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Pathways Study

Evaluation of Pathways to a Future Grid

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September 23, 2021

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Overview

- Purpose of today's presentation is to provide information on **outstanding quantitative model inputs and assumptions**
- We have endeavored to provide information on current thinking and will refine based on our continued analysis and additional feedback
- We appreciate stakeholder feedback to date and welcome further feedback on our inputs and assumptions to help ensure our assumptions are reasonable and reflect a range of viewpoints regarding future policies
- We plan to present central case results at the October Participants Committee Working Session

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Agenda

- Proposed approaches to outstanding **model inputs and assumptions**
  - Load Assumptions in Study Years
  - Behind-the-Meter Solar
  - Summer/Winter Qualified Capacity
  - Resource Siting and Transmission Upgrade Costs
  - Status Quo Resource Mix

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Load Modeling Assumptions for Study Years

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Load Modeling Assumptions for Study Years

- Pathways analysis requires annual load for 2020 to 2040. To develop these, we plan to:
  - For years 2030 and 2040, assume loads based on the MA 80x50 Study, as provided by NESCOE
    - Adjusted by ISO-NE System Planning to move from weather year 2012 to 2019
    - Same approach as used in FGRS Load Scenario 3 for 2040
  - For base year, assume actual 2019 load from CELT 2020, as COVID-19 is likely to have impacted loads in 2020 and all modeled years are shaped based on a 2019 weather year
  - Under this proposed methodology, the system will become winter peaking starting in 2029

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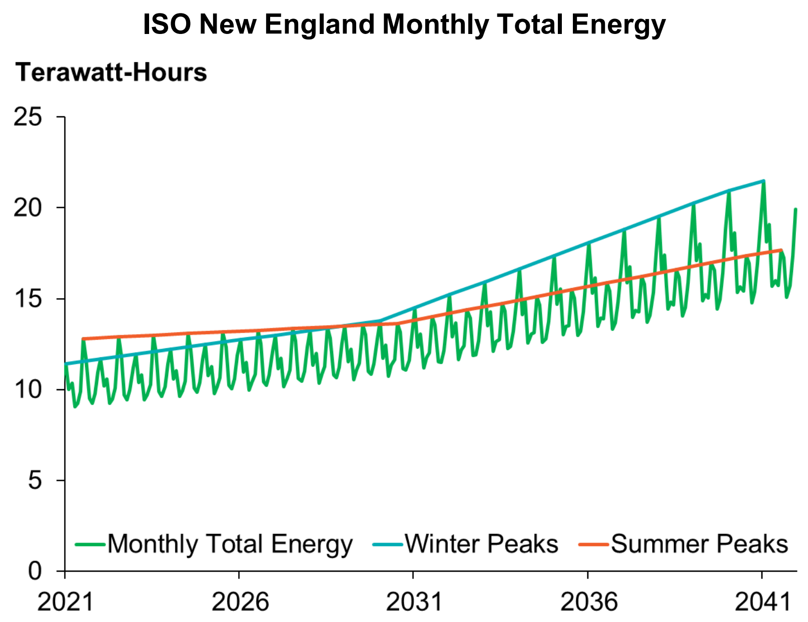
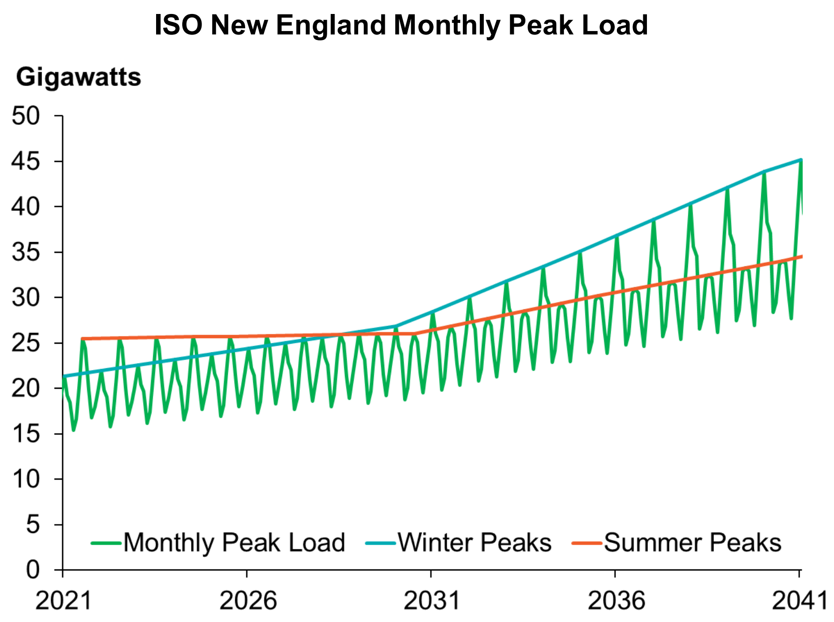
Load Forecast Modeling Assumptions for Intermediate Study Years

- Under this proposed methodology, we linearly interpolate loads in intermediate years





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Behind-the-Meter Solar Modeling Assumptions

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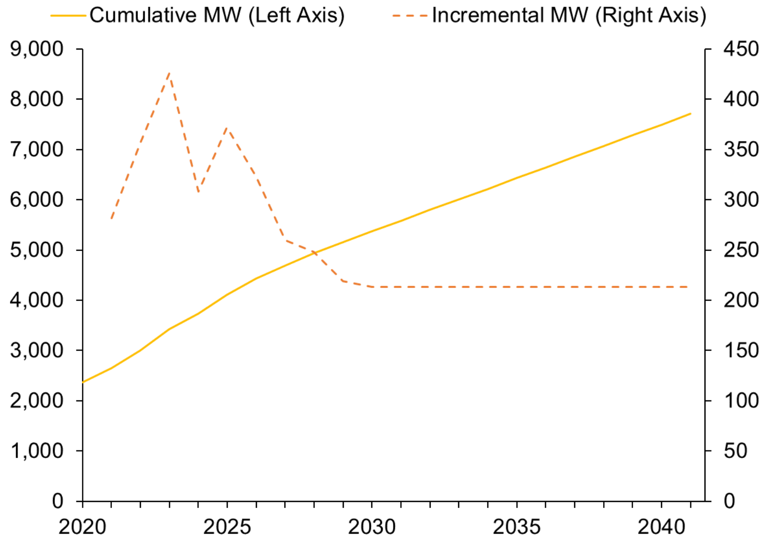
Behind-the-Meter Solar Modeling Assumptions

- Behind-the-meter solar growth in 2021-2030 in all scenarios will be based on the 2021 CELT
- For 2031-2040, growth will be constant and equal to the incremental growth in 2030
- In the figure and table below, 2020 BTM PV includes all existing BTM PV according to CELT
- BTM PV is being modeled as supply and is eligible for CECs

Assumed Model Buildout of BTM Solar



Assumed Model Annual Buildout of BTM Solar, by State (MW) 2021-2030

Year	CT	MA	ME	NH	RI	VT
2020	544	1,187	60	108	71	393
2021	19	187	29	17	8	22
2022	56	197	60	13	11	19
2023	143	180	63	12	10	18
2024	30	165	61	16	14	22
2025	88	203	29	16	14	22
2026	88	179	4	16	14	22
2027	88	116	4	16	14	22
2028	80	112	4	16	14	22
2029	54	109	4	16	14	22
2030	52	105	4	16	14	22

Source: 2021 CELT Report, ISO-NE.

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Qualified Capacity for Resource Adequacy Modeling Assumptions

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Summer/Winter Qualified Capacity Modeling Assumptions

- For all resources, we plan to estimate Qualified Capacity (for meeting resource adequacy) as the simple average of summer and winter Qualified Capacity (QC)
  - The adjustment from current market rules will help to account for the expected change in load profile in future years, including the shift from summer- to winter-peaking
  - It is not intended to approximate or predict potential future changes being contemplated by the region in the Resource Capacity Accreditation project
- For summer and winter QC:
  - For new and existing intermittent resources we use existing ISO rules; in particular, seasonal QC will be the median output during intermittent reliability hours, as defined in the ISO-NE Tariff and calculated using generation profiles that differ by location and rely on 2019 weather patterns
  - For dispatchable resources, the seasonal claimed capacity in CELT is used. If a resource is not in CELT but cleared FCA 15, the summer and winter QC from that auction is used

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Summer/Winter Qualified Capacity Modeling Assumptions

- Qualified Capacity for renewable resources is based on DNV profiles for 2019
- Utility PV has higher QC in the summer
- Wind has higher QC in the winter
- Significant variation in QC for wind based on location, even within the BOEM lease area

	Qualified Capacity as a Percentage of Nameplate Capacity		
Intermittent Resource	**Summer**	**Winter**	**Average**
Utility PV - CT	72%	0%	36%
Utility PV - ME	73%	0%	36%
Utility PV - NH	77%	0%	38%
Utility PV - RI	77%	0%	38%
Utility PV - VT	78%	0%	39%
Utility PV - MA	71%	0%	35%
Existing Onshore Wind - ME	22%	41%	31%
Existing Onshore Wind - NH	17%	33%	25%
Existing Onshore Wind - RI	12%	20%	16%
Existing Onshore Wind - VT	17%	40%	28%
Existing Onshore Wind - MA	17%	51%	34%
New Build Onshore Wind - Maine	30%	47%	38%
Offshore Wind - Block Island	28%	50%	39%
Offshore Wind - Bay State LA	28%	72%	50%
Offshore Wind - Equinor LA	24%	69%	46%
Offshore Wind - Mayflower LA	23%	68%	46%
Offshore Wind - Park City LA	18%	55%	37%
Offshore Wind - Revolution LA	29%	70%	49%
Offshore Wind - South Fork LA	23%	60%	41%
Offshore Wind - Vineyard East LA	24%	68%	46%
Offshore Wind - Vineyard West LA	20%	61%	41%
Offshore Wind - BOEM LA Average	27%	66%	46%
Offshore Wind - Floating off Cape Cod	32%	75%	53%
Offshore Wind - Floating off Maine	26%	66%	46%

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Resource Siting and Transmission Cost Modeling Assumptions

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Resource Siting and Transmission Upgrade Cost Modeling Assumptions

- The Pathways study aims to compare differences in outcomes, including total costs, between alternative approaches to decarbonization
- Because resource siting and transmission upgrade cost modeling assumptions will be the same in all central cases, differences in the level of costs (potentially higher or lower than the true cost) will tend to have comparable effects on each approach
- Nonetheless, we aim to assume reasonable estimates new resource costs that reflect the many factors affecting development of new resources, including plant costs (and cost change due to technological change), transmission costs, and other plant siting challenges
- Below, we provide on overview of the approach we plan to take with respect to onshore and offshore wind; similar approaches will be taken for other resource types, notably utility-scale PV
- We welcome stakeholder feedback on these assumptions

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Resource Siting and Transmission Upgrade Cost Modeling Assumptions

Onshore and Offshore Wind

- New resource capital costs will reflect both generation plant and transmission upgrades for certain technologies (e.g., onshore and offshore wind)
- Transmission upgrade costs will reflect existing available transmission capability and incremental transmission upgrades needed to increase deliverability

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Resource Siting Modeling Assumptions

Onshore Wind

- For onshore wind, buildout will be primarily sited in Maine, to reflect:
  - Relatively higher costs (and potential siting/land availability challenges) of buildout (at scale) outside of Maine
  - Location of majority of wind in the interconnection queue
- Wind profiles will be based on the four hypothetical DNV locations (labeled in green)

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Transmission Upgrade Cost Modeling Assumptions

Onshore Wind

- Many of the onshore wind sites with the highest expected capacity factors, such as those in Maine, are remote and require transmission upgrades to connect to the grid
- At present, transmission from Southern Maine to Southern New England has no incremental headroom. All new onshore wind resources will include the costs of transmission expansion
- Transmission upgrade cost estimates will be based on the ISO-NE Second Maine Resource Integration Study, and unit costs increasing in increments of 1,000 MW

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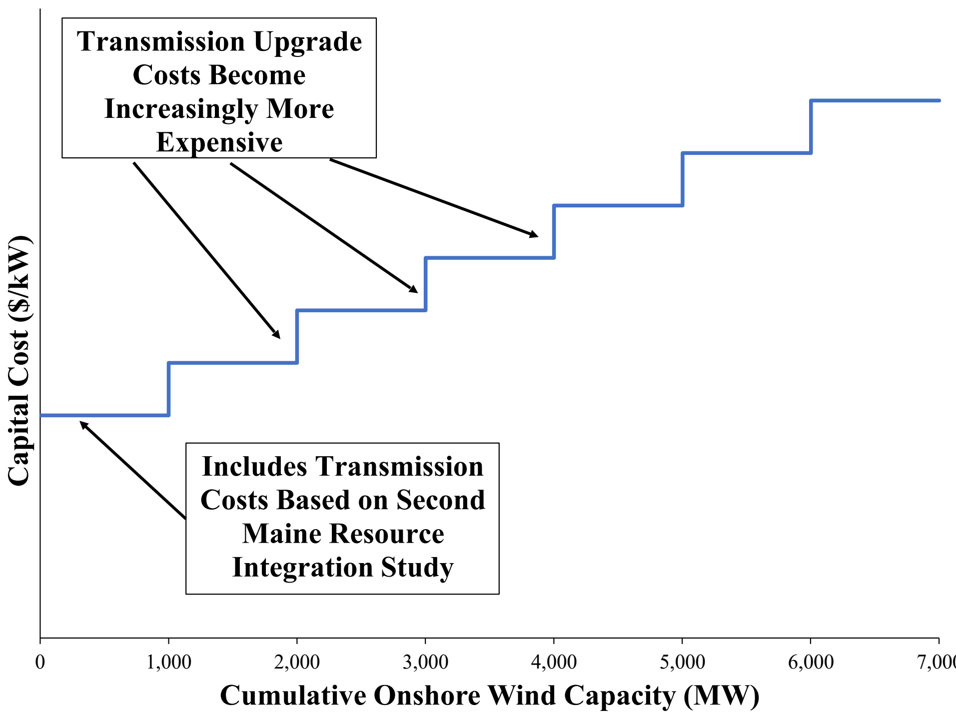
Transmission Upgrade Cost Modeling Assumptions

Onshore Wind

- Model assumes transmission will become increasingly more expensive due to challenges associated with permitting, right of way, and land costs (exhibit is illustrative and not to scale of assumed costs)
- We welcome feedback on this approach as this is not a resource adequacy study



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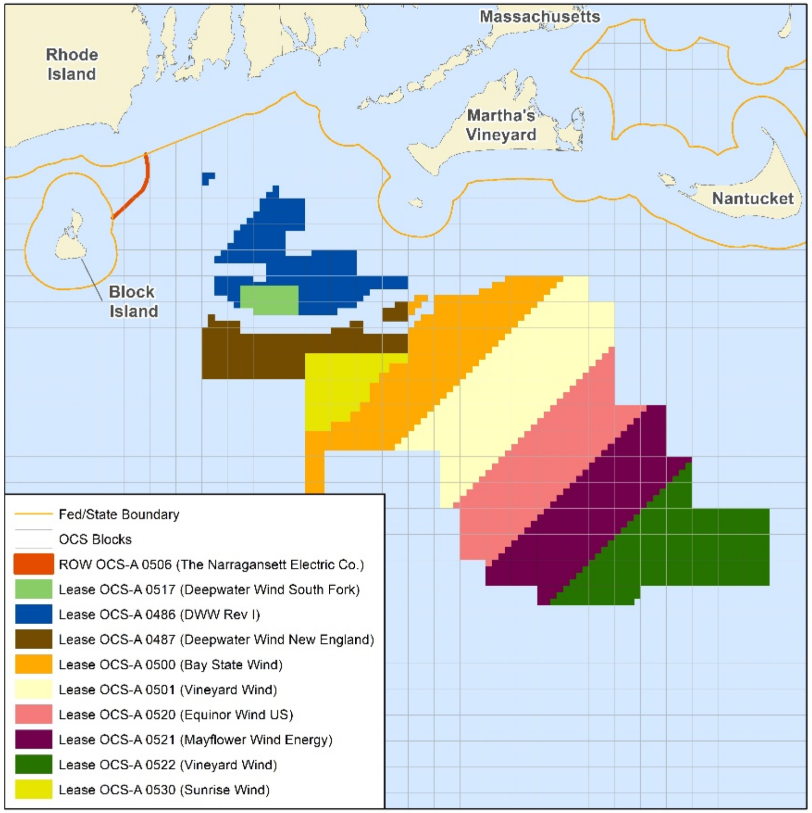
Resource Siting Modeling Assumptions

Offshore Wind

- For offshore wind, we assume that projects will be built in the BOEM lease area first
  - BOEM lease area capacity: 12,124 MW
  - Current procured and legislated offshore wind: 8,796 MW
  - Additional capacity available in BOEM lease areas: 3,328 MW
- Consistent with the MA and RI state-commissioned deep decarbonization studies, we assume an additional 3,000 MW of fixed-bottom offshore wind can be built around the existing BOEM lease areas
- Additional potential offshore wind is assumed to be floating off the southeast coast of Cape Cod or Maine



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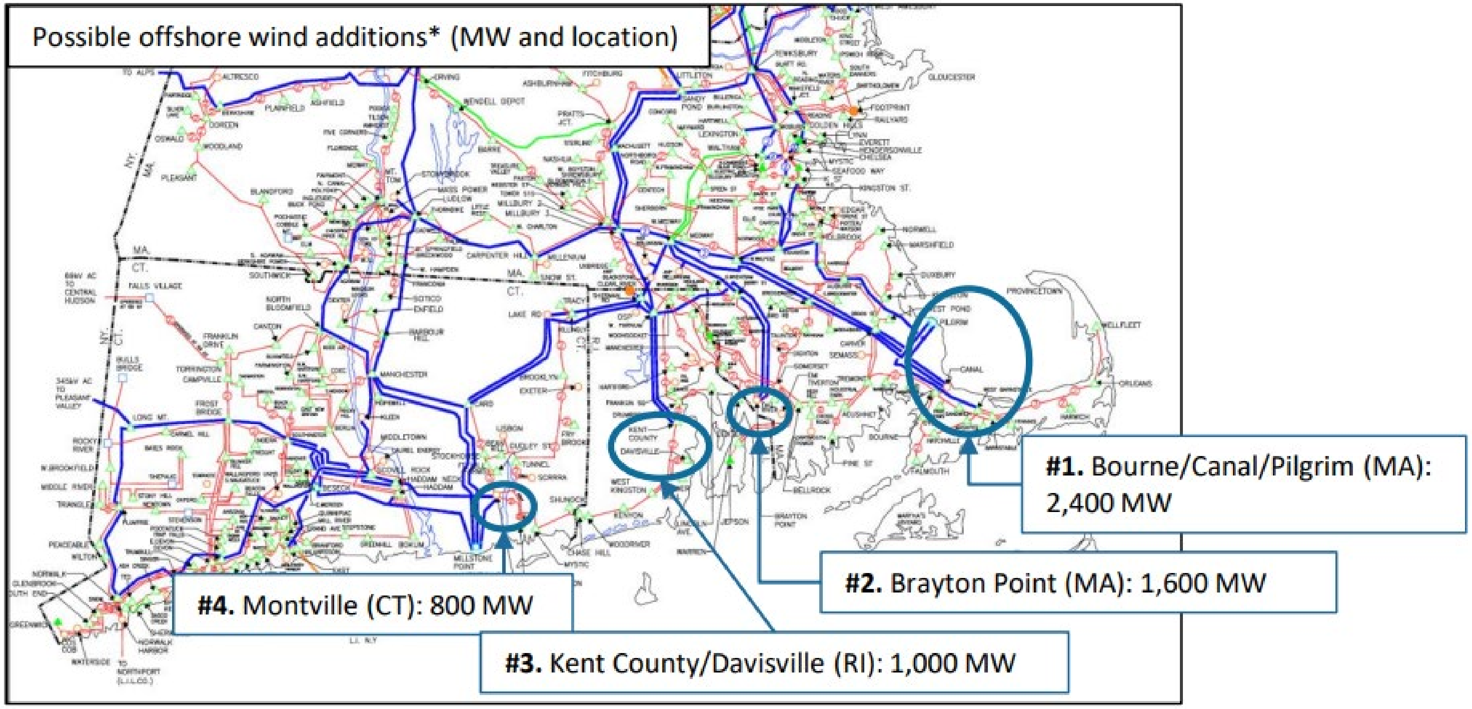
Transmission Upgrade Cost Modeling Assumptions

Offshore Wind

- ISO-NE study estimates ~5,800 MW can be interconnected without significant onshore transmission upgrades (ISO-NE 2019 Economic Study Offshore Wind Transmission Interconnection Analysis)



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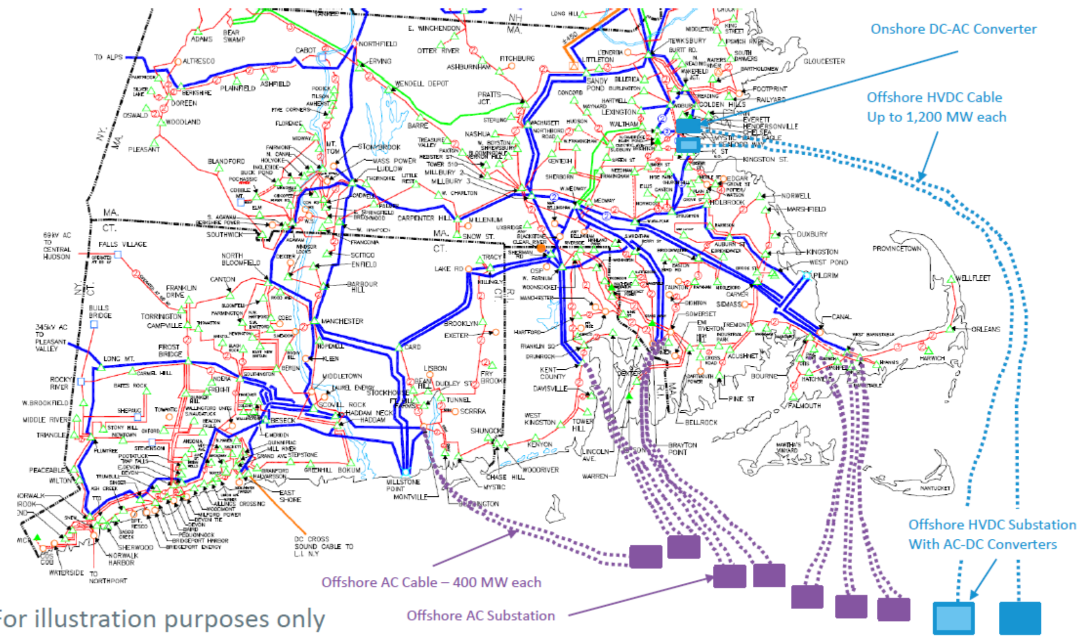
Transmission Upgrade Cost Modeling Assumptions

Offshore Wind

- Additional transmission will either require significant onshore transmission upgrades or offshore HVDC connections that bypass the onshore grid
- As more offshore wind is developed, it will become increasingly costly to find adequate landing sites.



For illustration purposes only

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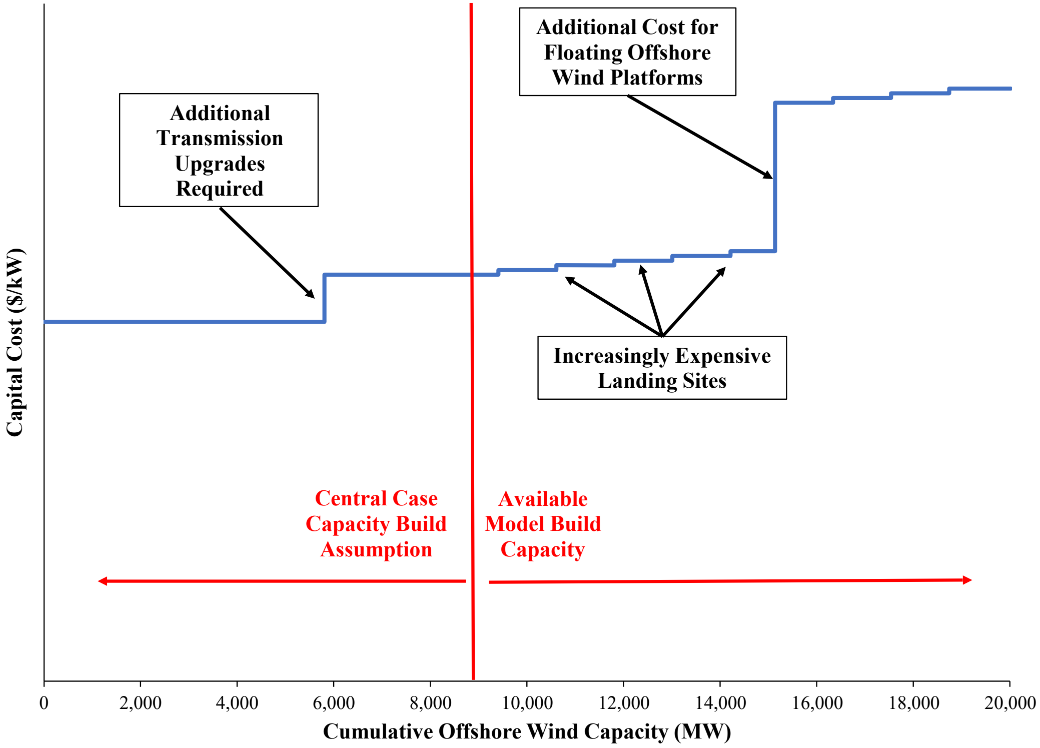
Transmission Upgrade Cost Modeling Assumptions

Offshore Wind

- Costs will become increasingly more expensive due to the need for significant transmission upgrades, siting challenges, and exhausting the BOEM lease areas (exhibit is illustrative and not to scale of assumed costs)



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Status Quo Resource Mix Modeling Assumptions

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Status Quo Resource Mix Modeling Assumptions

- As discussed at July's PC meeting, the Status Quo resource mix will align with the findings of state-commissioned deep decarbonization studies
- Assumed Status Quo resource mix typically reflects a state's decarbonization case and high-load (electrification) scenarios that most closely align with Pathways assumptions (emissions targets, continued operation of nuclear plants)
- Additional buildout required to meet states' clean energy demand and regional emissions reduction target will be determined by the model

	2020-2040 Incremental Build (GW)					
State	**Offshore Wind**	**Onshore Wind**	**Solar**	**Storage**	**NECEC**	**Total**
Connecticut	4.7	0.4	2.3	2.2	-	9.7
Maine	-	2.0	0.7	0.5	-	3.2
Massachusetts	9.2	0.4	5.5	0.4	1.2	16.6
New Hampshire	-	-	-	-	-	--
Rhode Island	2.0	-	1.4	1.0	-	4.4
Vermont	-	0.2	0.8	-	-	1.0
Total	16.0	3.0	10.7	4.1	1.2	35.0

Note: New Hampshire's 2018 State Energy Report expressed a desire to pursue the "lowest cost resources," so its SQ resource mix will be determined by model build.
Sources: AG review of state legislated policies, executive orders, and state-commissioned deep decarbonization studies, which are: Connecticut's "Draft Integrated Resources Plan: Pathways to achieve a 100% zero carbon electric sector by 2040" (2020), Maine's "State of Maine Renewable Energy Goals Market Assessment" (2021); Massachusetts' "Energy Pathways to Deep Decarbonization" (2020), Rhode Island's "The Road to 100% Renewable Electricity by 2030 in Rhode Island" (2020), and Vermont's "Energy Policy Options for Vermont: Technologies and Policies to Achieve Vermont's Greenhouse Gas and Renewable Energy Goals" (2014). NECEC represents the New England Clean Energy Connect.

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Next Steps

- October
  - Present initial set of results for each of the Pathway central cases
  - Discuss final set of scenarios to be run
- December
  - Present updates to central cases, if any, based on stakeholder feedback
  - Present initial set of scenario results

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