transmission System Operators, their regulators and the European Commission.
- A scenario-based planning approach was initiated in 2012; analysis then already showed benefits of having a planned meshed offshore system*
- More recent 2019 planning and analysis of very high OSW penetration in the North Seas (380 GW by 2050) indicates substantial benefits of meshed offshore grids: lowering the environmental burden, using infrastructure more efficiently, and reducing costs*

Models of Offshore Grid Development Considered

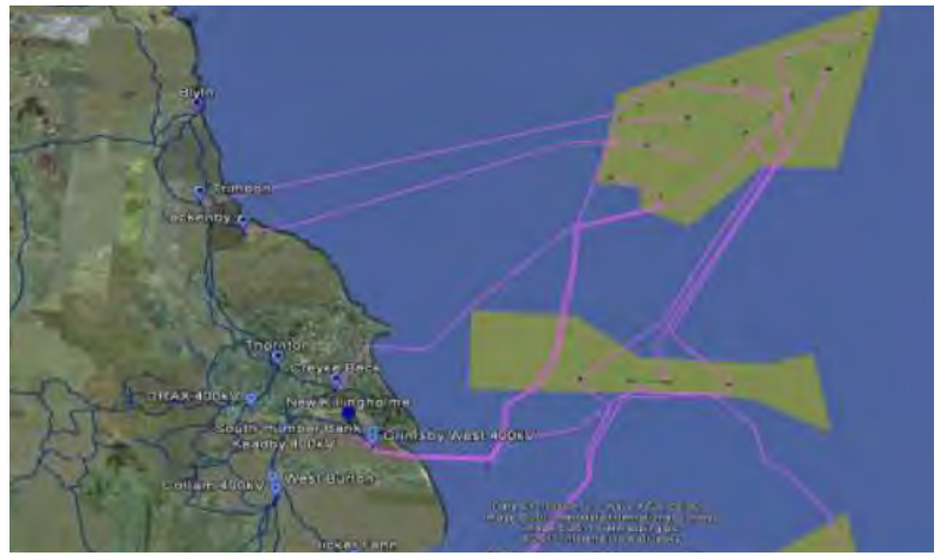


Sources: * The North Seas Offshore Grid Initiative, "Initial Findings," November 2012.
** Wind Europe, "Our energy, our future," November 2019.

Offshore transmission network in the U.K.

- To date, all OSW transmission in the UK has a radial design, with the transmission developed by the OSW developer and then sold to a separate transmission owner
- However, this approach is reaching its limits, as ad-hoc onshore interconnections are pushed further inland with increasing community impacts.
- Ofgem is currently studying and strongly considering implementing an offshore transmission network.

Ofgem Study of Possible Offshore Grid Design



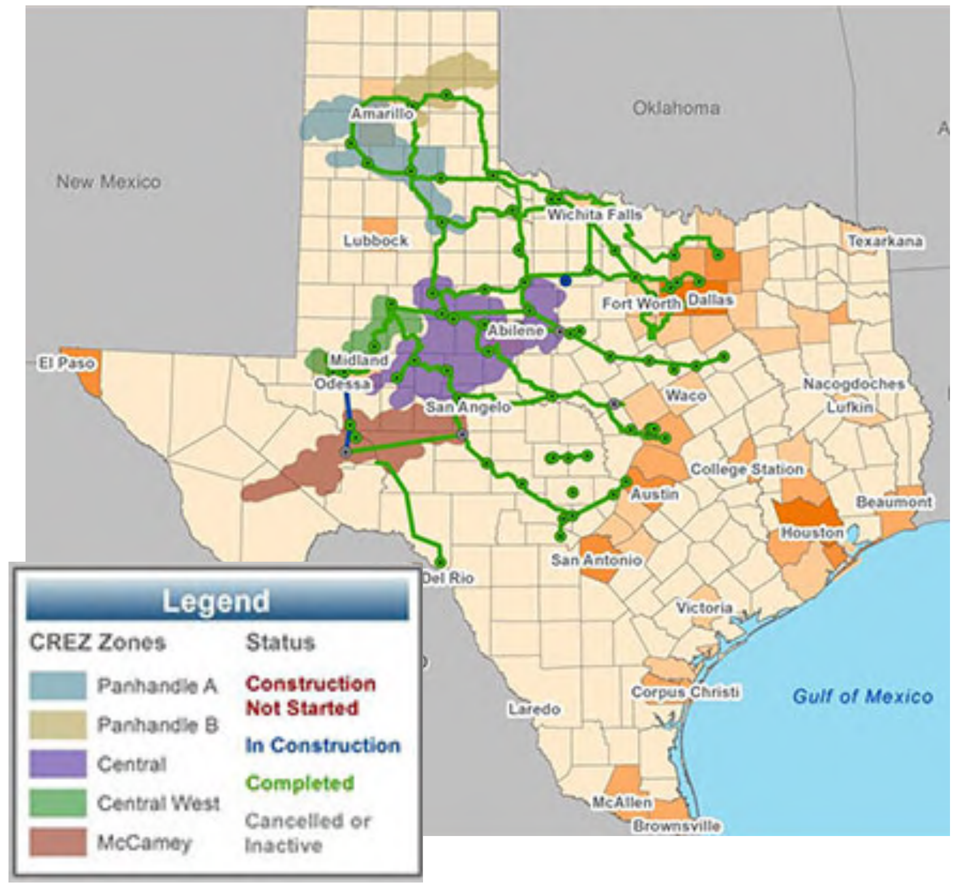
- Various studies conducted by Ofgem, utilities, and industry groups show that such a coordinated design could lower overall transmission costs by 9 to 15 percent.
- An offshore grid to support 34 GW of capacity would cost £24.2 billion ($31.5 billion), equivalent to a transmission cost of £5.36/$6.98 per MWh

Source: NewEnergyUpdate, Reuters Events, February 19, 2020.

Competitive Renewable Energy Zones (CREZ) in Texas

- $7 billion transmission-first program
- Phased development of transmission enabled 18.5 GW wind from five “competitive renewable energy zones” to rest of state
- Allowed rapid merchant development of wind in W. Texas, reducing electricity costs by $1.7 billion annually
- Process: ERCOT designed transmission system configurations to integrate each renewable energy zone through a staged, expandable approach. Desired configurations selected by PUC and developed by competitive transmission developers and incumbents

Texas CREZ Transmission Projects



Source: EIA, “Fewer wind curtailments and negative power prices seen in Texas after major grid expansion,” June 2014.

Tehachapi Renewable Transmission Project (TRTP) in California

- Tehachapi was identified as a high wind potential region in southern California almost 20 years ago
- California policy makers solicited interest in building wind in Tehachapi
- California ISO developed a transmission plan for the region
- The transmission enabled 4,500 MW renewable power development
- 250 circuit miles, $2.1 billion cost
- Built by transmission developer, with costs allocated using existing CAISO transmission cost allocation system

CAISO TRTP Transmission Projects

Seg	Description
1	New 500kV line between Antelope and Pardee Substations and Antelope Substation Expansion
2	New 500kV line between Antelope and Vincent Substations
3A	New Windhub Substation and new 500kV line between Windhub and Antelope Substations
3B	New Highwind Substation and New 220kV line between Windhub and Highwind Substations
3C	Upgrades to Antelope, Vincent, Windhub Substations
4	Single-circuit 500kV transmission line between Whirlwind and Antelope Substations
5	Replacement of two 220kV lines with one 500kV line between Antelope and Vincent Substations
6	32 miles of 500kV line from Vincent Substation through the Angeles National Forest
7	Replacement of 220kV line with 500kV line between Angeles National Forest and Mesa Substation
8	Replacement of 220kV line with 500kV line between Mesa and Mira Loma Substations. New and replacement double-circuit 220 kV lines between Chino and Mira Loma Substations
9	New Whirlwind Substation and upgrades to Antelope, Vincent, Windhub, Mesa, Gould, Mira Loma Substations
10	New 500kV line between Windhub and Whirlwind Substations
11	Replacement 500kV line between Vincent and Gould Substations. New 220kV circuit on existing structures between Gould and Mesa Substations

Source: SCE, "Tehachapi Renewable Transmission Project."

Support from Other Stakeholders

"Separating transmission from generation procurement, while complex, has the potential to deliver optimal outcomes for consumers and the environment."

*- Environmental Stakeholders**

"A separate contingent solicitation for structure installation offshore could result in greatly fewer impacts to fisheries, and must have the primary goal of developing a more efficient (less cable used) and better-sited structure in the water."

- Responsible Offshore Development Alliance

"By allowing for more options for consideration and fostering greater competition, a planned transmission system benefits the offshore wind industry, states, taxpayers, local communities, the environment, local businesses, and other stakeholders. To maximize benefits and the opportunities for scaling an offshore wind industry that can create thousands of good sustainable jobs, BOEM should facilitate making open access, planned transmission available as an option [...]"

- International Brotherhood of Electrical Workers

"[…] the size and speed of OSW installations could overwhelm and congest our current land-based coastal grid, damaging the industry's reputation and shortchanging its growth potential."

- Tufts Power Systems and Power Research Group

* Environmental Stakeholders include the National Wildlife Federation, Conservation Law Foundation, Sierra Club (Mass. Chapter), and Acadia Center

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Commercial Damages
Environmental Litigation & Regulation
Intellectual Property
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Labor & Employment
Mergers & Acquisitions Litigation
Product Liability
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Offshore Transmission in New England: Benefits of a Better Planned Grid
Appendix B

Transmission Security Analysis & Economic Production Cost Simulation

GE Energy Consulting for Anbaric

August 4, 2020

Overview of Planning Study Process & Methodology

Transmission Security Analysis

Purpose: *Model and Evaluate Costs of Current vs. Planned Transmission Development for ISONE Offshore Wind*

Modify ISONE Cases to Create OSW Buildout Base Cases(PSSE)

» Scenario 1: Current HVAC Transmission Buildout

» Scenario 2: Planned HVDC Transmission Buildout + Mystic Reliability Wind Link Project

Perform Transmission Security Analysis (TARA)

» NERC Transmission Planning Performance Requirements TPL-001-4

» NPPC Directory #1: Design and Operation of Bulk Power System

Economic Study Process & Methodology

Purpose: Compare Economic Production Cost Metrics in Current vs. Planned Transmission

Build[1] GE EC MAPS 4-Pool Database Model (PJM/NYISO/IESO/ISONE)

» Base Case: Install 3.1 GW of Baseline OSW in ISONE
» Scenario 1: Current HVAC Transmission Buildout (8.1 GW OSW)
» Scenario 2: Planned HVDC Transmission Buildout (8.6 GW OSW) + Mystic Reliability Wind Link Project

Base Case Assumption: Six Transmission Upgrades

» Upgrades assumed as necessary to address 44% curtailment resulting from Base Case injections

Scenario 1 & 2 Include Reliability Upgrades from Base Case Injections

» Necessary transmission upgrades to meet NERC TPL Standards / NPCC Directory 1 Requirements

Key Production Cost Simulation Metrics for ISONE

» Offshore Wind Curtailment (%)
» Annual Average LMP ($/MWh)
» Annual Production Cost Savings ($M)
» Load Payment Savings ($M)

[1] https://www.iso-ne.com/static-assets/documents/2019/05/a2_2019_economic_study_draft_scope_of_work_and_high_level_assumptions.pptx

Overview of Economic Study Process & Methodology

Comparison to ISONE Economic Study Methodology[1]

GE EC Anbaric Study

More granular and closely mirrors modeling new transmission overloads needed to be addressed to interconnect offshore wind

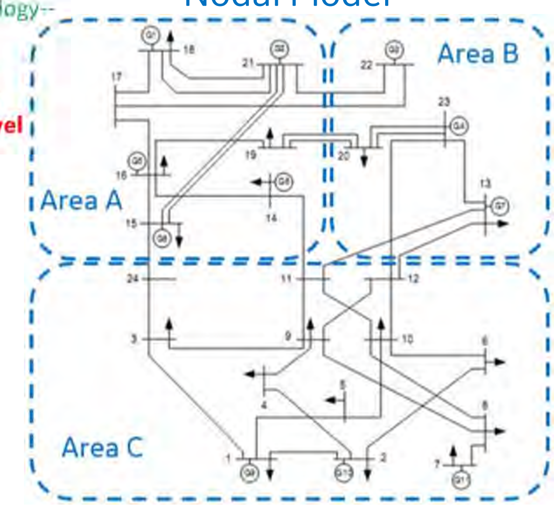
» Network Topology – Nodal model allows detailed specific N-1 transmission contingency constraints

» Transmission Constraints (Current) – Interface transfer limits *and* specific transmission element constraints (N-0 and N-1)

» Transmission Constraints (Offshore Wind Buildout) – Model additional constraints (N-0 and N-1) based on updated power flow analysis to more accurately capture future congestion patterns

- ISO Commitment & Dispatch Operations Modeling Methodology-- Uses AC Powerflow Data
- Monitor and Secures Flows on Individual Lines and Interfaces
- **Different Prices at Nodal Level**

Nodal Model



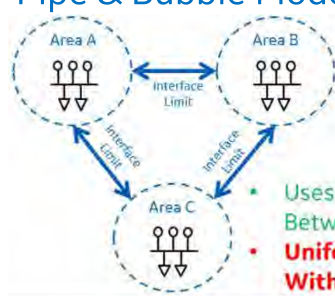
ISONE Economic Study

» Network Topology – Pipe and bubble model

» Transmission Constraints (Current) – Model interface transfer limits only

» Transmission Constraints (Offshore Wind Buildout) – None, only models existing interfaces

Pipe & Bubble Model



- Uses Interface Limits Between Areas
- **Uniform Price Within an Area**

[1] https://www.iso-ne.com/static-assets/documents/2020/02/a6_nescoe_2019_Econ_8000.pdf

Offshore Wind Point-of-Interconnection List

Scenario 1 AC vs Scenario 2 HVDC Buildout

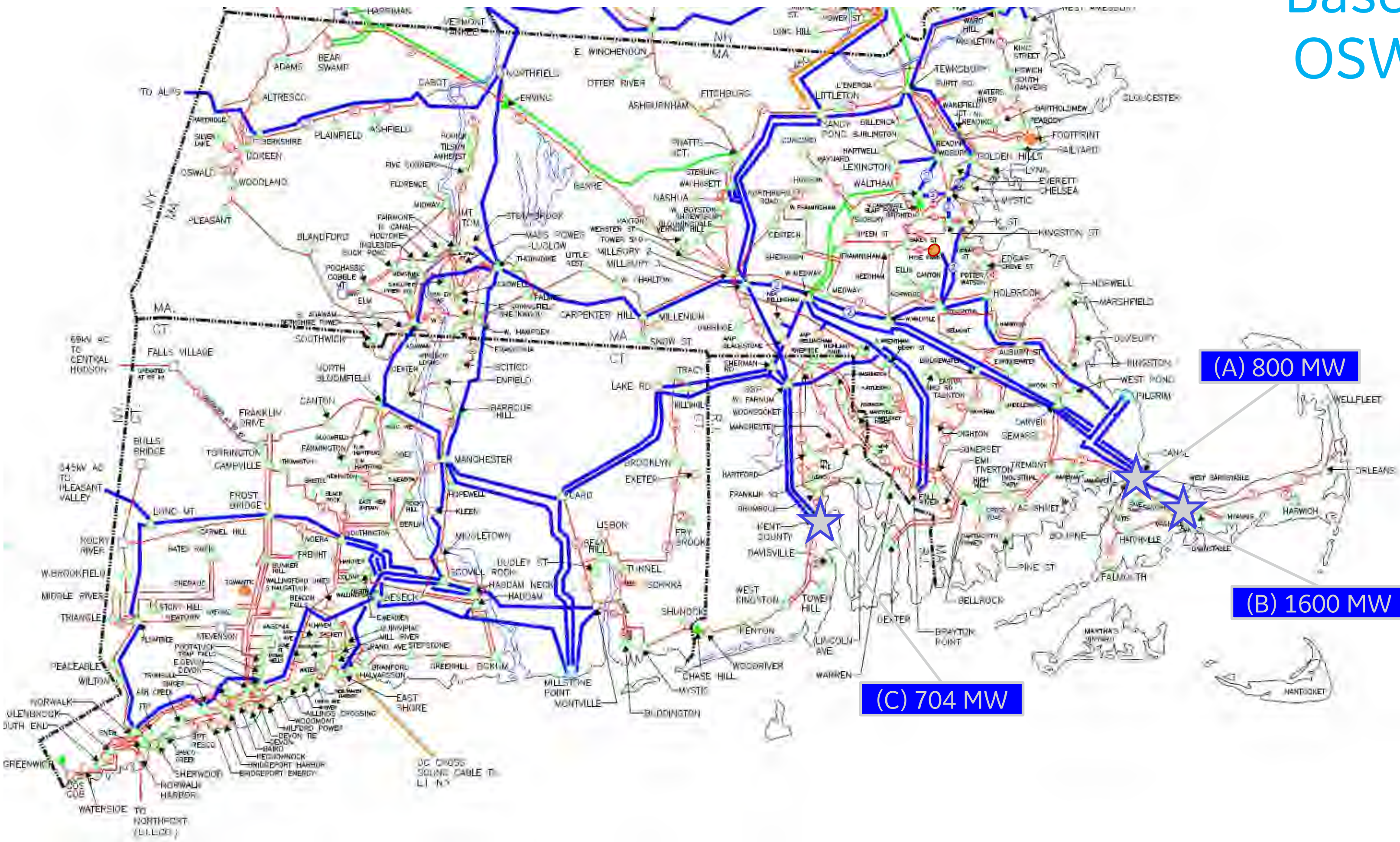
**Baseline 800 MW at Bourne 345 kV POI modeled at Canal 345 kV & Bourne 115 kV			Additional MWs Added to Baseline				
POI Substation Name	**Bus Number**	**Baseline Offshore Wind**	**Scenario 1: Current - Radial AC** Phased 2024	**Scenario 1: Current - Radial AC** Full 2028	**Scenario 2: Planned - Offshore HVDC Grid** Phased 2024	**Scenario 2: Planned - Offshore HVDC Grid** Full 2028	*POWER INJECTION AT POI (MW)*
Footprint (Salem Harbor 115kV)	114417						
Woburn 345 kV	110756					800	
Mystic 345 kV	110759				1200	1200	
K Street 345 kV	110790					800	
Bridgewater 345 kV	115446					970	
Pilgrim (alternate to Footprint) 115 kV	110783						
Canal 345 kV	111193	600**	1100	2500			
West Barnstable 345 kV	111134	1600					
Bourne 115 kV	111217	200**	100	445			
Brayton Point 345 kV	114734		800	800	1200	1200	
Kent County 345 kV	117301	704	800	2200		418	
Montville 345 kV	119180		800	2200			
Millstone/WaterfordCT 345 kV	119194					1200	
New Haven (alternate to Kent Co)							
East Devon 345 kV	119389					800	
Singer/BridgeportCT 345 kV	123626				1200	1200	
Incremental MW Total to Onshore POIs		**3104**	**3600**	**8145**	**3600**	**8588**	
POIs		2	5	5	3	9	

Millstone 1200 MW assumes continuing operation of Millstone Nuclear Plant in 2030, retirement of Unit 2 or 3 could enable additional offshore wind injection

Phased 2024 reflects next procurement round based on existing authorizations for MA (1600 MW), CT (1200 MW) and additional demand from other New England states and third parties

Full 2028 reflects development of full 14.5 GW estimated capacity of ISONE offshore lease areas. 2028 was chosen to remain within ISONE projections. Injection volumes in 2028 were based on assumed losses of 8% for Scenario 1 and 3% for Scenario 2. Subsequent revision of assumed losses to 4% for Scenario 1 and 2.4% for Scenario 2 would increase total 2028 injections to 8,499MW for Scenario 1 and 8,641MW for Scenario 2. Larger additional injections in Scenario 1 are not anticipated to change results significantly, as marginal injections at constrained POIs would have minimal system-wide impacts.

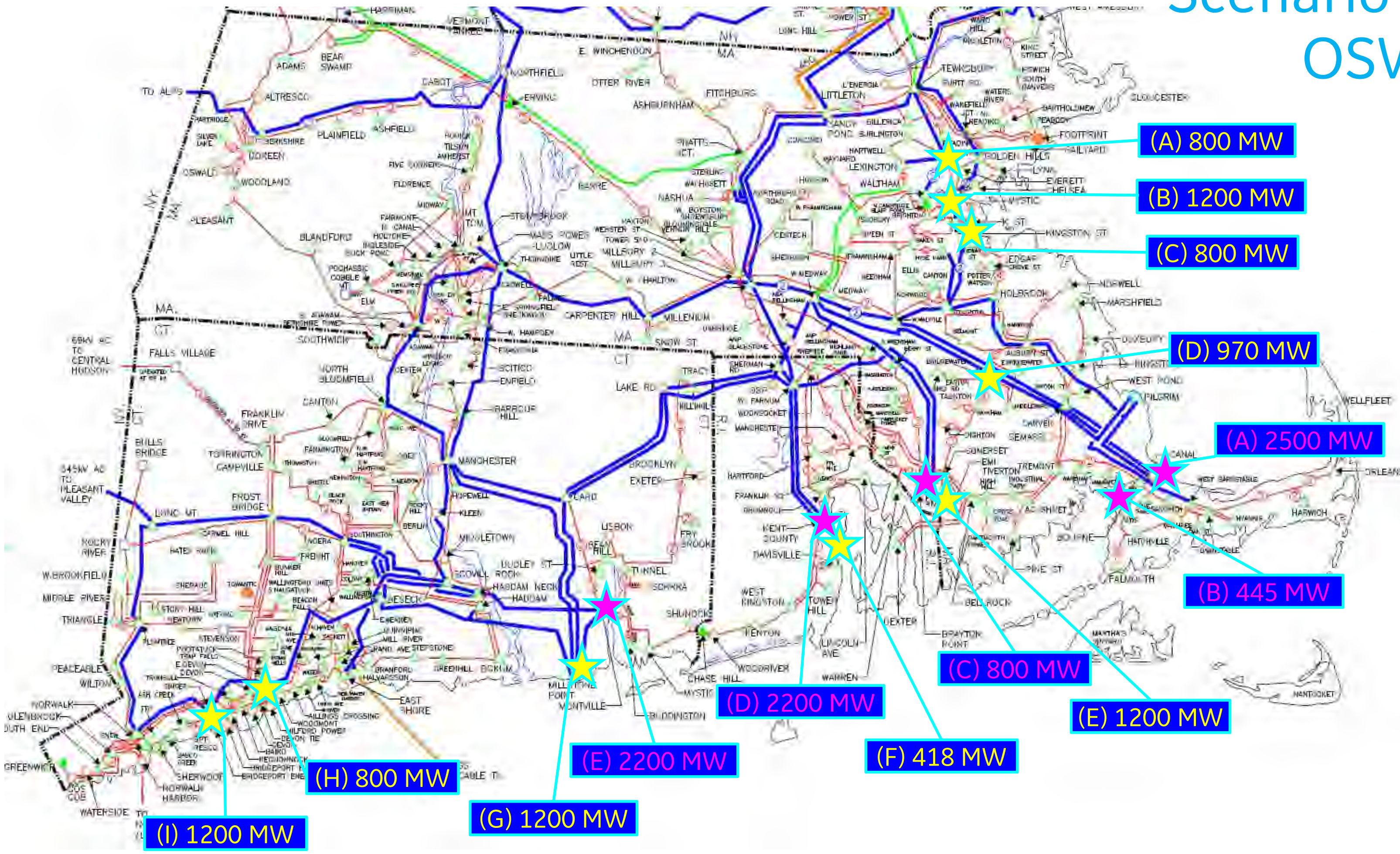
Base Case Baseline OSW Buildout Map



Baseline POI

- 3.104 GW
- 3 POIs:
  - A. Bourne 345 kV
  - B. W. Barnstable 345 kV
  - C. Kent County 345 kV

Scenario 1 vs Scenario 2 OSW Buildout Map



Scenario 1 POI

» 8.145 GW

» 5 POI

A. Canal 345 kV
B. Bourne 345 kV
C. Brayton Point 345 kV
D. Kent County 345 kV
E. Montville 345 kV

Scenario 2 POI

» 8.588 GW

» 9 POI

A. Woburn 345 kV
B. Mystic 345 kV
C. K Street 345 kV
D. Bridgewater 345 kV
E. Brayton Point 345 kV
F. Kent County 345 kV
G. Millstone 345 kV
H. East Devon 345 kV
I. Singer 345 kV

Transmission Security Results

TARA Contingency Analysis

- N-1
- N-1-1

N-1 Results

TARA Contingency Analysis

Overloaded Monitored Elements in Scenario 1 *Phased* OSW Buildout (2024)

Overloaded Transmission Elements (27)

- New Overloads (10)
- Overloaded in Base Case AND OSW (13)
- Overloaded in Base Case, Worse in OSW (4)

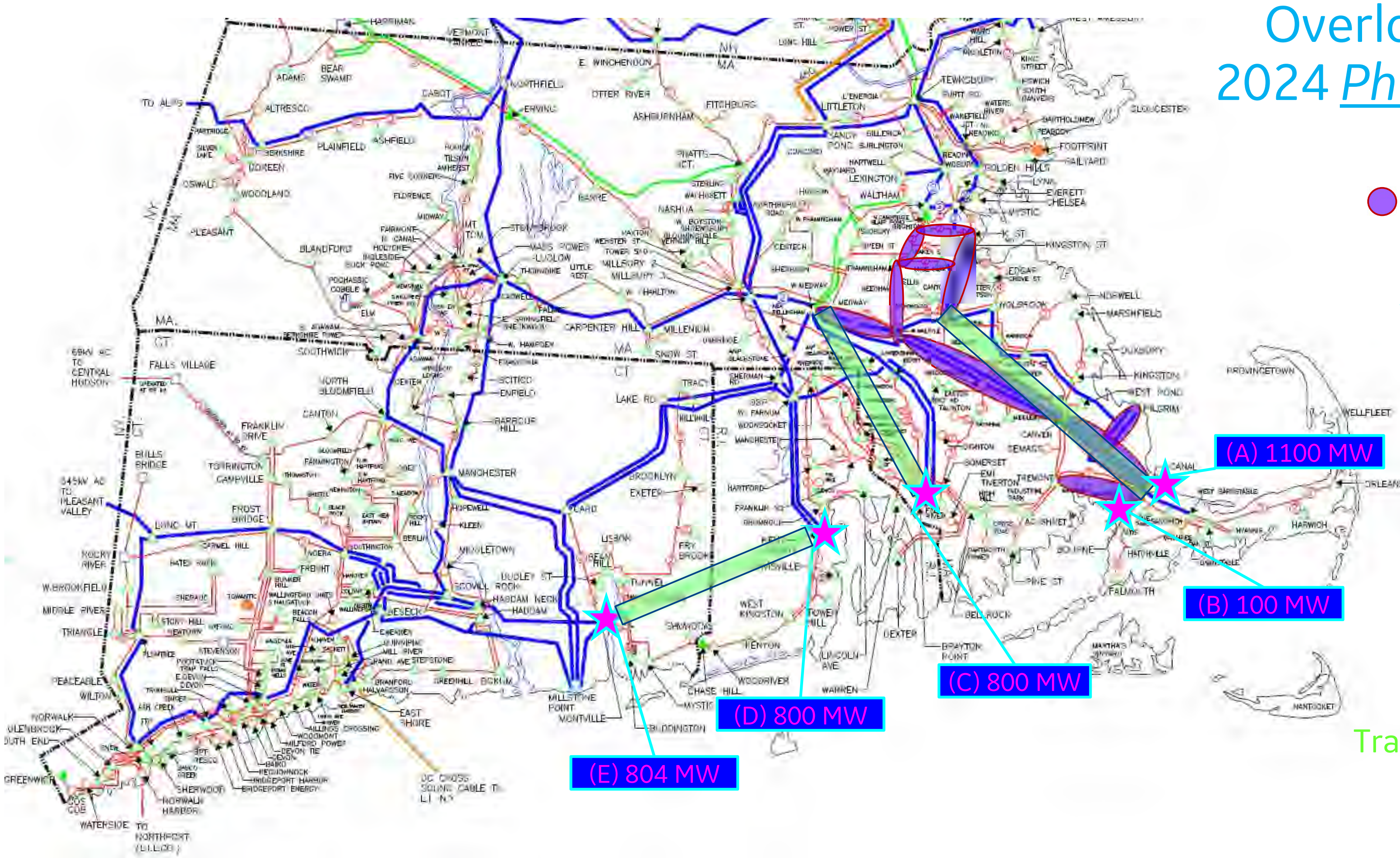
Overloaded Transmission Elements by kV:

- 345 kV Branches (11)
- 115 kV Branches (29)

Monitored Facility	kV	2024 OSW Buildout AC Loading %	Scenario 2 Base Case AC Loading %	Rating (MVA)	Frequency	Mitigated by Transmission Project
111133 CARVER 345 111193 CANAL 345 1	345	143	< 85%	1221	5	A
110814 BRIGHTON B 115 110855 WASH_TAP 511 115 1	115	129	< 85%	150	251	NONE
110813 BRIGHTON A 115 110854 WASH_TAP 510 115 1	115	129	< 85%	150	251	NONE
110782 JORDAN ROAD 345 111193 CANAL 345 1	345	128	< 85%	1446	5	A
110855 WASH_TAP 511 115 110887 BAKER ST PS2 115 1	115	123	< 85%	150	386	NONE
110854 WASH_TAP 510 115 110886 BAKER ST PS1 115 1	115	123	< 85%	150	386	NONE
111133 CARVER 345 111134 W BARNSTABLE 345 1	345	118	< 85%	1016	259	NONE
110853 COLBURN 511 115 110855 WASH_TAP 511 115 1	115	118	99	140	1	NONE
110852 COLBURN 510 115 110854 WASH_TAP 510 115 1	115	118	99	140	1	NONE
110887 BAKER ST PS2 115 110889 BAKER ST B 115 1	115	114	95	205	9	NONE
110886 BAKER ST PS1 115 110888 BAKER ST A 115 1	115	114	95	205	9	NONE
111133 CARVER 345 115013 NGR_356_NST 345 1	345	112	< 85%	1410	8	A
110786 STOUGHTON 345 110790 K STREET 1 345 2	345	111	< 85%	675	9	NONE
110786 STOUGHTON 345 110790 K STREET 1 345 1	345	110	91	675	5	NONE
111149 HORSEPDTP108 115 111156 VALLEYNB 108 115 1	115	109	< 85%	246	3	A
111133 CARVER 345 115036 NGR_331_NST 345 1	345	104	< 85%	1156	4	A
110780 WEST WALPOLE 345 115008 NST_331_NGR 345 1	345	104	< 85%	1156	4	A
111142 VALLEYNB 113 115 111158 HORSEPDTP113 115 1	115	103	< 85%	246	2	A
111158 HORSEPDTP113 115 111217 BOURNE 115 1	115	103	< 85%	246	2	A
111155 WAREHAM 108 115 111156 VALLEYNB 108 115 1	115	101	< 85%	246	2	A
111152 WAREHAM 113 115 111318 TREMONT 113 115 1	115	100	< 85%	246	2	A
111142 VALLEYNB 113 115 111152 WAREHAM 113 115 1	115	100	< 85%	246	2	A
111149 HORSEPDTP108 115 111217 BOURNE 115 1	115	101	88	354	1	A
110888 BAKER ST A 115 110892 HYDE PARK B 115 1	115	137	118	235	1	NONE
110889 BAKER ST B 115 110891 HYDE PARK A 115 1	115	136	116	235	1	NONE
110893 NEEDHAM 115 110894 DOVER MA 115 1	115	115	108	385	5	NONE
111137 TREMONT S 115 111155 WAREHAM 108 115 1	115	119	102	246	1	A

Transmission Project Code:
A) Canal - Stoughton 345 kV
B) Brayton Point - West Medway 345 kV
C) Monvale - Kent County 345 kV

Overloaded Elements
2024 *Phased* Scenario 1



Design Contingency

Scenario 1 POI
3.6 GW

» 5 POI

A. Canal 345 kV
B. Bourne 345 kV
C. Brayton Point 345 kV
D. Kent County 345 kV
E. Montville 345 kV

Potential 345kV Transmission Reinforcements Identified by ISONE

Overloaded Monitored Elements in Scenario 1 *Full* OSW Buildout (2028)

Overloaded Transmission Elements (60)

- New Overloads (42)
- Overloaded in Base Case AND OSW (17)
- Overloaded in Base Case, Worse in OSW (1)

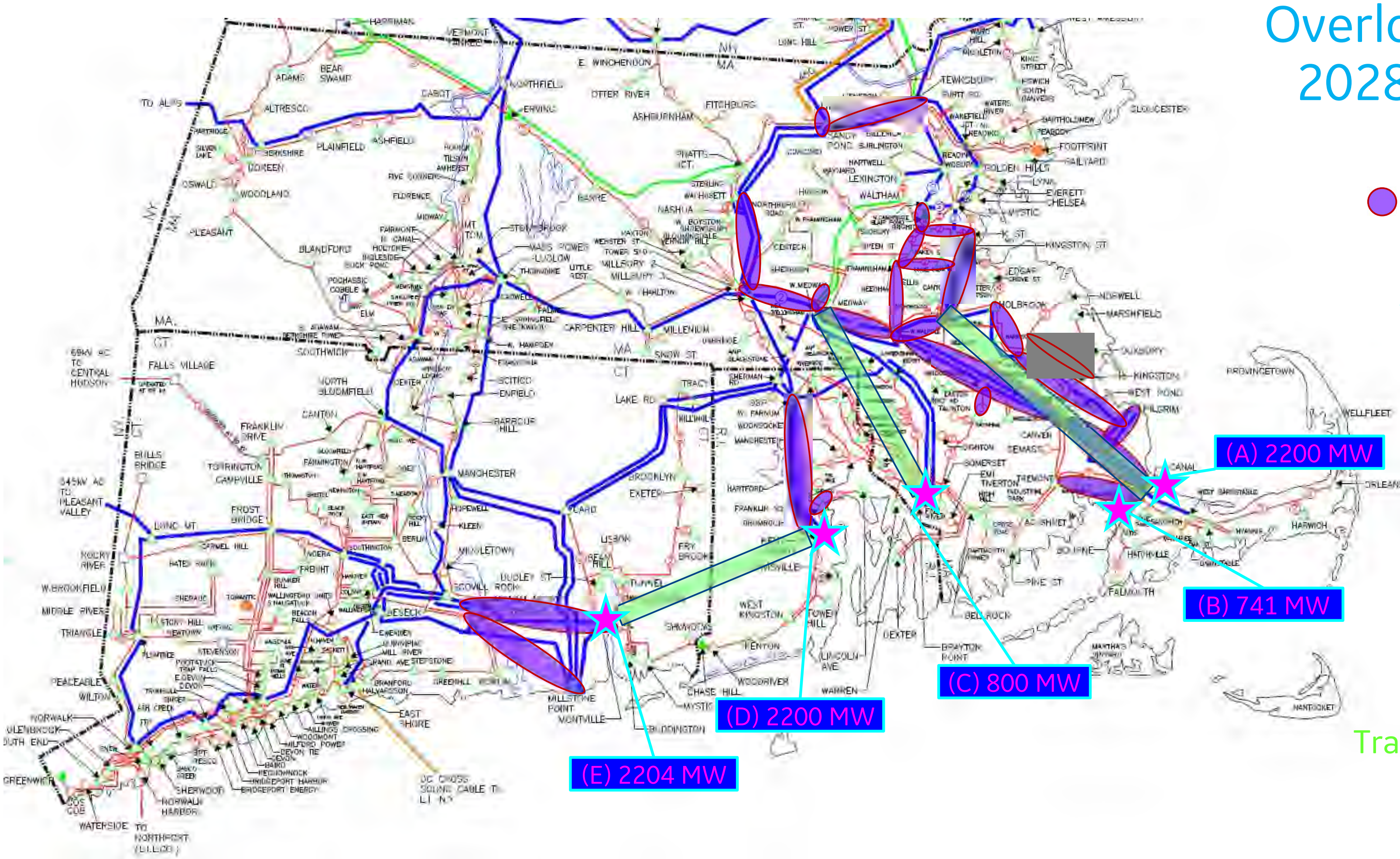
Overloaded Transmission Elements by kV:

- 345 kV Branches (22)
- 115 kV Branches (32)
- Transformers (6)

Transmission Project Code:
A) Canal - Stoughton 345 kV
B) Brayton Point - West Medway 345 kV
C) Monvale - Kent County 345 kV

Monitored Facility	kV	2028 OSW Buildout AC Loading %	Scenario 2 Base Case AC Loading %	Rating (MVA)	Frequency	Mitigated by Transmission Project
111133 CARVER 345 111193 CANAL 345 1	345	217	< 85%	1221	33	A
110782 JORDAN ROAD 345 111193 CANAL 345 1	345	192	< 85%	1446	888	A
110814 BRIGHTON B 115 110855 WASH_TAP 511 115 1	115	171	< 85%	150	372	NONE
110813 BRIGHTON A 115 110854 WASH_TAP 510 115 1	115	170	< 85%	150	371	NONE
111149 HORSEPDTP108 115 111156 VALLEYNB 108 115 1	115	165	< 85%	246	58	A
111142 VALLEYNB 113 115 111158 HORSEPDTP113 115 1	115	158	< 85%	246	11	A
111158 HORSEPDTP113 115 111217 BOURNE 115 1	115	158	< 85%	246	11	A
111155 WAREHAM 108 115 111156 VALLEYNB 108 115 1	115	157	< 85%	246	8	A
111133 CARVER 345 115013 NGR_356_NST 345 1	345	156	< 85%	1410	847	A
111142 VALLEYNB 113 115 111152 WAREHAM 113 115 1	115	156	< 85%	246	9	A
111152 WAREHAM 113 115 111318 TREMONT 113 115 1	115	156	< 85%	246	9	A
110855 WASH_TAP 511 115 110887 BAKER ST PS2 115 1	115	152	< 85%	150	303	NONE
110854 WASH_TAP 510 115 110886 BAKER ST PS1 115 1	115	152	< 85%	150	303	NONE
111137 TREMONT S 115 111155 WAREHAM 108 115 1	115	148	< 85%	246	5	A
111133 CARVER 345 115036 NGR_331_NST 345 1	345	144	< 85%	1156	22	A
110780 WEST WALPOLE 345 115008 NST_331_NGR 345 1	345	144	< 85%	1156	22	A
110852 COLBURN 510 115 110854 WASH_TAP 510 115 1	115	141	99	140	1	NONE
110853 COLBURN 511 115 110855 WASH_TAP 511 115 1	115	141	99	140	1	NONE
110781 HOLBROOK 345 115009 NGR_335_NST 345 1	345	139	< 85%	1410	35	A
110786 STOUGHTON 345 110790 K STREET 1 345 2	345	138	< 85%	675	893	NONE
110786 STOUGHTON 345 110790 K STREET 1 345 1	345	137	< 85%	675	17	NONE
110886 BAKER ST PS1 115 110888 BAKER ST A 115 1	115	136	< 85%	205	359	NONE
110887 BAKER ST PS2 115 110889 BAKER ST B 115 1	115	136	< 85%	205	359	NONE
110782 JORDAN ROAD 345 115011 NGR_342_NST 345 1	345	132	< 85%	1855	11	A
110834 HIGH ST 510 115 110836 K STREET 1 115 1	115	130	< 85%	190	45	NONE
110835 HIGH ST 511 115 110837 K STREET 2 115 1	115	129	< 85%	190	48	NONE
111133 CARVER 345 111134 W BARNSTABLE 345 1	345	129	< 85%	1016	100	NONE
110830 KINGSTN ST W 115 110836 K STREET 1 115 2	115	125	< 85%	190	29	NONE
111136 KINGSTON 115 115006 NGR_191_NST 115 1	115	124	< 85%	165	2	NONE
110830 KINGSTN ST W 115 110836 K STREET 1 115 1	115	124	< 85%	190	29	NONE
115446 BRIDGEWATER 345 115451 BRIDGEWATER 115 2	345	122	< 85%	472	1	A
111149 HORSEPDTP108 115 111217 BOURNE 115 1	115	121	< 85%	354	4	A
110772 W MEDWAY B 345 115014 NGR_357_NST 345 2	345	118	< 85%	1315	1	NONE
119168 HADDAM NECK 345 119180 MONTVILE_364 345 1	345	118	< 85%	1884	8	C
110836 K STREET 1 115 110790 K STREET 1 345 1	345	117	< 85%	750	7	NONE
110837 K STREET 2 115 110790 K STREET 1 345 1	345	117	< 85%	750	8	NONE
115011 NGR_342_NST 345 115447 AUBURN ST 345 1	345	116	< 85%	2108	5	A
110814 BRIGHTON B 115 110815 N. CAMBRIDGE 115 1	115	114	< 85%	231	4	NONE
115008 NST_331_NGR 345 115036 NGR_331_NST 345 1	345	113	< 85%	1466	8	A
115446 BRIDGEWATER 345 115451 BRIDGEWATER 115 1	345	112	< 85%	515	1	A
110813 BRIGHTON A 115 110989 BLAIR POND 115 1	115	111	< 85%	231	1	NONE
113950 SANDY POND 345 114027 SANDY PD T1 99.0 1	345	111	86	572	1	NONE
110888 BAKER ST A 115 110892 HYDE PARK B 115 1	115	110	< 85%	235	3	NONE
110889 BAKER ST B 115 110891 HYDE PARK A 115 1	115	110	< 85%	235	3	NONE
113264 MILLBURY 345 113265 WACHUSETT 345 1	345	108	< 85%	1609	1	NONE
110900 HOLBROOK 115 110908 E.HOLBRK TAP 115 1	115	107	< 85%	548	2	A
119194 MILLSTONE 345 119209 HADDAM 345 1	345	107	< 85%	1884	6	C
110791 HYDE PARK 115 110788 HYDE PARK 345 1	345	107	89	600	8	NONE
117001 WEST FARNUM 345 117301 KENT COUNTY 345 2	345	107	< 85%	1918	4	C
113950 SANDY POND 345 113951 TEWKSBURY 345 1	345	107	< 85%	1918	6	NONE
110770 W MEDWAY A 345 110794 W MEDWAY A 230 1	345	107	< 85%	585	9	NONE
117330 JOHNSTON_171 115 117334 RISE 171_TAP 115 1	115	106	< 85%	446	2	B
117001 WEST FARNUM 345 117301 KENT COUNTY 345 1	345	106	< 85%	1918	4	C
110832 KINGSTN ST A 115 110835 HIGH ST 511 115 1	115	106	< 85%	190	4	NONE
110833 KINGSTN ST B 115 110834 HIGH ST 510 115 1	115	105	< 85%	190	4	NONE
110781 HOLBROOK 345 110786 STOUGHTON 345 1	345	105	< 85%	1649	1	A
115013 NGR_356_NST 345 115446 BRIDGEWATER 345 1	345	104	< 85%	2108	4	A
110908 E.HOLBRK TAP 115 115020 NG451-536NST 115 1	115	102	< 85%	588	1	A
110893 NEEDHAM 115 110894 DOVER MA 115 1	115	101	< 85%	385	1	NONE
117327 DRUMROCK 115 117379 DRUMROCK T5 99.0 1	115	116	113	107	1	C

Overloaded Elements 2028 *Full* Scenario 1



Design Contingency

Scenario 1 POI
8.145 GW

» 5 POI

A. Canal 345 kV
B. Bourne 345 kV
C. Brayton Point 345 kV
D. Kent County 345 kV
E. Montville 345 kV

Potential 345kV Transmission Reinforcements Identified by ISONE

Overloaded Monitored Elements in Scenario 2 *Phased* & *Full* OSW Buildout (2024 & 2028)

Overloaded Transmission Elements (1 & 4)

- New Overloads (1 in 2024 & 4 in 2028)
- No Pre-existing Overloads Worse with OSW

2024

Monitored Facility	kV	2024 OSW Buildout AC Loading %	Scenario 2 Base Case AC Loading %	Rating (MVA)	Frequency
110758 N. CAMBRIDGE 345 110759 MYSTIC MA 345 1	345	113	< 85%	596	2

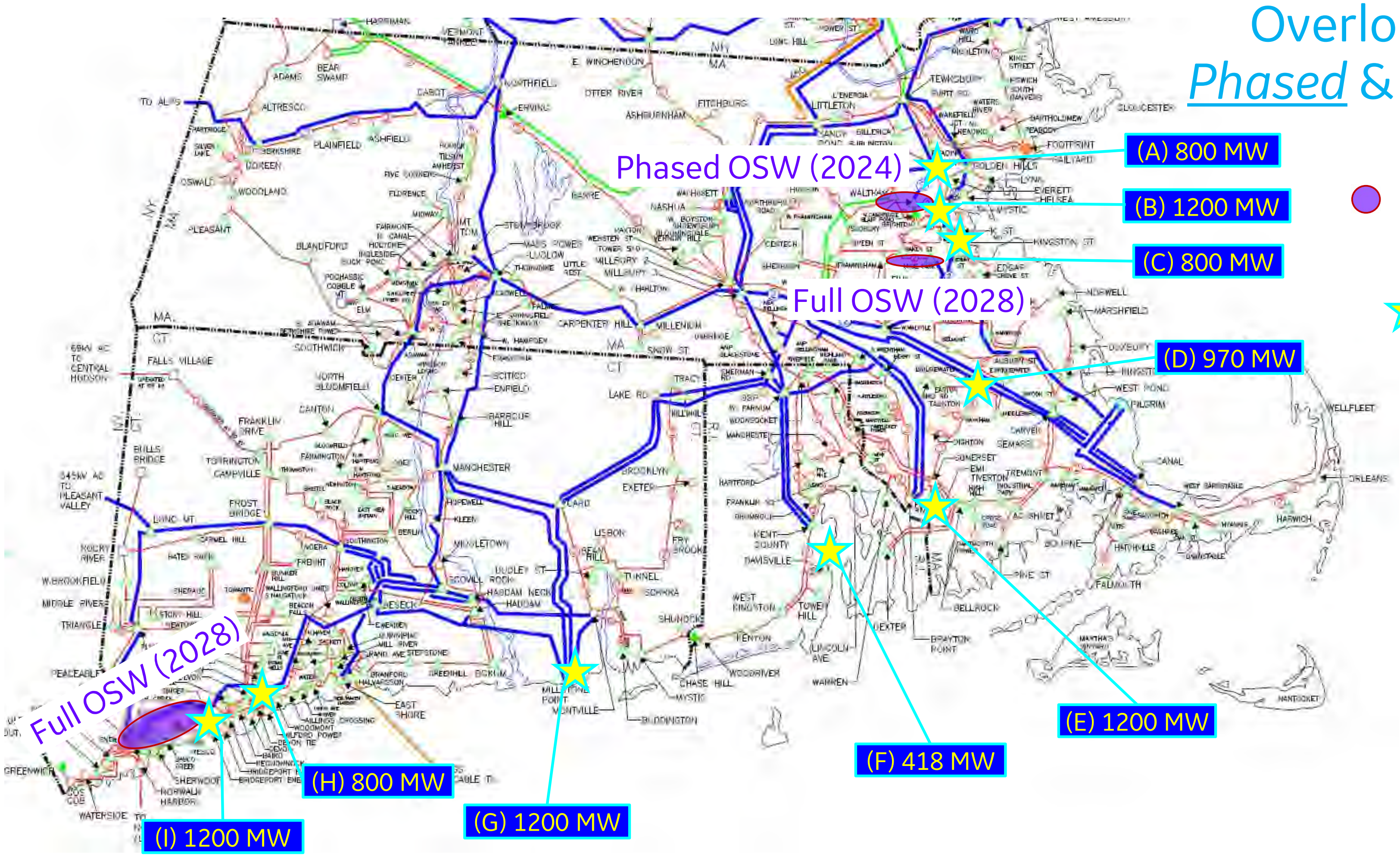
Overloaded Transmission Elements by kV:

- 345 kV Branches (1 in 2024 & 2 in 2028)
- 115 kV Branches (0 in 2024 & 2 in 2028)

2028

Monitored Facility	kV	2028 OSW Buildout AC Loading %	Scenario 2 Base Case AC Loading %	Rating (MVA)	Frequency
110888 BAKER ST A 115 110892 HYDE PARK B 115 1	115	115	100	235	1
110889 BAKER ST B 115 110891 HYDE PARK A 115 1	115	113	97	235	1
119441 NU_3921_UI 345 119480 NORWALK 345 1	345	107	< 85%	1133	3
119428 NU_3280_UI 345 119480 NORWALK 345 1	345	107	< 85%	1133	3

Overloaded Elements
Phased & *Full* Scenario 2



Design Contingency

Scenario 2 POI
8.588 GW

» 9 POI

A. Woburn 345 kV
B. Mystic 345 kV
C. K Street 345 kV
D. Bridgewater 345 kV
E. Brayton Point 345 kV
F. Kent County 345 kV
G. Millstone 345 kV
H. East Devon 345 kV
I. Singer 345 kV

N-1-1 Results

TARA Contingency Analysis

Overview of N-1-1 Methodology

Relevant Notes for TARA Analysis

N-1-1 analysis focuses on the next 3.6 GW offshore wind injection most immediately relevant

N-1-1 analysis for the full 8+ GW build out was beyond the scope of this analysis

NERC

» Allows Non-Consequential Load-Shedding for non-generator first contingency loss in N-1-1

NPCC

» For simplicity, Bulk Power System (BPS) Assumption for ISONE: 200kV+

» Actual ISONE BPS list contains many elements below 200kV

Overloaded Monitored Elements in Scenario 1

NPCC Criteria

Overloaded Monitored Element	OSW Buildout AC %Loading	Rating (MVA)	Total N-1-1 Contingency Combinations	Base Case AC %Loading	New Overload or Makes Existing Overload Worse
111133 CARVER 345 111193 CANAL 345 1	194.5	1221	3305	less than 85%	New Overloads Due to Scenario 1 OSW Buildout, NOT Overloaded in Base Case
110786 STOUGHTON 345 110790 K STREET 1 345 2	176.8	675	10474	100	
110786 STOUGHTON 345 110790 K STREET 1 345 1	174.6	675	4117	100	
110782 JORDAN ROAD 345 111193 CANAL 345 1	165.6	1446	1734	less than 85%	
111133 CARVER 345 115036 NGR_331_NST 345 1	144.1	1156	16	less than 85%	
110780 WEST WALPOLE 345 115008 NST_331_NGR 345 1	143.8	1156	16	less than 85%	
119168 HADDAM NECK 345 119180 MONTVILE_364 345 1	135.2	1884	3832	less than 85%	
111133 CARVER 345 115013 NGR_356_NST 345 1	130.3	1410	13	less than 85%	
119272 NE_398_NY 345 126294 PLTVLLEY 345 1	125.9	1382	7	less than 85%	
119194 MILLSTONE 345 119209 HADDAM 345 1	124.8	1884	104	less than 85%	
121408 NE_601_NY 138 129343 NRTHPT P 138 1	124.4	191	1	less than 85%	
121409 NE_602_NY 138 129343 NRTHPT P 138 2	124.0	191	1	less than 85%	
121410 NE_603_NY 138 129343 NRTHPT P 138 3	123.2	191	1	less than 85%	
113950 SANDY POND 345 113951 TEWKSBURY 345 1	121.8	1918	97	less than 85%	
119259 LONG MTN 345 119272 NE_398_NY 345 1	121.8	1428	6	less than 85%	
113264 MILLBURY 345 113265 WACHUSETT 345 1	118.9	1609	16	less than 85%	
110770 W MEDWAY A 345 110794 W MEDWAY A 230 1	117.6	585	327	91	
119181 MONTVILE_371 345 119194 MILLSTONE 345 1	114.7	1884	18	less than 85%	
104191 NU_381_VEL 345 107040 VERNON VT 345 1	114.6	1491	41	88	
115008 NST_331_NGR 345 115036 NGR_331_NST 345 1	113.6	1466	12	less than 85%	
119129 KLEEN 345 119142 SCOVILLE RCK 345 1	112.8	1912	15	less than 85%	
104191 NU_381_VEL 345 104195 NU_381_NU 345 1	109.6	1626	6	less than 85%	
113265 WACHUSETT 345 113950 SANDY POND 345 1	109.2	1611	3	less than 85%	
104159 NU_326_NGR 345 113950 SANDY POND 345 1	108.0	1635	13	less than 85%	
119142 SCOVILLE RCK 345 119168 HADDAM NECK 345 1	107.3	1697	11	less than 85%	
123637 ESHORE 9X 345 123638 ESHORE TELEM 345 1	107.1	617	7	less than 85%	
119168 HADDAM NECK 345 119220 BESECK 345 1	107.1	1884	8	less than 85%	
119142 SCOVILLE RCK 345 119233 SOUTHINGTON 345 1	107.0	1884	8	less than 85%	
110781 HOLBROOK 345 115009 NGR_335_NST 345 1	105.9	1410	14	less than 85%	
110785 ANP BLACKSTN 345 115015 NGR_3361_NST 345 1	105.8	1685	16	less than 85%	
110780 WEST WALPOLE 345 110786 STOUGHTON 345 1	105.8	1649	4	less than 85%	
119077 MANCHESTER 345 119194 MILLSTONE 345 1	104.6	1797	15	less than 85%	
119402 NU_3165_UI 345 123626 SINGER 345 1	104.2	1074	9	87	
119415 NU_3619_UI 345 123626 SINGER 345 1	104.2	1074	9	87	
119209 HADDAM 345 119220 BESECK 345 1	103.9	1884	11	less than 85%	
123636 ESHORE 8X 345 123638 ESHORE TELEM 345 1	102.9	642	2	less than 85%	
110782 JORDAN ROAD 345 115011 NGR_342_NST 345 1	102.6	1855	4	less than 85%	
119389 EAST DEVON 345 119402 NU_3165_UI 345 1	101.7	1106	2	less than 85%	
119389 EAST DEVON 345 119415 NU_3619_UI 345 1	101.7	1106	2	less than 85%	
104151 LAWRENCE RD 345 104159 NU_326_NGR 345 1	101.1	1747	1	less than 85%	
110786 STOUGHTON 345 110788 HYDE PARK 345 1	100.6	676	1	less than 85%	
110786 STOUGHTON 345 110790 K STREET 1 345 2	196.0	675	82	115	Overloaded in Base Case, Worse with Scenario 1 OSW Buildout
110786 STOUGHTON 345 110790 K STREET 1 345 1	193.7	675	46	114	
119389 EAST DEVON 345 119415 NU_3619_UI 345 1	143.0	1106	1	121	
119389 EAST DEVON 345 119402 NU_3165_UI 345 1	143.0	1106	1	121	
119415 NU_3619_UI 345 123626 SINGER 345 1	142.2	1074	1	121	
119402 NU_3165_UI 345 123626 SINGER 345 1	142.2	1074	1	121	
119428 NU_3280_UI 345 119480 NORWALK 345 1	109.6	1133	1	103	
119441 NU_3921_UI 345 119480 NORWALK 345 1	109.2	1133	1	103	

NERC Criteria

Overloaded Monitored Element	OSW Buildout AC %Loading	Rating (MVA)	Total N-1-1 Contingency Combinations	Base Case AC %Loading	New Overload or Makes Existing Overload Worse
110814 BRIGHTON B 115 110855 WASH_TAP 511 115 1	174.2	150	7814	91	New Overloads Due to Scenario 1 OSW Buildout, NOT Overloaded in Base Case
110813 BRIGHTON A 115 110854 WASH_TAP 510 115 1	174.1	150	7806	91	
110855 WASH_TAP 511 115 110887 BAKER ST PS2 115 1	166.0	150	7851	100	
110854 WASH_TAP 510 115 110886 BAKER ST PS1 115 1	166.0	150	7848	100	
110786 STOUGHTON 345 110790 K STREET 1 345 2	160.4	675	588	100	
111133 CARVER 345 111193 CANAL 345 1	159.9	1221	63	less than 85%	
110786 STOUGHTON 345 110790 K STREET 1 345 1	158.3	675	164	99	
110888 BAKER ST A 115 110892 HYDE PARK B 115 1	142.4	235	59	98	
110782 JORDAN ROAD 345 111193 CANAL 345 1	141.9	1446	83	less than 85%	
110889 BAKER ST B 115 110891 HYDE PARK A 115 1	140.7	235	61	96	
110886 BAKER ST PS1 115 110888 BAKER ST A 115 1	137.5	205	952	89	
110887 BAKER ST PS2 115 110889 BAKER ST B 115 1	137.5	205	951	89	
104900 NORTH KEENE 115 104902 KEENE 115 1	121.9	135	2	less than 85%	
110835 HIGH ST 511 115 110837 K STREET 2 115 1	121.6	190	8	less than 85%	
110834 HIGH ST 510 115 110836 K STREET 1 115 1	121.1	190	8	less than 85%	
104935 CHESTNUT HIL 115 104946 VERNONROAD_T 115 1	120.0	234	1	less than 85%	
113950 SANDY POND 345 113951 TEWKSBURY 345 1	118.1	1918	4	less than 85%	
110830 KINGSTN ST W 115 110836 K STREET 1 115 1	117.7	190	5	less than 85%	
110830 KINGSTN ST W 115 110836 K STREET 1 115 2	117.7	190	5	less than 85%	
110893 NEEDHAM 115 110894 DOVER MA 115 1	116.9	385	185	100	
111149 HORSEPDTP108 115 111156 VALLEYNB 108 115 1	115.2	246	15	less than 85%	
104913 A152_T 115 104924 WESTPORT 115 1	113.5	234	1	less than 85%	
104924 WESTPORT 115 104935 CHESTNUT HIL 115 1	113.5	234	1	less than 85%	
104895 TUTTLE HILL 115 104900 NORTH KEENE 115 1	111.6	135	2	less than 85%	
104891 JACKMAN 115 104895 TUTTLE HILL 115 1	111.3	135	2	less than 85%	
110836 K STREET 1 115 110790 K STREET 1 345 1	110.4	750	1	less than 85%	
110837 K STREET 2 115 110790 K STREET 1 345 1	110.4	750	1	less than 85%	
119718 MONTVILLE 115 119181 MONTVILE_371 345 2	110.3	527	254	less than 85%	
104191 NU_381_VEL 345 104195 NU_381_NU 345 1	109.6	1626	1	less than 85%	
111142 VALLEYNB 113 115 111158 HORSEPDTP113 115 1	109.4	246	15	less than 85%	
111158 HORSEPDTP113 115 111217 BOURNE 115 1	109.4	246	15	less than 85%	
117330 JOHNSTON_171 115 117334 RISE 171_TAP 115 1	108.8	446	53	less than 85%	
104191 NU_381_VEL 345 107040 VERNON VT 345 1	108.1	1491	7	88	
111155 WAREHAM 108 115 111156 VALLEYNB 108 115 1	107.9	246	14	less than 85%	
119168 HADDAM NECK 345 119180 MONTVILE_364 345 1	107.5	1884	216	less than 85%	
111142 VALLEYNB 113 115 111152 WAREHAM 113 115 1	107.0	246	14	less than 85%	
111152 WAREHAM 113 115 111318 TREMONT 113 115 1	107.0	246	14	less than 85%	
113264 MILLBURY 345 113265 WACHUSETT 345 1	106.3	1609	1	less than 85%	
110770 W MEDWAY A 345 110794 W MEDWAY A 230 1	105.9	585	3	less than 85%	
117331 JOHNSTON_172 115 117360 RISE 172_TAP 115 1	103.6	446	3	less than 85%	
104159 NU_326_NGR 345 113950 SANDY POND 345 1	102.2	1635	1	less than 85%	
110814 BRIGHTON B 115 110815 N. CAMBRIDGE 115 1	102.2	231	2	less than 85%	
110785 ANP BLACKSTN 345 115015 NGR_3361_NST 345 1	101.0	1685	1	less than 85%	
110791 HYDE PARK 115 110788 HYDE PARK 345 1	100.3	600	1	less than 85%	
110855 WASH_TAP 511 115 110887 BAKER ST PS2 115 1	187.5	150	60	119	Overloaded in Base Case, Worse with Scenario 1 OSW Buildout
110854 WASH_TAP 510 115 110886 BAKER ST PS1 115 1	187.5	150	60	119	
110786 STOUGHTON 345 110790 K STREET 1 345 2	178.5	675	3	108	
110786 STOUGHTON 345 110790 K STREET 1 345 1	176.7	675	3	107	
110893 NEEDHAM 115 110894 DOVER MA 115 1	124.5	385	55	109	

Overloaded Monitored Elements in Scenario 2

NPCC Criteria

Overloaded Monitored Element	OSW Buildout AC %Loading	Rating (MVA)	Total N-1-1 Contingency Combinations	Base Case AC %Loading	New Overload or Makes Existing Overload Worse
110758 N. CAMBRIDGE 345 110759 MYSTIC MA 345 1	174.1	596	22	less than 85%	New Overloads Due to Scenario 2 OSW Buildout, NOT Overloaded in Base Case
110758 N. CAMBRIDGE 345 110759 MYSTIC MA 345 2	147.6	705	10	less than 85%	
110786 STOUGHTON 345 110790 K STREET 1 345 2	120.7	675	1	less than 85%	
110786 STOUGHTON 345 110790 K STREET 1 345 1	120.1	675	1	less than 85%	
119428 NU_3280_UI 345 119480 NORWALK 345 1	111.1	1133	52	less than 85%	
119441 NU_3921_UI 345 119480 NORWALK 345 1	111.1	1133	52	less than 85%	
119181 MONTVILE_371 345 119194 MILLSTONE 345 1	106.7	1884	14	less than 85%	
114734 BRAYTN POINT 345 114900 BERRY STREET 345 1	104.4	1157	2	less than 85%	
119428 NU_3280_UI 345 119480 NORWALK 345 1	177.5	1133	1	102	Overloaded in Base Case, Worse with Scenario 2 OSW
119441 NU_3921_UI 345 119480 NORWALK 345 1	177.5	1133	1	102	

NERC Criteria

Overloaded Monitored Element	OSW Buildout AC %Loading	Rating (MVA)	Total N-1-1 Contingency Combinations	Base Case AC %Loading	New Overload or Makes Existing Overload Worse
115743 GRAND ARMY 115 115744 Z1_TAP 115 1	117.9	446	1	less than 85%	New Overloads Due to Scenario 2 OSW Buildout, NOT Overloaded in Base Case
115743 GRAND ARMY 115 115745 Y2_TAP 115 1	117.9	446	1	less than 85%	
115711 SOMERSET 115 115744 Z1_TAP 115 1	108.0	446	1	less than 85%	
115711 SOMERSET 115 115745 Y2_TAP 115 1	108.0	446	1	less than 85%	

Economic Production Cost Results

GE-MAPS Analysis

Much More Consistent LMP Change in Scenario 2

Necessary Transmission Upgrades Assumption

What happens with no transmission upgrades in the Base Case with 3.1 GW OSW?

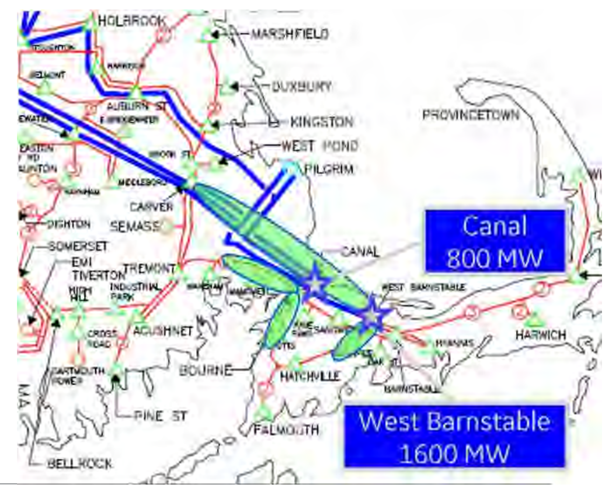
- Initial MAPS simulation showed 44% OSW curtailment at West Barnstable POI
- Curtailment is way too high and not a realistic starting point

<u>Six transmission segments where upgrades necessary for reasonable starting point in **Base Case,** which are similar to the upgrades proposed in the QP828 Feasibility Study:</u>

- Carver – West Barnstable 345 kV Line (399)
- West Barnstable – Mashpee 115 kV (137) and Otis – Bourne 115 kV Line (107)
- West Barnstable 345/115 kV Transformer
- Bourne – Horse Depot – Valley NB 115 kV Line (108)

Transmission Upgrades Assumed in Base Case

Powerflow					Ratings		
From Bus Number & Name		To Bus Number & Name		Ckt	Initial	Upgrade	Upgrade Description
111134	W BARNSTABLE345.00	111135	W BARNSTABLE115.00	1	604	1585	2nd Larger Parallel Transformer
111133	CARVER 345.00	111134	W BARNSTABLE345.00	1	1016	1585	Reconductor Line
111214	OTIS 115.00	111217	BOURNE 115.00	1	407	431	Reconductor Line
111135	W BARNSTABLE115.00	111215	MASHPEE 137 115.00	1	244	488	Parallel or Reconductor Line
111149	HORSEPDTP108115.00	111156	VALLEYNB 108115.00	1	246	291	Reconductor Line
111149	HORSEPDTP108115.00	111217	BOURNE 115.00	1	246	291	Reconductor Line



Transmission Upgrades for Reliability (NERC/NPCC)

Transmission upgrades modeled in respective offshore wind buildout scenarios required to mitigate N-1-1 transmission security violations according to NERC TPL Standards and NPCC Directory 1 Criteria

Scenario 1

- West Barnstable – K Street 345 kV
- West Barnstable – Mashpee – Hatchville – Fallmouth Tap 115 kV
- West Barnstable – Bourne – Canal – Valley – Wareham – Tremont 115 kV
- Johnson – Rise 115 kV

Scenario 2

- Mystic – North Cambridge – Woburn 345 kV
- Norwalk – Singer 345 kV

Annual Offshore Wind Generation Curtailment

Occurs when transmission constraints cause reduced generation output below full capability

Average ISONE Curtailment

- Base Case: 3% in 2024 & 2028*
- Scenario 1:   0.5% in 2024; 12.9% in 2028
- Scenario 2:   1.4% in 2024; 3.7% in 2028

Max Offshore Wind Generation Curtailment:

- Base Case: 6% (West Barnstable 1600MW)
- In 2024, Scenario 1 & 2 have relatively low curtailment % of OSW POIs, all OSW curtailment is located in SEMA
- In 2028, Scenario 1 top OSW POI curtailment is significantly higher (Scenario 1: ***34%*** *vs* Scenario 2: ***14%***)
- In 2028, Scenario 1 showed curtailment > 5% in multiple areas: SEMA and CT; only SWCT for Scenario 2
- Scenario 2 OSW buildout does not result in any additional West Barnstable POI curtailment compared to Base Case

		Average ISO-NE Curtailment			
Year	Technology Type	Base_S1	Base_S2	OSW_S1	OSW_S2
2024	Offshore	3.0%	3.0%	0.5%	1.4%
	Onshore	0.1%	0.1%	0.1%	0.1%
2028	Offshore	2.9%	3.0%	12.9%	3.7%
	Onshore	0.1%	0.1%	0.2%	0.8%

Percent Curtailment by ISO-NE Offshore Site						
Simulation Year	POI	MAPS Area	Base_S1	Base_S2	OSW_S1	OSW_S2
2024	Bourne	SEMAA	0%	0%	0%	0%
	Brayton Point	SEMAA			0%	0%
	Canal	SEMAA	0%	0%	0%	0%
	Kent County	RIA	0%	0%	0%	0%
	Montville	CTA			0%	
	Mystic	BOSTONA				0%
	Singer Bridgeport	SWCTA				
	West Barnstable	SEMAA	6%	6%	1%	6%
2028	Bourne	SEMAA	0%	0%	0%	0%
	Brayton Point	SEMAA			0%	2%
	Bridgewater	SEMAA				1%
	Canal	SEMAA	0%	0%	34%	1%
	East Devon	SWCTA				6%
	K Street	BOSTONA				1%
	Kent County	RIA	0%	0%	1%	1%
	Millstone	CTA				3%
	Montville	CTA			13%	
	Mystic	BOSTONA				0%
	Singer Bridgeport	SWCTA				14%
	West Barnstable	SEMAA	6%	6%	6%	6%
	Woburn	BOSTONA				2%

*2018 ISONE averaged 2% onshore wind curtailment

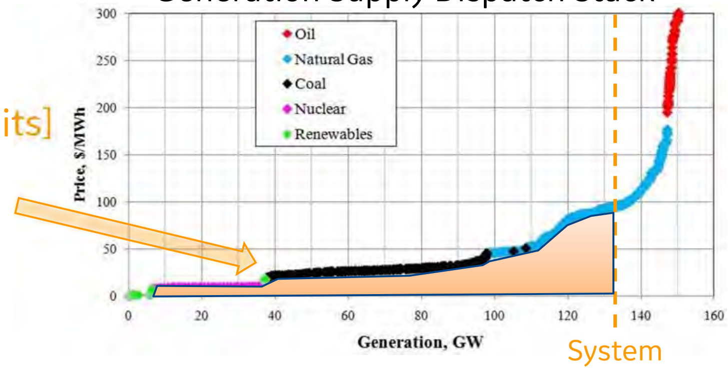
Annual ISONE Production Cost Savings

Electric energy production cost reflects variable operating costs

System Production Cost = Σ [Variable O&M Costs of Dispatched Units]

Generation Supply Dispatch Stack

Area Under the Dispatch Curve



System Demand

Production Cost Saving Comparison

- Production cost savings for both Scenario 1 & 2 are similar in 2024
- In 2028, Scenario 2 shows more production cost savings than Scenario 1 (difference of **$55M**)

	ISO-NE Production Cost ($M)			
Year	**Base_Case**	**Base_S2**	**OSW_S1**	**OSW_S2**
2024	$1,774	$1,776	$1,489	$1,492
2028	$2,064	$2,062	$1,500	$1,443

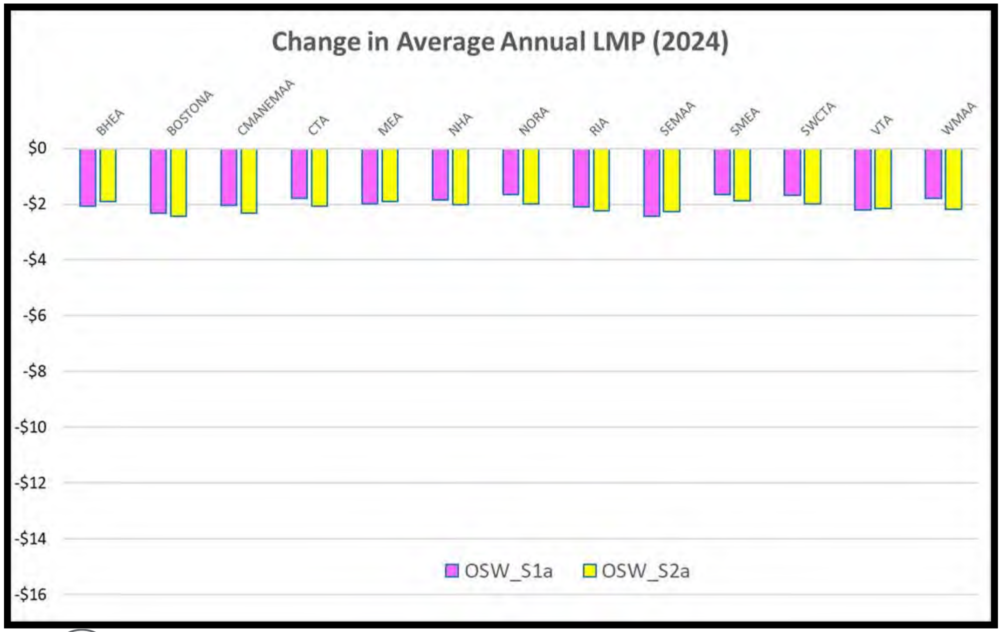
	Production Cost Savings ($M)	
Year	**OSW_S1**	**OSW_S2**
2024	$285	$284
2028	$564	$619

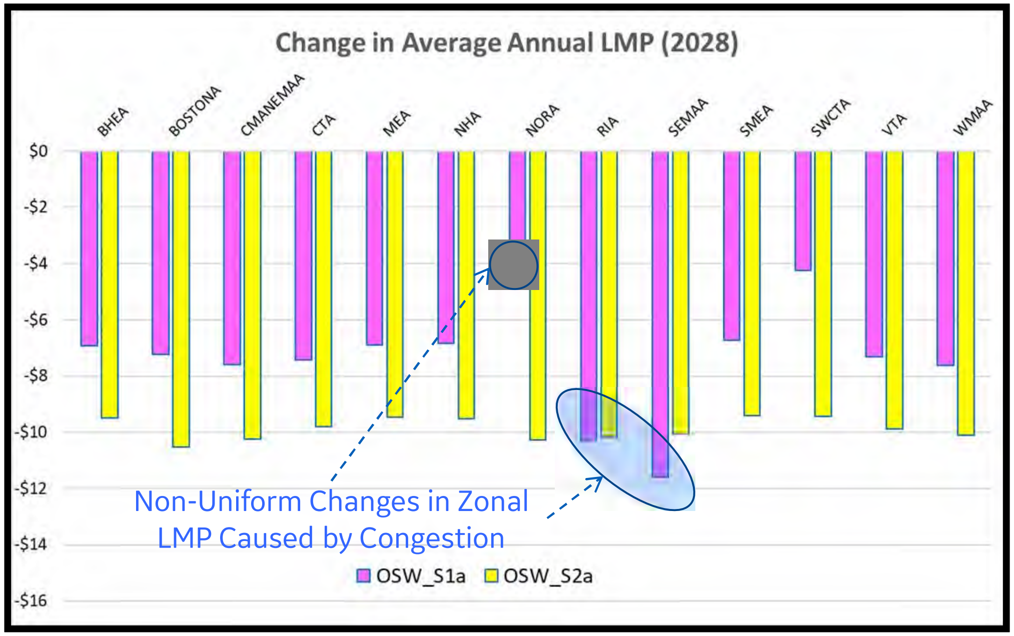
Annual ISONE Zonal LMP Change

Locational Marginal Price (LMP) = Marginal Cost of Electricity + Transmission Congestion Cost + Cost of Losses

In 2028, More Uniform Zonal LMP Decrease in Scenario 2 than Scenario 1 is an indication of:

- More efficient and cost-effective use of added cheap energy from OSW
- Less transmission congestion moving cheap OSW energy
- More load payment savings





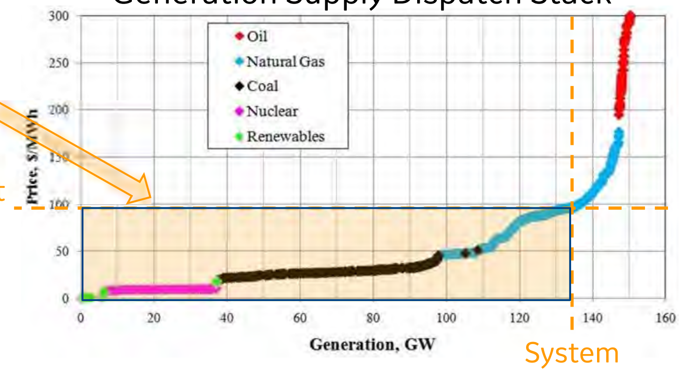
Load Payment Savings

Electricity Load Payment = Marginal Cost of Electricity ($/MWh) x System Demand (MWh)

Load payment is the amount the rate payers ultimately pay to serve the load in their area

Rectangle area bound by Marginal Price and Demand

Generation Supply Dispatch Stack



<u>Load Payment Comparison</u>

- In 2024, similar annual load payment savings occur in Scenario 1 ($259M) vs. Scenario 2 ($281M), reflecting in a modest difference between the two OSW transmission scenarios (**$22M or 0.5%**).
- In 2028, the load payment savings between the two begin to diverge between Scenario 1 ($1,000M) vs. Scenario 2 ($1,306M) and the resulting annual difference is significant (**$306M or 5.2%**).

Annual ISO-NE Load Payment ($M)				
Year	**Base_S1**	**Base_S2**	**OSW_S1**	**OSW_S2**
2024	$4,815	$4,808	$4,557	$4,527
2028	$5,921	$5,897	$4,921	$4,591

	Load Payment Savings ($M)	
Year	**OSW_S1**	**OSW_S2**
2024	$259	$281
2028	$1,000	$1,306

Offshore Transmission in New England: Benefits of a Better Planned Grid

Appendix C: System Upgrades Required for 2024 Offshore Wind Connection

Dwayne Basler, PE
CHA Consulting
May 7, 2020

System Upgrades Required for 2024 Offshore Wind Connection – *Unplanned* vs *Planned* Transmission

1. Summary of Results
2. Analysis Details
3. Overload Maps
   A. *Unplanned* interconnection
   B. *Planned* interconnection
4. System Upgrade Costs
   A. Unit Costs
   B. *Unplanned* interconnection
   C. *Planned* interconnection
5. Transmission Overload Tables

Dwayne Basler, PE
CHA Consulting
May 7, 2020

Summary of Results

Phase 1 (2024) of the *Unplanned* (also referred to in this study as the *current approach*) offshore wind interconnection described in General Electric's 'Anbaric Offshore Wind POI Transmission Security Analysis' would create approximately four times as many facility overloads as a *Planned* interconnection resulting in significantly higher interconnection costs.

Extensive transmission system siting and construction to mitigate overloads for an *Unplanned* Offshore Wind interconnection in New England would be challenging and could require ten or more years to complete based on similar projects in the region.

***Unplanned** scenario overlaods:*

- West Barnstable to the North (to K-Street)
- Boston area
- West Barnstable to the West (Tremont and Falmouth Tap paths)
- Connecticut and Rhode Island

Planned scenario overloads:

- Mystic - North Cambridge - Woburn
- Connecticut

	Planned Transmission	Unplanned Transmission
Overloaded Lines (>110%)	6	47
Overloaded Substation Equipment (>110%)	4	17
Overloaded Lines (<110%)	11	44
Overloaded Substation Equipment (<110%)	3	6
(**Note**: overloads <110% are not included on the New England maps.)		
Total Overloaded Facilities	24	114

The cost of transmission system upgrades are estimated to be:

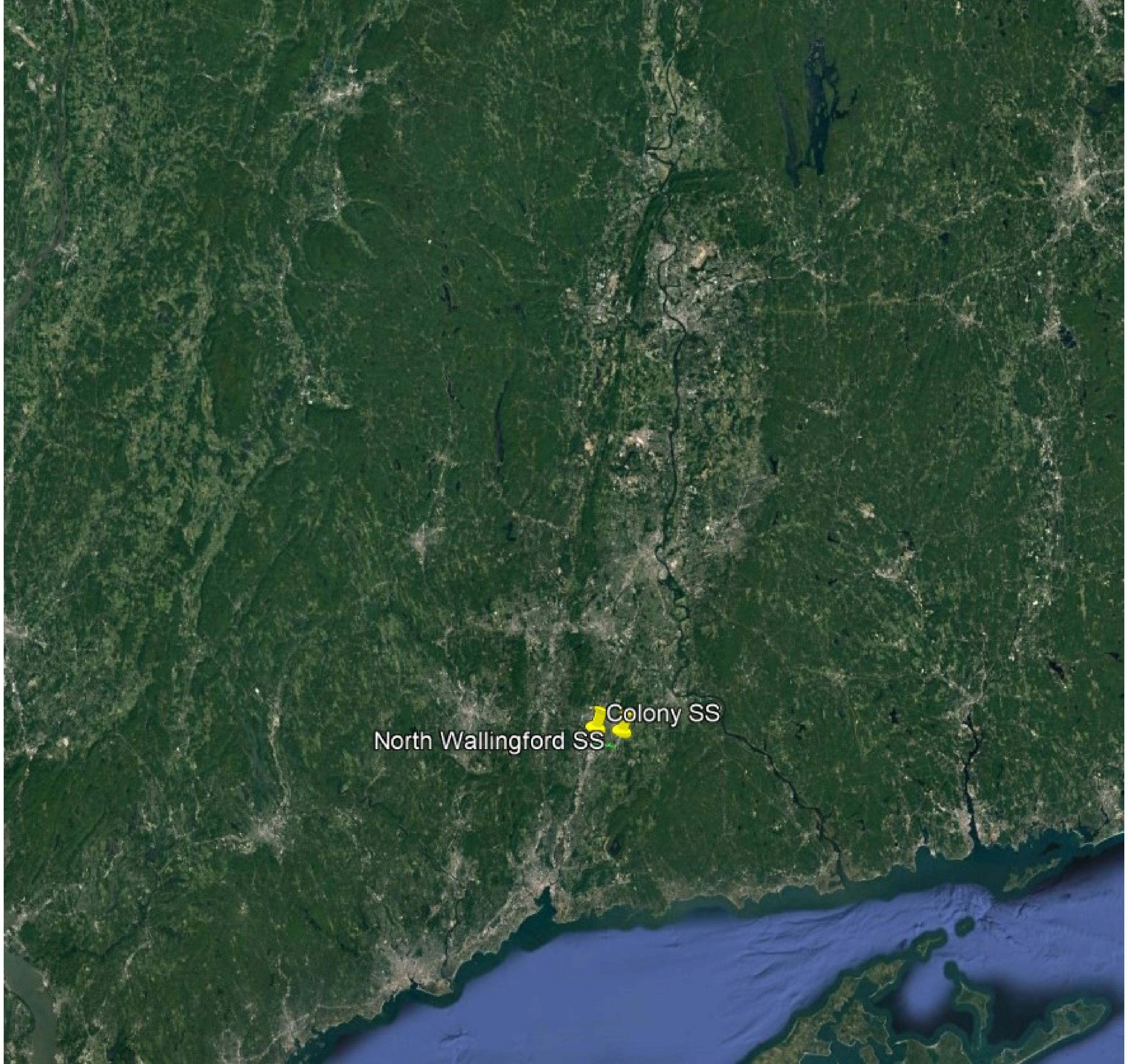
		Midpoint
Unplanned transmission system	\$1.2B - \$2.3B	\$1.7B
Planned transmission system	\$390M - \$710M	\$550M

- Costs are order of magnitude to illustrate the differences between an ***Unplanned*** and ***Planned*** transmission interconnection only. Mitigation options have not been verified by power flow analysis, routing assessment, or detailed engineering.
- Ranges have been established for illustrative purposes only and not to imply a level of precision. For example, $\pm$25% was applied to the project averages in the *Greater Boston Cost Comparison, NHT Analysis using New England Comparables January 2015;* however, that analysis identified a larger variability in project costs.

Analysis Details

- General Electric Power Flow studies using NERC and NPCC N-1-1 criteria identified transmission overloads for a Phase 1 (2024) ***Planned*** and ***Unplanned*** interconnection of offshore wind projects.
- NERC N-1-1 overloads were verified to be a subset of the NPCC N-1-1 overloads. The overload percentages in this analysis are NPCC criteria overloads.
- Transmission line lengths were estimated to be 1.2 times the straight line distances between substations.
- Pre-existing overloads were not included. For example, the West Barnstable to Carver transmission line was overloaded in the Base Case and therefore is not included in either the *Planned* or *Unplanned* interconnection scenarios.
- Overloads less than 110% are listed separately to simplify the mitigation cost analysis.
- Transmission system upgrades required for the *Unplanned* scenario being approximately four times more extensive would result in a much longer time to complete which could result in increased costs. These increased costs have *not* been included in this analysis.
- Extreme Event analysis (NPCC Directory 1) such as Loss of ROW contingencies would require some new transmission lines to be on new ROWs rather than constructed on existing ROWs. This would result in increased costs and time to complete. This is consistent with ISO-NE conclusions in **2019 Economic Study Offshore Wind Transmission Interconnection Analysis**, March 18, 2020. A 50% factor was included for the West Barnstable to Stoughton 345kV overhead transmission line to account for construction in a new ROW.

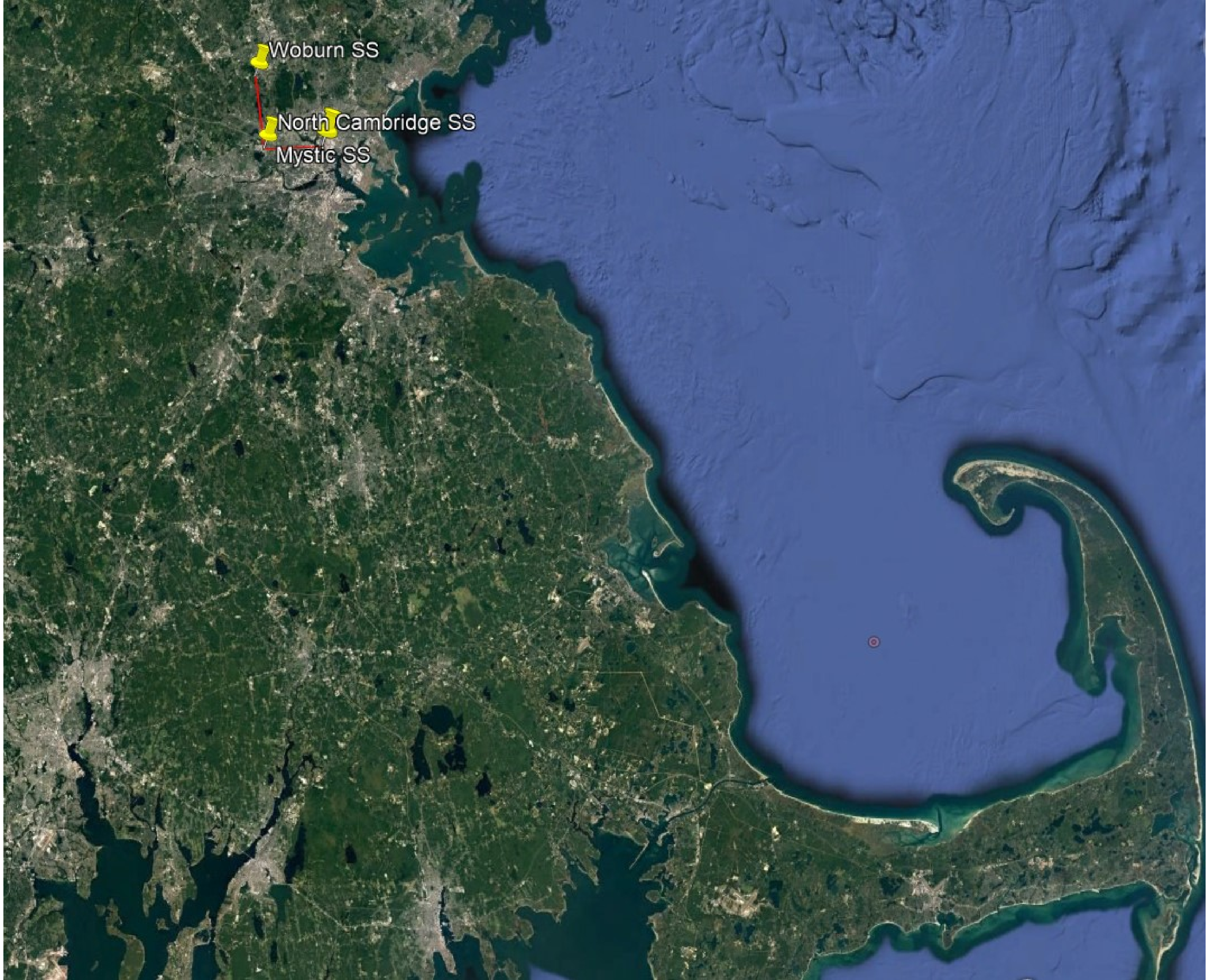

New England Overloads – Unplanned Transmission System (2024) – slide 1 of 2
50 overloads less than 110% not shown
High Street SS
Kingston Street SS
Brighton SS
K Street
Baker Street SS
Needham SS
Hyde Park SS
Dover SS
Holbrook SS
West Medway SS
West Walpole SS
Dupont SS
Auburn SS
Kingston SS
Bridgewater SS
Brook Street SS
Jordan Tap
Carver SS
Johnston SS
Rise SS
Tremont SS
Wareham SS
Valley SS
Horse Pond Tap
Bourne SS
West Barnstable SS
Falmouth Tap SS
Hatchville SS
Mashpee SS
115kV overhead transmission line
115kV underground transmission line
345kV overhead transmission line
345kV underground transmission line



New England Overloads – Unplanned Transmission System (2024) – slide 2 of 2

50 overloads less than 110% not shown

115kV overhead transmission line
115kV underground transmission line
345kV overhead transmission line
345kV underground transmission line



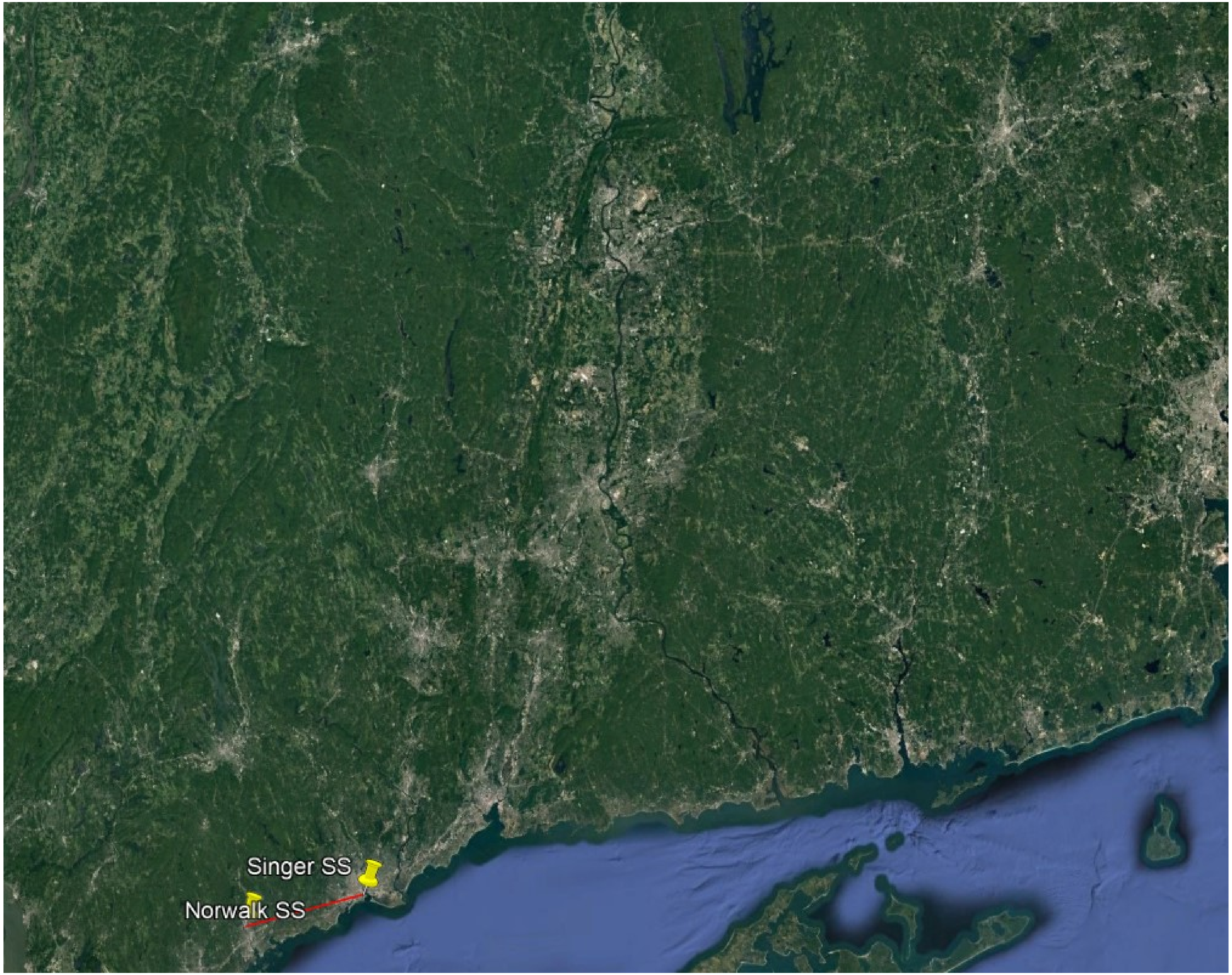
New England Overloads – Planned Transmission System (2024) – slide 1 of 2

14 overloads less than 110% not shown

115kV overhead transmission line
115kV underground transmission line
345kV overhead transmission line
345kV underground transmission line

New England Overloads – Planned Transmission System (2024) – slide 2 of 2

14 overloads less than 110% not shown



115kV overhead transmission line
115kV underground transmission line
345kV overhead transmission line
345kV underground transmission line

System Upgrade Costs – Unit Costs

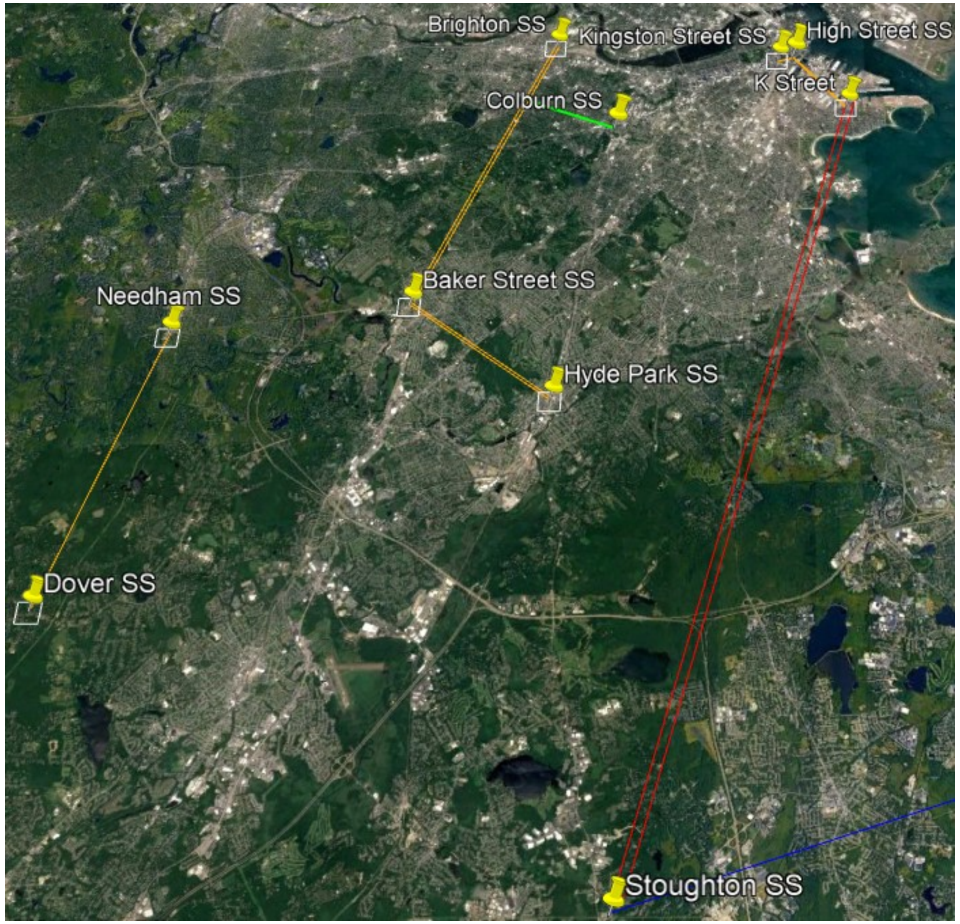
- ***New transmission lines -*** costs were determined using the *Greater Boston Cost Comparison, NHT Analysis using New England Comparables January 2015* (https://www.iso-ne.com/static-assets/documents/2015/02/a2_nht_greater_boston_cost_analysis_public.pdf). The 115kV per mile overhead line costs were not included in the 2015 New England analysis so a 45% cost ratio (115kV to 345kV) was used; $5.4M/mile (basis: Transmission Cost Estimation Guide MTEP19, Section 4, https://cdn.misoenergy.org/20190212%20PSC%20Item%2005a%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP%202019_for%20review317692.pdf).
- ***Transmission reconductoring*** (overhead lines only) – costs were determined using 30% - 70% of the new line average construction cost (this assumes some new structures would be required for the larger conductors and to meet current NESC design criteria)
- ***Transmission lines overloaded to less than 110%*** - a mitigation cost range of $200K - $500K was applied to each line. Thermal ratings could be limited by smaller conductors on some spans, sag limiting spans, encroachments, conservative ratings methodology inconsistent with ISONE PP7, or limiting substation equipment (breakers, switches, connectors, system protection, …). Transmission lines could be rerated a variety of ways to achieve sufficient ratings. While mitigation for some transmission lines would exceed this cost, the assumed cost range is conservative. Precise mitigation costs would likely *increase* the cost differential between the *Planned* and *Unplanned* scenarios.
- ***Overloaded substation equipment*** – costs for overloaded equipment could vary considerably; an overloaded auto transformer or phase shifter could cost $10M while overloaded substation breakers and disconnect switches would cost much less. Costs were determined using a cost range of $200K-$10M per overload. Note that many of the overloads are transformers or phase shifters.

Unit Costs (per mile) - New Lines

Overhead	
345	$12M
115 / 69	$5.4M
Underground	
345	$19.5M
115	$16.9M

System Upgrade Costs - *Unplanned*

- The ***Unplanned*** scenario overloads are in the following areas:
  - West Barnstable to the North (to K-Street)
  - Boston area
  - West Barnstable to the West (Tremont and Falmouth Tap paths)
  - Connecticut and Rhode Island
- Analysis Assumptions:
  - A new transmission line from West Barnstable to Stoughton to K-street will resolve other overloads in the Boston area (several overloaded lines and substation facilities). If this is *not* the case, significant additional costs will result since many of the transmission lines in the Boston area are underground. Refer to the first diagram on the next slide.
  - The *High Street to K-street* and *Kingston St to K-street* overloads would be mitigated by a new 115kV underground line from *Kingston St to K-street*.
  - Overhead transmission line overloads could be mitigated by reconductoring.



Boston Area Overloads

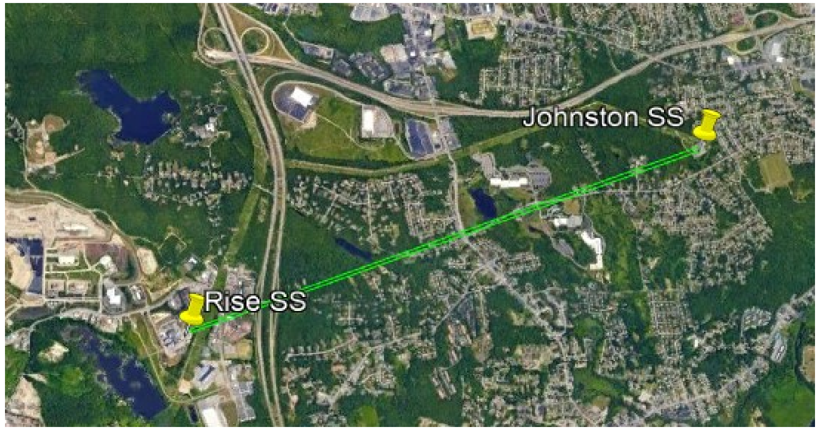
Overloaded Lines (>110%)	OL %	Voltage
110786 STOUGHTON 345 110790 K STREET 1 345 2	160.4	345kV UG
110786 STOUGHTON 345 110790 K STREET 1 345 1	158.4	345kV UG
110854 WASH_TAP 510 115 110886 BAKER ST PS1 115 1	161.9	115kV UG
110855 WASH_TAP 511 115 110887 BAKER ST PS2 115 1	161.9	115kV UG
110814 BRIGHTON B 115 110855 WASH_TAP 511 115 1	154.8	115kV UG
110813 BRIGHTON A 115 110854 WASH_TAP 510 115 1	154.8	115kV UG
110888 BAKER ST A 115 110892 HYDE PARK B 115 1	144.3	115kV UG
110834 HIGH ST 510 115 110836 K STREET 1 115 1	142.6	115kV UG
110889 BAKER ST B 115 110891 HYDE PARK A 115 1	140.4	115kV UG
110893 NEEDHAM 115 110894 DOVER MA 115 1	128.4	115kV UG
110835 HIGH ST 511 115 110837 K STREET 2 115 1	126.9	115kV UG
110830 KINGSTN ST W 115 110836 K STREET 1 115 2	122.6	115kV UG
110830 KINGSTN ST W 115 110836 K STREET 1 115 1	122.6	115kV UG
110853 COLBURN 511 115 110855 WASH_TAP 511 115 1	121.7	115kV OH
110852 COLBURN 510 115 110854 WASH_TAP 510 115 1	121.7	115kV OH

Overloads from West Barnstable to the West

Overloaded Lines (>110%)	OL %	Voltage
111217 BOURNE 115 111226 CANAL 126 115 1	157.9	115kV OH
111217 BOURNE 115 111222 CANAL 121 115 1	157.0	115kV OH
111158 HORSEPDTP113 115 111217 BOURNE 115 1	143.2	115kV OH
111142 VALLEYNB 113 115 111158 HORSEPDTP113 115 1	143.1	115kV OH
111155 WAREHAM 108 115 111156 VALLEYNB 108 115 1	141.2	115kV OH
111142 VALLEYNB 113 115 111152 WAREHAM 113 115 1	141.1	115kV OH
111152 WAREHAM 113 115 111318 TREMONT 113 115 1	139.9	115kV OH
111149 HORSEPDTP108 115 111156 VALLEYNB 108 115 1	138.9	115kV OH
111137 TREMONT S 115 111155 WAREHAM 108 115 1	137.9	115kV OH
111135 W BARNSTABLE 115 111215 MASHPEE 137 115 1	136.0	115kV OH
111217 BOURNE 115 111219 CANAL 120 115 1	132.1	115kV OH
111135 W BARNSTABLE 115 111217 BOURNE 115 1	122.9	115kV OH
111209 HATCHVILLE 115 111212 MASHPEE 136 115 1	122.1	115kV OH
111149 HORSEPDTP108 115 111217 BOURNE 115 1	116.6	115kV OH

Connecticut Overload

120587 NU_1588_CMEC 115 120596 CMEC_1588_NU 115 1	127.7	115kV OH



Rhode Island Overloads

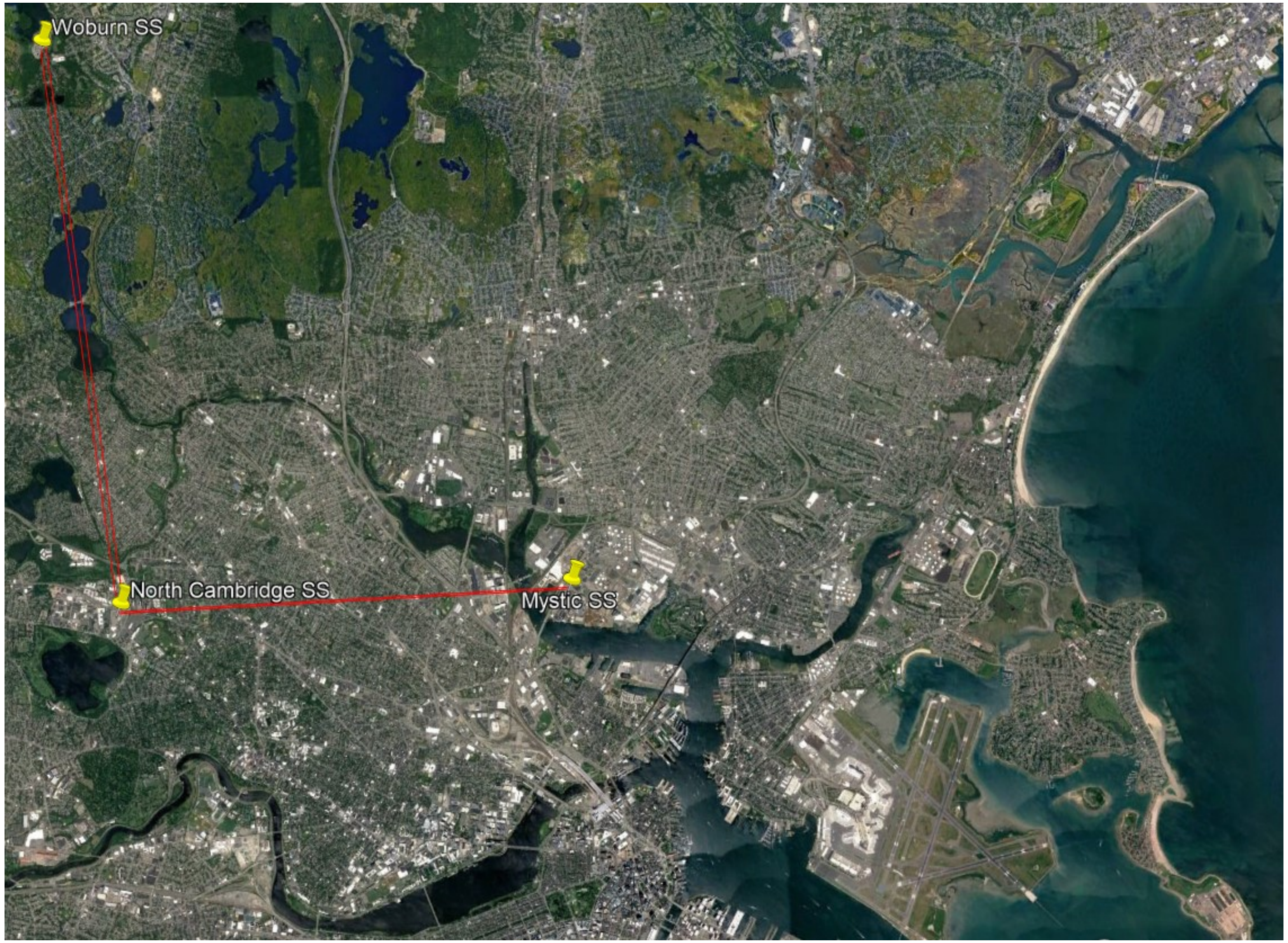
117330 JOHNSTON_171 115 117334 RISE 171_TAP 115 1	124.4	115kV OH
117331 JOHNSTON_172 115 117360 RISE 172_TAP 115 1	122.1	115kV OH

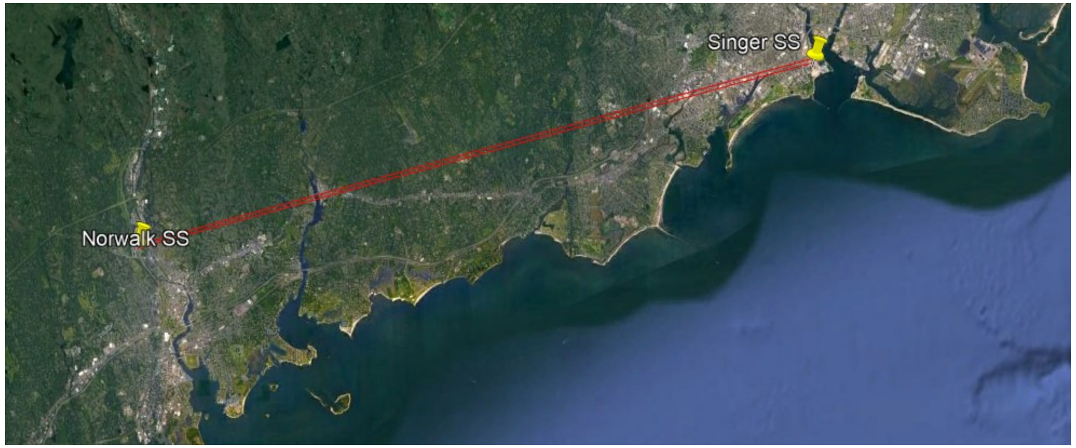
System Upgrade Costs - *Unplanned*

		Voltage	Miles or Units	Cost/Mile (Low)	Cost/Mile (High)	Cost/Mile (Midpoint)	Cost (Low)	Cost (High)	Cost (Midpoint)
1	**West Barnstable to Stoughton to K-Street - New Line**								
	Overhead portion (on new ROW)	345kV OH	60	$ 13,500,000.00	$ 22,500,000.00	$ 18,000,000.00	$ 810,000,000.00	$ 1,350,000,000.00	$ 1,080,000,000.00
	Underground portion	345kV UG	16.8	$ 14,625,000.00	$ 24,375,000.00	$ 19,500,000.00	$ 245,700,000.00	$ 409,500,000.00	$ 327,600,000.00
2	**Kingston St to K-street - New Line**								
	Underground	115KV UG	1.8	$ 12,675,000.00	$ 21,125,000.00	$ 16,900,000.00	$ 22,815,000.00	$ 38,025,000.00	$ 30,420,000.00
3	**Eastern Massachusetts - Reconductoring**								
	West Barnstable to Mashpee	115kV OH	9	$ 1,620,000.00	$ 3,780,000.00	$ 2,700,000.00	$ 14,580,000.00	$ 34,020,000.00	$ 24,300,000.00
	Mashpee to Hatchville	115kV OH	5.16	$ 1,620,000.00	$ 3,780,000.00	$ 2,700,000.00	$ 8,359,200.00	$ 19,504,800.00	$ 13,932,000.00
	Hatchville to Falmouth Tap	115kV OH	2.28	$ 1,620,000.00	$ 3,780,000.00	$ 2,700,000.00	$ 3,693,600.00	$ 8,618,400.00	$ 6,156,000.00
	West Barnstable to Bourne	115kV OH	14.58	$ 1,620,000.00	$ 3,780,000.00	$ 2,700,000.00	$ 23,619,600.00	$ 55,112,400.00	$ 39,366,000.00
	Bourne to Canal	115kV OH	3	$ 1,620,000.00	$ 3,780,000.00	$ 2,700,000.00	$ 4,860,000.00	$ 11,340,000.00	$ 8,100,000.00
	Bourne to Valley	115kV OH	3.12	$ 1,620,000.00	$ 3,780,000.00	$ 2,700,000.00	$ 5,054,400.00	$ 11,793,600.00	$ 8,424,000.00
	Valley to Wareham	115kV OH	5.52	$ 1,620,000.00	$ 3,780,000.00	$ 2,700,000.00	$ 8,942,400.00	$ 20,865,600.00	$ 14,904,000.00
	Wareham to Tremont	115kV OH	4.56	$ 1,620,000.00	$ 3,780,000.00	$ 2,700,000.00	$ 7,387,200.00	$ 17,236,800.00	$ 12,312,000.00
4	**Rhode Island - Reconductoring**								
	Johnston to Rise	115kV OH	2.76	$ 1,620,000.00	$ 3,780,000.00	$ 2,700,000.00	$ 4,471,200.00	$ 10,432,800.00	$ 7,452,000.00
5	**Connecticut - Reconductoring**								
	Colony to North Wallingford	115kV OH	3.12	$ 1,620,000.00	$ 3,780,000.00	$ 2,700,000.00	$ 5,054,400.00	$ 11,793,600.00	$ 8,424,000.00
7	**Overloaded lines {less than 110%}**	345/115kV	46	$ 200,000.00	$ 500,000.00	$ 350,000.00	$ 9,200,000.00	$ 23,000,000.00	$ 16,100,000.00
8	**Substation Overloads**	345/115kV	23	$ 200,000.00	$ 10,000,000.00	$ 5,100,000.00	$ 4,600,000.00	$ 230,000,000.00	$ 117,300,000.00
	Total Cost Estimate Range						**$ 1,178,337,000**	**$ 2,251,243,000.00**	**$ 1,714,790,000.00**

System Upgrade Costs - *Planned*

- The ***Planned*** scenario overloads are in the following areas:
  - Mystic - North Cambridge - Woburn
  - Connecticut
- Analysis Assumptions:
  - A new underground transmission line from Mystic to North Cambridge to Woburn would be required to resolve overloads out of Mystic.
  - Overhead transmission line overloads could be mitigated by reconductoring.
  - Underground transmission line overloads (Norwalk to Singer) would require a new 345kV underground transmission line.





Connecticut Overloads

119441 NU_3921_UI 345 119480 NORWALK	345 1	160.3	345kV UG
119428 NU_3280_UI 345 119480 NORWALK	345 1	160.4	345kV UG

Boston Area Overloads

Overloaded Lines (>110%)	OL %	Voltage
110758 N. CAMBRIDGE 345 110759 MYSTIC MA 345 1	190.2	345kV UG
110758 N. CAMBRIDGE 345 110759 MYSTIC MA 345 2	160.6	345kV UG
110756 WOBURN 345 110758 N. CAMBRIDGE 345 2	117.4	345kV UG
110756 WOBURN 345 110758 N. CAMBRIDGE 345 1	117.4	345kV UG

System Upgrade Costs - *Planned*

		Voltage	Miles or Units	Cost/Mile (Low)	Cost/Mile (High)	Cost/Mile (Midpoint)	Cost (Low)	Cost (High)	Cost (Midpoint)
1	**Boston Area - New Lines**								
	Mystic to North Cambridge to Woburn	345kV UG	10.56	$ 14,625,000.00	$ 24,375,000.00	$ 19,500,000.00	$ 154,440,000.00	$ 257,400,000.00	$ 205,920,000.00
2	**Norwalk to Singer - New UG Line**	345kV UG	15.54	$ 14,625,000.00	$ 24,375,000.00	$ 19,500,000.00	$ 227,272,500.00	$ 378,787,500.00	$ 303,030,000.00
3	**Overloaded lines {less than 110%}**	345/115kV	15	$ 200,000.00	$ 500,000.00	$ 350,000.00	$ 3,000,000.00	$ 7,500,000.00	$ 5,250,000.00
4	**Substation Overloads**	345/115kV	7	$ 200,000.00	$ 10,000,000.00	$ 5,100,000.00	$ 1,400,000.00	$ 70,000,000.00	$ 35,700,000.00
	Total Cost Estimate Range						**$ 386,112,500.00**	**$713,687,500.00**	**$ 549,900,000.00**

Unplanned Transmission Overloads (>110%)

	Overloaded Lines (>110%)	OL %	Voltage
1	110786 STOUGHTON 345 110790 K STREET 1 345 2	160.4	345kV UG
2	110786 STOUGHTON 345 110790 K STREET 1 345 1	158.4	345kV UG
3	111133 CARVER 345 111193 CANAL 345 1	152.8	345kV OH
4	110782 JORDAN ROAD 345 111193 CANAL 345 1	148.8	345kV OH
5	111133 CARVER 345 115036 NGR_331_NST 345 1	139.4	345kV OH
6	110780 WEST WALPOLE 345 115008 NST_331_NGR 345 1	138.6	345kV OH
7	110772 W MEDWAY B 345 115012 NGR_344_NST 345 1	136.4	345kV OH
8	110781 HOLBROOK 345 115009 NGR_335_NST 345 1	133.2	345kV OH
9	110782 JORDAN ROAD 345 115011 NGR_342_NST 345 1	131.6	345kV OH
10	115008 NST_331_NGR 345 115036 NGR_331_NST 345 1	127.7	345kV OH
11	111133 CARVER 345 115013 NGR_356_NST 345 1	124.9	345kV OH
12	115013 NGR_356_NST 345 115446 BRIDGEWATER 345 1	124.1	345kV OH
13	110781 HOLBROOK 345 110786 STOUGHTON 345 1	115.8	345kV OH
14	115011 NGR_342_NST 345 115447 AUBURN ST 345 1	115.8	345kV OH
15	110888 BAKER ST A 115 110892 HYDE PARK B 115 1	144.3	115kV UG
16	110834 HIGH ST 510 115 110836 K STREET 1 115 1	142.6	115kV UG
17	110854 WASH_TAP 510 115 110886 BAKER ST PS1 115 1	161.9	115kV UG
18	110855 WASH_TAP 511 115 110887 BAKER ST PS2 115 1	161.9	115kV UG
19	110814 BRIGHTON B 115 110855 WASH_TAP 511 115 1	154.8	115kV UG
20	110813 BRIGHTON A 115 110854 WASH_TAP 510 115 1	154.8	115kV UG
21	110889 BAKER ST B 115 110891 HYDE PARK A 115 1	140.4	115kV UG
22	110830 KINGSTN ST W 115 110836 K STREET 1 115 2	122.6	115kV UG
23	110830 KINGSTN ST W 115 110836 K STREET 1 115 1	122.6	115kV UG
24	110893 NEEDHAM 115 110894 DOVER MA 115 1	128.4	115kV UG
25	110835 HIGH ST 511 115 110837 K STREET 2 115 1	126.9	115kV UG

	Overloaded Lines (>110%)	OL %	Voltage
26	111142 VALLEYNB 113 115 111158 HORSEPDTP113 115 1	143.1	115kV OH
27	111158 HORSEPDTP113 115 111217 BOURNE 115 1	143.2	115kV OH
28	111155 WAREHAM 108 115 111156 VALLEYNB 108 115 1	141.2	115kV OH
29	117330 JOHNSTON_171 115 117334 RISE 171_TAP 115 1	124.4	115kV OH
30	111217 BOURNE 115 111219 CANAL 120 115 1	132.1	115kV OH
31	110853 COLBURN 511 115 110855 WASH_TAP 511 115 1	121.7	115kV OH
32	110852 COLBURN 510 115 110854 WASH_TAP 510 115 1	121.7	115kV OH
33	117331 JOHNSTON_172 115 117360 RISE 172_TAP 115 1	122.1	115kV OH
34	111136 KINGSTON 115 111144 BROOK STREET 115 1	118.6	115kV OH
35	111149 HORSEPDTP108 115 111217 BOURNE 115 1	116.6	115kV OH
36	120587 NU_1588_CMEC 115 120596 CMEC_1588_NU 115 1	127.7	115kV OH
37	111217 BOURNE 115 111226 CANAL 126 115 1	157.9	115kV OH
38	111217 BOURNE 115 111222 CANAL 121 115 1	157.0	115kV OH
39	115449 DUPONT 115 115452 AUBURN ST 115 1	113.3	115kV OH
40	111209 HATCHVILLE 115 111212 MASHPEE 136 115 1	122.1	115kV OH
41	111135 W BARNSTABLE 115 111217 BOURNE 115 1	122.9	115kV OH
42	111135 W BARNSTABLE 115 111215 MASHPEE 137 115 1	136.0	115kV OH
43	111142 VALLEYNB 113 115 111152 WAREHAM 113 115 1	141.1	115kV OH
44	111152 WAREHAM 113 115 111318 TREMONT 113 115 1	139.9	115kV OH
45	111149 HORSEPDTP108 115 111156 VALLEYNB 108 115 1	138.9	115kV OH
46	111137 TREMONT S 115 111155 WAREHAM 108 115 1	137.9	115kV OH
47	111136 KINGSTON 115 115006 NGR_191_NST 115 1	130.6	115kV OH

	Overloaded Substation Equipment (>110%)	OL %
1	111226 CANAL 126 115 111193 CANAL 345 1	160.5
2	119718 MONTVILLE 115 119181 MONTVILE_371 345 2	153.0
3	119718 MONTVILLE 115 119180 MONTVILE_364 345 1	148.8
4	111222 CANAL 121 115 111193 CANAL 345 1	139.0
5	117301 KENT COUNTY 345 117332 KENT COUNTY 115 8	124.4
6	117301 KENT COUNTY 345 117332 KENT COUNTY 115 4	122.1
7	114734 BRAYTN POINT 345 114742 BRAYTN POINT 115 1	132.3
8	115447 AUBURN ST 345 115452 AUBURN ST 115 1	130.8
9	110887 BAKER ST PS2 115 110889 BAKER ST B 115 1	125.3
10	110886 BAKER ST PS1 115 110888 BAKER ST A 115 1	125.3
11	115450 E BRGWTR_E20 115 115451 BRIDGEWATER 115 1	117.4
12	110836 K STREET 1 115 110790 K STREET 1 345 1	116.4
13	110837 K STREET 2 115 110790 K STREET 1 345 1	116.4
14	111269 IND PRK 112T 115 111319 INDUST_PK112 115 1	113.0
15	114742 BRAYTN POINT 115 114907 BP XFMR 115 115 1	113.9
16	110791 HYDE PARK 115 110788 HYDE PARK 345 1	110.0
17	111134 W BARNSTABLE 345 111135 W BARNSTABLE 115 1	262.4

Unplanned Transmission Overloads (<110%)

	Overloaded Lines (<110%)	OL %
1	110866 MEDWAY 115 110879 HOLLISTON 115 1	109.7
2	110870 FRAMINGHAM 115 110871 SPEEN STREET 115 1	110.6
3	115450 E BRGWTR_E20 115 115452 AUBURN ST 115 1	108.9
4	115448 BELMONT_F19 115 115451 BRIDGEWATER 115 1	108.7
5	110894 DOVER MA 115 110895 WEST WALPOLE 115 1	108.5
6	110868 SHERBORN 115 110879 HOLLISTON 115 1	108.2
7	110832 KINGSTN ST A 115 110835 HIGH ST 511 115 1	107.6
8	110889 BAKER ST B 115 110893 NEEDHAM 115 1	106.8
9	110833 KINGSTN ST B 115 110834 HIGH ST 510 115 1	106.6
10	110900 HOLBROOK 115 114764 S RANDLPH509 115 1	107.4
11	119718 MONTVILLE 115 119957 NU_1090_CMEC 115 1	109.0
12	123163 GRAND AVENUE 115 123782 WEST RIVER B 115 2	108.2
13	123163 GRAND AVENUE 115 123780 WEST RIVER A 115 1	107.9
14	111139 CARVER 115 111144 BROOK STREET 115 1	105.6
15	110811 WATERTWN 520 115 110987 WALT PS-D 115 1	105.5
16	110812 WATERTWN 521 115 110988 WALT PS-E 115 1	105.5
17	110811 WATERTWN 520 115 110926 ELECTRIC AVE 115 1	104.7
18	110812 WATERTWN 521 115 110926 ELECTRIC AVE 115 1	104.7
19	115448 BELMONT_F19 115 115452 AUBURN ST 115 1	104.6
20	113271 WYMNGRDN57_T 115 113909 CENTECH_E157 115 1	104.2
21	113271 WYMNGRDN57_T 115 113286 MILLBURY 115 1	104.2

	Overloaded Lines (<110%)	OL %
24	113950 SANDY POND 345 113951 TEWKSBURY 345 1	104.4
25	111257 HIGH_HL_111 115 111268 INDUSTRL PRK 115 1	102.4
26	110922 CANTON 509_T 115 114764 S RANDLPH509 115 1	103.0
27	120434 BRISTOL CT 115 120444 FORESTVIL 25 115 1	103.9
28	110900 HOLBROOK 115 110908 E.HOLBRK TAP 115 1	101.9
29	123221 ELM WEST A 115 123780 WEST RIVER A 115 1	103.0
30	123222 ELM WEST B 115 123782 WEST RIVER B 115 1	103.0
31	110830 KINGSTN ST W 115 110849 CARVER ST 13 115 1	102.2
32	110830 KINGSTN ST W 115 110848 CARVER ST 12 115 1	102.2
33	110849 CARVER ST 13 115 110851 SCOTIA ST513 115 1	101.5
34	110920 CANTON 508_T 115 114765 S RANDLPH508 115 1	103.1
35	110848 CARVER ST 12 115 110850 SCOTIA ST512 115 1	101.4
36	110900 HOLBROOK 115 114765 S RANDLPH508 115 1	102.4
37	110786 STOUGHTON 345 110788 HYDE PARK 345 1	101.0
38	100150 SECT 83C TAP 115 100212 HEYWOOD ROAD 115 1	100.9
39	117351 HARTFORD AVE 115 117353 PUTNAM PK_71 115 1	103.1
40	117333 PHILLIP 83_T 115 117336 FRANKLIN SQ 115 1	103.0
41	120470 SOTHNGTN50_R 115 120938 CANAL CT 115 1	102.2
42	120227 DOOLEY 115 120236 WEST SIDE 115 1	101.7
43	113924 HUDSON 115 115040 NGR_H160_HLP 115 1	100.2
44	111209 HATCHVILLE 115 111407 FAL TAP 136 115 1	104.7

	Overloaded Substation Equipment (<110%)	OL %
1	115446 BRIDGEWATER 345 115451 BRIDGEWATER 115 2	104.4
2	110770 W MEDWAY A 345 110794 W MEDWAY A 230 1	102.4
3	111219 CANAL 120 115 111193 CANAL 345 1	103.0
4	115447 AUBURN ST 345 115452 AUBURN ST 115 2	103.9
5	110900 HOLBROOK 115 110781 HOLBROOK 345 1	101.9
6	115446 BRIDGEWATER 345 115451 BRIDGEWATER 115 1	103.0

Planned Transmission Overloads (>110%)

	Overloaded Lines (>110%)	OL %	Voltage
1	110758 N. CAMBRIDGE 345 110759 MYSTIC MA 345 1	190.2	345kV UG
2	110758 N. CAMBRIDGE 345 110759 MYSTIC MA 345 2	160.6	345kV UG
3	119441 NU_3921_UI 345 119480 NORWALK 345 1	160.3	345kV UG
4	119428 NU_3280_UI 345 119480 NORWALK 345 1	160.4	345kV UG
5	110756 WOBURN 345 110758 N. CAMBRIDGE 345 2	117.4	345kV UG
6	110756 WOBURN 345 110758 N. CAMBRIDGE 345 1	117.4	345kV UG

	Overloaded Substation Equipment (>110%)	OL %
1	114734 BRAYTN POINT 345 114742 BRAYTN POINT 115 1	200.4
2	114742 BRAYTN POINT 115 114907 BP XFMR 115 115 1	170.9
3	114734 BRAYTN POINT 345 114907 BP XFMR 115 115 3	119.4
4	114734 BRAYTN POINT 345 114907 BP XFMR 115 115 2	116.6

Planned Transmission Overloads (<110%)

	Overloaded Lines (<110%)	OL %		Overloaded Substation Equipment (<110%)	OL %
1	116360 PLEASANT 115 116364 BLANDFORD 115 1	105.2	1	110759 MYSTIC MA 345 110818 MYSTIC MA 115 1	106.2
2	121337 NORWALK 115 121457 GLENBROOK 115 1	103.2	2	110759 MYSTIC MA 345 110818 MYSTIC MA 115 2	105.0
3	121337 NORWALK 115 121457 GLENBROOK 115 2	103.2	3	110799 WOBURN 115 110756 WOBURN 345 1	102.3
4	116356 WOODLAND 115 116360 PLEASANT 115 1	104.0			
5	100150 SECT 83C TAP 115 100212 HEYWOOD ROAD 115 1	100.9			
6	110813 BRIGHTON A 115 110926 ELECTRIC AVE 115 1	100.7			
7	110814 BRIGHTON B 115 110926 ELECTRIC AVE 115 1	100.7			
8	110888 BAKER ST A 115 110892 HYDE PARK B 115 1	100.5			
9	114734 BRAYTN POINT 345 114900 BERRY STREET 345 1	103.7			
10	110833 KINGSTN ST B 115 110834 HIGH ST 510 115 1	104.7			
11	110832 KINGSTN ST A 115 110835 HIGH ST 511 115 1	104.6			

Overview Summary of Future Grid Analysis Proposals

August 4, 2020
NEPOOL Markets and Reliability Committee Meeting

DAY PITNEY LLP

Overview

- This presentation provides a summary of the nine Future Grid Analysis Proposals received and their key features.
- We have reserved our high level observations until committee members have had more of a chance to review the proposals.
- The contents of this presentation are intended to provide a one-stop shop for the substance of the proposals and to enable easier comparing and contrasting of the proposals.
- In most cases, the summaries are not verbatim due to space constraints on the slides but are intended to portray accurately all of the key features of the proposals. The proponents reviewed the summaries of their respective proposals, and we have included any edits from them.
- This presentation should help assist in the further refinement and consolidation of the proposals.

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Proposals Submitted

- American Petroleum Institute (“API”)
- Anbaric Development Partners
- Energy Market Advisors (“EMA”) on behalf of multiple public power entities.
- Eversource Energy
- FirstLight Power Management (only provided suggestions to Base Case Input Assumptions)
- Multi-Sector Group A (Acadia Center, Advanced Energy Economy, Brookfield Renewables, Conservation Law Foundation, Energy New England, Natural Resource Defense Council, and PowerOptions)
- Multi-Sector Group B (Advanced Energy Economy, Borrego Solar, Conservation Law Foundation, Energy New England, ENGIE, Natural Resources Defense Council, Power Options)
- National Grid
- NextEra Energy and Dominion Energy

To access the forms, please click here.

Summaries of Proposals

- The following slides summarize the following information from each proposal
- Request Details
  - Objective
  - Base Case Description
  - Additional Scenarios
  - Associated Prior/Ongoing Study
- Outputs and Deliverables
  - Metrics to Develop and Examine
  - Deliverable(s)
- Proposal Technical Summary
  - Analysis Type
  - Proposed Modeling Tool(s)
  - Proposed Modeling Approach

API

Objective: How will the future grid in New England balance policy goals with other reliability, affordability, and energy access objectives
Base Case: An evaluation that assumes typical load using most current assumptions for regional natural gas and renewable costs. Use AEO 2020 Reference Case prices for natural gas prices; if necessary, could use a backward-looking weighted average differential from Henry Hub to Algonquin. Use EIA AEO 2020 LCOE cost components for new builds. No extensions to PTC or ITC tax credits and no changes to planned phasedowns
Addition Scenarios: Assume no constraints on building new economic natural gas infrastructure
Other Studies: Over the past decade there have been several studies and reports released by the ISO that show that natural gas infrastructure can further economic and reliability objectives in the region

Metrics to Develop: Regional demand projections (including seasonal variations), wholesale power prices, technology cost assumptions, reserve margins, commodity cost assumptions, power generation fleet assumptions, consumer expenditures in the region (via BLS CEX), state-level expenditures by energy source (via EIA SEDS), and emissions factors (via EIA monthly or annual figures) to understand people's willingness to continue paying relatively high rates on gas and electricity, how much states may be saving *already* by incorporating more gas and less coal/liquids/wood into the electricity mix, how incorporating more gas into the mix has already brought power sector and total emissions down in the region overall.
Deliverables: Modeled output and corresponding report provide insight into energy transition pathways for ISO-NE, reflective of state policy goals and technological innovation and feasibility. The report should specify how ISO-NE plans to achieve its objectives for reliability and ratepayer protection, while increasing its integration of variable energy resources.

Analysis Type: Regional supply/demand projections, engineering/feasibility analysis of generation technologies, hourly power dispatch projections
Modeling Tool: No preference

Anbaric

Objective: Identify an onshore and offshore Grid of the Future blueprint for a power system that is carbon free by 2035, inline with the Joe Biden July 2020 energy plan and build upon Other Studies
Base Case: Current grid within the planning horizon
Additional Scenarios: Scenarios will be levels of storage, PV, and on-shore and off-shore wind needed to enable a carbon-free New England grid by 2035; sensitivities would also include varying levels of nuclear and electrification in-line with the Brattle Sept. 2019 study, adjusted to meet a 2035 target
Other Studies: ISO-NE's 2019 Economic Study Offshore Wind Transmission Interconnection Analysis; 2020 Brattle/GE/CHA study; Sept. 2019 study regarding system needs to meet MA's 2050 goals

Metrics to Develop: Informed by the Other Studies and should develop a picture of what is needed in terms of design and supply on that grid to meet the 2035 Biden zero carbon energy plan
Deliverables: An overview of the best ways (cost effective, fewer cables/lower environmental impact, maximize existing grid, provide resiliency, reliability, and controllability for system operators) to develop the transmission system to interconnect offshore wind, PV, battery storage, onshore wind and other distributed or zero carbon resources; resulting document would be a blueprint for a Grid of the Future (onshore and offshore) reflecting what transmission and resources need to be constructed to meet the Biden 2035 zero carbon energy system target while providing reliable electrical service; an output will build upon Brattle and other work to realistically identify the level and location of storage needed for a zero carbon power system that is in-line with the Biden energy plan target and provides the capabilities to meet electric system needs for ramping, intermittent power changes, and contingencies.

Analysis Type: Power Systems Analysis
Modeling Tool: Steady-State Power Flow (PSS/E, TARA, PowerWorld, PSAT/VSAT, etc.)

EMA

Objective: Provide information about implications of the two interconnection options defined in the Tariff available to new resources to address State policy objectives
Base Case: Not defined
Additional Scenarios: Two Condition Interconnection Cases would be applied to whatever base case is used**:**

- *Capacity Interconnection Case*: New resources added to address State energy/environmental policies and interconnected based on the Capacity Network Resource Interconnection Service (CNRIS) standard; participate in the Capacity, Energy, and Ancillary Service markets, as applicable
- *Minimum Interconnection Case*: New resources added to address State energy/environmental policies and interconnected based on the Network Resource Interconnection Service (NRIS) standard; participate in the Energy and Ancillary Service markets as applicable but not in the Capacity market

Metrics to Develop: NESCOE 2019 Economic Study metrics; develop FCM clearing prices under the various resource mix configurations
Deliverable: Similar to NESCOE 2019 Economic Study plus forecasted FCM prices, revenues, and costs

Modeling Approach: NESCOE 2019 Economic Study's approach to evaluate market and system operation impacts; need to develop an FCM pricing model to evaluate FCM prices, revenues, and costs

Eversource 1

Objective: For each case, provide LOLE, other related reliability metrics, market prices, total cost to load, a narrative of how the supply mix could potentially develop under current market rules and a qualitative assessment of how likely it is for such a supply mix is to develop

Base Case: Consistent with the current system, e.g., loads from 2020 CELT & existing capacity

- *Supply Mix 1*: Mixed Portfolio to meet 80% economy-wide emission reduction by 2050 state goals
- *Supply Mix 2*: High Offshore Wind Portfolio to meet 80% economy-wide emission reduction by 2050 state goals
- *Supply Mix 3*: High Solar Portfolio to meet 80% economy-wide emission reduction by 2050 state goals

Additional Scenarios:

- *Scenario A*: Assume all resources participate in capacity market under current capacity market rules
- *Scenario B*: Assume no renewable resources obtain CSOs in the capacity market

Other Studies: Eversource Grid of the Future Study

Metrics to Develop: LOLE based on initial supply mix, emissions from initial supply mix, total cost of supply, clearing prices and total cost to load

Deliverable: Report out all modeling metrics (LOLE, emissions, total cost of supply, clearing prices and total cost to load); a qualitative assessment of how each supply mix provided in the Supply Resource Mix Base Case Input Assumptions could develop under current or proposed market rules

Analysis Type: Power Systems Analysis & Market Analysis

Modeling Tools: Resource Adequacy (GE MARS, etc.) & Production Cost (e.g., Gridview)

Modeling Approach: Run GE MARS to determine resource adequacy of the proposed supply mix and whatever else is needed to provide deliverables (e.g., hourly market simulations in Gridview)

Eversource 2

Objective: Identify total installed nameplate capacity of a future system where LOLE meets the NPCC standard of 1 day in 10 years, assuming state environmental goals are met, electrification occurs as proposed in Eversource 1, but no renewables built with out of market PPAs ever clear as new in the primary or substitution auctions; provide installed capacity by resource type.
Additional Scenarios: Use the demand and electrification forecasts provided in Eversource 1 for a capacity expansion model that outputs a supply mix with adequate supply to meet decarbonization goals and resource adequacy metrics
Other Studies: Demand forecast determined by Eversource's Grid of the Future Study scenarios with 80% economy-wide emissions reduction by 2050

Metrics to Develop: System installed nameplate capacity by resource, LOLE, electric sector emissions, reliability metrics

Analysis Type: Power Systems Analysis
Modeling Tools: Resource Adequacy (GE MARS, etc.)
Modeling Approach: Run GE MARS to determine resource adequacy of the proposed supply mix and whatever else is needed to provide deliverables

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FirstLight

Supply Resource Mix: In order to avoid understating the potential future reliability service shortfalls (if any) in the existing design, the base scenarios should not assume significant new electric storage entry.

- Instead, addition of new electric storage entry should be based on as-modelled market prices.
- Electric storage modelling of energy discharge/charging prices (i.e., generator energy offer prices and Dispatchable Asset Related Demand prices) should consider both round-trip efficiency and variable O&M costs.

Cycling Impacts on Storage: Important to model full variable O&M costs.

- All storage cycling consumes useful life of some components but the life of components, as well as their costs, are quite different.
- For example, lithium battery cycling consumes battery cell life while pumped storage cycling impacts wear on a different set of equipment.

Multi-Sector Group A

Objective: Update and extend the 2016 PAC Economic Study on Reserves (not operating reserves) to assess the possible need of or benefit from ramping, regulation, or load-following resources as the system decarbonizes

Base Case: Reflect best information about the system in 2030 to (1) allow a comparison to the 2016 study and (2) provide a snapshot 10-years hence to identify any gaps that would require immediate attention. Similar to the 2016 study's "2030 Scenario 2 (ISO Queue)," update to reflect the current ISO queue, including off-shore wind, NECEC, planned retirements, and probable retirements from the At Risk Generator list. Updates should be made to ensure that the supply mix meets state policy goals for GHG emissions and assumptions for load should include the ISO's electrification forecast that was included in CELT 2020 for the year 2029, extrapolated out to 2030.

Multi-Sector Group A

Additional Scenarios:

- *End State Zero Carbon Generation*: Technical outputs from MA's 80-by-50 study (Central Case) for the year 2050 appears to capture a carbon-free system of this sort; the Eversource/LEI "2040 Aggressive Decarbonization" scenario appears close to this goal
- *Mid-Point*: Directional information about the system in flux.
- Scenarios not necessarily simple interpolations between 2030 runs and end-state runs, nor assign any particular year to this midpoint. Data from MA's 80-by-50 study (Central Case) for the year 2040 or Eversource/LEI "2040 Balanced Portfolio" capture a system in transition. Scenarios proposed because reflect technical attributes of a system in the process of decarbonizing.
- For all scenarios, do not presuppose the date of if/when such a scenario might occur. Scenarios may require interpolation or scaling to translate the hourly data from these models into minute-level data required for the EPECS Simulator (additional analysis required, perhaps an additional interim step using a production cost model).
- Assume 20% flexible demand is available to absorb renewable generation surplus or any needs for ramping, peak loads, etc. before fossil generation is dispatched.
- If MA EEA 2050 Roadmap data on load and supply is available, then it appears this would meet the intent of request.

Multi-Sector Group A

Other Studies: PAC 2016 Economic Study Phase II - Regulation, Ramping, and Reserves (Amro M. Farid)

Metrics to Develop: PAC 2016 Economic Study Phase II metrics
Deliverable: 2016 Economic Study Phase II deliverables: (1) simulated Operating Reserves: Load Following, Ramping and Curtailment Performance; (2) Simulated Interface & tie-line Performance; (3) Simulated Regulation Performance; (4) Simulated Balancing Performance; and (5) Time series data outputs on the most granular time-scale (e.g., 1- or 10-minute data) for each kind of assessed reserve.

Analysis Type: Market Analysis
Modeling Tools: EPECS Simulator (Dartmouth)
Modeling Approach: PAC 2016 Economic Study Phase II

Multi-Sector Group B

Objective: Develop a long-term transmission system assessment to identify the limitations in the transmission system to implementing a net zero carbon future; identify new transmission investments needed to solve any identified limitations that are potentially more economical than the upgrades that would be considering near-term transmission system needs; and identify whether distribution system generation, mobile and stationary storage, increased energy efficiency, or flexible demand could reduce the need for any new transmission infrastructure.
Base Case: *End-state Scenario*: A zero-carbon generation scenario; base case would reflect best information about the system when decarbonization goals have been achieved. Requestors do not presuppose the date of if/when such a scenario might occur.
Additional Scenarios: *Mid-Point Scenario*: Providing directional information about the system in flux; scenarios are not necessarily simple interpolations between 2030 runs and end-state runs nor assign any particular year to this midpoint; data from MA's 80-by-50 study (Central Case) for the year 2040 or Eversource/LEI "2040 Balanced Portfolio" capture a system in transition.
Other Studies: MA 2050 Roadmap Study; Eversource/LEI "2040 Aggressive Decarbonization" scenario; 2019 NESCOE Offshore Wind Economic Study

Metrics to Develop: List of system limitations, including interface transfer limit constraints, thermal and/or voltage constraints, stability concerns (system inertia) and bottlenecks. Specifically, voltage violations on an N-0 and N-1 scale. Costs in $/bn.
Deliverable: Identify potential constraints in the transmission system to accommodate the net zero carbon emissions resource mix and identify necessary transmission upgrades and additions, as well as potential non-transmission alternatives to those upgrades and additions

Analysis Type: Power Systems Analysis
Modeling Tools: Steady-State Power Flow (PSS/E, TARA, PowerWorld, PSAT/VSAT, etc.)
Modeling Approach: Transmission planning models, accounting for location of interconnection of new generation, anticipated increased load from heating and transportation electrification, whether distributed generation will interconnect at the distribution or bulk electric system level, the technology mix, retirements, etc. Possibly consider similar methodology to the Needs Assessments and Cluster Studies adding new supply and demand profiles pursuant to the MA 80-by-50 study to assess voltage needs given contingencies.

National Grid

Objective: Determine (1) impact of bi-directional controllable transmission to external regions, in particular Quebec, on use and spillage of intermittent resources, emissions, and LMPs; (2) extent of transmission system upgrades needed for a future resource mix under a fully decarbonized economy; & (3) if (current) market outcomes under high renewable/storage penetration cases would provide revenues to cover expected capital and/or operational/maintenance costs for resources (by resource type)
Base Case: National Grid 2020 Economic Study's Bi-directional Transmission 1 Scenario (with Base Case Input Assumptions)
Additional Scenarios: Differences in exports to Quebec and the threshold prices outlined in the 2020 Economic Study (with Base Case Input Assumptions); sensitivities increasing battery storage to 5,000 MW, as well as further retiring oil units and 50% of the natural gas-fired units
Other Studies: National Grid 2020 Economic Study

Metrics to Develop: (1) National Grid 2020 Economic Study metrics; (2) detailed transmission analysis; & (3) forecasted FCA clearing prices by unit type
Deliverable: (1) National Grid 2020 Economic Study Request deliverables with a more detailed transmission analysis; (2) contingency and upgrade analysis; & (3) forecasted FCA clearing prices by unit type as one revenue source when assessing if current market outcomes cover capital/expenses

Analysis Type: (1) Market Analysis; (2) Power System Analysis; and (3) Market Analysis
Modeling Tools: (1) Grid View; (2) Steady-State Power Flow; and (3) FCA MCE
Modeling Approach: (1) Simulate economic operation of power system chronologically; (2) simulate the FCA for capability year 2035; & (3) simulate the FCA for capability year 2035

NextEra/Dominion

Objective: Determine how the loss of the Seabrook and Millstone nuclear power plants would impact or change system operations; determine how the loss of the Seabrook and Millstone nuclear power plants impacts state RPS targets and decarbonization goals; determine market outcomes under the loss of the Seabrook and Millstone nuclear power plants
Base Case: Base case assumptions similar to other base cases that will be used as part of this “Transition to the Future Grid” analysis, important to keep assumptions consistent; model loss of the Seabrook and Millstone nuclear power plants in year 2030
Additional Scenarios: Loss of the Seabrook and Millstone nuclear power plants should be considered with additional scenarios requested by stakeholders, such as variants in meeting state RPS goals and/or decarbonization of the economy to reflect the impact across likely scenarios

Metrics to Develop: No preference
Deliverable: No preference

Analysis Type: Production Cost Model; Primary Frequency Model; Network Reliability

Base Case Input Assumptions

- The following slides summarize the following seven assumptions specified in each proposal:
- Transmission Network
- Study Year(s)/Timeframes
- Supply Resource Mix (New and Retired)
- Wholesale Net Load (Gross, EE, Btm PV, Utility PV)
- Electrification Forecasts (Heating and Transportation)
- Battery and Other Storage Additions
- Other

API

Timeframe: 2020–2040

Supply Resource Mix: For all generation technologies, utilize most recent assumptions for technological cost and operational performance

Wholesale Net Load: Ensure the model requires demand be met on at least an hourly basis to most accurately reflect grid dynamics

Battery & Other Storage: Utilize recent assumptions from publicly available sources such as EIA

Anbaric

Transmission Network: Current grid as starting point that changes (retirements of fossil, additions of significant PV, storage, offshore wind, etc.) to meet 2035 zero carbon target
Timeframe: 2035
Supply Resource Mix:

- Retire current fossil fuel generation fleet for 2035; replace and adjust for electrification with PV, storage, offshore wind resources, and other non-carbon resources
- Scenario analysis is with and without Millstone

Wholesale Net Load Gross and Electrification Forecasts: Brattle projections and other sources of policy target input to adjust 2035 load to account for electrification
Battery & Other Storage: Significant grid scale and distributed battery storage should be assumed to help provide for ramping and system contingencies
Other: Discussion regarding the type and kind of resources should help fill-in resource blanks in terms of what do the States and system operations staff want to see in the 2035 zero carbon resource mix to provide necessary reactive power, ramping capability, contingency coverage, and firm energy requirements for load. Transmission Adequacy and Reliability Assessment may be the best if only one is utilized.

EMA

Transmission Network: FCA 14 topology (but use FCA 15 if available), plus upgrades needed to interconnect new resources to meet State energy/environmental policies (evaluated by CNRIS and NRIS) and to meet reliability requirements
Timeframe: Minimum 10 years
Supply Resource Mix: Meets State energy/environmental policy objectives developed through the stakeholder process; consider using a capacity resource optimization model to identify potential resource retirements and additional new resource additions to address reliability “gaps”
Wholesale Net Load: 2020 CELT forecast models; if timeframe is beyond 10 years, then extend the base forecast models, including assumptions about additional EV and ASHP penetration
Other: Analytical framework rather than specific resource mix, load forecast, and commodity price assumptions. Assuming the proposed “Condition Case” structure incorporated, EMA comfortable with using the major assumptions proposed by NESCOE and other stakeholders. Develop explicit estimates of FCM prices, revenues, and costs that are typically not done in economic studies. Evaluate implications of the impact of new resources added to meet State energy/environmental policy objectives. Develop a more structured (model-based) methodology to look at likely resource retirements, as well as any other new resources that might be needed to meet resource adequacy, economic, and system operation needs.

Eversource 1

Transmission Network: Existing planning transmission topology
Timeframe: Base Case: 2020; Supply Mixes 1–3: 2030, 2040, and 2050
Supply Resource Mix Base Case: Existing resources are the generation fleet and demand response and EE resources as of FCA 15, plus: (i) any additional generation operating or under construction but not cleared in an FCA as of April 1, 2020; and (ii) any generation with an approved I.3.9 and that is still in the interconnection queue as of April 1, 2020. Individual cases will model amounts of capacity and energy-only resources consistent with their respective designs, unless otherwise noted.
Wholesale Net Load Base Case: 2020 CELT

Supply Resource Mix: Installed Nameplate Capacity MW (2030/2040/2050)			
	Supply Mix 1	Supply Mix 2	Supply Mix 3
Offshore Wind	3,134/7,934/11,998	5,630/10,126/15,000	3,314/6,000/7,998
Land-based Wind	2,803/2,803/2,803	1,303/1,303/1,303	1,738/1,738/1,738
Imports	2,149/3,149/4,149	2,149/3,149/3,149	2,149/2,149/2,149
Hydro	3,356/3,356/3,356	3,356/3,356/3,356	3,356/3,356/3,356
BTM PV	5,207/11,899/27,186	5,207/11,899/27,186	7,708/24,401/34,650
Utility PV	3,252/8,820/16,474	3,252/7,320/16,474	3,252/10,119/27,469
Gas	15,931/14,995/11,245	15,931/14,995/11,245	15,931/14,995/11,245
Coal/Oil	0/0/0	0/0/0	0/0/0
Nuclear	3,358/2,482/0	3,358/2,482/0	3,358/2,482/0
Other	1,585/1,300/1,273	1,585/1,300/1,273	1,585/1,300/1,273

Wholesale Net Load Base Supply Mixes 1–3 (2030/2040/2050)	
Summer Peak Gross (MW)	31,303/33,618/36,135
Winter Peak Gross (MW)	24,788/26,287/27,895
Annual Gross (GWh)	158,915/178,158/199,868
EE Summer Peak Reduction (MW)	5,661/7,366/9,580
EE Winter Peak Reduction (MW)	5,280/6,886/8,988
EE Annual Reduction (GWh)	35,617/47,072/62,274
*All solar PV (BTM and utility scale) values are included in Supply Resource Mix assumptions	

Eversource 1

Electrification Forecasts Base Case: 2020 CELT

Electrification Forecasts Supply Mixes 1–3 (2030/2040/2050)	
EV forecast (total vehicles/annual demand)	2030: 1,896,693 vehicles/9,457 GWh 2040: 3,703,366 vehicles/18,466 GWh 2050: 6,204,616 vehicles/30,938 GWh
Heating forecast (annual demand from residential and commercial heat pumps)	2030: 1,511 GWh 2040: 6,606 GWh 2050: 11,637 GWh

Battery & Other Storage Base Case: None

Battery & Other Storage (Installed Nameplate MW; 2030/2040/2050)	
Supply Mix 1	3,616/3,940/18,860
Supply Mix 2	3,136/3,136/8,000
Supply Mix 3	3,427/10,119/34,016

Other Base Case: All supply installed capacity MW are the total installed nameplate capacity of that resource in the study year (as opposed to incremental additions or de-rated capacity); all supply and demand forecasts are available by zone

Other Supply Mixes 1–3: Additional questions to consider when developing the specific modeling approach given the proposed scenario assumptions (supply, demand, transmission, etc.): (1) What is the impact of an extended outage of nuclear units on reliability and market operations? (2) What is the impact of a multi-day weather event resulting in loss of most/all renewable supply? (3) How does the operation of storage impact reliability and market dynamics? (4) What is the impact of modeling negative price bidding?

Eversource 2

Transmission Network: TBD
Supply Resource Mix: TBD as modeling output; installed nameplate BTM PV for demand forecast: 2030 = 5,207 MW; 2040 = 11,899 MW; 2050 = 27,186 MW

Wholesale Net Load Base Case (2030/2040/2050)	
Summer Peak Gross (MW)	31,303/33,618/36,135
Winter Peak Gross (MW)	24,788/26,287/27,895
Annual Gross (GWh)	158,915/178,158/199,868
EE Summer Peak Reduction (MW)	5,661/7,366/9,580
EE Winter Peak Reduction (MW)	5,280/6,886/8,988
EE Annual Reduction (GWh)	35,617/47,072/62,274

Electrification Forecasts	
EV forecast (total vehicles/annual demand)	2030: 1,896,693 vehicles/9,457 GWh 2040: 3,703,366 vehicles/18,466 GWh 2050: 6,204,616 vehicles/30,938 GWh
Heating forecast (annual demand from residential and commercial heat pumps)	2030: 1,511 GWh 2040: 6,606 GWh 2050: 11,637 GWh

Battery & Other Storage: TBD as modeling output

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Multi-Sector Group A

Transmission Network: NESCOE 2019 Economic Study (Report Figure 5.1), unless meaningful variation between proposed queue interconnection for OSW and the 2019 Study assumptions.
Timeframe: Note that these nominal years are indicative only as an end state and a mid-point. With that caveat, 2030 (Base Case), 2050 (End State), and 2040 (Mid-Point)
Supply Resource Mix: Base Case: Existing resources will be the generation fleet and DR as of FCA 15, less At Risk resources, plus EE forecast, additional renewables, proportional to existing + queue required to meet the state RPS requirements (should the queue be insufficient). Assume battery energy storage fills in any shortfall.
Wholesale Net Load: Base Case, End State, and Mid-Point cases per Mass EEA data, if available; additional scenario assumes at least 20% of demand is flexible to absorb surplus or reduce demand
Electrification Forecasts: Per Mass EEA data, if available
Battery & Other Storage: At a minimum: Base Case (2030): 4 GW/8 GWh; End State (2050): 20 GW/80 GWh; Mid-Point (2040): 10 GW/30 GWh
Other: When adding bulk energy storage to avoid shortfalls, location will first be assumed to be at the location of retired units and then at the Hub. When adding renewable/clean energy resources, their locations will be at locations consistent with resources in the current interconnection queue as of July 1, 2020 with the same relative proportion of MW at those locations (i.e., first include generation in the current queue and then add generation, if needed, proportionally based on current locations of generation in the queue); except that Offshore wind resources will be added at the ISO interconnection points closest to federally-designated Wind Energy Areas. Should there be an energy shortfall, work with stakeholders to specify and locate gas-fired generation resources (retain existing units). Resource capital and operating costs should decline with currently available trends or forecasts. Fuel price forecasts will come from the EIA data for New England. The impact of alternative fuel prices can be determined exogenously unless they affect the dispatch order of resources. Use high and low fuel price sensitivities to determine effect on dispatch order. After initial runs are done, determine if any fine tuning of EIA prices should be done to recognize seasonal price or basis differentials. Further discussion with stakeholders on how to model imports. Assume prices for RGGI allowances and prices for other environmental emission allowances. Specific assumptions of prices will be developed through further discussion with stakeholders and determine if there is a need to create sensitivities for high and low emissions prices.

Multi-Sector Group B

Transmission Network: NESCOE 2019 Economic Study (Report Figure 5.1), unless there is meaningful variation between proposed queue interconnection for OSW and the 2019 Study assumptions. To the extent the model finds this inadequate, note the gap and assume sufficient transmission to serve load
Timeframe: Any future year where the New England states achieve their carbon reduction goals or net zero carbon by 2050
Supply Resource Mix: Resource mix needed to achieve net zero carbon emissions per technical outputs of the MA 2050 Roadmap Study or the Eversource/LEI "2040 Aggressive Decarbonization" scenario
Wholesale Net Load & Electrification Forecasts: MA 2050 Roadmap Study
Battery & Other Storage: At a minimum for net zero carbon: 20 GW/80 GWh
Other: Sensitivities should assess the role of non-transmission alternatives in reducing the need for new transmission infrastructure; sensitivities should assess the role of optimized DER deployment, mobile storage with managed charging, increased energy efficiency, and flexible demand in reducing bulk transmission needs to achieve state goals; sensitivities should also consider the role of grid-enhancing technologies (e.g., dynamic line rating) in reducing the need for new transmission infrastructure

National Grid

Transmission Network: Topology used in FCA 14, plus upgrades associated with resources that cleared in FCA 14 and any proposed or planned reliability projects on ISO-NE's March 2020 RSP Project List; increase of the Surowiec-South interface limit to 2,500 MW; addition of a bi-directionally capable controllable (DC) line 1,200 MW with Quebec; export capability over PHII and NB ties of 1,200 MW and 550 MW, respectively
Timeframe: 2035
Supply Resource Mix: FCA 14 retirements (Mystic 8 & 9, Millstone 2, NE Coal, and 75% of conventional NE oil including dual-fuel based on performance); to meet state policies (about 62% RPS as a region) include 1,330 MW onshore wind, 8,000 MW offshore wind, 5,400 MW BTM PV, and 6,400 MW utility-scale PV
Wholesale Net Load: 2035 values for gross demand and EE are extrapolated from 2020 CELT Forecast (33,112 MW peak demand; 177,762 GWh annual energy; 6,777 MW for EE capacity; and 36,030 GWh for EE energy)
Electrification Forecasts:
Heating Pump Peak Demand: 5,214 MW; *EV Peak Demand*: 1,817 MW
Battery & Other Storage: 2,000 MW
Other: Use REC-inspired threshold prices (some resources at negative prices) to initiate exports and order spillage appropriately; fuel price forecasts will come from the 2020 EIA Annual Energy Outlook for New England; emissions allowance prices will assume as \$4.00/ton for NO_X, \$2.00/ton for SO_2 and \$33.52/ton for CO_2

NextEra/Dominion

Transmission Network: No preference

Timeframe: Loss of the Seabrook and Millstone nuclear power plants in year 2030 studied for ten years until 2040

Supply Resource Mix: No preference

Wholesale Net Load: No preference

Electrification Forecasts: No preference

Battery & Other Storage: No preference

Side-by-Side View of Key Features

- The following slides provide a “side-by-side” view of how each proposal addresses the following features of the study.
- Base Case Description
- Associated Prior/Ongoing Study
- Metrics to Develop and Examine
- Deliverable(s)
- Transmission Network
- Timeframe

Base Case Description

API: An evaluation that assumes typical load using most current assumptions for regional natural gas and renewable costs. Use AEO 2020 Reference Case prices for natural gas prices; if necessary, could use a backward-looking weighted average differential from Henry Hub to Algonquin. Use EIA AEO 2020 LCOE cost components for new builds. No extensions to PTC or ITC tax credits and no changes to planned phasedowns

Anbaric: Current grid within the planning horizon

EMA: Not defined

Eversource 1: Consistent with the current system, e.g., loads from 2020 CELT & existing capacity

- *Supply Mix 1*: Mixed Portfolio to meet 80% economy-wide emission reduction by 2050 state goals
- *Supply Mix 2*: High Offshore Wind Portfolio to meet 80% economy-wide emission reduction by 2050 state goals
- *Supply Mix 3*: High Solar Portfolio to meet 80% economy-wide emission reduction by 2050 state goals

Base Case Description

Multi-Sector Group A: Reflect best information about the system in 2030 to (1) allow a comparison to the 2016 study and (2) provide a snapshot 10-years hence to identify any gaps that would require immediate attention

Multi-Sector Group B: Base case would reflect best information about the system when decarbonization goals have been achieved. Requestors do not presuppose the date of if/when such a scenario might occur. Essentially, an “end-state” zero-carbon generation scenario

National Grid: National Grid 2020 Economic Study’s Bi-directional Transmission 1 Scenario (with Base Case Input Assumptions)

NextEra/Dominion: Base case assumptions similar to other base cases that will be used as part of this “Transition to the Future Grid” analysis, important to keep assumptions consistent; model loss of the Seabrook and Millstone nuclear power plants in year 2030

Associated Prior/Ongoing Study

API: Over the past decade there have been several studies and reports released by the ISO that show that natural gas infrastructure can further economic and reliability objectives in the region

Anbaric: ISO-NE's 2019 Economic Study Offshore Wind Transmission Interconnection Analysis; 2020 Brattle/GE/CHA study; Sept. 2019 study regarding system needs to meet MA's 2050 goals

Eversource: Eversource Grid of the Future Study

Multi-Sector Group A: PAC 2016 Economic Study Phase II - Regulation, Ramping, and Reserves (Amro M. Farid)

Multi-Sector Group B: MA 2050 Roadmap Study; Eversource/LEI "2040 Aggressive Decarbonization" scenario; 2019 NESCOE Offshore Wind Economic Study

National Grid: National Grid 2020 Economic Study

Metrics to Develop

API: Regional demand projections (including seasonal variations), wholesale power prices, technology cost assumptions, reserve margins, commodity cost assumptions, power generation fleet assumptions, consumer expenditures in the region (via BLS CEX), state-level expenditures by energy source (via EIA SEDS), and emissions factors (via EIA monthly or annual figures) to understand people's willingness to continue paying relatively high rates on gas and electricity, how much states may be saving *already* by incorporating more gas and less coal/liquids/wood into the electricity mix, how incorporating more gas into the mix has already brought power sector and total emissions down in the region overall.

Anbaric: Informed by the Other Studies and should develop a picture of what is needed in terms of design and supply on that grid to meet the 2035 Biden zero carbon energy plan

EMA: NESCOE 2019 Economic Study metrics; develop FCM clearing prices under the various resource mix configurations

Eversource 1: LOLE based on initial supply mix, emissions from initial supply mix, total cost of supply, clearing prices and total cost to load

Eversource 2: System installed nameplate capacity by resource, LOLE, electric sector emissions, reliability metrics

Multi-Sector Group A: PAC 2016 Economic Study Phase II metrics

Multi-Sector Group B: List of system limitations, including interface transfer limit constraints, thermal and/or voltage constraints, stability concerns (system inertia) and bottlenecks. Specifically, voltage violations on an N-0 and N-1 scale. Costs in $/bn

National Grid: (1) National Grid 2020 Economic Study metrics; (2) detailed transmission analysis; & (3) forecasted FCA clearing prices by unit type

Deliverables

API: Modeled output and corresponding report provide insight into energy transition pathways for ISO-NE, reflective of state policy goals and technological innovation and feasibility. The report should specify how ISO-NE plans to achieve its objectives for reliability and ratepayer protection, while increasing its integration of variable energy resources

Anbaric: An overview of the best ways (cost effective, fewer cables/lower environmental impact, maximize existing grid, provide resiliency, reliability, and controllability for system operators) to develop the transmission system to interconnect offshore wind, PV, battery storage, onshore wind and other distributed or zero carbon resources; resulting document would be a blueprint for a Grid of the Future (onshore and offshore) reflecting what transmission and resources need to be constructed to meet the Biden 2035 zero carbon energy system target while providing reliable electrical service; an output will build upon Brattle and other work to realistically identify the level and location of storage needed for a zero carbon power system that is in-line with the Biden energy plan target and provides the capabilities to meet electric system needs for ramping, intermittent power changes, and contingencies.

EMA: Similar to NESCOE 2019 Economic Study plus forecasted FCM prices, revenues, and costs

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Deliverables

Eversource 1: Report out all modeling metrics (LOLE, emissions, total cost of supply, clearing prices and total cost to load); a qualitative assessment of how each supply mix provided in the Supply Resource Mix Base Case Input Assumptions could develop under current or proposed market rules

Multi-Sector Group A: 2016 Economic Study Phase II deliverables: (1) simulated Operating Reserves: Load Following, Ramping and Curtailment Performance; (2) Simulated Interface & tie-line Performance; (3) Simulated Regulation Performance; (4) Simulated Balancing Performance; and (5) Time series data outputs on the most granular time-scale (e.g., 1- or 10-minute data) for each kind of assessed reserve.

Multi-Sector Group B: Identify potential constraints in the transmission system to accommodate the net zero carbon emissions resource mix and identify necessary transmission upgrades and additions, as well as potential non-transmission alternatives to those upgrades and additions

National Grid: (1) National Grid 2020 Economic Study Request deliverables with a more detailed transmission analysis; (2) contingency and upgrade analysis; & (3) forecasted FCA clearing prices by unit type as one revenue source when assessing if current market outcomes cover capital/expenses

Transmission Network

Anbaric: Current grid as starting point that changes (retirements of fossil, additions of significant PV, storage, offshore wind, etc.) to meet 2035 zero carbon target

EMA: FCA 14 topology (but use FCA 15 if available), plus upgrades needed to interconnect new resources to meet State energy/environmental policies (evaluated by CNRIS and NRIS) and to meet reliability requirements

Eversource 1: Existing planning transmission topology

Multi-Sector Group A & Multi-Sector Group B: NESCOE 2019 Economic Study (Report Figure 5.1), unless meaningful variation between proposed queue interconnection for OSW and the 2019 Study assumptions.

National Grid: Topology used in FCA 14, plus upgrades associated with resources that cleared in FCA 14 and any proposed or planned reliability projects on ISO-NE's March 2020 RSP Project List; increase of the Surowiec-South interface limit to 2,500 MW; addition of a bi-directionally capable controllable (DC) line 1,200 MW with Quebec; export capability over PHII and NB ties of 1,200 MW and 550 MW, respectively

Timeframe

API: 2020–2040

Anbaric: 2035

EMA: Minimum 10 years

Eversource 1: Base Case: 2020; Supply Mixes 1–3: 2030, 2040, and 2050

Multi-Sector Group A: Note that these nominal years are indicative only as an end state and a mid-point. With that caveat, 2030 (Base Case), 2050 (End State), and 2040 (Mid-Point)

Multi-Sector Group B: Any future year where the New England states achieve their carbon reduction goals or net zero carbon by 2050

National Grid: 2035

NextEra/Dominion: Loss of the Seabrook and Millstone nuclear power plants in year 2030 studied for ten years until 2040

Analytical Framework - Grid Transformation Analysis

Joint RC/MC Teleconference Meeting
July 1, 2020

Brian Forshaw
Energy Market Advisors LLC

Energy Market Advisors LLC

Overview

- *ISO-NE Objectives*
- *Overarching Assumption/Focus of Presentation*
- *Proposed Analytical Framework*
- *Analytical Tools*
- *Questions & Comments*

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ISO-NE Objectives

- *The current ISO objectives were initially developed in the late 1990s when we were transitioning from a cost-based construct to an offer-based construct.*
- *What has been missing is consideration of how these objectives have led to the situation we are in today.*
- *We need to consider whether new objectives might be necessary to achieve the outcomes anticipated desired by consumers and state policymakers.*

Focus & Overarching Assumption

- *Our focus is on developing an analytical framework that can be applied no matter what assumptions and resource mix scenarios are assumed.*
- *Overarching assumption is that resources to meet regional energy and environmental policies will be developed irrespective of how they participate in the wholesale markets.*
- *Leave it to the the Committees figure out how to identify the mix of resources & other assumptions to meet these objectives.*

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Proposed Analytical Framework

- *Under the current Market Rules there are 2 ways that resources can interconnect and participate in the wholesale markets.*
  - *Resources with capacity network interconnections (CNRIS) can participate in the Capacity, Energy & Ancillary Service markets.*
  - *Resources with minimum interconnection service (NRIS) can only participate in the Energy & Ancillary Service markets*

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Proposed Analytical Framework (cont.)

- *The Grid Transition Analysis should consider the two options that policy resources have for interconnecting and participating in the wholesale markets across all scenarios and cases*
  - *All policy resources would be CNRIS and participate in Capacity, Energy, and Ancillary Service markets.*
  - *All policy resources would be NRIS and only participate in the Energy & Ancillary Service markets.*

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Proposed Analytical Framework (cont.)

- *If the policy resource cannot get a CSO through the FCA (either due to the MOPR or the CASPR test price) or if the cost of a CNRIS is too high, NRIS may well become the preferred outcome.*
- *Resources participating as CNRIS and NRIS can have different implications for consumer costs, payments to resources, system operations, resource adequacy, and other metrics.*

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Proposed Analytical Framework (cont.)

- *It appears that most have assumed all resources would be CNRIS and participate in all wholesale markets.*
- *While NRIS resources may need additional non-wholesale market support, understanding the broader implications will be helpful in evaluating potential "gaps" in the market.*
- *This approach is consistent with the ESI Condition Cases (Frequently, Infrequently, and Extended Stress Cases).*

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Analytical Tools

- ISO does not currently have a tool to develop estimated Forward Capacity Market prices in its planning studies.
  - This has been an issue in interpreting the results from previous Economic Studies.
- To help evaluate the implications of various resource mixes, a capacity "optimization" tool should be developed to help evaluate both competitive entry and exit from the markets under the future policy resource scenarios.

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Questions?

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Regulation, Ramping, and Reserves

Requested by Multi-Sector Group A*

**Acadia Center, Advanced Energy Economy (AEE), Brookfield Renewable, Conservation Law Foundation (CLF), Energy New England (ENE), Natural Resources Defense Council (NRDC), and Power Options*

Overview

- **Objective:**
  - To assess if there is a need for or benefit from additional ramping, regulation, or load-following resources as the system decarbonizes
- **Study Information:**
  - **Associated Prior Study:** PAC 2016 Economic Study Phase II (Regulation, Ramping, and Reserves), updated and extended beyond 2030
  - **Modeling Tool:** EPECS Simulator (Dartmouth)
- **Scenarios:**
  - **Base Case** reflecting best information about the system in 2030 (updating inputs to 2016 PAC study), adjusted as needed to meet state policy goals
  - **System in flux** between base case and end state (not tied to a particular year)
  - **End State** low-carbon generation scenario (potentially based on end state technical outputs from Massachusetts 80x50 study or Eversource "Aggressive Decarbonization" scenario; not tied to a particular year)

Study Details

- **Deliverables:**
  - Simulated operating reserves: Load Following, ramping and curtailment performance
  - Simulated interface & tie-line performance
  - Simulated regulation performance
  - Simulated balancing performance
  - Timeseries data outputs on the most granular time-scale (e.g. 1- or 10-minute data) for each kind of assessed reserve
- **Other notes:**
  - Mid-point not necessarily linear extrapolation
  - Requestors would like additional information and discussion of the model's treatment of energy storage and flexible demand
  - Inputs should assume declines in resource capital and O&M costs
  - Inputs should assume prices for RGGI allowances / other emission allowances

Thank You

Contact

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Long-Term Transmission Study

REQUESTED BY MULTI SECTOR GROUP B*

*Advanced Energy Economy (AEE), Borrego Solar, Conservation Law Foundation (CLF), Energy New England (ENE), ENGIE, Natural Resources Defense Council (NRDC), Power Options.

Purpose and Scenarios

Purpose

- Power flow model to identify any transmission system limitations to implementing a net zero carbon future.
- Identify potential new transmission investments that could resolve identified limitations.
- Identify whether distribution system generation, mobile and stationary storage, or flexible demand could reduce the need for any new transmission infrastructure.

Base Case Scenario

- “End-state” net zero-carbon generation scenario (not tied to a particular year), e.g., MA 80-by-50 study 2050 end-state scenario or Eversource/LEI “2040 Aggressive Decarbonization” scenario

System in Flux Scenario

- “Mid-point” scenario (not tied to a particular year) providing directional information about the system in flux e.g. MA 80-by-50 study 2040 scenario “Central Case” or Eversource/LEI “2040 Balanced Portfolio” study

Metrics and Deliverables

Metrics

- List of system limitations i.e. interface transfer limit constraints, thermal and/or voltage constraints, stability concerns (system inertia)

Associated/Ongoing Studies

- MA 20-by-50 Study; Eversource/LEI "2040 Aggressive Decarbonization" scenario; 2019 NESCOE Offshore Wind Economic Study

Deliverables

- Identify any potential constraints in the transmission system to facilitating the net zero emissions resource mix
- Identify any necessary transmission upgrades and additions
- Identify non-transmission alternatives to upgrades and additions
- Identify amount of DER required to minimize required transmission upgrades

Thank you

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Future Grid Proposal

A Carbon Free Power System by 2035

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NEPOOL Markets & Reliability Committees
August 4, 2020

ANBARIC®

Future Grid Study Drivers

> State targets and renewable procurement goals are advancing rapidly, with additional procurements added every few months across the mid-Atlantic and Northeast. For example, the MA senate just passed an authorization for an additional 2,800 MW – for a total MA mandate of 6 GW; a New England total of 9,300 MW. This is in addition to current, significant PV goals.

> New England state 100% renewable or 0 carbon energy goals over the 2030 to 2050 timeframe

Atlantic states setting pace with offshore wind goals, projects

State	OSW target	Awarded to date
Massachusetts	3,200 (6,000 - pending)	1,604
Rhode Island	1,000	430
Connecticut	2,300	1,108
New York	9,000	1,826
New Jersey	7,500	1,100
Maryland	1,568	368
Virginia	5,200	12
Total	**29,768 MW (32,568 MW)**	**6,448 MW**

Biden Energy Plan – Zero Carbon by 2035

In July of 2020, the Biden campaign endorsed its energy policy working group recommendation of a zero-carbon electricity sector by 2035

Whether this federal policy is adopted in the coming months or not, it simply advances the energy and climate laws and policies already set by the New England States. In short: we know where we're headed

Anbaric Future Grid Study Proposal

The Anbaric study proposal seeks to identify for policymakers, stakeholders and grid planners the sort of bulk electric system we would need to plan and build to enable a carbon-free electric energy sector

This is important because the current state and possible federal laws require a different and more capable grid. And a 2035 target year is less than 15 years away. Given that transmission and supply planning, procurement and siting takes years (e.g. a single transmission project can take 5 to 9 years to site and construct), this work needs to begin now and a high-level guiding Future Grid roadmap study is needed

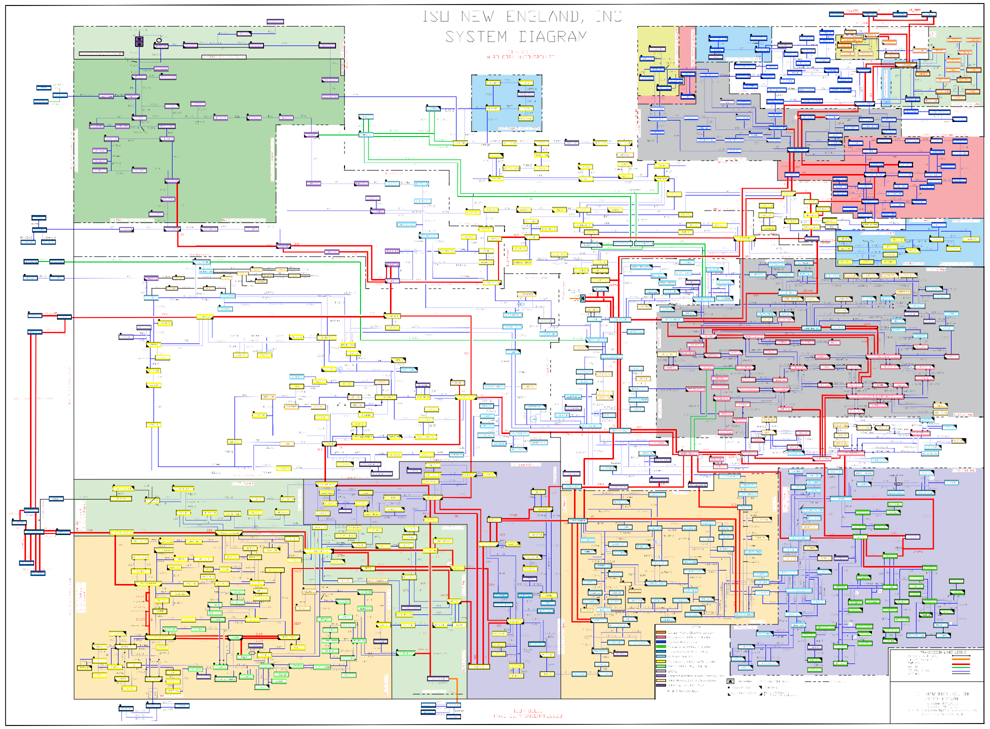
Key Study Points

Objective: Identify an onshore and offshore Future Grid blueprint for a power system that is carbon free by 2035, inline with the Joe Biden July 2020 energy plan and build upon other studies

Base Case: Current grid within the planning horizon

Additional Scenarios: Scenarios will be levels of storage, PV, and on-shore and off-shore wind needed to enable a carbon-free New England grid by 2035; sensitivities would also include varying levels of nuclear and electrification in-line with the Brattle Sept. 2019 study, adjusted to meet a 2035 target

Metrics to Develop: Informed by the other studies and should develop a picture of what is needed in terms of design and supply on that grid to meet the 2035 Biden zero carbon energy plan



Key Study Points - Continued

Transmission Network: Current grid as starting point that changes (retirements of fossil, additions of significant PV, storage, offshore wind, etc.) to meet 2035 zero carbon target

Supply Resource Mix:

Retire current fossil fuel generation fleet for 2035; replace and adjust for electrification with PV, storage, onshore and offshore wind resources, and other non-carbon resources.

Scenario analysis is with and without Millstone

Wholesale Net Load Gross and Electrification Forecasts: Brattle projections and other sources of policy target input to adjust 2035 load to account for electrification

Battery & Other Storage: Significant grid scale and distributed battery storage should be assumed to help provide for ramping and system contingencies

Key Storage Points

This is an opportunity to re-think grid-scale storage and the roles it can play / how it's utilized / how it's modeled

Storage should not be thought of a just a supply resource, but can and should be utilized in Future Grid studies to show the full value of storage to the grid – including ability to provide/avoid transmission facilities/upgrades upon interconnection of renewables (or growth of sub-transmission level renewables), in addition to firm energy supply, blackstart, ramping, regulation and contingency reserve

Advanced modeling can show where storage may be more cost-effective vs. a transmission circuit

Study Deliverable: A Future Grid Guiding Blueprint

An overview of the best ways (cost effective, fewer cables/lower environmental impact, maximize existing grid, provide resiliency, reliability, and controllability for system operators) to develop the transmission system to interconnect offshore wind, PV, significant battery storage, onshore wind and other distributed zero carbon resources; resulting document would be a blueprint for a Future Grid (onshore and offshore) reflecting what transmission and resources needed to be constructed to meet the Biden 2035 zero carbon energy system target while providing reliable electrical service. The output will build upon Brattle and other work to realistically identify the level and location of storage needed for a zero-carbon power system that is in-line with the Biden energy plan target and provides the capabilities to meet electric system needs for ramping, intermittent power changes, and contingencies.

Studies To Build On, A Non-Exclusive List

- Anbaric 2019 Economic Study Regarding 8,000 to 12,000 MW of Offshore Wind (Note: these levels are below the ~25 to 40 GW needed)
- ISO New England Grid Upgrades for Offshore Wind – June 2020 PAC
- Brattle September 2019 Study Looking at Grid Needed to Meet New England 2050 Goals
- Brattle / GE / CHA May 2020 Study Regarding Transmission for Offshore Wind
- MASSCEC Request and ISO-NE Response Re: Impact of OSW on 2017-2018 Cold Snap
- California ISO / Avangrid Study on Essential Grid Services That Can Be Provided by Wind Farms: http://www.caiso.com/Documents/WindPowerPlantTestResults.pdf

Thank you

New England States Committee on Electricity

To: **NEPOOL and ISO New England**
From: **NESCOE *(contact: Ben D'Antonio)***
Date: **August 3, 2020**
Subject: Future Grid Analysis Submission - Pathway Scenario: 2035 and 2040

Through the Transition to the Future Grid initiative, NEPOOL is planning to conduct analysis of a hypothetical future New England system that accounts for the requirements of state laws. ISO-NE has agreed to conduct this analysis, subject to its information policy obligations, of state and stakeholder requested scenarios.

NESCOE submits the following information that represents one plausible vision of a future system that contemplates the requirements of state laws. This scenario is just that, a scenario. It is not a projection, prediction or statement of preference.

I. NESCOE Pathway Scenario

The Pathway Scenario presents one hypothetical approach to achieving economy-wide carbon reduction. Northeastern States for Coordinated Air Use Management (NESCAUM) describes this strategy in greater detail in a white paper.[1] The Pathway Scenario assumes that an increasing amount of homes and businesses will, over time, replace their used cars with newer and cleaner alternatives like plug-in hybrid cars and trucks. It also assumes that more buildings and homes will continue to make energy efficiency improvements and use cleaner energy sources for space and water heating, like air- and ground-source heat pumps. To serve these new and existing demands for electricity, the power sector grows in size over time in the Pathways Scenario. Despite the load growth, the resource mix continues to transition towards a cleaner emissions profile. For example, the Pathways Scenario assumes that resource additions are at least 1,000 MW of incremental clean energy per year for the next several decades.[2] The combined effect of these measures is assumed, for purposes of study, to result in economy-wide carbon reduction that would put New England on a pathway to compliance with state law requirements.

A. Pathway Scenario Assumptions

To serve the demand for electricity on a carbon compliant pathway, the Pathway Scenario assumes that the resource mix in New England will change over time. For example, coal, oil, and natural gas usage declines over time in the Pathway Scenario while increasing amounts of incremental solar and wind resources are added to the system.

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1 The NESCAUM White Paper from September 2018 provided high-level insights about the magnitude of actions needed to achieve New England's ambitious climate goals.

2 The Pathway Scenario uses the term "clean" to mean zero- or low-carbon resources, which may nor may not be renewable as defined in various states' laws.

The Pathways Scenario focuses only on two years:

- 2035 – This year is just far enough into the future that it (a) has not yet been studied closely and (b) is plausibly within a timeframe by which reforms could be implemented.

- 2040 – This year is far enough into the future that it includes significant amounts of new loads and changes in the resource mix. The degree of change would stress the model, and in combination with 2035 provide contrast through a range of values.

II. Pathway Scenario Assumptions

The proposed Pathways Scenario could be included in the Future Grid Analysis in several ways. As described at the May MC/RC meeting, the Pathways Scenario could be included in energy market modeling to get an hour-by-hour dispatch pattern for the system. These results could then be mapped to an ancillary services model for a minute-by-minute examination of system operating characteristics and requirements. The Pathways Scenario – and any related energy market results - could also be incorporated into analyses of transmission. For example, two types of transmission analyses described in May were a high-level feasibility (steady-state thermal and voltage) and dynamic stability. The Pathways Scenario details also include detailed electricity demand information – hourly, zonal electricity demand by sub-sector.

Year	Electricity Demand and Electrification			General System Description	
	Traditional Electricity Demand	Transportation	Space & Water Heating	Net Energy For Load	Capacity
2035	105 TWh	21 TWh	28 TWh	155 TWh	55 GW
2040	109 TWh	37 TWh	39 TWh	185 TWh	70 GW

Pathways Scenario: Resource Mix (MW)	**2035**	**2040**
Combustion Turbine	1,150	1,500
Combined Cycle Gas Turbine	13,750	15,000
Biomass	Same as Today	
Nuclear		
Hydro		
Onshore Wind	1,750	1,300
Rooftop PV	11,500	12,500
Ground-mounted PV	9,000	15,000
Offshore Wind Fixed	7,000	8,000
Offshore Wind Floating	2,500	8,500

NESCOE appreciates the opportunity to advance this scenario and looks forward to discussing this and other scenario assumptions as the process moves forward.